Framework
Network Planning

CitiPower Pty Ltd, Powercor Australia Ltd
and United Energy Services Pty Ltd
FW-0001

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1. Executive Summary

CitiPower, Powercor and United Energy (**CPPCUE**) are committed to providing customers with safe, reliable and affordable electricity network services. The framework describes our approach to network planning to support that outcome, recognising our goal to meet customer and stakeholder needs, and legislated compliance obligations. The outcome of our approach is a portfolio of augmentation and network interventions which drive customer outcomes.

Our approach to planning includes:

- Considering growth on the network driven by both new customers requests and increases to existing customers supply
- stakeholder requirements including economic, environmental, health and safety, information, operational, reliability and technical requirements that are derived from interfaces with external stakeholders. These include customers, developers, the Australian Energy Regulator (**AER**), the Australian Energy Market Operator (**AEMO**), transmission asset owners, other Distribution Network Service Providers (**DNSP**s), the Victorian Government, the Essential Services Commission (**ESC**) and other external stakeholders. Similar requirements are also derived from interfaces with internal design, asset management, project, control, operational and customer teams.
- Regulatory compliance requirements, most notably the *National Electricity Rules* (**NER**), the Victorian *Electricity Distribution Code of Practice* (**EDCoP**) and the Electrical Safety Management Schemes (**ESMS**s) which all contain significant obligations.
- Guidance from regulators including the AER, ESC and ESV, also heavily influence network planning, and the AER is guided by the principles stated in the *National Electricity Objective* (**NEO**) which include price, quality, safety, reliability and security of supply of electricity and the achievement of targets for reducing Australia's greenhouse gas emissions.

Incorporating the requirements above, the approach describes the way in which network planning brings value to customers. Our approach factors in the:

- need for network augmentations to maximise value to consumers
- compliance and complaints resolution approach favouring low cost network and customer interventions
- approach taken to network constraints that includes the consideration of both network and non-network solutions
- strategic approach to compliance management, voltage control and CER/DER integration
- compliance requirements including Rapid Earth Fault Current Limiters (REFCLs) performance and the obligation to maintain a higher level of security of supply for the sub-transmission network in Melbourne's CBD
- support Network Planning provides to internal and external stakeholders, including advice related to reliability improvement, operational loading, maintenance and replacement
- techno-economic and scenario based probabilistic forecasts of maximum and minimum demand, using our customers data as a primary input.

The output of our approach to network planning is a portfolio of network augmentation and interventions which may be network, non-network, customer or industry related interventions. This portfolio is refined in line with CPPCUE's Network Investment Strategy (STR-0023).

The effectiveness of this approach is continually reviewed using feedback from systems along with reports from customers and other stakeholders to address issues in the network. This information forms an input to the risk-based approach to determine future investments.

By taking a systems-based approach, this framework assists CPPCUE in meeting new network connection requirements, safety, reliability and compliance objectives at least cost while allowing for future customer needs. It also assists CPPCUE in addressing strategic challenges, as outlined in the Strategic Network Management Plans (**SNMPs**) (CPPAL-PL-0003 and UE-PL-2034), such as CPPCUE's transition to becoming a leading Distribution System Operator (**DSO**).

2. Purpose and Scope

2.1 Purpose

This document outlines the CPPCUE approach to network planning and how CPPCUE identifies the need for both physical and operational changes in the network over the short, medium and long term. It also summarises how CPPCUE develops its network augmentation plans to meet both customers' expectations and performance obligations as imposed by regulatory instruments.

This document is consistent with principles set out in the Asset Management Policy (PO-0001), in particular the requirement to:

- 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 network and systems
- invest in programs that sustainably optimise total lifecycle management.

2.2 Scope

The scope of this framework covers CPPCUEs approach to Network Planning, encompassing the short, medium and long term planning of the electricity distribution network up to its transmission connection point at each terminal station supplying the relevant areas of the CPPCUE networks. The scope of this framework also covers CPPCUEs approach to plan transmission connection assets and participate in joint planning activities with AEMO and other DNSPs.

This framework applies to planning activities related to both new and existing assets installed and operated as part of the electricity network consistent with the scope of the CPPCUE Integrated Network Management System (STR-1440). It covers the planning of the network to meet both existing and forecast limitations on the network.

The scope of this framework excludes system strength and frequency management as these are obligations held predominantly by AEMO and external parties. CPPCUE do provide support to these through specific obligations, such as the design, construction, and support for under frequency load shedding schemes (on the distribution networks) and systems strength assessments only as part of a new large scale connection.

Further, this framework does not provide details of specific plans, rather it covers the requirements, approach and outcomes. Evidence and justification for each program or project are provided in individual business cases for each project or program of works.

3. INMS Framework

This framework complies with the requirements of the INMS Document Management Standard (ST-1750) for a framework or strategy. This framework integrates the Network Planning activities with the Network Investment Strategy (STR-0023) and INMS Policies, Objectives and Measures (PO-2050).

The network planning framework has been set to contribute to the following network management objectives as described in the Network Investment Strategy (STR-0023):

- Manage and operate the network safely.
- Meeting network reliability performance targets.
- Manage assets on a total life cycle basis at least cost.
- Manage compliance obligations.
- Monitor opportunities and drive continuous improvement.
- Adapt to customers' input, interest and needs.

