Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review
Regulatory Proposal

Attachment 7-5

Asset Management Plan 2016-2020

ELE PL 0004

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Jemena Electricity Networks (Vic) Ltd

Asset Management Plan 2016-2020

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Name	Job Title	Date	Signature
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Approved by:			
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History

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1	21/04/2015	First Issue.	David Speairs and Stephen Henry **Contributors:** Ashley Lloyd Catherine Lee Dalibor Balicevic Graeme Wirges	Kieran Coughlan Peter Wong Ranjan Vaidya

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This Asset Management Plan has been prepared to inform relevant stakeholders of the asset management approach, processes and strategies applied to the Jemena Electricity Network.

Some of the information and statements contained in the Plan are comprised of, or are based on, assumptions, estimates, forecasts, predictions and projections made by Jemena. In addition, some of the information and statements in the Plan are based on actions that Jemena currently intends it will take in the future. Circumstances will change, assumptions and estimates may prove to be wrong, events may not occur as forecasted, predicted or projected, and Jemena may at a later date decide to take different actions to those it currently intends to take.

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When considering any part of the Plan, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgement and expert advice obtained.

April 2015

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Foreword

Welcome to Jemena Electricity Networks (Vic) Ltd (JEN) Asset Management Plan (AMP), which is a central component of JEN's asset management system. It sets out the plans which Jemena has for managing the network and assets over the period 2016 to 2020 and has been prepared to inform stakeholders of the asset management approach, processes and strategies adopted in order to meet its asset management strategy and objectives.

JEN specialises in the distribution of electricity. JEN owns one of the five licensed electricity distribution networks in Victoria that supplies electricity to approximately 320,000 homes and businesses via approximately 6,000 kilometres of distribution network. The network services 950 square kilometres of northwest greater Melbourne.

JEN is committed to being recognised as a world class owner and manager of energy delivery assets by maximising the long-term value of our shareholder's investments in a legally and environmentally compliant and sustainable manner and delivering a reliable and value adding service to customers, without compromising the health and safety of our employees, customers or the public.

JEN is committed to employing good industry asset management practice to prudently manage the assets over their total life cycle to satisfy our customers. JEN recognises the importance of sound asset management in ensuring the efficient delivery of services that meet customer and stakeholder requirements, both current and future. Network design, network construction, maintenance, operations, asset investment and innovation are vital components of asset management, with effective asset management having a direct impact on customer service, electricity pricing, safety and shareholder value.

The AMP covers all of JEN's key investment processes; in particular the way capital and operational projects and programs are identified and undertaken.

In particular, this AMP ensures that all investment decisions are justified on economic grounds and appropriately consider:

- Key asset management objectives relating to safety, compliance and sustainability;
- The cost and flow-on effects on electricity prices for customers;
- The external operating environment and emerging issues such as climate change;
- Technological advancements such as smart grids;
- The level of service required by network users;
- Forecast demand for network services;
- Options for non-network and demand side solutions; and
- A life-cycle approach to the management of assets.

We hope you find this plan informative and we welcome your comments on it or any other aspect of JEN's performance. Comments can be emailed to haveyoursay@jemena.com.au.

Alf Rapisarda
Executive General Manager, Asset Management

Executive Summary

This Asset Management Plan relates to Jemena Electricity Network's (JEN's) electricity network assets and non-network assets[1].

In implementing this plan, JEN will continue to focus on public and employee safety as our number one priority.

JEN has established an asset management system to manage its assets. In 2014, JEN was accredited with compliance to the PAS 55-1:2008 specification for the optimised management of physical assets. PAS 55 is a leading internationally recognised best practice asset management framework. Key principles and attributes of PAS 55 include ensuring practices are: sustainable, holistic, systematic, systemic, risk-based and optimised.

This plan covers the creation, maintenance and disposal of assets. Assets are created through new customer connections, replacement of aging assets and supporting increasing locational demand for electricity.

- We will connect approximately 4,000 new customers to the network each year, and will continue to either invest in the augmentation of the network or implement demand management opportunities to ensure that we can continue to supply customers.
- There are growth corridors to the north and regions in the south that are undergoing urban renewal.
- The demand for electricity is forecast to increase at a rate of 1.4%. Network augmentations are planned to provide additional network capacity to meet this demand.
- Replacement programs have been developed to ensure that safety and reliability are maintained at existing levels.

As a result of an increasing frequency of severe weather events, programs have been developed to deliver improved customer service during major emergency events, as well as continue to support a positive customer service business culture.

