



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).

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

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1 Overview

The Distribution Annual Planning Report (**DAPR**) provides an overview of the current and future changes that CitiPower proposes to undertake on its network. It covers information relating to 2023 as well as the forward planning period of 2024 to 2028.

CitiPower is a regulated Victorian electricity distribution business. It distributes electricity to around 349,000 homes and businesses in Melbourne's central business district (**CBD**) and inner suburbs. Electricity is received via sub transmission lines at 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, during normal operation, or following an outage of an asset, retirements or de-rating 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.

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

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/>

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 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 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
Locked Bag 14090
Melbourne VIC 8001

2 Background

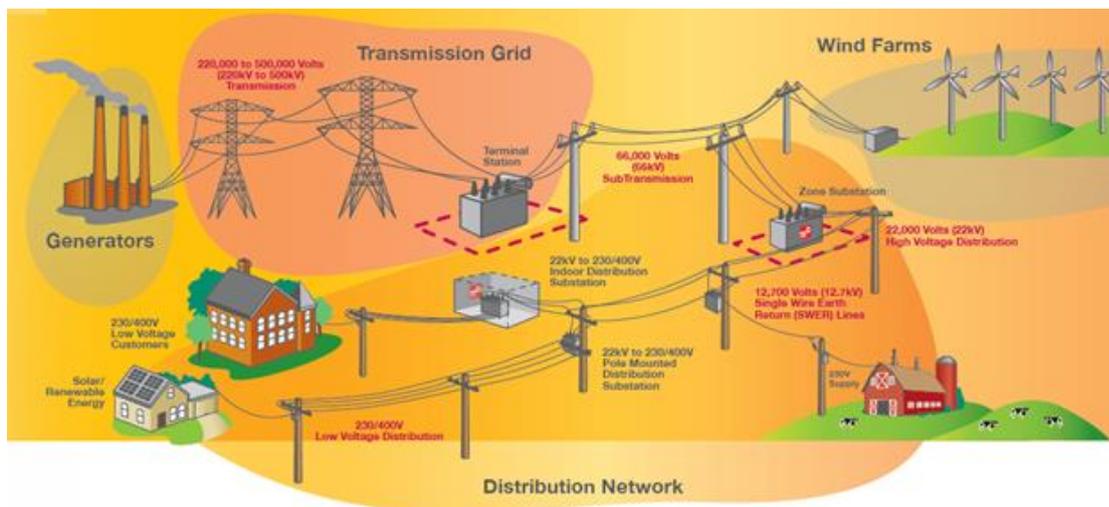
This chapter sets out background information on CitiPower Pty Ltd (**CitiPower**) and how it fits into the electricity supply chain.

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.

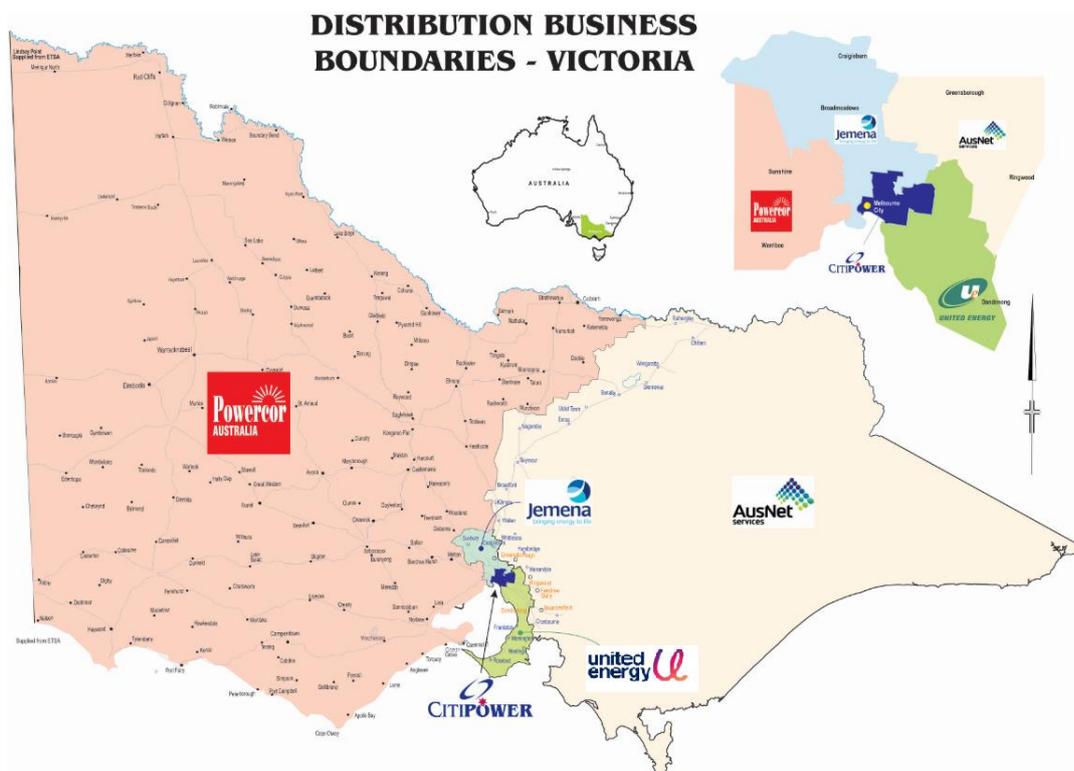
2.2 The five Victorian distributors

In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates an 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, supplying 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

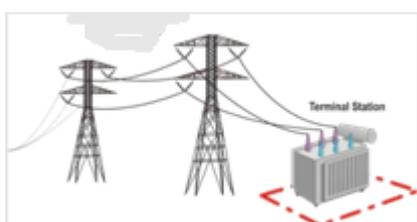


In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network. In order to continue to provide efficient, secure and reliable supply to its customers, CitiPower must plan augmentation and asset replacement of the network to match network

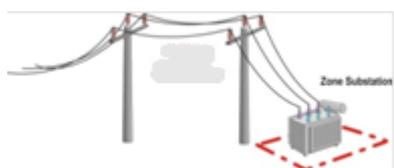
capacity to customer demand. The need for augmentation is largely driven by customer peak demand growth, local generation (PV) and geographic shifts of demand due to urban redevelopment.

2.3 Delivering electricity to customers

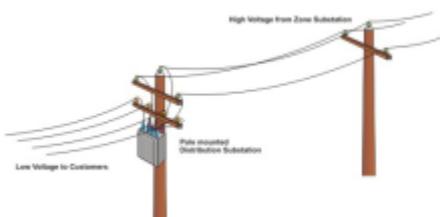
Power that is produced by large-scale generators is transmitted over the high voltage transmission network and is changed to a lower voltage before it can be used in the home or industry. This occurs in several stages, which are simplified below.



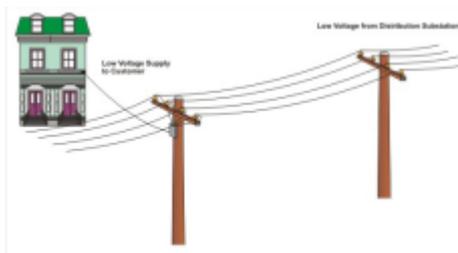
Firstly, the voltage of the electricity that is delivered to **terminal stations** is reduced by transformers. Typically in Victoria, most of the transmission lines operate at voltages of 500,000 volts (500 kilovolts or kV) or 220,000 volts (220kV). The transformer at the terminal station reduces the electricity voltage to 66kV or 22kV. 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.



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



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 349,000 homes and businesses in a 157 square kilometre area, or around 2,223 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
- 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 2022-23FY, the CitiPower network comprised approximately:

Table 2.1 CitiPower network statistics

Item	Number / km
Poles	57,491
Overhead lines	4,144
Underground cables	3,407
Sub-transmission lines	88
Zone substation transformers	93
Distribution feeders	735
Distribution transformers	5,015

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 low voltage levels have generally not been a concern however recent increases in PV have created overvoltage issues
- **other system security requirements:** the completion of the Melbourne CBD security of supply upgrade plan has added considerable security to the Melbourne CBD, however significant investment is required to maintain this security across the whole of the 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.
- **Distribution System Operator (DSO) enhanced capability:** to respond to the future challenges of the network at least cost, it is recognised that Powercor needs to implement and support new capabilities under an enhanced DSO role.
- **System Strength Locational Factor:** system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node

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.
- **electric vehicle chargers:** the increase in electric vehicles is increasingly causing a charging demand that could influence the maximum demand requirement.
- **Electrification of gas:** the substitution of electrical loads for gas over time will increase loading on the electrical system adding to maximum demands. <to add>

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 failure of insulation 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 calculates the prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to enable the selection and setting of 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 the CitiPower network:

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, 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 2023 to implement the plan
- an evaluation of whether the relevant security of supply objectives specified in the plan were achieved in 2023
- 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 2023 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), which are now at capacity, CitiPower is

planning to stage the construction of two new feeders into this area from each of zone substation Southbank (SB) and subsequently from zone substation Montague (MG). These zone substations will then satisfy the need for extra capacity to cover any 66kV cable failure according to the N-1 secure definition for the foreseeable future. ETable 3.2 below presents the project timeline for the ongoing CBD security of supply project.

Table 3.2 Future CBD upgrade works

Description of capital works	2024	2025	2026	2027	2028
<i>Distribution, Security Enhancement</i>					
Three new feeders from zone substation MG			X	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 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 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 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.

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) was completed in 2022 for the majority of CitiPower zone substations. This has enabled 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 and 2023. This involved network interventions across the CitiPower network.

Further works involving high and low voltage interventions and system upgrade activities are planned for 2024, 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 [Error! Reference source not found.](#). 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.

3.9 System Strength Locational Factor

In October 2021, the AEMC made its final rule determination on efficient management of system strength on power system. The Rule introduces a new way for system strength remediation in the NEM, allowing the embedded generators to either pay for system strength charges or self remediation. The system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node (a location on a transmission network that AEMO declares under NER clause 5.20C.1(a)) and is used to calculate the system strength charge in accordance with the methodology in the AEMO's System Strength Impact Assessment Guidelines[1].

Under NER Schedule 5.8 (q), the system strength location factor information for each embedded generation (or generating system) in the CitiPower network in which the embedded generation system has elected to pay the system strength charge under clause 5.3.4B(b1) is to be included in this report.

CitiPower currently does not have any embedded generator in its network that has elected to pay system strength charge for the purpose of system strength remediation.

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 forcibly 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). It relates to a maximum average temperature that will be exceeded, on average, once every two years. It is often referred to as 50 per cent probability of exceedance (**PoE**).

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

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 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 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. This is also known as the “firm” rating;
- **N-1 export rating:** this provides the capacity of the zone substation according to the equipment in place up to its nameplate value and assuming the outage of one transformer. This is also known as the “firm” export 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 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 transmission-distribution connection point 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.