This framework is aligned with *ISO 55000* and the SNMPs.

4. Objectives

This document's main objectives are to provide direction in carrying out Network Planning activities to:

- comply with legislative requirements
- provide reliable, affordable, safe, and secure electricity supply to customers
- maintain long-term supply reliability of the distribution network
- maximise network availability for import and export services

- minimise safety risks as far as practicable
- enhance customer experience and adapt to future needs
- maintain a uniform and consistent approach, which facilitates continuous improvement.

These objectives are in line with the overall INMS objectives.

5. Network Planning Overview

The following figure shows an overview of the key elements in CPPCUE Network Planning. It covers the customer, stakeholder and compliance requirements, the integrated network planning approach and customer outcomes. Each of these elements is described in the sections below.

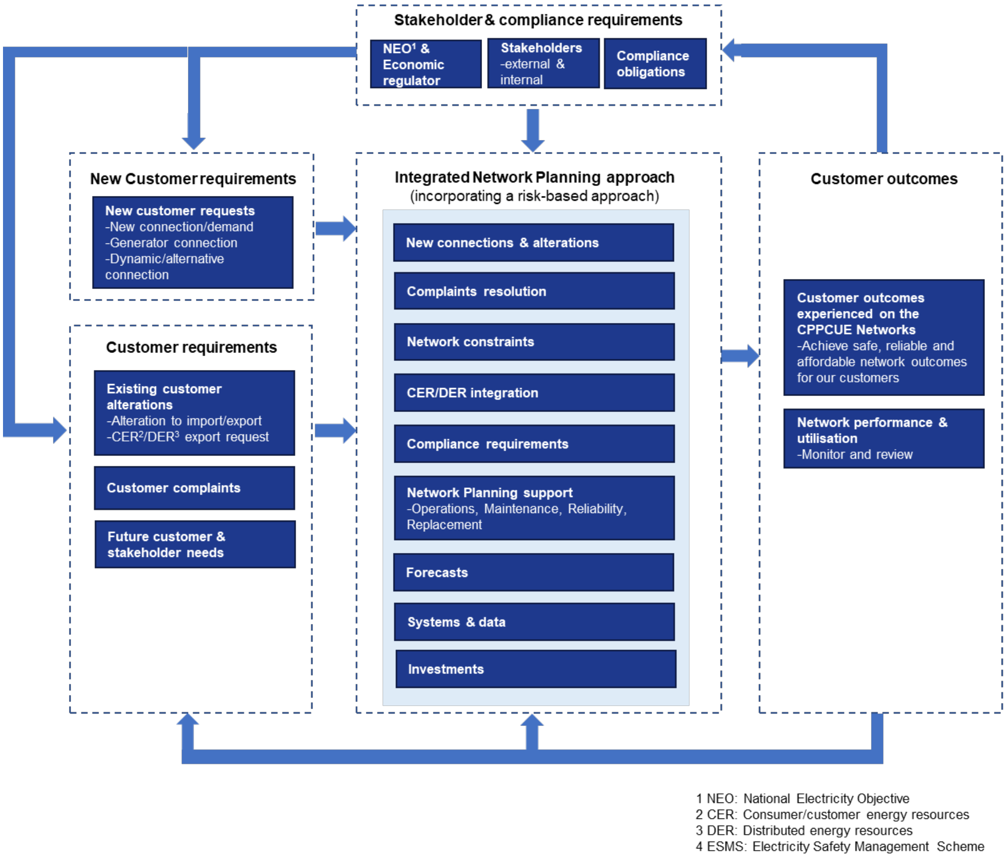

Figure 1: Overview of the Key Elements in Network Planning

6. Customer, Stakeholder and Compliance Requirements

This section describes the high-level customer, stakeholder and compliance requirements that Network Planning need to meet to achieve the objectives and customer outcomes.

6.1 New customer requirements

New customers request network connections every day, these include:

- new connections which request electrical connection for demand (import) capacity from the network
- generator connections which request electrical connection for generation (export) capacity from the network
- dynamic connection requests which may involve a request for import or export capacity from the network at certain times, or under certain network conditions.

Network Planning receive connections requests from the customer and project delivery teams based on the level of complexity of the request (the referral criteria is defined in the CPPC Network Planning Referral document (04-30-F0002) and section 9 of the UE Network Planning Guidelines (UE-GU-2200). Network Planning then collaborate with these teams to ensure that customer requirements are effectively and efficiently obtained so that they can be incorporated into the integrated network planning approach. The approach allows for an iterative change of requirements, as customer needs can change from initial request through to the customer (connection) offer stage.

6.2 Customer requirements

This section (6.2) provides and overview of existing customer alterations, complaints and future customer and stakeholder requirements. Customer requirements are also derived from the compliance obligations described in section 6.4.

6.2.1 Existing customer alterations

Existing customers can request alterations to their connection due to changes in needs. This may include:

- alterations to network import and/or export capacity requirements
- CER/DER export requests.