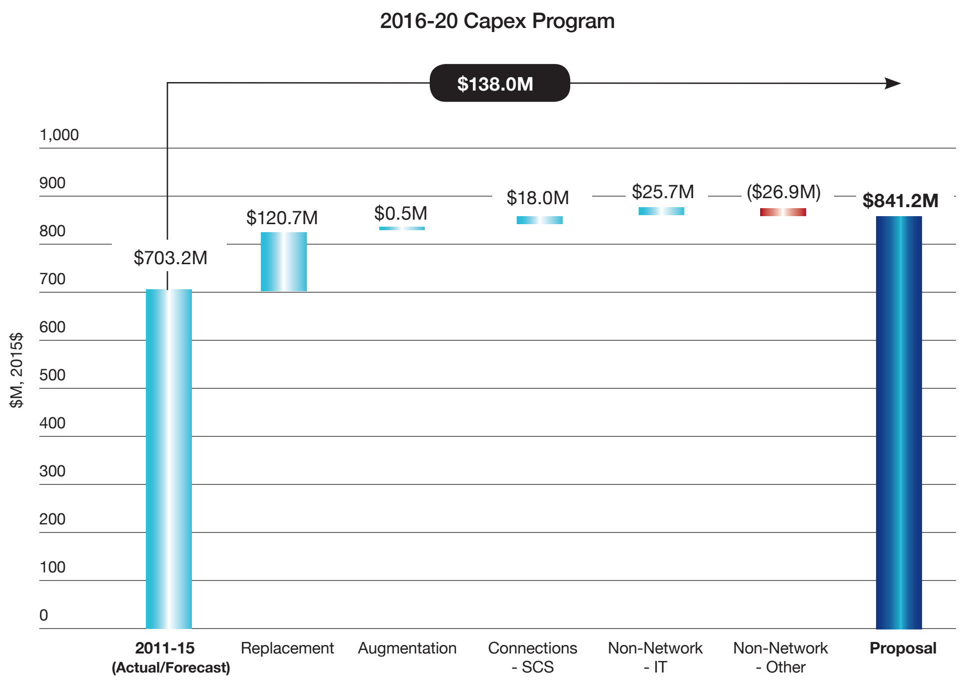
Through our customer engagement activities, our customers have identified a number of preferences, including strong support for our focus on safety, as well as feedback that we had generally struck the right 'balance' between safety, price and service levels, and a preference to maintain current levels of reliability. There was strong support for maintaining current response service levels (85%).

Customers also want us to explore new ways of more efficiently delivering our services and ways of enabling them to use our services more efficiently.

Continued modernisation of the distribution network through smart network initiatives promises to deliver improved operational efficiency, enhanced asset safety, improved supply reliability and quality, enhanced customer service and efficient integration of embedded renewable energy resources. Details of JEN's smart network plan can be found in Section 5.10.

Figure 1.1 shows the variance between the proposed capital investment in 2016-2020 and the 2011-2015 actual/forecast.

1 Non-Network assets covered by this plan include fleet and tools and equipment. IT is excluded. For information on IT, refer to the JEN IT Asset Management Plan 2016-20.



The Non-Network – IT capex variance displayed here is for illustration purposes only. For information on the capex spend for this expenditure category, refer to the JEN IT Asset Management Plan 2016-20.

Figure 1.1 Variance of Proposed Investment in 2016-2020 and the 2011-2015 Actual/Forecast Investment

Table 1.1 provides a high-level overview of some of the major works proposed to take place during the plan period.

Program Description	Volume over 2016-20
New or augmented zone substations	Craigieburn, Sunbury, Flemington
New zone substation control buildings	Airport West and Broadmeadows
Preston/East Preston 6.6kV to 22kV conversion	New zone substation and distribution plant
Zone substation transformer replacements	Nine new transformers
Zone substation switchgear replacement	Six new switchboards and 10 circuit breakers
New distribution feeders and reconfigurations	10 new feeders and 10 new feeder reconfigurations
Upgraded distribution substations	150 upgraded substations
Overhead service replacements	49,000 new services
Replaced pole tops	19,500 new pole tops
Replaced and staked poles	10,000 new or staked poles
Install Rapid Earth Fault Current Limiters (REFCL)	Four REFCL's

Table 1.1 High level physical deliverables from the proposed investment in the 2016-2020 period

Connections (+$18.0M)

Significant public infrastructure, business, commercial and residential projects will occur in the Jemena network area in the next period. Examples include expansion of Melbourne International Airport, widening of the Tullamarine Freeway, redevelopment of the Amcor Paper Mill and other ex-industrial sites into high rise apartments and the development of residential precinct structures in the northern urban growth corridor as well as technology parks. These projects are expected to attract further business and housing development in the region.