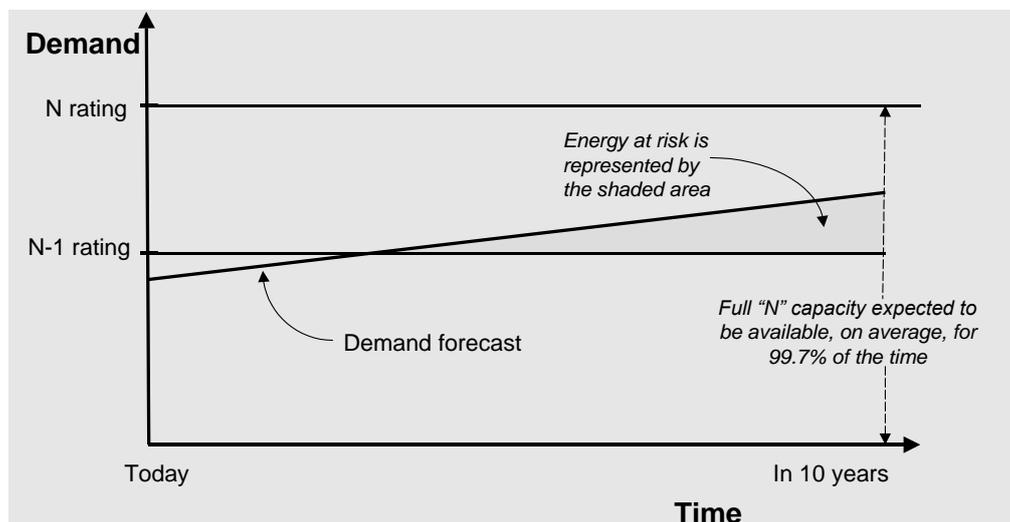
6.2 Interpreting “energy at risk”

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”) as well as conditions resulting in supply reduction for an N condition where all plant is in service..

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 used in this DAPR

Sector	VCR for 2023 (\$/kWh)
Residential	\$23.84
Commercial	\$49.54
Agricultural	\$42.14
Industrial (<10MVA)	\$70.98

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 Generation curtailment

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 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

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.

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

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 generation constraints in the DAPR as the method for determining generation curtailment is still being assessed.

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 2028
 - summer and winter cyclic N-1 import ratings for each zone substation
- Export limitations:
 - forecasts for minimum demand to 2028
 - 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 2023 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)				
		2024	2025	2026	2027	2028
BK	Offload to C and decommission	0.67	6.8	12.9	6.4	
C	Rebuild Zone Substation C as 66/11kV	1.7	17.2	32.6	16.1	
B	New Transformer					0.5
BQ	New Transformer					0.5
F	Offload to C and decommission	0.75	7.6	14.3	7.1	
PM	Offload to WG			0.5	7	10
R	Rebuild			70		

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)				
		2024	2025	2026	2027	2028
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/UaPnYI6yeV>

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
- Rebuild Zone Substation C at 66/11kV to enable retirement of BK and F Zone substations.

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 MVA in summer 2023/24 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 2028, CitiPower estimates that there will be 12.95 MVA of load at risk and for 1,105 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 5.6 MVA
- Install a 20/27MVA third transformer and complete associated station work at B zone substation for an estimated cost of \$5 million in next regulatory reset period July 2026 – July 2031.

CitiPower's preferred option is to establish a third transformer at B in 2028. 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 83.59 MVA in summer 2023/24 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 2028, CitiPower estimates there will be 22.6 MVA of load at risk and for 280 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 6.9MVA load away to adjacent zone substations WA, VM and JA
- establish a 3rd 55MVA transformer at BQ zone substation at estimated cost of \$4.5 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 in 2028. 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 16.47 MVA in summer 2023/24 which will exceed the N-1 cyclic capacity of 13.5 MVA.

CitiPower estimates that in 2027 there will be 6.9 MVA of load at risk and for 31.5 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 1.1 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 \$56.7 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 42.95 MVA in summer 2023/24 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 2028, CitiPower estimates that there will be 14.44 MVA of load at risk and for 73.5 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 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 Port Melbourne (PM) zone substation

The zone substation in Port Melbourne (PM) is served by sub-transmission lines from Fishermans Bend terminal station 66kV (FBTS66). This zone substation supplies areas of

Port Melbourne, which is a mixed-use area, with residential, commercial and industrial customers.

Currently, PM zone substation is comprised of two 10/13MVA transformers operating at 66/6.6kV. The maximum demand is forecast to be 21.2 MVA in summer 2023/24 which will exceed the N-1 cyclic capacity of 17 MVA.

CitiPower estimates that in 2026 there will be 4.44 MVA of load at risk and for 179.5 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 PM. 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 PM 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 Fishermans Bend (E) and Westgate (WG) via autotransformers up to a maximum transfer capacity of 5 MVA,
- offload PM to WG and convert the 6.6kV feeders to 11kV to enable more transfers for an estimated cost of \$17.5 million.

CitiPower's preferred option is to offload PM and convert the 6.6kV feeders to 11kV by end of 2028 to meet the load growth in Port Melbourne area as well as to reduce the load at risk for an N-1 event.

7.2.6 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 36 MVA in summer 2023/24 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 2028, CitiPower estimates there will be 11.74 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 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 7.1 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.

7.2.7 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 41.17 MVA in summer 2023/24 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 2028, CitiPower estimates that there will be 20.28 MVA of load at risk and for 3,423 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 MVA.
- rebuild R zone substation at 66/11kV with estimated cost of \$70 million.

CitiPower's preferred option is to start rebuilding R in 2026 and upgrade from the existing 22/6.6kV to 66/11kV with higher capacity to meet the load growth in the area as well as to reduce the load at risk for an N-1 event. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.8 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 36.05 MVA in summer 2023/24 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 2025, CitiPower estimates there will be 11.6 MVA of load at risk and for 68 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 6.4 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.

7.3 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 7.3 during the forward planning period.

Table 7.3 Proposed new or redeveloped zone substations

Name	Location	Proposed commissioning date	Reason
Brunswick (C)	Brunswick	2026	Enable retirement of F and BK zone substations
Laurens Street (LS)	North Melbourne	2030	To facilitate demand growth in the area.
Richmond (R)	Richmond	2026	To address subtransmission line constraints

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.

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

7.3.1 Brunswick (C) zone substation

CitiPower is planning to rebuild the existing zone substation at Brunswick (**C**), located in Brunswick Road, Brunswick. It will be upgraded from the existing 22/6.6kV to 66/11kV with higher capacity.

Elements of the new zone substation are required to enable the retirement of Brunswick (BK) and Fitzroy (F) zone substations. Providing extra capacity at 11kV will allow the offloading of BK and F zone substations which are at end of life.

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

- Brunswick (**BK**): 14 MVA
- Fitzroy (**F**): 14 MVA.

Other benefits of the new zone substation are to support load growth in the Brunswick area and defer major refits at the aged Brunswick (BK) and Fitzroy (F) zone substations.

7.3.2 Laurens Street (LS) zone substation

CitiPower is planning to rebuild the existing zone substation at Laurens Street (**LS**), located in Laurens Street, North Melbourne. It will be redeveloped with new HV feeders to increase the supply capacity at LS to facilitate demand growth in the area.

The redeveloped zone substation will take load from Victoria Market (VM) and Little Bourke Street (JA) ZSS and will also support load from the new Arden station that is being developed as part of the Metro Tunnel project.

The majority of expenditure to rebuild LS sits just outside the DAPR period.

7.3.3 Richmond (R) zone substation

CitiPower is planning to rebuild the existing zone substation at Richmond (**R**), located in Palmer Parade, Cremorne. It will be upgraded from the existing 22/6.6kV to 66/11kV with higher capacity.

This will address constraints on the subtransmission lines RTS-R135 and RTS-R136 currently supplying R zone substation, as stated in section 8.2.

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 2028
 - line import ratings for each subtransmission line
- Export limitations:
 - forecasts for N-1 minimum demand to 2028
 - 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 2023, 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)				
		2024	2025	2026	2027	2028
B-CW	Connect and tie in OOS 66kV sub-transmission line with existing B-CW	-	-	0.15	-	-

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)				
		2024	2025	2026	2027	2028
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/UaPnYI6yeV>

The options and analysis is undertaken below.

8.2 Sub-transmission lines with forecast system limitations

8.2.1 B-CW 66kV sub-transmission line

The B-CW 66kV sub-transmission line supplies the Collingwood (**B**) and Collingwood (**CW**) zone substations at 66kV and is part of the RTS-CW-B-NR loop.

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

CitiPower estimates that in 2028 for the lines within this loop there will be:

- 23 MVA of load at risk, and for 24 hours it will be unable to supply all customers on the B-CW line during an outage of the RTS-CW-B-NR loop.

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:

- Upgrade existing B-CW 66kV sub-transmission line summer rating from 85.7MVA to 120MVA.
- Connect and tie in OOS 66kV sub-transmission line with existing B-CW to run in parallel to uprate sub-transmission rating between B zone substation and CW zone substation, at an estimated cost of \$0.15 million.

CitiPower's preferred option is to tie in OOS 66kV line in parallel to CW-B line in 2026 to meet the load growth in Collingwood area as well as to reduce the load at risk for an N-1 event.

8.2.2 RTS-R135 22 kV sub-transmission line

The RTS-R135 22 kV sub-transmission line supplies the Richmond (**R**) zone substation from Richmond terminal station (**RTS**) 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 2028 for the lines within this loop there will be:

- 10.5 MVA of load at risk, and for 130 hours it will be unable to supply all customers on the RTS-R135 line during an outage of the RTS-R134 or RTS-R136 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 Richmond (**R**) via 11kV links to adjacent zone substations Toorak (**TK**), West Balaclava (**BC**) and North Richmond (**NR**) up to a maximum transfer capacity of 12.7 MVA.
- rebuild R zone substation at 66/11kV with estimated cost of \$70 million.

CitiPower's preferred option is to start rebuilding R in 2026 and upgrade from the existing 22/6.6kV to 66/11kV with higher capacity to meet the load growth in the area as well as to reduce the load at risk for an N-1 event.

8.2.3 RTS-R136 22 kV sub-transmission line

The RTS-R136 22 kV sub-transmission line supplies the Richmond (**R**) zone substation from Richmond terminal station (**RTS**) 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 2028 for the lines within this loop there will be:

- 10.5 MVA of load at risk, and for 130 hours it will be unable to supply all customers on the RTS-R136 line during an outage of the RTS-R135 or RTS-R134 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 Richmond (**R**) via 11kV links to adjacent zone substations Toorak (**TK**), West Balaclava (**BC**) and North Richmond (**NR**) up to a maximum transfer capacity of 12.7 MVA.
- rebuild R zone substation at 66/11kV with estimated cost of \$70 million.