Similarly to section 6.1, Network Planning receive referrals (based on the complexity of the request) and then collaborate with customer and delivery teams to ensure that requirements from existing customers are effectively and efficiently obtained and updated during the customer journey from the initial engagement.

CER/DER export requests are noted separately as they are high volume and are typically addressed via a systems approach which is described in the integrated network planning approach.

6.2.2 Customer complaints

CPPCUE has communication channels available for customers to make complaints. Each complaint is reviewed, triaged and actioned by the CPPCUE customer teams. Network Planning typically receive triaged complaints relating to:

- network capacity import and/or export limitations
- network reliability
- power quality.

Network Planning collaborate with customer teams and directly with customers to understand the complaints so that they can be effectively managed in the integrated network planning approach.

6.2.3 Future customer & stakeholder needs

The electricity industry is in transition and the emerging changes can either be viewed as risks (threats) or opportunities to grow our customer offerings. The important aspect is that Network Planning need to stay abreast of the industry trends and make necessary adjustments to ensure that the network is ready for future requirements. This is in line with the strategic pillars of the business, specifically 'building a network for the future' and the SNMPs.

Some of the emerging trends that materially affect Network Planning activities are:

- advancement of technology and availability of better alternatives to network augmentation
- changes in regulations and/or government policies
- change in demand profiles and associated impact on distribution assets
- climate change and its impact on distribution assets
- customer expectations for higher (better) network reliability, and ease of DER export and import
- increased penetration of electric vehicles (**EV**) and vehicle-to-grid (**V2G**) arrangements
- increased penetration of solar PV and hosting capacity or export limitations
- the DSO transition
- the electrification of gas connected customers and new all-electric (non-gas) customers
- the role of storage and its impact on the network, both locally and at scale
- reducing minimum demand and its associated operational challenges for DNSPs, TNSPs and AEMO

CPPCUE continually monitor all aspects of the network, including the import/export capacity to customers to determine any emerging trends so that planning can be put in place to address changing customer needs. CPPCUE also interface with stakeholders to identify changes and influence future needs.

6.3 Stakeholder requirements

Network Planning interface with multiple internal and external stakeholders to achieve the objectives stated in this framework. Stakeholder requirements are considered in the network planning approach, some of which include:

- asset information and network visibility requirements
- asset management requirements such as plant loading, fault levels and protection reach
- health, safety and environmental requirements
- investment, economic and other portfolio requirements
- operational and work practices requirements
- other technical requirements such as standards and guidelines
- network reliability requirements including sectionalisation and recovery
- wants and needs of key stakeholders.

A list of key stakeholders is described in the following sections.

6.4 Compliance Obligations

CPPCUE operates under a combination of national and state legislation. While electricity safety legislation is set within each jurisdiction, all market participants of the National Electricity Market (**NEM**) operate under the National Electricity Law (**NEL**) and within the National Electricity Rules (**NER**).

CPPCUE must comply with all obligations including (but not limited to) the following:

- *Electricity Safety (Bushfire Mitigation) Regulations*
- *Electricity Safety (Management) Regulations*
- *National Electricity Rules*
- *Victorian Electricity Distribution Code of Practice*
- *Victorian Service and Installation Rules.*

CPPCUE also operate the networks under Electrical Safety Management Schemes (**ESMS**s) that are accepted by Energy Safe Victoria (**ESV**) in accordance with s99 of the *Electricity Safety Act* (**ESA**).

6.4.1 NEO and the AER

Sitting within the NEL is the National Electricity Objective (**NEO**):

"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

a) price, quality, safety, reliability and security of supply of electricity; and

b) the reliability, safety and security of the national electricity system; and

c) the achievement of targets set by a participating jurisdiction:

   i. for reducing Australia's greenhouse gas emissions; or

   ii. that are likely to contribute to reducing Australia's greenhouse gas emissions."

The AER incorporate these principles in their decisions regarding the ongoing regulation of the electricity sector.

Network Planning are heavily involved in providing information to the AER to allow them to monitor both CPPCUE's ongoing obligations and the alignment of CPPCUE's actions with the NEO. This includes the provision of artefacts required by the NER such as:

- Distribution Annual Planning Reports (**DAPR**s)
- provision of Regulatory Investment Tests for Distribution (**RIT-D**)'s and Regulatory Investment Tests for Transmission (**RIT-T**)'s
- Regulatory Information Notices (**RIN**) normally issued yearly
- Transmission Connection Planning Reports (**TCPR**s)
- the five yearly Electricity Distribution Price Reviews (**EDPR**).

7. Network Planning Approach

The objective of CPPCUE's network planning activities is to bring value to its customers by maintaining long-term supply reliability of the electricity distribution network and the CPPCUE transmission connection points, in response to electricity demand growth and penetration of renewable energy generation and energy storage, while minimising whole-of-lifecycle capital and operating costs.

The general objectives of network planning are to:

- manage the network performance associated with electrical plant and equipment loading in a safe and prudent manner
- respond to customer requests for connection to provide least cost technically acceptable (LCTA) solutions
- undertake strategic network development and risk management to cater for existing and future customer needs
- develop least cost, technically acceptable solutions that minimise current and future capital spending for distribution, sub-transmission, and transmission connection asset constraints
- planning to ensure solutions to current problems are optimal to meet both current and future requirements.