In terms of Connections growth, residential customer numbers are forecast to grow by 1.3% per annum, small business customer numbers by 1.1% per annum and large business customer numbers by 3.0% per annum. Maximum demand is forecast to grow by 1.4% per annum from summer 2014-15 to summer 2020-21.

Some growth corridors such as Craigieburn and Sunbury are expected to grow at a much higher rate than the network average, with summer maximum demand forecast to grow at around 5% per annum. Forecast peak demand in areas which are predominantly industrial (such as Tottenham) is expected to decline or remain unchanged.

Jemena regularly meets with major customers and large land/property developers to understand their future plans for electricity connections and consumptions. During these discussions Jemena will explore, together with customers, the technological options that will result in more efficient use of existing network capacity and optimal connection costs while meeting the current and future needs of customers.

Augmentation Capex (+$0.5M)

The Preston region is one of the new high rise hubs in the JEN network, undergoing urban revitalisation and providing housing and employment on under-utilised land.

The capacity of 6.6kV distribution assets in the area supplied by Preston (P) and East Preston (EP) zone substations is low compared to 22kV and by today's standards. Many of the 6.6kV high voltage feeders are heavily loaded with insufficient spare capacity to accommodate customer load increases.

The lack of spare capacity means that even modest customer load increases in this area in the next few years would require major feeder augmentation at considerable high costs to the customer. Additionally, the 32 feeders exiting Preston (P) and East Preston (EP) have utilised all of the available land space surrounding the zone substations. JEN will convert Preston (P) and East Preston (EP) to 22kV and hence increase the capacity of the network to meet forecast demands. This strategy provides for a lower cost solution for customers in the longer term.

Sunbury has developed over the years from a rural country area with mostly farms and paddocks to a suburban area with a mixture of commercial, medium density housing close to the town centre and farms at outer bound. Development in recent years has been rapid and there have been significant housing estate and land developments. Established in the 1960's, the Sunbury (SBY) zone substation now supplies 14,500 customers has reached full capacity and is of low reliability 'country style design' that is no longer appropriate for this growth region of Melbourne. JEN will upgrade the zone substation to meet customer expectations for reliability of supply and to meet forecast demands.

The establishment of the Craigieburn (CBN) zone substation will augment the distribution network in Craigieburn, Somerton, Roxburgh Park and surrounding areas. The new zone substation will provide capacity to meet on-going load growth and will maintain supply reliability at current levels.

Somerton (ST) zone substation currently supplies 13,500 domestic, commercial and industrial customers via twelve 22kV HV feeders. ST's peak demand is forecast to grow at an average rate of 4.5% per annum. This high rate is driven by the ongoing developments in the growth corridor to the north of Melbourne along the Hume Highway. The driver for the investment in this area is to mitigate the risk of substantial customer load shedding due to inadequate HV feeder and zone substation supply capacity at peak times.

JEN will continue to invest in the augmentation of distribution feeders and substations in response to customer load growth to ensure that safety, reliability and the ability to provide supply are maintained to the current standard in the next period.

Replacement Capex (+$120.7M)

Condition based replacement offers the potential to lower costs through 'just in time' replacement. It represents good industry practice. Jemena assesses the condition of critical items of plant to determine when replacement is required in order to avoid catastrophic failure and extended outages to customers.

The operating environment of Jemena's network is changing. Climate change is also having an increasing impact on network performance, increasing the duration of the bushfire season and creating conditions conducive to pole fire ignition. As well as this, more frequent wind storms and heat waves are likely to prevail.

In this regard Jemena continues to look at and evaluate new initiatives such as improving network resilience to wind and extreme heat events, improving the management of such weather events and responding to government climate change policies.

Protection relays are devices installed at zone substations which perform the critical function of cutting electricity supply when called upon to do so and making the distribution network safe for employees and the public. The majority of the relays at Broadmeadows (BD), Coburg North (CN), Footscray West (FW) are obsolete electro-mechanical relays, circa 1975 and are without any real time monitoring features, hence, any failure remains undetected until a fault occurs causing widespread loss of supply, damage to assets and potentially impacting personal safety.