CitiPower's preferred option is to start rebuilding R in 2026 and upgrade from the existing 22/6.6kV to 66/11kV with higher capacity to meet the load growth in the area as well as to reduce the load at risk for an N-1 event,

8.2.4 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 2028 for the lines within this loop there will be:

- 7.4 MVA of load at risk, and for 424 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 substations Collingwood (CW) and West Brunswick (WB) up to a maximum transfer capacity of 2 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.

8.2.5 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 2028 for the lines within this loop there will be:

- 4.9 MVA of load at risk, and for 114 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) and West Brunswick (WB) up to a maximum transfer capacity of 2 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.

8.2.6 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 2028 for the lines within this loop there will be:

- 32.2 MVA of load at risk, and for 28 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 substation of Camberwell (CL) for up to a maximum transfer capacity of 11.5 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.

8.3 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
Nil	-	-	-

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 2028
 - 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 2024, 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 2025
 - summer and winter cyclic import ratings for each feeder
- Export limitations:
 - forecasts for minimum demand to 2025
 - 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)	
		2024	2025
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)	
		2024	2025
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 proposed for construction in the next two years.

Table 10.3 – Proposed new primary distribution feeders

Feeder	Description	Direct cost estimate (\$ million)	
		2024	2025
Nil	-	-	-

10.3 Future primary distribution feeder projects

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 2023-24.

- BQ feeder augmentation
- MG new feeders
- BC013 feeder rearrangement
- AP003 feeder augmentation
- AR011 feeder augmentation
- L feeders rearrangement

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 2023. 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 2022

The following information details load forecasts and project timing changes that have occurred since the publication of the 2022 DAPR.

12.1 Constraints addressed or reduced due to projects completed

CitiPower has undertaken the following projects in 2023 to address constraints which were identified in the 2022 DAPR:

- (LS) zone substation has been offloaded to Bouverie-Queensberry (BQ) zone substation

12.2 New constraints identified

Changes in load forecasts or other factors during 2023 have resulted in CitiPower undertaking risk assessments for the zone substations and sub-transmission loops which were not included in the 2022 DAPR:

- Port Melbourne (PM) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits

12.3 Other material changes

In addition to the matters identified above, material changes compared to the 2022 DAPR include:

- Nil

13 Asset Management

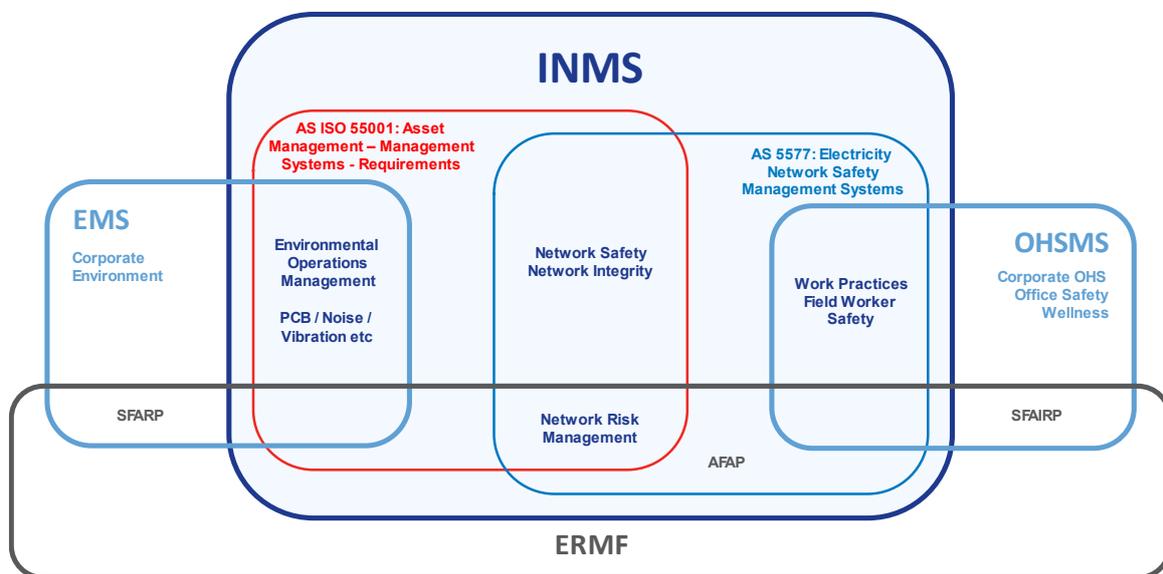
This chapter details the CitiPower Asset Management System (**AMS**), that forms part of the Integrated Network Management System (**INMS**) and harmonises the requirements of the various management systems.

13.1 Integrated Network Management System (INMS)

The INMS integrates the requirements of four management systems, underpinned by the the Enterprise Risk Management Framework (**ERMF**). It articulates the integrated management system policies, strategies, plans, and procedures:

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

Figure 13.1 Scope of the integrated network management system



The scope of the INMS, as defined in Figure 13.1, is limited to the electricity network and the associated operating environment and the requirements of the following two management system standards:

- AS ISO 55001:2014 Asset Management – Management Systems – Requirements
- AS 5577:2013 Electricity Network Safety Management Systems.

These management system standards are aligned with the following management system standards for which CPPAL already has certification:

- AS/NZS ISO 45001:2018 Occupational Health and Safety Management Systems – Requirements with Guidance for Use
- AS/NZS ISO 14001:2016 Environmental Management System – Requirements with Guidance for Use

and also the business' ERMF (13-10-CPPCUE0005) which is based upon AS/NZS ISO 31000:2018 Risk Management – Guidelines.

The INMS complies with the Electricity Safety (Management) Regulations 2019 and replaces the previous UE Electricity Safety Management Scheme (UE-ST-2921) and the CPPAL Electricity Safety Management Scheme (v3.27) documents previously approved by ESV. The scope of the INMS does not include the legislative obligations, non-electrical risks, nor risks associated with:

- Assets owned by generators, other Major Electricity Companies (MECs), or consumers.
- Corporate offices and general business equipment such as computers and motor vehicles.
- Depot facilities and vehicles, non-network related operations and activities.
- Corporate processes and associated IT systems for business communication, human resources and financial management.

The INMS, and associated management system standards, integrate the business policies, strategies, plans and procedures in a manner that facilitates the effective and efficient delivery of the INMS objectives, and;

- inform stakeholders including ESV, shareholders, staff, customers, the community, government and industry on how the INMS objectives and obligations are being achieved
- demonstrate a risk-based management approach in developing operating systems and management practices to identify the hazards and establish controls to minimise the risks associated with the operation of the electricity distribution network, as far as practicable
- define the approach established to manage the safe design, construction, commissioning, operation, maintenance and decommissioning of the electricity network.

13.2 Asset management system

The AMS aims to provide a clear 'line-of-sight' between the company's activities and the overall vision, organisational strategic plans and objectives, expressed in;

- Asset Management Policy
- Asset Management Strategy and Objectives
- Strategic network management plan (**SNMP**)
- Asset Management Plans (**AMP**)
- Network Investment Plan (**NIP**)
- Capex / Opex Works Program (**COWP**)

13.3 Asset management policy principles

The Asset Management Policy defines the overarching principles for managing the network assets in a manner that is aligned with the Corporate Objectives and Asset Management System; Through the application of our asset management framework, we aim to meet business objectives and customer, stakeholder and employee needs.

We will achieve our commitment by adopting the following principles:

- Minimise safety risks as far as practicable.
- Provide safe, affordable (least long-term cost) and reliable network services, taking into consideration customer values and needs.
- Apply a risk-based approach to optimise the management of our network and systems.
- Build network resilience, including to the impacts of climate change.
- Engage and listen to our customers and communities to incorporate their input into decisions and adapt to their interests and needs.
- Invest in programs that sustainably optimise total lifecycle management.
- Comply with all relevant legislative and regulatory requirements as well as Australian and industry standards and any other requirements to which we subscribe.
- Develop high performance services by engaging with our employees and enabling them with the right skills and capabilities.
- Monitor and evaluate appropriate metrics to effectively manage the network and customer service performance.
- Continuously improve our asset management framework and activities by embracing innovation and technology to enhance our reputation, leading the industry in adopting and promoting asset management practices.

13.4 Asset management strategies, and objectives

The Strategic Network Management Plan (**SNMP**) guides the decision making processes to manage uncertainty and minimise the risk around capital deployment.

The network management strategies and objectives expand on the requirements of the Asset Management Policy;

- 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.

13.5 Asset class management plans

The Asset Management Plans (**AMP**) detail the management activities for each asset class, from creation to disposal, including the asset maintenance and replacement requirements. The delivery of optimum outcomes for each asset class shall be guided by the asset management policies, strategies and objectives and combine them with an in-depth knowledge of the specific assets to identify the requirements that will ensure delivery of optimum outcomes. The group for Asset Class Strategies and Plans are as follows:

- Line Assets;
- Distribution Plant Assets;
- Primary Assets;
- Secondary Assets;
- Communication Assets;
- Metering; and
- Operational Property.

13.6 Capex / Opex Works Program (COWP)

The COWP details the AMP list of projects that have been derived from the strategic planning process. Data is collected and analysed to determine the required network modifications to produce a capital plan. It translates the asset strategies and asset management plans into a detailed 10 year investment plan. It strikes a balance between efficient and cost-effective investment, the required level of service, and an appropriate level of risk that is consistent with the CitiPower risk appetite statement.

The COWP details the execution of the AMP on a two-year cycle, setting out the actions, responsibilities, resourcing, time scales for the activities in each program, and the expenditure associated with both capital and operational activities.

To optimise the COWP investment in replacement, demand and performance programs, three sets of requirements are balanced:

1. Customer requirements: customer expectations and current performance
2. Economic requirements: projects are subject to a level of economic analysis in accordance with regulatory requirements and prudent investment tests
3. Technical requirements: inputs that drive the network requirements, including:
 - Network performance: asset maintenance and replacement programs: driven by an analysis of fault/performance/cost data, based on reliability centred maintenance analysis
 - Safety compliance: INMS, and the Electricity safety legislation, detail the risk-based approach to managing electrical safety
 - Capacity planning: probabilistic analysis and contingency planning
 - Risk analysis: ERMF, and ISO 31000 for significant asset risks

13.7 System limitations identified through asset management

The system limitations (and the actions to resolve the limitations) listed within this DAPR have been identified by the asset management system.

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

13.8 Contact for further information

Further information on the CitiPower asset management strategy and methodology may be obtained by 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

An overview of the CitiPower AMS has been provided in Chapter 13.

CitiPower adopts a minimum risk, whole of life, whole-system cost approach (**WLWS**) to asset management. Reliability Centred Maintenance (**RCM**) principles are used to manage the network assets over their life cycle; determine the asset maintenance requirements, and the actions that need to be taken to ensure cost-effective, reliable operation.