This planning is undertaken within the context of the regulatory framework set by the *National Electricity Rules (NER 5.13)* and is reported annually in the Distribution Annual Planning Report (**DAPR**) and Transmission Connection Planning Report (**TCPR**) publications.

The remainder of section 7 is split up into key sections which cover the risk-based approach to network planning, the network planning sub-elements and integration and feedback.

7.1 Risk based approach in network planning

7.1.1 Risk Management Framework and Methodology

The Enterprise Risk Management Framework (**ERMF**) (13-10-CPPCUE0005) is a structured, disciplined approach that aligns strategy, process, people, technology, and knowledge to identify, evaluate and manage the uncertainties that the organisation faces as it strives to create value.

The document outlines the risk management framework, procedure and tools used to assess risks and controls as part of the risk management process for CPPCUE. This framework is based on *ISO 31000:2018* and provides an approach and supporting toolset that enables CPPCUE to:

- identify and assess risk
- balance risk, particularly critical risks, with the objective of improved business value
- determine the optimum treatment for risk, including the assessment of whether mitigating actions are required
- complete risk assessment as an element of management decision-making and not as a separate set of activities.

The probabilistic planning approach and associated treatment of risk in Network Planning are aligned with the ERMF.

7.1.2 Risk based approach

CPPCUE adopt a probabilistic planning approach when planning zone substation and sub-transmission network capacity. This approach involves estimating the probability of a plant outage occurring, assessing and valuing the amount of energy that would not be supplied during the outage and weighting the costs of such an occurrence by its probability to assess:

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

The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower volumes of unserved energy and provides a reasonable estimate of the expected net present value to customers of the network asset augmentation for network planning purposes. This is the also the approach taken to when planning transmission connection assets and participating in joint planning activities with AEMO and other DNSPs.

This probabilistic planning approach is consistent with the business's ERMF. CPPCUE Network Planning also has compliance obligations that are treated outside of the probabilistic planning approach, these include obligations relating to Rapid Earth Fault Current Limiters (REFCLs), specific security of supply requirements for the Melbourne CBD and security of supply as defined in the Systems Standards of the NER.

7.1.3 Key risks and controls

Network Planning are accountable for managing the key corporate level risk relating to network development and network capacity. These key risks and related controls are reviewed bi-annually via a Risk Profiling report produced by the Network Risk & Assurance team and key internal stakeholders. In general terms the key risks to be considered in Network Planning are:

- insufficient capacity to supply the load under system normal (N)
- overloading of assets under system abnormal conditions (N-1)

- safety of personnel or public
- fire ignition due to asset failures
- regulatory non-compliances including quality of supply breaches
- constrained solar customers.

The key controls to be considered include:

- application of dynamic ratings
- augmentation of the network
- fault level mitigation
- network reconfiguration to redistribute demand and offload assets
- other technically and economically viable alternatives that become known over time with the advancement of the industry
- power quality interventions
- redesigning the network to improve safety and bushfire risk reduction (REFCL application)
- sectionalisation, automation and fusing of the distribution network
- the use of dynamic operating envelopes via a high voltage distributed energy resource management system (**HV-DERMS**)
- voluntary and/or involuntary demand management (non-network alternatives).

7.1.4 Assessing Risks

The process by which CPPCUE calculate risk associated with potential shortfall in network capacity over a forecast period is by means of identifying the network asset(s) that are at risk of electrical overload and options for corrective action to relieve the constraint or system limitation. The approach used to determine the risk to CPPCUE assets is by 'probabilistic planning', where estimating the probability of an asset outage occurring within a peak loading period.

This is performed by:

- determining the expected unserved energy and costs incurred to customers due to supply interruption if no action is taken to address the constraint
- advertising constraints and prospective solutions yearly through the DAPRs and non-network tenders
- determining the economic timing to augment the network capacity or reduce demand to alleviate the network constraint
- reviewing alternative options to address constraints
- reviewing loading of high voltage feeders, distribution substations and low voltage lines and addressing any overloads
- constructing alternative future load forecasts to determine future constraints.

This is inherently possible since zone substation and sub-transmission networks are, most often, constructed with a level of redundancy allowing for an outage to a single element without losing the ability to supply all customers.

CPPCUE's high voltage and low voltage feeder networks, and some zone substations and sub-transmission lines with single supplies, are built without a level of 'system normal' redundancy and hence it is not possible to apply the same risk management approach to the system normal condition in all cases. However, risk management approaches are used to determine the economic value of investments compared to the alternative of not investing (i.e., valuing the lost load above an asset rating to load shedding should the investment not go ahead), and to also value investments that establish and maintain alternative supplies to assist with supply in the event of outages. This includes the establishment of feeder ties and low voltage ties as well as automation to resupply.

A probabilistic planning approach results in a reduced level of network redundancy at times of high demand when assets are highly utilised. To reduce this risk, CPPCUE perform detailed contingency planning of the sub transmission system including zone substations prior to the high demand periods, coupled with yearly reviews of the loading on the high and low voltage systems including distribution substations. The purpose of the contingency planning is to reduce the impact of unplanned outages should they occur.