The impact of recent relay failures at these zone substations has been to unnecessarily interrupt significantly more customers than required to make the network safe. JEN will replace the relays used to protect major primary plants including power transformers and 66kV and 22kV buses. The zone substations where the replacements are required supply one-third of Jemena's 320,000 customers.

Battery banks and chargers are critical equipment to protect the integrity of the zone substation plant and equipment. Experience has shown that the failure of these items may lead to the catastrophic failure of plant and extended customer interruptions – potentially for several days.

Condition Based Risk Management (CBRM) modelling is used to assist in the development of asset investment plans for critical assets. CBRM develops a Health Index for each asset based on a scale from 0 to 10 (a Health Index >= 7 indicates plant is in poor condition and a high probability of failure exists).

JEN will replace three transformers at Fairfield (FF) zone substation which were installed in circa 1955 and have Health Indexes of 8.19, 8.19 and 8.32. Essendon (ES) zone substation will have two transformers replaced which are circa 1965 and have Health Indexes of 7.36 and 7.71. Heidelberg (HB) zone substation will have two transformers replaced which are circa 1966. The No. 1 transformer has a Health Index of 7.0 and the No. 2 transformer is the same age and exhibited similar duty levels. For this reason both transformers have formed part of the replacement proposal.

The switchgear at Footscray West (FW) zone substation is 75 years old. It consists of 16 oil circuit breakers that provide supply to 13,500 customers. In the event of a failure, the switchgear is unable to be repaired as it is not designed to current standards and would most likely fail catastrophically. Condition monitoring indicates partial discharge at elevated levels which indicate elevated probability of failure and consequently extended customer interruptions. JEN will replace these circuit breakers.

JEN will continue to focus on employee and public safety as our number one priority and we have developed asset replacement programs to ensure that the same level of reliability and public safety is provided to our customers in the next period.

As many assets are entering their end-of-life phase, JEN's operating strategy is one of continually reviewing its asset management approach in order to ensure that assets continue to meet safety, compliance or service performance requirements. Jemena focuses on maintaining its service performance. Changing regulatory obligations are also impacting on safety and compliance work plans. The following items have been identified for the next period.

An increasing volume of crossarms are in the wear out phase, with 19% exceeding the expected life of 45 years. This has resulted in an increasing trend of in service pole top failures. JEN has identified that 19,500 pole tops will require condition based replacement in the next period. Of these, JEN will replace 3,249 high voltage wooden crossarms that have been identified as being at high risk of experiencing pole top structure fires.

JEN shares the concerns of Energy Safe Victoria (ESV) regarding the increasing trend of pole top fires since 2012 and the exposure of customers to significant outages and the potential for customer property damage through high voltage injections.

Approximately 65% of JEN's 170,000 overhead services are of a type that are not meeting required performance criteria. JEN has a detailed strategy to implement condition based replacement of 49,000 neutral screened and twisted wire services in the next period to address the increasing trend of minor electric shocks experienced by some customers.

The continuation of condition based pole replacement is required in the next period to maintain reliability and safety levels. The increasing condemnation rate of steel poles in residential areas and timber poles that have been classified as unserviceable are the drivers of this program.

The safety of customers and the public is the driver for the replacement of pole mounted cable terminations that consist of metal boxes filled with an insulating compound. The recent catastrophic failure of some of these metal boxes in public locations has driven the requirement to prioritise and replace those in locations with the highest potential impact on public safety. Condition monitoring is not a feasible option and replacement is required.

As a result of an increasing frequency of severe weather events, programs are required to minimise the fire risk associated with the network assets to as low as reasonable practicable.

Resonant earthing at zone substations has the capability to reduce high voltage earth fault currents and as a result, risks arising from fire ignition are substantially reduced. JEN will install four resonant earthing systems at zone substations which supply customers in the highest bushfire loss consequence areas of Sunbury, Craigieburn, Coolaroo and Somerton.

In addition to our plans to remove all timber high voltage crossarms from the hazardous bushfire risk area by the end of 2015, JEN also has delivered the recommendation of the Victorian Bushfire Royal Commission (VBRC) to remove Single Wire Earth Return (SWER) from Victorian distribution networks. A logical progression is JEN's proposal to progressively remove all 42km of bare low voltage mains conductors from the hazardous bushfire risk area in the next period.

Non-Network (+$26.9M)[2]

The SCADA and Network Control function involves monitoring, controlling and managing the routing of electricity supply throughout the network.