To assess asset performance, determine the required level of maintenance tasks, and the time intervals, CitiPower;

- Identifies the key components, and functions of the asset class
- Performs a Failure Mode, Effects and Criticality Analysis (FMECA) to assess component failure, and the effect of the failures on asset function
- Determines cost-effective techniques (where possible) to manage failure modes
- Combines tasks into maintenance packages for implementation
- Reviews and improves asset and maintenance performance as necessary.

Where the performance of asset has deteriorated, or is no longer capable of performing the required function, the asset AMP shall be reviewed. The trigger for a review may be network changes, operational or business changes, learnings from failure investigations, field observations, deterioration in condition, an increase in the likelihood or consequence of asset failure. Depending on the outcome of the assessment, asset replacement may be necessary.

Distribution assets

The majority of distribution assets ('poles and wires' assets) are replaced upon asset failure, or where condition assessment has identified that the asset has reached the end of its service life. The condition assessment measures may vary between asset classes, examples include;

- Measurement of the sound wood: poles
- Dissolved Gas Analysis (**DGA**) and oil quality assessment of some primary plant and HV cables
- Partial Discharge (**PD**): primary plant and HV/MV cables
- Thermography
- Monitoring of insulation levels (gas/oil).

Condition assessment shall consider equipment technical thresholds, safety, risk and economic assessment, industry practice in developing a safe, reliable, least cost AFAP solution.

Upon indication that an asset has reached the end of its service life, actions may include:

- More frequent condition assessment or inspection
- Asset reinforcement, pole staking

- Asset de-rating or retirement
- Overhaul / refurbishment
- Non-network solutions
- Asset replacement.

Zone substation assets

Due to the increased inter-connectivity, redundancy, and capability to monitor asset condition, the design of zone substations facilitates the use of a number of options to manage the risks associated with assets approaching the end of their useful life.

Since zone substations provide more information on asset condition, risk assessment and economic optimisation can be conducted at a more detailed level compared to other distribution assets;

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

Given the complexity and structure of larger zone substations, a greater variety of practical options may be used to identify the least-cost solution to managing risk;

- Increased ongoing condition assessment
- Overhaul / refurbishment
- Retrofit of on-line condition monitoring systems
- Component replacement
- Non-network solutions
- Asset de-rating or retirement
- Load transfers and increased redundancy
- Contingency plans and increased spares holdings.

Assessments of potential solutions shall generally be performed over a forward looking period, typically 10 years. Optimal timing for the works shall be determined by identifying the least-cost option over the period.

Generally, the asset is retired and/or replaced based on the most economic solution that maintains safety and reliability standards, considering;

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

-
- Other costs

The asset replacement outlined in Retirements and De-ratings Chapter is a forecast based on the historic number of asset replacements (typical number for high volume assets such as poles), and based on an assessment of the currently available condition data for specific assets. Next chapter includes methodologies used for the replacement of each asset class.

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 2022 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	2022 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

Location	Asset	Project	Retirement date	2022 DAPR
Celestial Avenue (WA) Zone Substation	Transformer 1	Replacement	2025	2024
Celestial Avenue (WA) Zone Substation	Transformer 2	Replacement	2028	2026
Collingwood (B) Zone Substation	B 11kV Email J18 HV Switchboard	Replacement	2026	2026
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	2027	2026
North Richmond (NR) Zone Substation	Transformer 1	Replacement	2029	2027
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
Little Bourke St (JA) Zone Substation	Transformer 1, 2 & 3 Cooling Towers	Replacement	2024	2023
Little Queen (LQ) Zone Substation	LQ 11kV Email HQ18 HV Switchboard	Replacement	2029	2029

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/UaPnYl6yeV>

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 2024/5 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 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 preferences 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 2025. 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 2025. 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 15.2 MVA of load at risk and for 532 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 2025 with a new transformer of similar rating for an estimated cost of \$4.0 million.

CitiPower's preferred option is to replace the No.1 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 8.4 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 2028. 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 2028. 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 2028 there will be 20.5 MVA of load at risk and for 2,202 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 2028 with a new transformer of similar rating for an estimated cost of \$4.0 million.

CitiPower's preferred option is to replace the No2 transformer in 2028. 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 20.5 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 2026.

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 41.1 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 \$12.2 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 38.2 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 preference is to replace the J18 & J22 circuit breakers within the existing switchboard.

A demand side initiative to reduce the forecast maximum demand load by 38.2 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 2027.

With the No2 transformer retired, CitiPower estimates that in 2027 there will be 27.9 MVA of load at risk and for 3.081 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 \$3.8 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 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 27.9 MW at NR zone substation would defer the need for this capital investment by one year

15.1.7 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 2029.

With the No1 transformer retired, CitiPower estimates that in 2029 there will be 33.1 MVA of load at risk and for 3,705 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 \$3.8 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 2029. 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 33.1 MW at NR zone substation would defer the need for this capital investment by one year.

15.1.8 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 61.9 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.

15.1.9 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 122.5 MVA of load at risk and for 8,757 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 Little Queen (LQ) Zone Substation 11kV Email HQ18 HV Switchboard

Little Queen (**LQ**) zone substation is supplied by three sub-transmission circuits originating from the West Melbourne terminal station (**WMTS**) via Victoria Market (**VM**) and Little Bourke Street (**JA**) zone substations. This zone substation supplies the central Melbourne CBD.

LQ zone substation comprises three 60 MVA transformers operating at 66/11kV connected to 66kV sub-transmission lines from JA and VM and three double bus bar 11kV busses in a compound insulated metal clad switchboard.

The insulation of the 11kV switchboard has been deteriorating over the last few years with an online partial discharge (PD) monitor system installed in November 2017. A number of minor PD sources have been identified and rectified however these repairs are not a long-term solution as other PD sources detected from within the bus by the online monitoring system indicate that replacement is warranted with a forecast completion in 2029.

LQ zone substation 11kV switchboard is non arc fault contained and consists of three compound insulated double bus sections with fifty-six panels containing mainly J18 and J22 bulk oil circuit breakers with five retrofitted Siemens 3AH vacuum circuit breakers installed in 2005 for the capacitor banks.

This switchgear has been in service since 1971 and the CBRM model has determined a average health index of the Email CBs rising to 8.4 in the next five years. The average health index of the switchboard is rising to 7.6 with a maximum of 9.6 on Buses B and C, both front and rear 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 switchboards with oil filled circuit breakers to significantly increase safety while reducing the fire risks and network reliability risks should a catastrophic failure occur on one of these oil filled circuit breakers.

This switchgear is currently inspected and tested according to twelve yearly maintenance plans. In addition, online PD monitoring sensors have been installed on this switchboard for continuous monitoring. This ensures early detection of potential failures and implementing control measures in event of a failure prior to the complete replacement by 2029.

To complete the switchboard replacement CitiPower estimate of the entire 108MVA zone substation load approximately 63MVA will be at risk as only 45MVA can be transferred elsewhere. As such construction will be undertaken in stages, one bus section at a time to best maintain supply to customers from the zone substation from the other bus sections remaining in service during the works. Implementing transfer of this magnitude would restrict the existing switching and contingency transfer capability within the CBD.

The adjacent substations also have emerging capacity and asset condition constraints that would be exacerbated by transferring load from LQ zone substation.

CitiPower's preferred option is to replace the 11kV switchboard between 2025~2028. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date.

15.1.11 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 **DA** 22/11kV transformers have now been replaced in 2022 and 2023 by two 66/11kV transformers to complete the transfer of **DA** to 66kV supply.

The remaining customers connected to 22kV WMTS will be transferred to the WMTS 66kV point of supply in the next five years.

The exact timing of these works is currently being co-ordinated with AusNet Services. As these works are driven by asset replacement needs, CitiPower considers these works to be non-demand driven augmentation.

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.

15.1.12 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. 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 uprating 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.

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 classes:

- **Automatic Circuit Reclosers (ACR)** – interrupts fault current using SF6 gas or Vacuum to automatically restore supply post removing system transients
- **Air Break Switches (ABS)** – provide electrical isolation using air to break load current
- **Circuit Breakers** – interrupts fault current protecting an electrical circuit from damage caused by overcurrent/overload or short circuit
- **Pole Mounted Gas Switches** – provides electrical isolation using SF6 gas to break load current. Switches can be manually operated or configured with motors drives and control systems for remote operation.
- **Ring Main Units and Metal Clad Switches** – provides electrical isolation and earthing using SF6 gas or oil to break load current. Switches can be manually operated or configured with motors drives and control systems for remote operation.
- **Isolators** – provides single phase electrical isolation using air as an insulating medium. Some isolators can be configured with an arc shoot to provide some level of load breaking capability

Most 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 most switchgear assets in each year of the forward planning period in line with historical volumes for most assets. Some assets classes have proactive replacement programs established where higher than historical replacement volumes are forecast. This addresses issues such as poor performance, obsolescence and/or risk. Switchgear with proactive replacement programs established include:

- Air Break Switches
- Ring Main Units and Metal Clad Switches
- LV Circuit Breakers

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.

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 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 most underground cables in line with historical volumes. Higher volumes of repair works are forecast for sub-transmission cables due to an increase cable joint defects from damage cable sheaths and oil leaks.

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 increased volumes of aged metal box type terminations due to measured and observed condition defects
- 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 roadway 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.
- Bridge cable support structures which are required to secure sub-transmission, HV and LV to the underside of bridges crossing roadways, railways and rivers. Over the forward planning period CitiPower plans to replace increased volumes of defective support structures which post an increase in risk
- 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 Transformers and other distribution plant

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

- 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. Higher than historical volumes of replacements for indoor transformers are expected as a result of improvements to reporting and management of oil leaks.

- Pole top capacitors are attached to the network to improve power factor, usually on longer lines. These are replaced based on condition when inspected or through defect reports. Replacement prioritisation is determined by conducting risk and economic assessments.
- 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.

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**), Flinders Ramsden (**FR**), Little Bourke Street (**JA**), Deepdene (**L**),

Montague (**MG**), Northcote (**NC**), North Richmond (**NR**), Kew (**Q**), Riversdale (**RD**), Toorak (**TK**), Victoria Market (**VM**) 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

A review of CitiPower transformer performance at substation VM has identified issues with the building thermal performance. As a result, the cyclic ratings of the transformers at these substations will be altered in accordance with AS IEC 60076.7.

A summary of the rating changes as of December 2023 is shown below. CitiPower will continue to monitor the transformers during the summer period and determine if any further action is warranted.