7.1.5 Activities to Control Risk

CPPCUE utilises several methods to control the risk of loading network assets above plant (or equipment) capability, including:

- network augmentation
- non-network solutions (which may include demand management, generation or battery storage support)
- control systems
- contingency or permanent load transfers
- load shedding.

CPPCUE monitor risk through the annual DAPR and TCPR where system limitations are identified, and network or non-network options analysed.

CPPCUE utilises the DAPR and non-network tenders (in line the Demand Management Incentive Scheme (DMIS)) to seek out competitive network augmentation alternatives that can reduce costs by deferring or avoiding capital expenditure by minimising the system limitation of overloaded assets. Non-network proposals (also known as flexible services) are assessed on their ability to address a specified network constraint at a cost that is more economic than an equivalent network solution. This typically means that the operating cost (or payment) associated with a non-network solution (or flexible service) must be lower than the annualised cost of capital associated with the proposed network solution. In addition to the assessment of the solution and costs, there is often risk associated with the provision of non-network (or flexible) services, including contractual delays and the risk of non-delivery. These risks are considered and addressed when assessing prospective non-network solutions and as part of entering into any contractual commitment.

7.2 Network planning sub-elements

Network Planning's integrated approach factors in the requirements and guidelines stipulated in the policies, strategies, plans and guidelines developed and managed by the Network Planning team and stored on the INMS intranet site.

A sub-set of key documents is shown here:

- CPPC Distribution System Augmentation Policies and Guidelines (CPPAL-PR-0008)
- CPPC High Voltage Augmentation Planning Policy and Guidelines (15-20-CP0001)
- CPPC Low Voltage Augmentation Planning Policy and Guidelines (01-10-CP0001)
- CPPCUE Voltage Control Strategy
- UE Network Planning Guidelines (UE-GU-2200).

These documents are considered in our Network Planning approach, which is described as a series of sub-elements in the following sections. Network Planning is in the process of aligning the abovementioned documents across CPPCUE.

Further to the documents managed by the Network Planning team, our approach also enables Network Planning to adapt to the needs of CPPCUE strategies such as the Network Safety Strategy (STR-0003), Network Reliability Strategy (STR-0002), Network Investment Strategy (STR-0023), Network Environment Strategy (STR-0009) and Minimum Demand Strategy (STR-0022) strategies. This includes adaptation to the need for CPPCUE to support system security management associated with NEM minimum and maximum demand (where required/directed by AEMO). The minimum demand strategy describes CPPCUE's strategy for managing the emerging minimum demand constraint in Victoria, whilst the maximum demand constraint is managed via established protocols between CPPCUE's and AEMO's control centres. This can include the use of systems to temporarily alter demand (by making changes to voltage levels using CPPCUE's Dynamic Voltage Management Systems (DVMS)) and controlled load shedding.

7.2.1 New connections and alterations

Customers request network connections and network alterations which can cover import or export capacity requests or alterations, or dynamic capacity requirements.

CPPCUE as the Distribution Network Service Provider must provide a customer connection to its network subject to the application request being consistent with the AER's *Connection Charge Guideline for Electricity Customers* and Chapter 5 and Chapter 5A of the National Electricity Rules.

Network Planning determines the technical requirements to supply the new connection depending on:

- location
- capacity availability
- network ability to accept import/export within power quality constraints and fault level limitations
- power requirement
- reliability requested
- when supply is required
- any import or export constraint (static or dynamic) that may be required.

Connection requests are assessed using the least cost technically acceptable (LCTA) approach, in line with the network planning guidelines.

7.2.1.1 CER/DER connections and export requests

The approach to CER/DER connections and export requests is described below:

- Small CER/DER (<=200kVA) are assessed based on their impact to the existing network, primarily from a voltage and capacity perspective. To cater for the large volume of these requests, Network Planning has developed a system to take the customer requirements and assess the network impact using an automated power flow calculation. This system can be adapted to suit changing compliance or stakeholder needs. This system is active for customer applications up to 200kVA in VPN and 30kVA in UE, with a near term plan to make the system active for applications up to 200kVA in UE. Customers requiring CER/DER systems <=30kVA are offered connection under model standing offers, whilst connections >30kVA require an agreement. The assessment of CER/DER will change shortly as CPPCUE will soon need to provide a minimum level of export to customers (post 2026), in addition to allowing a dynamic connection (export) agreement with customers. Network Planning is developing an approach to this requirement in conjunction with internal and external stakeholders.
- CER/DER (>200kVA to 1MVA) also require network impact assessments and they are now subject to new technical standards which require runback schemes to cater for the new emergency backstop (minimum demand) response requirements. This enables CPPCUE to runback (or turn off) CER/DER >200kW when an emergency minimum demand instruction is received from AEMO.
- Medium to large scale connections (>=1MVA) are also subject to a suite of requirements and process steps defined in the NER chapter 5 and 5A. This can include steady state, dynamic and electromagnetic transient simulations and assessments, impact assessments on network fault levels, as well as other assessments including system strength impacts where required. CPPCUE work with customers, stakeholders (such as AEMO) to enable the LCTA approach to connection generator (and/or storage import/export) customers. This may involve an offer to a customer to enter into a dynamic connection agreement. This approach makes use of the dynamic capacity in the network via the high voltage distributed energy resource system (HV-DERMS) and may enable the customer to avoid or lower the augmentation costs associated with a network connection.