The main driver for the investment in SCADA and Network Control is the upgrade of the SCADA system in order to maintain network management capability. This will ensure continued visibility, monitoring and management of the electricity network and will deliver benefits to the end consumer.

With the successful completion of the Advanced Metering Infrastructure (AMI) project delivering the scope mandated by the Victorian government, Jemena believes it is appropriate to focus on further use of the infrastructure and meter data for network benefit realisation. A number of enhancements to the meter functions and back-end IT systems are therefore planned in the regulatory period, with closer integration of AMI to the SCADA system to improve situational awareness and operational response. These initiatives are covered in the JEN IT Asset Management Plan 2016-20.

JEN completed its corporate property strategy in the 2011 to 2015 period, hence the reduction in expenditure in the forecast period. Investment in fleet, tools and equipment for field service resources is forecast at similar levels to the current period.

2 This variance excludes Non-Network - IT capex.

1 Introduction

This chapter sets out the scope, purpose and layout of this Asset Management Plan (AMP) document. It describes the asset management system used and administrative procedures for maintaining the document.

1.1 Scope

This Asset Management Plan (AMP) relates to Jemena Electricity Network's (JEN's) electricity network assets and non-network assets such as fleet, buildings and tools and equipment. IT is excluded from this plan. For information on IT, refer to the JEN IT Asset Management Plan 2016-20.

The AMP covers both regulated and non-regulated assets. While different management practices could apply to non-regulated assets, in practice this is not done. All financial information relates to regulated assets only.

The AMP is supported by the Capital and Operational Work Plan (COWP), which provides additional information on the expenditures required to implement the AMP.

1.2 Purpose

The purpose of the AMP is to:

- Detail the operating environment, levels of service, summarise risks and opportunities, contingency planning and governance;
- Identify the type, number, condition, performance, technical and commercial risk with respect to the assets;
- Outline the asset management plans for the next five years to deliver the JEN asset management strategy and objectives, including formal obligations and regulatory requirements;
- Inform the operational and capital expenditure and also the two-year plan of work;
- Define the long-term plan on how to optimally and sustainably manage the assets and asset systems; and
- It also aims to ensure investment decisions and strategies are aligned to the operational and capital expenditure objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the National Electricity Rules.

Section 1 outlines the purpose of the AMP, the asset management system including hierarchy, approval and communication of the document, JEN's operating environment including operations, services performed, a description of the network ownership and control, approval timeframes, stakeholders, the regulatory and legislative environment and expenditure drivers.

Section 2 outlines the JEN business. It describes the high level corporate strategy and how asset management is structured to enable the company to achieve its strategy. The section also contains a description of the asset portfolio and an overview of the drivers for investment.

Section 3 provides an outline of the Jemena asset management policy, and reference to the asset management strategy and objectives which both provide the direction and guidance for the development of the AMP.

Section 4 describes how JEN goes about managing its assets. It includes an overview of the governance, processes and standards the business seeks to achieve through its asset management practices. It also outlines the knowledge management and the critical systems used.

Section 5 describes the environment in which JEN operates. It describes a wide-ranging set of issues which affect how JEN operates and which ultimately require the company to invest in assets or manage assets to meet various levels of corporate responsibility and requirements. It covers issues impacting the entire network relating to quality of supply, compliance and safety, emergency/contingency planning, bushfire management and climate change.

Section 6 presents an overview of JEN's customer focus and levels of service. It describes current performance and the reliability plan to meet performance targets.

Section 7 examines how the company manages its network assets to cope with growth in customer numbers and the need for new connections.

Section 8 describes the planning processes to deal with the impacts of increasing demand across the network. The section examines network planning criteria, forecasts and the risk based approach to maintaining a reliable, prudent and efficient supply to customers.

Section 9 describes JEN's lifecycle asset management strategy in detail. It outlines the asset types and classes in operation, and their historical and projected performance and condition. It does so in a systematic manner - highlighting specific asset strategies, and the requirements on JEN to operate, inspect, maintain, and eventually replace or dispose of each critical asset.

1.3 Asset Management System

This section provides a high-level overview of JEN's Asset Management System and how the AMP fits into the system's hierarchy.

This plan covers the creation, maintenance and disposal of assets. Assets are created through new customer connections (see Chapter 7), increasing demand for electricity (see Chapter 8) and replacement activities (see Chapter 9),

In 2014, JEN was independently accredited with the PAS 55-1:2008 specification for the optimised management of its physical assets. PAS 55 is a leading internationally recognised best practice asset management framework. Accreditation demonstrates that JEN's capital planning and governance framework for asset management represents best practice. Roles and responsibilities for asset management are clearly set out in role statements and assigned within JEN's organisational structure.