Table 2 Summary of asset de-ratings

Transformer	Existing Rating	New Rating
VM #1	31.4 MVA	28.9 MVA
VM #2	32.5 MVA	28.9 MVA
VM #3	35.6 MVA	33.1 MVA

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	2022 DAPR	2023 DAPR
Celestial Avenue (WA) Zone Substation Transformer 1	2024	2025
Celestial Avenue (WA) Zone Substation Transformer 2	2026	2028
North Richmond (NR) Zone Substation Transformer 1	2027	2029
Little Bourke St (JA) Zone Substation Transformer 1, 2 & 3 Cooling Towers	2023	2024
Little Queen (LQ) Zone Substation 11kV HV Switchboard	Not included	2029

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 2023.

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	Replacement of the 11kV switchboard
Western CBD and Docklands security strategy	October 2024	Significant reduction in forecast CBD load growth due to COVID-19 pandemic requires re-assessment and development of strategic options to meet project aim.
HV Switchboard Replacement LQ 11kV HQ18	March 2024	Replacement of the 11kV switchboard

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

There are presently no excluded projects from the RIT-D.

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 three minutes or less. SAIFI is expressed per 0.001 interruptions
- Momentary average interruption frequency index event (**MAIFIE**): calculates the total number of momentary interruption events 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 2022/23 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)	2022-2023 performance
CBD	SAIDI	8.855	5.061
	SAIFI	0.108	0.050
	MAIFI	0.0024	0.0368
Urban	SAIDI	28.173	18.825
	SAIFI	0.392	0.273
	MAIFI	0.1949	0.2647

In 2022/23 FY, CitiPower achieved its targets for CBD SAIDI and 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.

17.2 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 (but are not limited to):

- undertaking the various routine asset management programs, including:
 - inspection of 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 assets in zone substations, such as indoor switchgear, including several continuous on line monitoring systems
- partial discharge detection program for underground cables
- vegetation management programs to improve line clearances
- animal and bird mitigation measures to reduce the risk of 'flash-overs'
- conductor clashing 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
- continual improvements to outage management processes
- undertake asset failure trend analysis and outage cause analysis to identify any emerging asset management issues and to mitigate those through enhancing the related asset management plans, maintenance policies or technical standards.

Evaluation of the 2022/23 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.

17.3 Quality of supply measures and standards

The main quality of supply measures that CitiPower control are:

- Voltages and voltage unbalance, including measuring customer voltage and network voltage using AMI data as well as power quality meters at the zone substations
- Harmonics, and
- Flickers.

17.3.1 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%	Phase to Phase +20%, -100%	
3	1 – 6.6	± 6%	± 10%	Phase to Earth +80%, -100%	60 kV peak
4	11	(± 10% Rural Areas)		Phase to Phase +20%, -100%	95 kV peak
5	22			150 kV peak	
6	66	± 10%	± 15%	Phase to Earth +50%, -100%	325 kV peak
				Phase to Phase +20%, -100%	

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 2022-23 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 2022-23 FY

Voltage variations	Number of occurrences
Steady state (zone substation)	1287
One minute (zone substation)	0
10 seconds (zone substation) Min<0.7	344
10 seconds (zone substation) Min<0.8	47
10 seconds (zone substation) Min<0.9	245

17.3.2 Customer voltage performance at low voltage

AS 61000.3.100 requires that the 99th percentile voltage must be less than 253V and the 1st percentile voltage must be above 216V. This is a deviation from the previous requirements that stipulated a hard limit of 216V and 253V. The VEDCoP 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

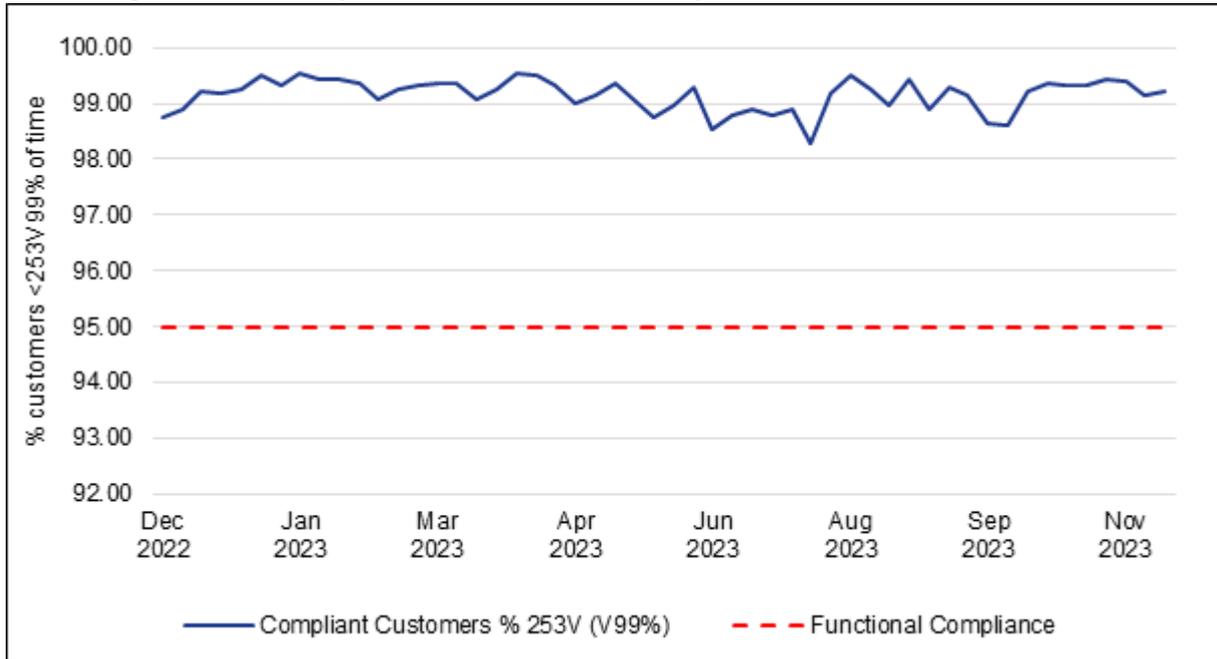


Figure 17.2 Monthly V1% 216V customer compliance

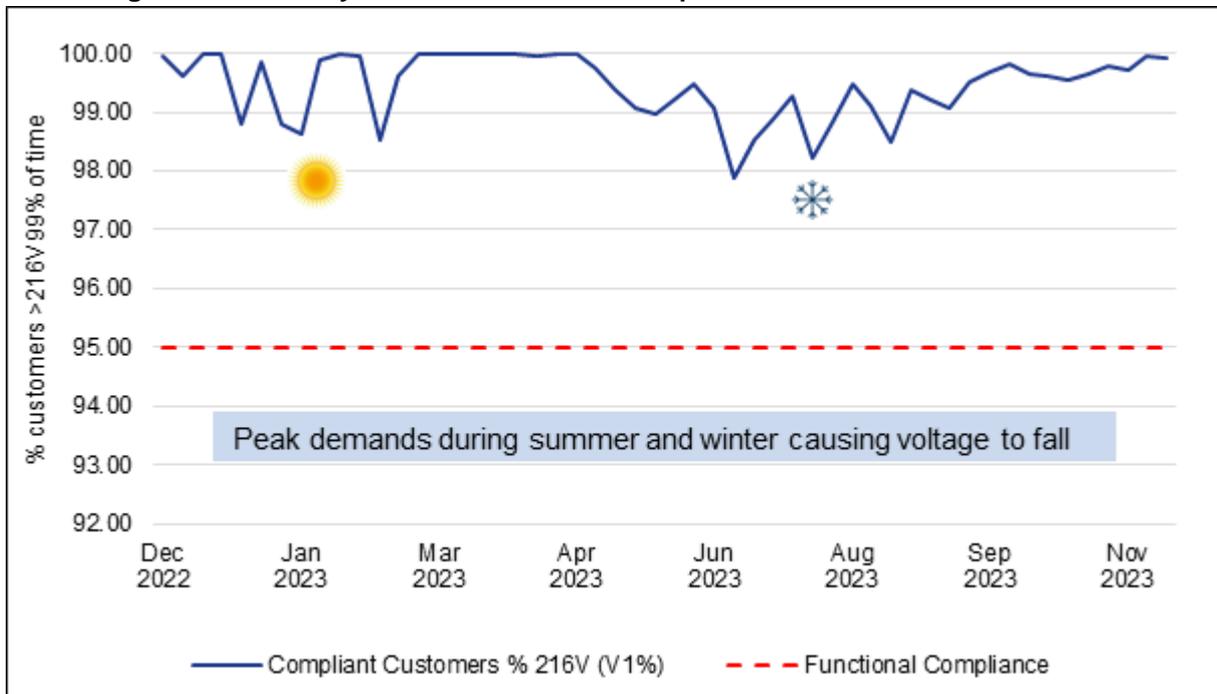
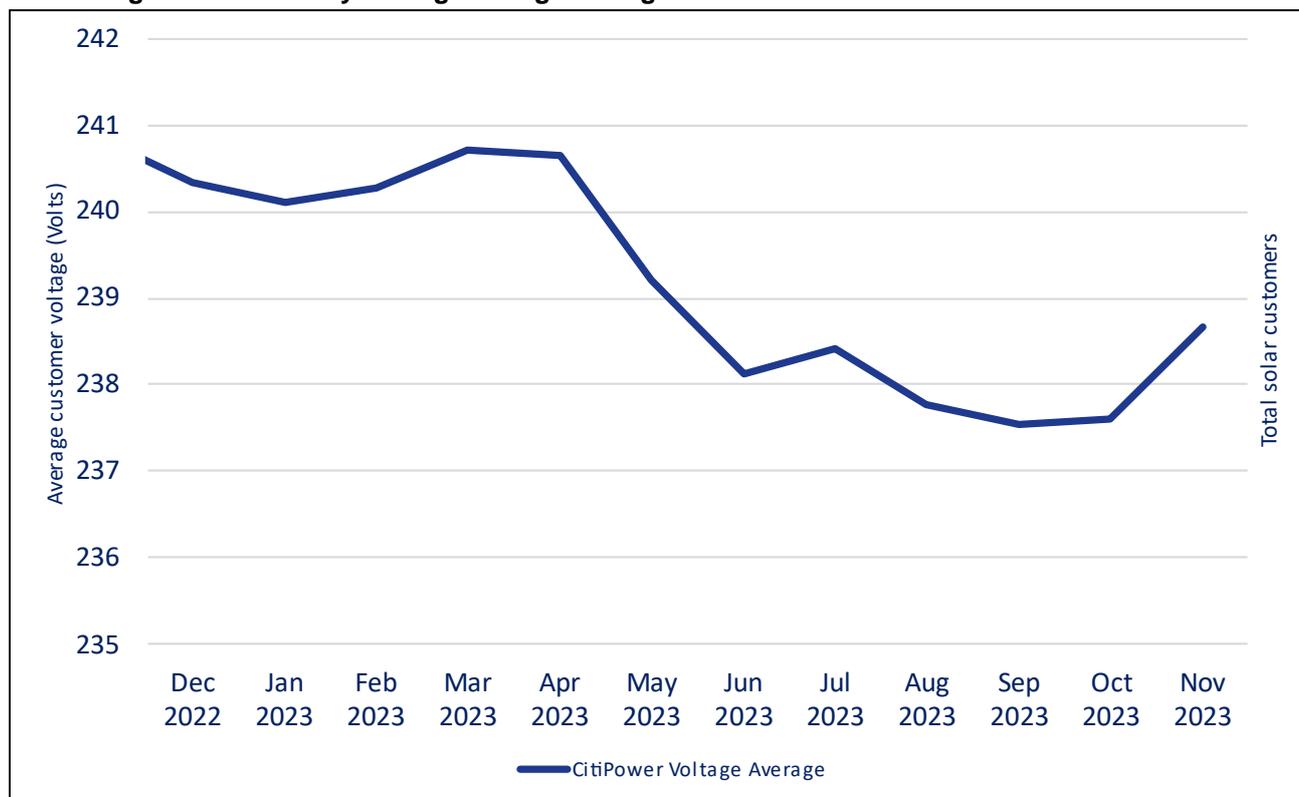


Figure 17.3 Monthly average voltage during 2022-23



As noted in Section 3.7, CitiPower is undertaking numerous steps to improve customer voltage and have significantly increased works in 2023 with CitiPower’s 5-year Solar Enablement program. As a result, V99% performance has demonstrably improved year-on-year (i.e. comparison of June 2022 vs. June 2023). 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).