7.2.2 Complaints resolution

Network Planning collaborate with customer teams and directly with customers to manage complaints, in line with the information gathered and CPPCUE's supply quality commitments. Customer complaints generally relate to power quality, network capacity import or export limitation or reliability and the approach taken is to assess the impact, and the network and/or customer invention options that may be available to resolve the constraint. Low-cost power quality interventions are generally actioned as part of a program and higher cost interventions are assessed individually, taking into account the impact and other interventions that may delay the need for large investments. Customers are kept informed during this journey from inquiry to closeout.

The approach to managing customer complaints is aligned to the Essential Services Commission's EDCoP.

Network Planning also seek to minimise customer complaints by proactively undertaking network interventions. These interventions are targeted based on assessments undertaken using information from CPPCUE systems. An example is the CPPCUE solar enablement program which targets interventions at specific parts of the network based on assessments of voltage performance data. This program along with the introduction of DVMS has reduced customer complaints relating to voltage.

7.2.3 Network constraints

Periodic reviews (including the annual DAPR) are undertaken to identify constraints using planning inputs, including forecasts and information from systems. Constraints can include:

- sub-transmission, HV or LV line or cable thermal limitations
- transformer thermal limitations
- fault current limitations
- security of supply limitations (as described in codes or otherwise)
- voltage limitations
- system strength
- transmission connection asset constraints identified via periodic reviews (including the annual TCPR) and via joint planning activities with AEMO and other DNSPs.

This can include limitations that arise from the traditional flow of power and reverse power flow (caused by embedded generation). Fault level constraints are also identified via periodic modelling of the network, from the sub transmission network to the zone substation distribution bus. The impact on existing fault levels is also assessed as part of the connections approach described in section 7.2.1.1 (for generator connections >=1MVA).

CPPCUE manage and resolve constraints using the risk-based approach and controls described in section 7.1.

CPPCUE's network reliability must also meet customer expectations for a level of service that is maintained or improved at a cost less than what customers value reliability. This is achieved by adopting the Value of Customer Reliability (VCR) or STPIS in project assessments where network reliability is impacted.

7.2.4 CER/DER integration

Local energy resources, whether customer owned (CER) or distributor owned (DER) require careful integration to avoid overloading the network or causing unwanted power quality consequences.

Issues to be considered by Network Planning include:

- voltage constraints
- loading constraints
- AEMO requirements
- NER Load shedding requirements to maintain system stability.

In the role as a Distribution Service Provider, CPPCUE adopts a wholistic approach to the integration of CER and DER as described in the CPPCUE Voltage Control Strategy. An example is ensuring compliance with customer side controls for power quality (primarily solar inverter compliance) to optimise the benefits of these controls to enable more customers to export.

Network Planning also factor in the economic benefits of investments proposed to enable CER/DER export. This approach aligns with the AER's *Customer Export Curtailment Value* (**CECV**) *Methodology*.

7.2.5 Compliance requirements

Network Planning always consider the requirement of compliance with various codes as listed in section 6.4 and its obligations under the ESMS. As well as the traditional compliance objectives of voltage, current and fault level standards, the advent of REFCL equipped substations has meant recognition of their operational constraints. Rapid Earth Fault Current Limiters (REFCLs) are installed in 22 zone substation networks in Powercor and satisfy the requirements of the Electricity Safety (Bushfire Mitigation) Regulations (as shown in Figure 2).

Network Planning is responsible for forecasting, identifying constraints and proposing network interventions to resolve REFCL constraints on REFCL networks throughout the Powercor supply area. Network Planning also manages augmentation and transfers between REFCL and non-REFCL areas in line with Augmentation and Transfers Between REFCL and Non-REFCL Networks Procedure (CPPAL-PR-0005).

United Energy has REFCLs at Frankston South (FSH), Mornington (MTN) and Dromana (DMA), however the same regulations do not apply there.