Key principles and attributes of PAS 55 include ensuring practices are: sustainable, holistic, systematic, systemic, risk-based, and optimised. PAS 55 promotes a 'Plan-Do-Check-Act' framework, where the focus is on continuous improvement across all facets of asset management.

We have a proven track record in safety, reliability, cost efficiency and customer satisfaction, but we are constantly looking at how we can improve and become more efficient. One key step in this was the recent certification of our electricity assets to the PAS 55 framework.

Figure 1.2 shows the inputs and outputs of the Asset Management System, which aims to fulfil JEN's corporate strategy and objectives by meeting key success measures. For more information about JEN's corporate strategy and objectives and key success measures, refer to Chapter 3.

Refer to Appendix A for a full document map.

Asset Management Framework

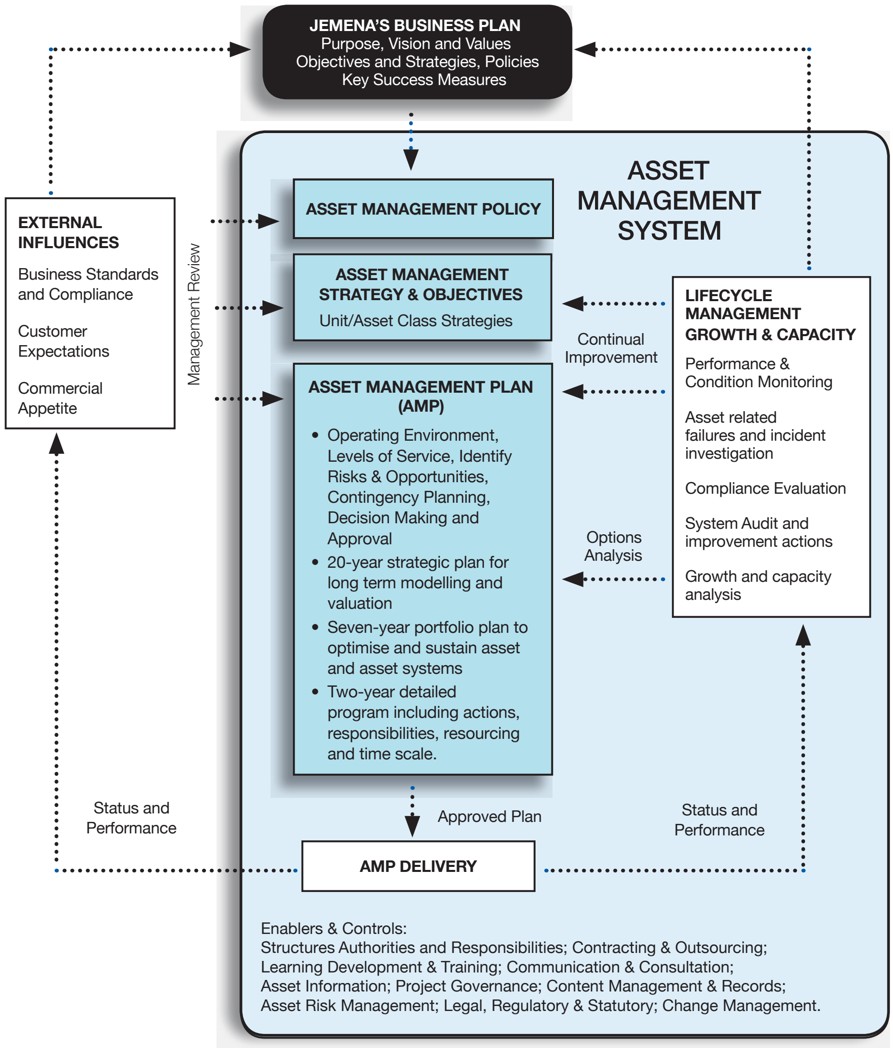


Figure 1.2 The Asset Management Framework and System

JEN has established asset management documentation to ensure that its asset management system can be adequately understood, communicated and operated. At the highest level, the key document informing the AMP is the JEN Asset Management Strategy and Objectives (AMSO) document. The AMSO encapsulates JEN's asset management policy, long term objectives and performance and condition targets. The AMP is supported by, and draws together, other more detailed strategic documents such as asset class strategies and network development strategies.