The 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 since the introduction of the new commissioning process. This will be a continued focus, 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.

17.3.3 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. They are calculated by taking the average across all customers for each 10 minute block within each day of the year. The 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

17.3.4 Voltage performance at medium voltage network

Voltage variations at the medium voltage networks are required to maintain within the limit prescribed by the VEDCoP as stated in Section 17.2.1. The allowable limit for voltage variation is $\pm 6\%$ for urban and CBD networks. Moreover, the limit for negative-sequence voltage unbalance is up to 2% for medium voltage networks as per the NER chapter 5 (Clause S5.1a.7). One or multiple power quality meters are used in each zone substation for observing the voltage performance in the medium voltage CitiPower networks. The steady state voltage at all sites at the CitiPower networks are within the upper (V99%) and lower (V1%) limits. Moreover, the voltage unbalances at the CitiPower networks are within the limit.

17.3.5 Harmonics performance at medium voltage network

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.

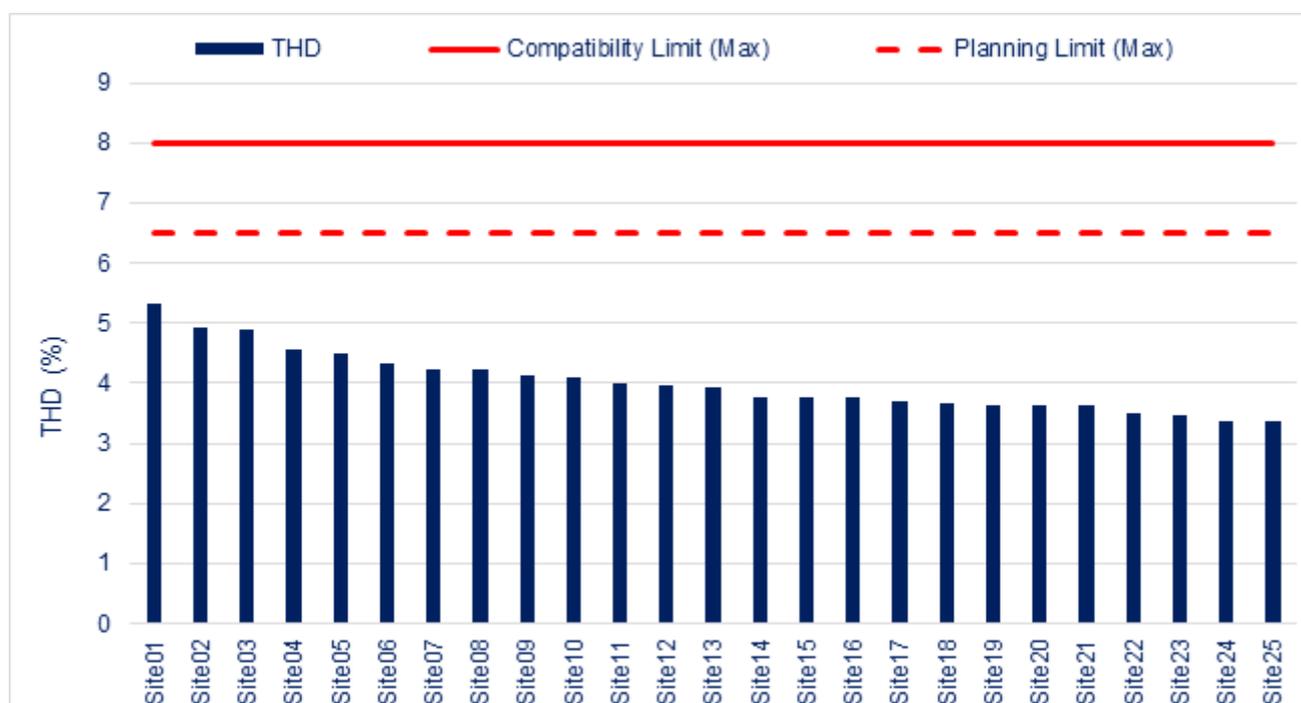
Table 17.4 Voltage harmonic distortion limits

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 %.

Harmonics data for 25 worst performing sites are presented in Figure 17.6. It is clear from this figure that the total harmonic distortion (THD) at all CitiPower sites are within the compatibility limit as well as the planning limit (planning limit is 6.5%, suggested by Australian standard AS 61000.3.6).

Figure 17.6 Voltage harmonics for 25 worst performing sites (measured at the zone substation)



17.3.6 Flicker performance at medium voltage network

According to VEDCoP and NER, the voltage flicker is required to be limited as prescribed in Table 1 of Australian Standard AS/NZS 61000.3.7-2001 which is provided in Table 17.5. Flicker levels for 25 worst performing sites are provided in Figure 17.7 and Figure 17.8. These figures show that the both the short-term (P_{st}) and long-term (P_{lt}) flicker for all CitiPower medium voltage sites are well within the limit.

Table 17.5 Compatibility levels for flickers in low and medium voltage systems

	Compatibility levels
P _{st}	1,0
P _{lt}	0,8

Figure 17.7 Short-term flicker for 25 worst performing sites (measured at the zone substation)

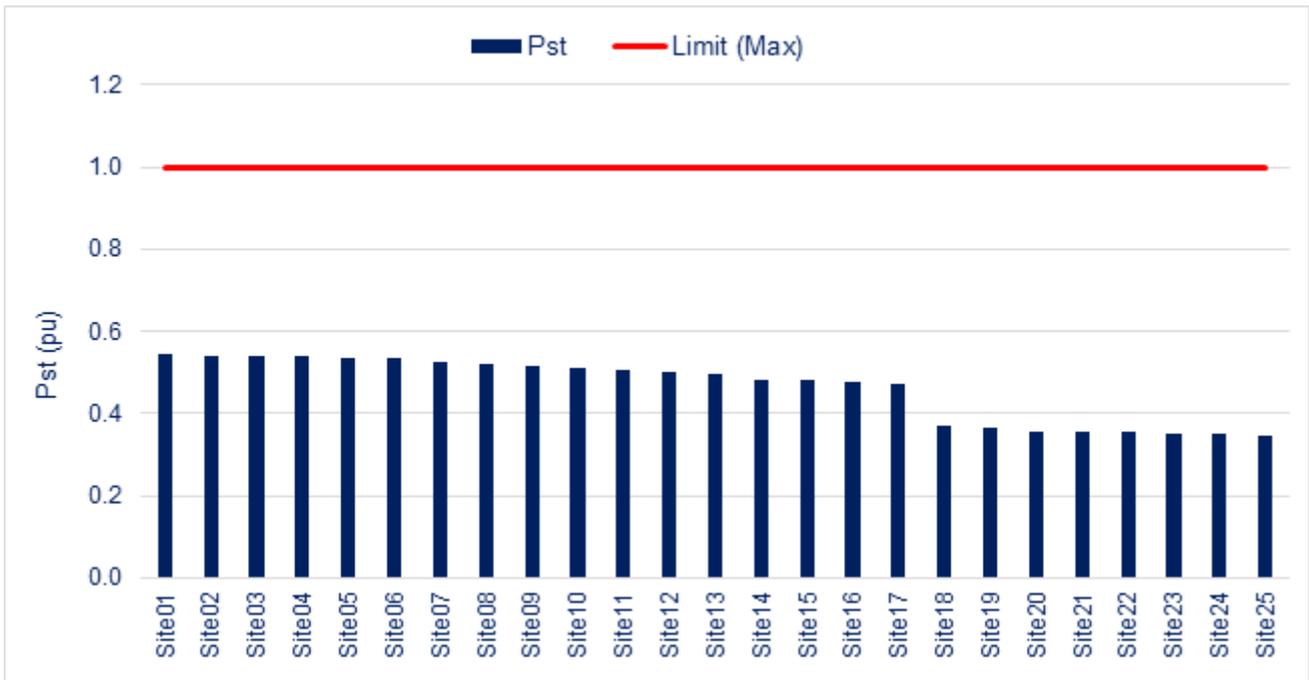
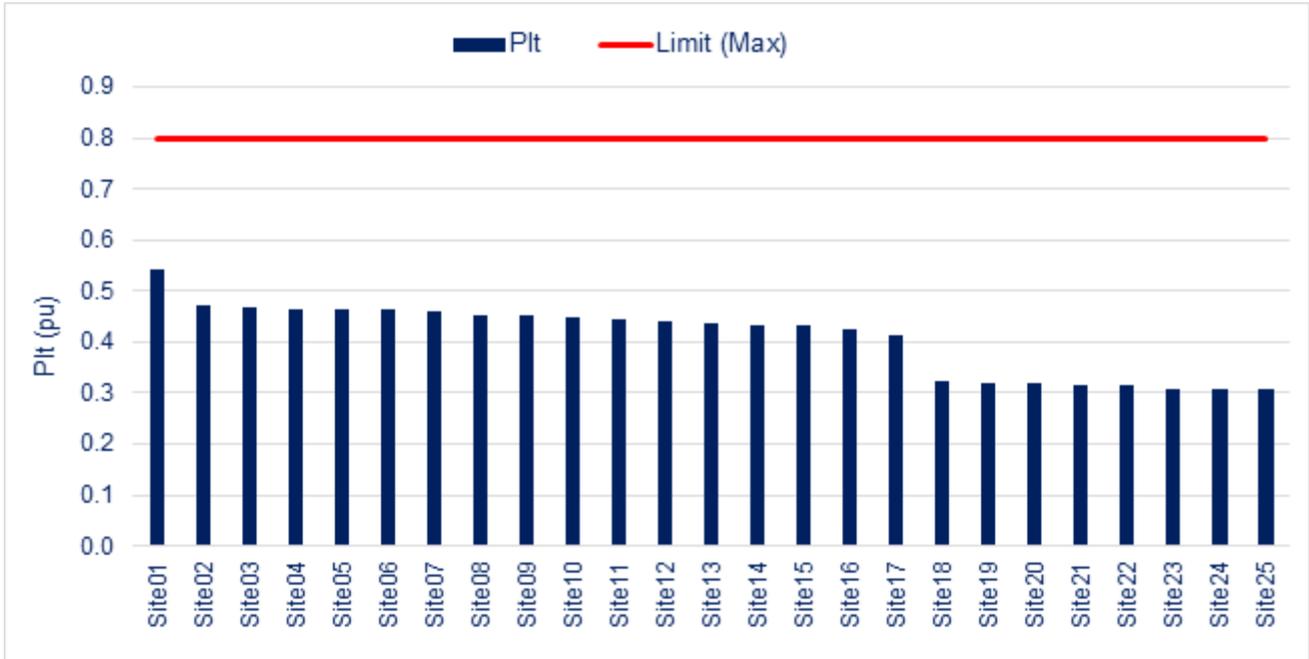