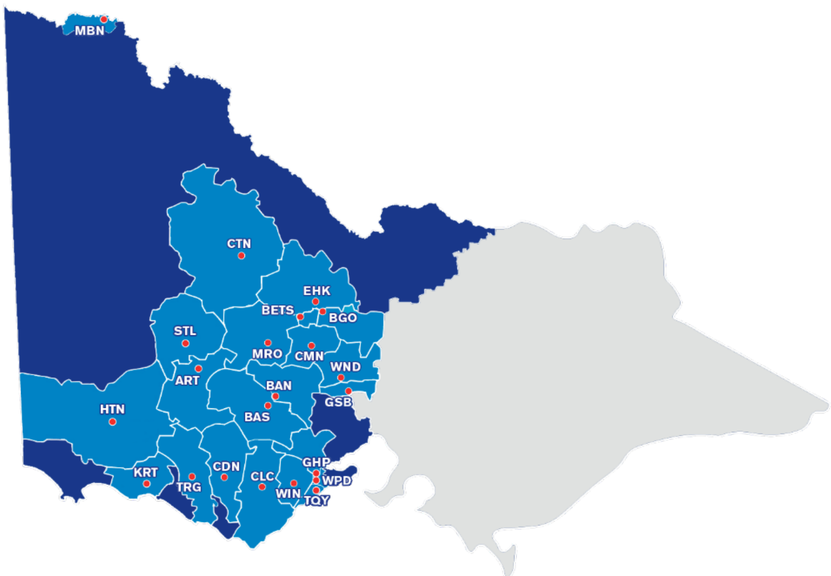

Figure 2: Map of Powercor's REFCL Zone Substation Locations

CitiPower also has an obligation (in the Electricity Distribution Code) to maintain a higher level of security of supply for the sub-transmission network in Melbourne's CBD. Network Planning is responsible for forecasting, identifying constraints and proposing network interventions to meet to this higher-level standard.

Generator connections also carry considerable compliance obligations for the lifetime of the connection, notably compliance with their individual generator performance standards as lodged with CPPCUE and AEMO. CPPCUE ensure that generator customers are capable of meeting generator performance standards through the connection and commissioning process. Ongoing adherence to generator performance standards is an obligation for generator participants through both the NER and additional contractual obligations, however CPPCUE do respond and act when there are incidents regarding generator performance.

7.2.6 Network Planning support

Network Planning provide support to other internal stakeholders as listed in Section 6.3.1. Activities that may be required by these stakeholders include:

- advice on short term emergency loading
- advice on network offloading to allow plant replacement and/or maintenance
- alternatives for improving reliability
- alternative supply arrangements to allow plant retirement
- assistance with Annual Planning Report obligations
- assistance with RIT-D applications.

7.2.7 Forecasts

Network Planning produce seasonal, probabilistic maximum and minimum demand forecasts based on past performance and known future changes in order to determine future network requirements across a number of scenarios. These forecasts are provided as 10%, 50%, and 90% Probability of Exceedance (POE) levels from transmission connection points down to HV feeders to inform planning analysis and decision making. Aspects to be taken account of in these forecasts include:

- battery connections
- electric vehicle charger connections
- future embedded generation connections
- historical demand and energy data
- new connections (planned and committed developments)
- new equipment efficiency improvements
- population growth and economic factors.

The forecast approach takes in historical data and factors in weather correction, as the maximum and minimum demands can vary according to the weather conditions experienced over a given period. The forecasts are also modelled using multiple scenarios to cater for possible futures, with an appropriate scenario agreed annually to meet the needs of network planning and the DAPR.

The outputs of the forecasts are reviewed and updated each year and made available internally in an accessible user interface so that the information can be used across all the network planning elements. Forecasts are also published annually in CPPCUE's DAPR and TCPR.

7.2.8 Systems and data

Network Planning use a suite of systems and data to enable effective planning of the network. This includes the following systems that house data:

- Geographical Information System (**GIS**) houses asset, network and geographic information
- Power Quality Monitoring (**PQM**) collects and stores power quality information
- SAP HANA in CPPC and SAP ISU in UE are databases that house meter, tariff and billing data.

It also includes systems that use data, such as the:

- Distributed Energy Resource Management System (**DERMS**) which is used to provide dynamic operating envelopes (via control signals) to generators and batteries and controllable loads
- Distribution Management System (**DMS**) which presents the network topology and network status in real time
- Dynamic Voltage Management System (**DVMS**) which optimises voltage levels in a closed loop control system that uses AMI data. The DVMS is also being set up to raise voltages to curtail PV generation in response to AEMO minimum demand events and test for PV inverter compliance

- Energy Workbench (**EWB**) and Network Load Management (**NLM**) are tools that aggregate meter data and are used to assess demand in locations (or levels) on the network. The EWB tool is being expanded to include voltage, power flow and forecasting components
- Map Insights which is used to visualise network asset information and demand data
- Meter Insights which is used to assess voltage and current data from AMI meters
- Strategic Network Analytics Platform (**SNAP**) in CPPC and Network Analytics Platform (**NAP**) in UE which are used to assess voltage and current data from AMI meters. They are also used for the DVMS and operational applications
- The Forecasting Tool which uses technical and economic inputs and historical network data to present demand forecasts at the network, zone substation and high voltage feeder levels
- TrendSCADA and OSI Pi which are used to visualise, analyse and report data.

Network Planning also use a suite of off-the-shelf tools and applications to effectively plan and assess the network. This includes:

- DIgSILENT power system software which is used for protection and harmonic assessments
- PSCAD power system software used for power systems analysis, particularly dynamic and transient assessments
- Python and SQL which are used to interrogate and analyse data
- Siemens PSS/E power system software used for power systems analysis and dynamic assessments
- Siemens PSS SINCAL power system software used for power systems analysis on the distribution network
- Tableau which is used to visualise, analyse and report data.

In addition, Network Planning use a workflow system, ServiceNow, in VPN to effectively manage the interface with customer, delivery and operational teams. A workflow system is also under consideration for the UE service model.

Network Planning periodically review and update the Network Technology Roadmap which directs future investment in technology. This roadmap attempts to forecast what technologies will be most useful for the future running of the grid.