The key outcomes of the asset management system are documented in the Capital and Operational Work Plan, a five-year plan that details the specific projects and programs of work being undertaken to implement the asset management plan.

The interaction between key asset management documents and JEN's AMP is outlined in Figure 1.4, while a list of key documents is provided in Appendix B.

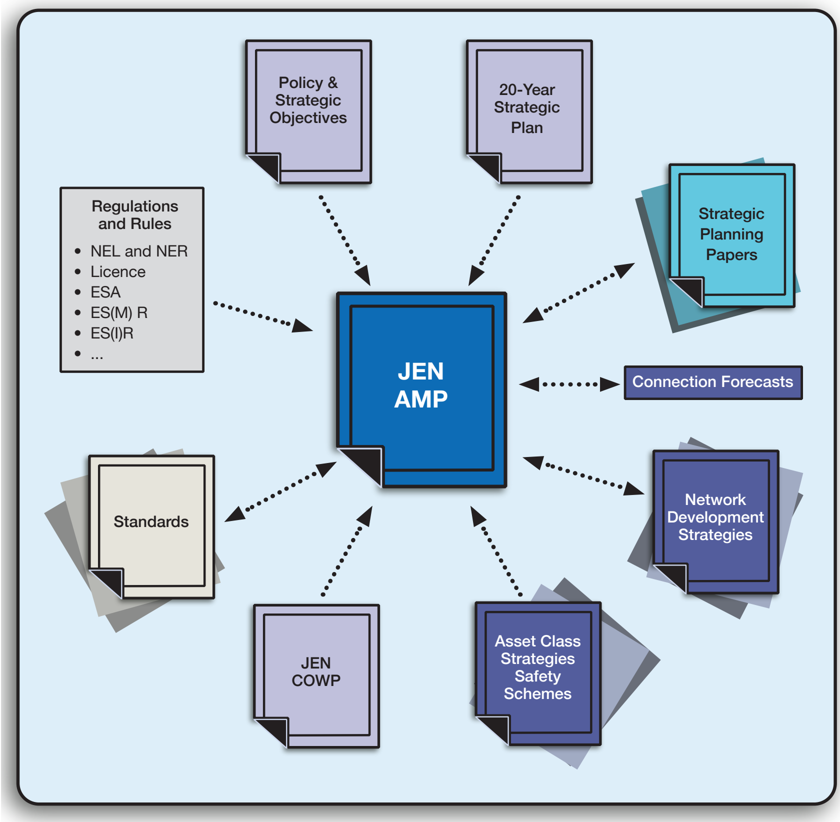


Figure 1.3 The interaction between key asset management documents and JEN's AMP

1.4 Approval and Communication

The AMP is reviewed annually as part of the normal business planning, budgeting and review cycle. The next review is due before 1 February 2016.

This document is reviewed annually to reflect any changes to the Jemena Five-Year Business Plan and external influences.

This AMP is communicated internally within Asset Management but also to the Service Delivery group who is the principal infrastructure delivery business, responsible for the safe, hands-on provision of all the maintenance and capital expenditure works programs.

1.5 Operating Environment

This section provides a high-level overview of JEN's operating environment including:

- JEN's operations, ownership and control, stakeholder information, and regulatory and legislative environment; and
- A description of the JEN's critical elements and location within the Greater Melbourne electricity network, expenditure drivers, and services performed.

1.5.1 Operations

The JEN's electricity distribution network supplies electricity to over 320,000 customers (approximately 88% residential) in a 950 square kilometre area of Melbourne's city and north-western suburbs, with Melbourne Airport at the approximate physical centre. The network area borders each of the other electricity distribution businesses in Victoria: CitiPower, Powercor, AusNet Services and United Energy Distribution, as well as interconnecting with the transmission network owned by AusNet Services and planned by the Australian Energy Market Operator (AEMO).

1.5.2 Services Performed

JEN provides distribution network services to electricity consumers, electricity retailers, the electricity market operator, other distribution businesses and third parties seeking access to JEN infrastructure. JEN also provides external services to third party asset/infrastructure owners that include:

- Electricity delivery;
- Non-standard control services;
- Customer connections;
- Inter-distribution business (DB) settlement;
- Meter provision;
- Meter data management; and
- Dial Before You Dig.