Figure 17.8 Long-term flicker for 25 worst performing sites (measured at the zone substation)



17.3.7 Maintaining power quality in CitiPower networks

CitiPower responds quickly to investigate and resolve power quality issues such as voltage, harmonics and flickers. 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 power quality.

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.
- installation of harmonic filtering equipment to improve voltage harmonic performance.

CitiPower may also identify issues with power quality 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, flickers 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 2023 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 2023

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	101
Applications to connect received under 5A.D.3	23

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 2023/24, 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.
- CitiPower is participating 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 Energy, Environment and Climate Action (DEECA) 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. 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. A mapping tool is being developed 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.

18.4 Demand side engagement strategy and register

CitiPower has a Demand Side Engagement Strategy that 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 2023, no formal submissions from non-network providers were received.

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

We continue to deliver on our commitments in our Cybersecurity strategy to ensure our network and customers remain protected. Our program of work continues to focus investments in Cybersecurity governance, risk and assurance management, security operations and technical capabilities to address the evolving threat landscape and regulatory requirements under the Security of Critical Infrastructure Act (SOCI) 2018. Our focus remains on building and maintaining a Cybersecurity function that can proactively prevent, detect, respond to, and recover from Cybersecurity threats that have the potential to disrupt the operation of the distribution network and our services.

Through our Cybersecurity strategy, we have delivered security uplift programs to our network/communications and identity platforms. Our current in-flight projects will progress into 2024 and deliver on uplifting our web security, identity management, operational technology (OT), and training and awareness programs. Our current cyber security strategy will be fully delivered by 2025 and we have begun planning for our next phase of the strategy. We have met all current requirements under the SOCI act, including the Risk Management Program (RMP) Cyber and Information Security Hazard rules. We remain on target to meet additional requirements in 2024.

As part of our cybersecurity assurance program, we also conduct a series of formal and applied assessments that ensure the effectiveness of our controls and procedures. These include formal audits, penetration testing and simulated responses to a broad range of threat scenarios.

We will continue to align our security strategy and initiatives to ensure compliance with the SOCI act, and 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.

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 2023, we continued 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 and onto the latest product version PowerOn Advantage
- 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 – this upgrade went live in August 2023

In 2023 we also undertook following upgrades:

- Field Collection System (FCS) – this upgrade was to support collection of 5 minute data from meters which necessitated various component changes to servers and moving away from the old handheld to a tablet which will support the Itron Mobile applications

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
- TrendSCADA (Historian) replacement – this includes replacement of the current legacy historian (Operational Technology data store) application, used to support planning of the network, with an improved platform called OSI Pi to address IT security and reliability risks, and uplift business functionality. The project is in flight, due to go-live in late 2024
- Geospatial Information System (GIS) upgrade – this will include a major upgrade targeted to commence in 2027
- ADMS Upgrade – this upgrade will ensure that we maintain resilience and currency of our ADMS so that we can continue to manage the network – targeted to commence in 2028

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.

In 2023 we completed Phase 3 of the five-minute settlement program which included:

1. bringing the operating environments up to date to meet security standards and benchmarks, tuning and performance improvements and enhancements of system processes identified through defects and problem tickets, resulting from previous 5MS and GS go-live activities.
2. At CitiPower, this initiative covers changes and enhancements to the key market systems including MTS/ IEE as well as key supporting revenue management functionality.

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 3.8 procedure changes to improve communication between market participants
- 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
- Minor updates to systems resulting from the Consumer Data Rights reform.

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 2023 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 an upgrade to the new storage infrastructure deployed in 2022.
- Deployed a new backup solution for large sized databases that provides a tenfold reduction in backup and restore times compared to the previous solution.
- Refreshed critical network infrastructure to ensure we were on a supportable solution, have the capacity to accommodate increasing network traffic volumes and provide the ability to protect our devices against cyber-attacks.
- Refreshed critical network security “firewall” devices to ensure we were on a fully supported solution, and consolidated onto a single vendor to enhance our security against cyber threats.

- Upgraded server infrastructure to ensure that we are running on a modern supportable platform, have the capacity to accommodate increasing application demands and ensure that our servers are able to have security patches applied.
- Deployed new meeting room technology to effectively support the post COVID mix of remote and on premise staff.

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-premise 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.

Faults communication was a focus of 2023 where system enhancements were introduced to reduce unnecessary ETR notifications received by customers, to issue alternative 'Restore' messages where customers have a defect and improve the display of outage information on the corporate website. In addition to system changes, we have procured a second on-the-ground vehicle, Vehicle for Engagement Response and Assistance (VERA), ready for deployment to support vulnerable customers and communities during prolonged outages.

Further enhancements to our digital offerings enabled customers to upload photos of faults or issues with our assets, allowed customers to submit network data requests electronically and myEnergy portal subscribers to see a display of planned outage information for their property.

The Customer strategy refresh identified 10 key focus areas for the remainder of the current regulatory period, outlining 31 initiatives and 96 sub-initiatives beneath these focus areas that, when implemented, will help deliver on our strategic imperatives. We have commenced work on priority initiatives, which will be implemented in 2024, these include:

- An 'Uber' faults pilot experience to allow customers and employees to view progress of crews travelling to, and working on, faults. This will provide greater transparency and accuracy of faults restoration to customers and employees.
- A Contact Centre of the future where customers are offered their channel of choice to engage with the business, customer service agents can work across a range of enquiry types and further benefits are derived from the speech analytics platform informing improvements in call handling and proactive identification of issues.
- Outage communication enhancements making use of network analytics to identify customers still off supply resulting in accurate communication and faster restoration; further improvements in faults and planned outage notifications providing customers more timely; and outage map improvements providing customers with more information about outages.
- Customer service online training, for new and existing employees, emphasising a culture where employees provide the customer with options, feel empowered to make decisions and have empathy for the customer's circumstances. Training will also focus on enhancing

employee phone, face to face and written communication skills, particularly when dealing with difficult or angry customers.

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.

Through 2023 we have progressed a number of initiatives including:

- Enhancements to the community battery solution, to enable more community batteries to connect to our network, including the Tarneit Community Battery
- Network Hosting Capacity modelling, used to produce granular long-term forecasts on network hosting capacity, critical for identifying constraints and informing targeted and well-timed network investment.
- Development of dynamic LV control capability required to meet the Emergency Backstop Response compliance mandate. This capability enables us to remotely ramp down or switch off customers with solar during a minimum demand event, avoiding wide-scale power outages.
- Expansion of the Community Portal mapping tool, which visualises network data to community groups and entities to enable improved visibility of suitable areas for rewable energy solutions

Part of the digital revolution is being able to provide more information on how the electricity network is performing in more usable formats.

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, via a Flexible Exports Trial (currently in development, due to commence in H1 2024)
- Continued expansion of the visualisation of network performance and constraints to more community groups and entities, to enable improved visibility of suitable areas for renewable energy solutions
- Building on network constraint visualisation, trial a flexibility marketplace (procurement platform) implementation to test market viability for non-network solutions(due to go-live in H1 2024)
- Development of further minimum demand response mechanisms, including AMI load shedding, which will seek to identify and cluster exporting customers to curtail export during a minimum demand event. This will enable us to avoid shedding feeders as a first resort (which takes load customers off supply), improving customer and network outcomes.

- Development of sophisticated AMI forecasting capability, to improve LV management outcomes

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 2023 we have completed works on the following: -

- Commenced scoping the introduction of MPLS technology to ease capacity issues on some sections of CitiPower's optical fibre network
- Enhancing the physical security of our communications assets by introducing a state of the art locking system.
- 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.
- Continued to replace 3G devices with new 4G technology introducing centralised and remote configuration management and real time performance monitoring and reporting. The CitiPower replacement program will be more than 75% complete at the end of 2023.

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, 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.
- Minimum demand management – by shifting loads such as hot water connected to the meter, we are able to help manage minimum demand that is becoming more evident as renewable energies become more prevalent.

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.