The above-mentioned systems are also continually monitored and periodically upgraded or updated to ensure they improve and add value to the activities of planning and assessing the network.

7.2.9 Augmentation and interventions

Considering the network planning elements listed above, and the risk-based approach described in section 7.1, a portfolio of network augmentation, non-network service contracting, and customer or industry related interventions is defined and updated annually. This list is then refined in line with the Network Investment Strategy (STR-0023), and the Portfolio Governance Framework (STR-0013). The portfolio includes investments that cover compliance and safety requirements. It also includes an allowance for the customer connections program which is driven by the needs of customers requesting connections to the network and alterations to their supply. The customer connections program is ongoing and managed in line with the connection dates negotiated and agreed with customers. An allowance is also made for interventions required to address customer complaints that may arise throughout each year.

7.3 Integration and feedback

Network Planning continually review feedback from the systems described in section 7.2.8 along with reports from customers and other stakeholders to address issues in the network. This information forms an input to the risk-based approach to determine future investments.

Should any safety or compliance issue arise at any time, this may override planned investments due to being urgent and unforeseen.

These feedback loops are pictured diagrammatically in Figure 1 and demonstrate the continuous process of planning for the future, carrying out necessary and approved projects, assessing the performance of the system after the change and applying any corrections, if necessary, from the results obtained from the post project review.

The integrated approach links the sub-elements via monitoring and periodic reviews, in line with the portfolio governance framework described in Portfolio Governance Framework (STR-0013). Management monitoring and review is also ongoing as all sub-elements fit under the one CPPCUE Network Planning section.

The integrated approach also incorporates stakeholders, for example AEMO, who have been engaged on matters relating to the operation of the sub-transmission network that affect the distribution network, such as AEMO's VAR dispatch control system. Engaging AEMO on these items was derived in the CPPCUE voltage control strategy and via monitoring the network where issues were discovered. This is only one example; however it describes the approach taken.

8. Referenced Documents

Table 1: Referenced Documents

Title	Document No.
Asset Management Policy	PO-0001
Augmentation and Transfers Between REFCL and Non-REFCL Networks	CPPAL-PR-0005
Connection Charge Guideline for Electricity Customers	https://www.aer.gov.au/industry/registers/resources/guidelines/connection-charge-guideline
Customer Export Curtailment Value (CECV) Methodology	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/customer-export-curtailment-value-methodology
Distribution Annual Planning Reports (DAPRs) and Transmission Connection Planning Reports (TCPRs)	https://spaces.hightail.com/space/UaPnYl6yeV
Distribution System Augmentation Planning Policy and Guidelines - CPPC	CPPAL-PR-0008
Electricity Distribution Code of Practice	https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-and-policies/electricity-distribution-code-practice
Enterprise Risk Management Framework	13-10-CPPCUE0005
Electrical Safety Act	https://www.legislation.vic.gov.au/in-force/acts/electricity-safety-act-1998/081
Electricity Safety (Bushfire Mitigation) Regulations	https://www.legislation.vic.gov.au/as-made/statutory-rules/electricity-safety-bushfire-mitigation-regulations-2023
Electricity Safety (Management) Regulations	https://www.legislation.vic.gov.au/in-force/statutory-rules/electricity-safety-management-regulations-2019/001
Electricity System Code	https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-codes-guidelines-and-policies
High Voltage Augmentation Planning Policy and Guidelines - CPPC	15-20-CP0001
Integrated Network Management System	STR-1440
INMS Document Management Standard	ST-1750
INMS Policies, Objectives and Measures	PO-2050
Low Voltage Augmentation Planning Policy and Guidelines - CPPC	01-10-CP0001
Minimum Demand Strategy	STR-0022
National Electricity Objective	https://www.aemc.gov.au/regulation/neo
National Electricity Law	https://www.aemc.gov.au/regulation/legislation
National Electricity Rules	https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules
Network Environment Strategy	STR-0009
Network Investment Strategy	STR-0023
Network Planning Guidelines - UE	UE-GU-2200
Network Planning Referral	04-30-F0002
Network Reliability Strategy	ST-0002
Network Safety Strategy	STR-0003

Title	Document No.
Portfolio Governance Framework	STR-0013
Strategic Network Management Plan – CPPC	CPPAL-PL-0003
Strategic Network Management Plan – UE	UE-PL-2034
Values of Customer Reliability	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability
Victorian Service & Installation Rules	https://www.victoriansir.org.au/
Voltage Control Strategy	Issued 11/07/2022

Appendix A: List of REFCL Sites

Table 2: List of REFCL sites

ART	Ararat
BAN	Ballarat North
BAS	Ballarat South
BETS	Bendigo Terminal Station
BGO	Bendigo
CDN	Camperdown
CLC	Colac
CMN	Castlemaine
CTN	Charlton
EHK	Eaglehawk
GHP	Gheringhap
GSB	Gisborne
HTN	Hamilton
KRT	Koroit
MBN	Merbein
MRO	Maryborough
STL	Stawell
TQY	Torquay
TRG	Terang
WIN	Winchelsea
WND	Woodend
WPD	Waurn Ponds