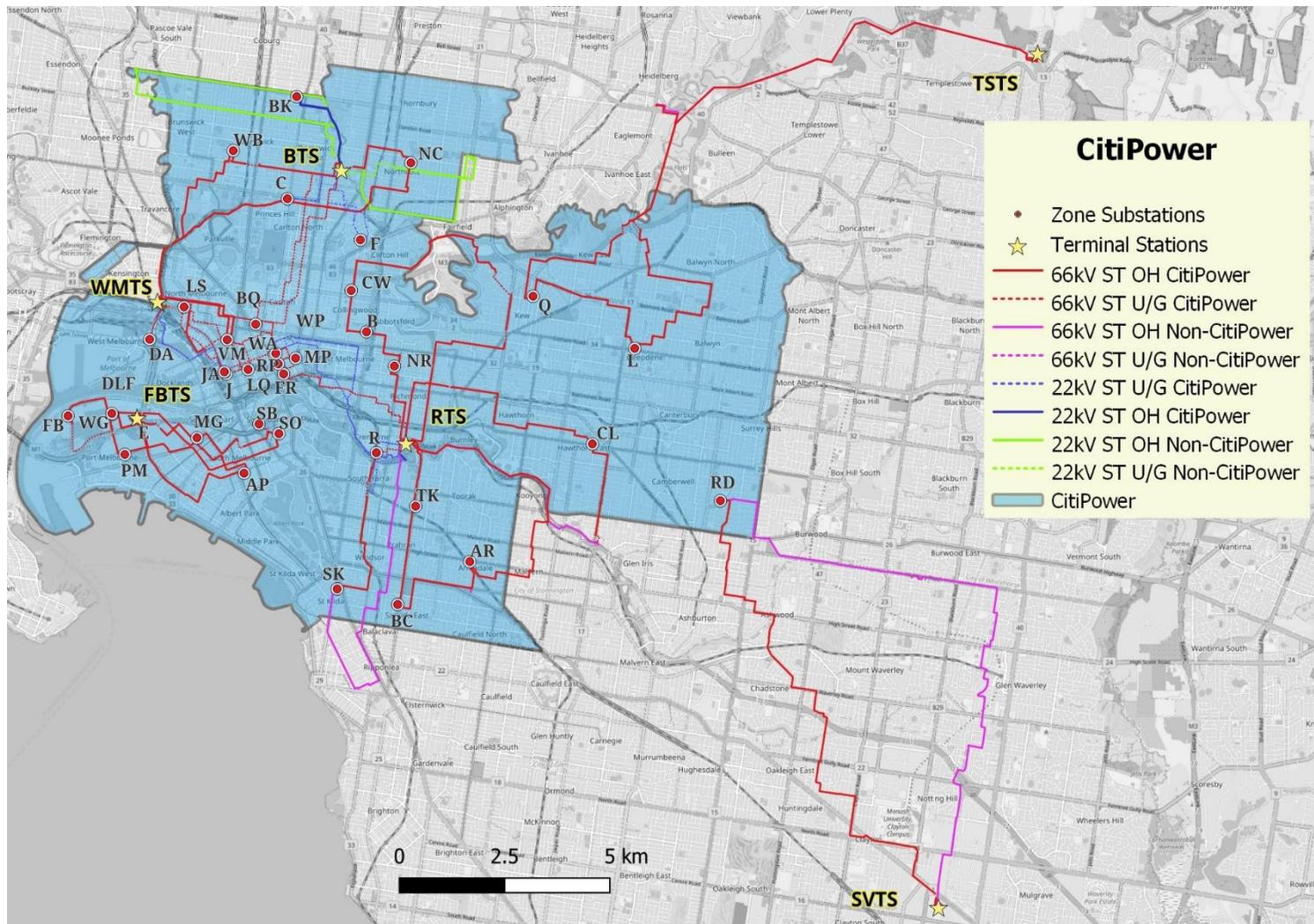
AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state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

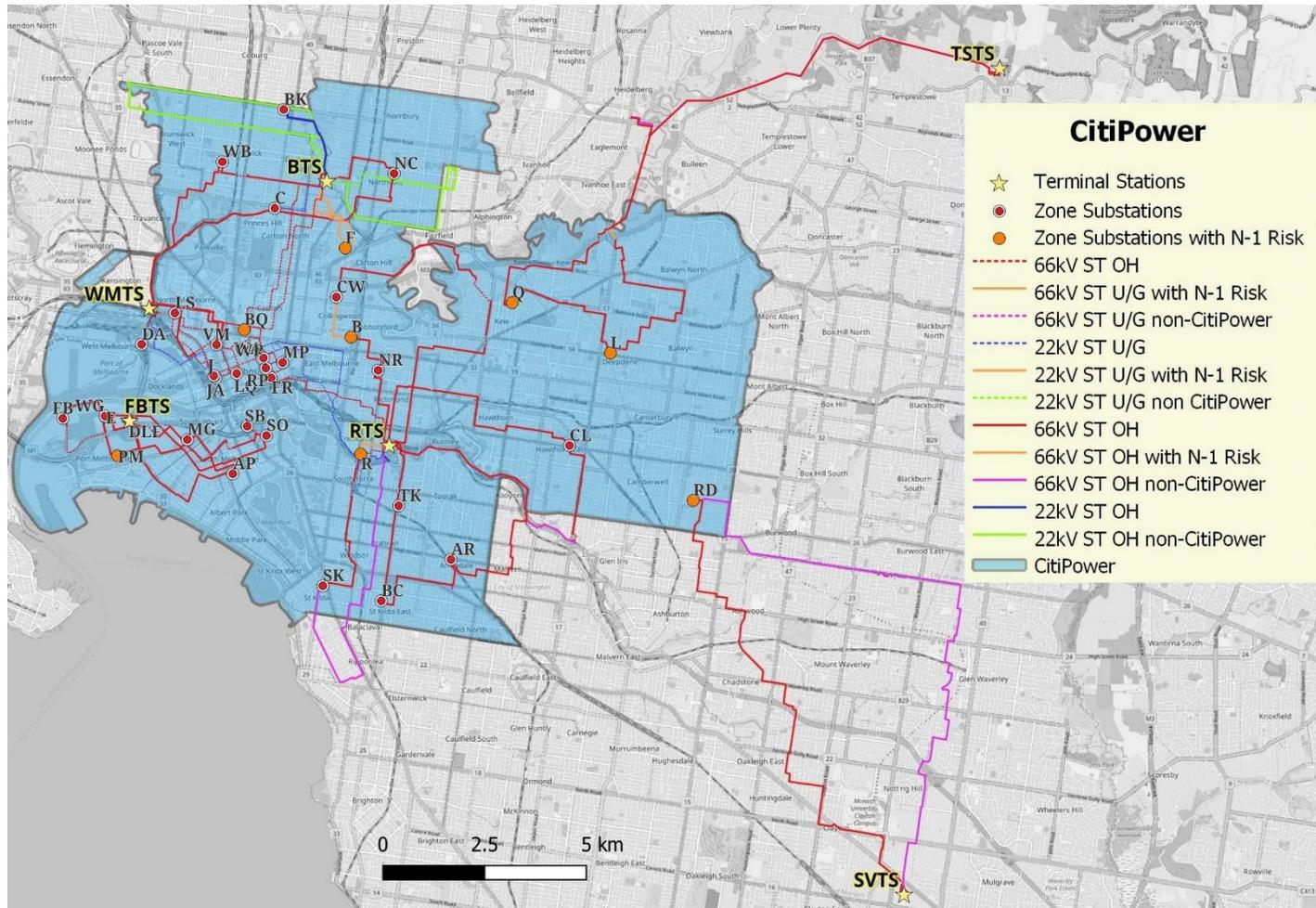
Appendix A Maps

A.1. Citipower zone substation and sub-transmission lines



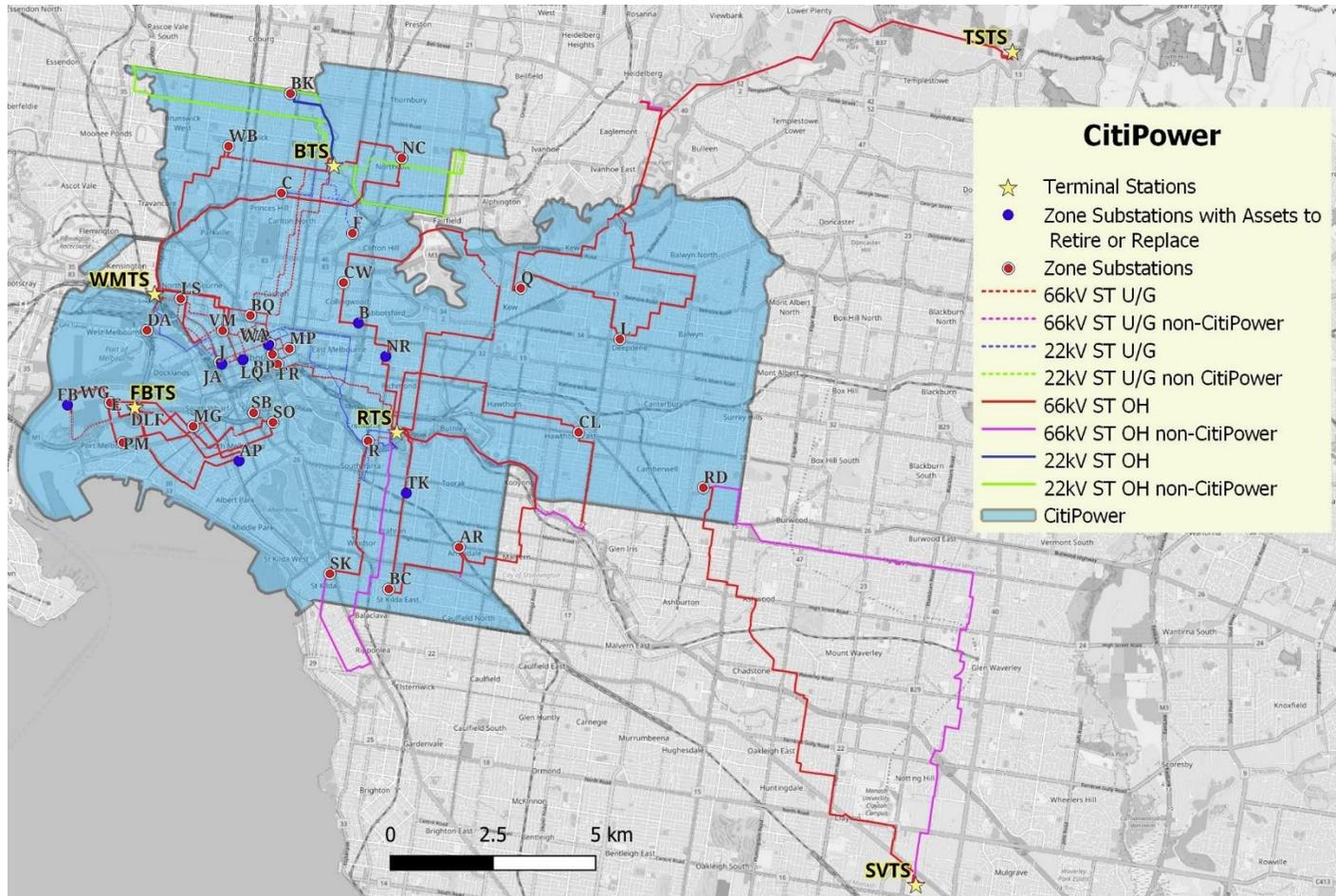
Appendix B Maps with forecast system limitations

B.1. CitiPower zone substation and sub-transmission lines with forecast system limitation



Appendix C Maps with asset to be replaced or retired

C.1. CitiPower zone substations with assets to be relaced or retired



Glossary and Abbreviations

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.

Zone substation abbreviations

Abbreviation	CitiPower Zone Substation	Abbreviation	CitiPower Zone Substation
AP	Albert Park	MG	Montague
AR	Armadale	MP	McIlwraith 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	VM	Victoria Market
FR	Flinders/Ramsden	WA	Celestial Avenue
J	Spencer Street	WB	West Brunswick
JA	Little Bourke Street	WG	Westgate
L	Deepdene	WP	Waratah Place
LQ	Little Queen		
LS	Laurens Street		

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