Electricity Delivery

JEN provides electricity delivery services to electricity consumers and retailers that include:

- Delivering electricity to retailers and consumers over the distribution network in accordance with regulatory performance, quality, reliability and safety standards;
- Responding to customer enquiries and complaints;
- Providing security lighting;
- Providing reserve feeder;
- Managing planned interruptions;
- Rectifying unplanned interruptions; and
- Billing electricity retailers for electricity consumed at (and distribution services provided to) national meter identifiers (NMI) for which they are the financially responsible market participant.

Non-Standard Control Services

JEN provides non-standard control services to local councils, VicRoads, telecommunications organisations, local councils and consumers that include:

- Public lighting;
- Facilities access; and
- Unmetered supplies.

Other services requested by retailers on behalf of customers include:

- Meter installation testing;
- Service vehicle visits;
- Field officer visits; and
- Temporary supplies.

Customer Connections

JEN's customer connection services involve connecting new premises to the distribution network in accordance with regulatory performance, quality, reliability and safety standards, and customer specific requirements such as security lighting and reserve feeder. This service also includes connection of load and embedded generation.

Inter-Distribution Business (DB) Settlement

JEN provides inter-DB settlement services to DBs where the distribution network crosses billing boundaries. The services include settlement of energy delivered to metering installations that exist in areas allocated to other DBs, or where JEN metering installations are supplied by another DB network.

Meter Provision

JEN provides meters for AEMO and electricity retailers, involving electricity meter installation and maintenance.

Meter Data Management

JEN also provides meter data management services to AEMO and electricity retailers, involving the collection, validation, substitution, estimation and publishing of metering data.

Dial Before You Dig

JEN provides Dial Before You Dig (DBYD) services to the public, involving a response to enquiries about where it is safe to dig to avoid underground electricity cables.

JEN also receives contributing services from:

- Jemena Ltd, which provides enterprise support function services; and
- Various competitive and related party service providers.

1.5.3 Network Description

Table 1.2 provides key information relating to the JEN. Figure 1.4 shows its location within the Greater Melbourne network.

Location	North Western Metropolitan Melbourne
Area (sq km)	950
Line Length (km)	6,159 (4,440 overhead, 1,719 underground)
Subtransmission Lines (66kV and 22kV)	46
Number of Feeders	220
Number of Poles	97,813
Customers	318,294
Transmission Connection Points	7
Number of Zone Substations	25
Zone Substations Capacity (MVA)	1,770
Number of Distribution Substations	5,962
Energy Served (supplied) (GWh)	4,330
Maximum Demand (MW)	989

Table 1.2 The Jemena Electricity Network (JEN)

Figure 1.4 The Jemena Electricity Network (JEN)

1.5.4 Ownership and Control

The Jemena Electricity Network Pty Ltd. is wholly owned by SGSP (Australia) Assets Pty Ltd. SGSP (Australia) Assets Pty Ltd is 60% owned by State Grid International Development Australia Investment Company (**SGIDAIC**) and 40% owned by Singapore Power International Pty Ltd (**SPI**). SGIDAIC is 100% owned by State Grid International Development (**SGID**). SGID is a wholly owned subsidiary of State Grid Corporation of China (**SGCC**) and is the platform for undertaking the overseas investment and operations of SGCC. SPI is wholly owned by Singapore Power (**SP**) . SP is 100% owned by Temasek Holdings (Private) Limited (Temasek).

1.5.5 Stakeholders

Table 1.3 lists JEN's key stakeholders and the interests that need to be considered in each case.

Stakeholders	Stakeholder Interests
End-use Customers[2]	Reliable supply of electricity of suitable quality Fair price Health and safety Environment Information during outage situations Timely response to complaints and enquiries Timely connections

3 The preferences and interests of end-use customers are discussed in section 4.10.

Stakeholders	Stakeholder Interests
Shareholders	Return on investment Growth Reliability Regulatory compliance Reputation
Retailers	Reliable supply of electricity Quality of supply Management of customer issues Information in outage situations Good systems and processes
Regulators	Compliance with statutory requirements Accurate and timely provision of information Value for money Open and honest communication on views specific to regulation
Public	Health and safety Environment Good corporate citizen
Employees and Contractors	Health and safety Career development and opportunities Appropriately rewarded Accurate records and information systems Construction and maintenance standards Innovation A good place to work

Table 1.3 JEN Stakeholders and Stakeholder Interests

1.5.6 Regulatory and Legislative Environment

Economic regulation of the electricity distribution industry currently falls under the jurisdiction of the Australian Energy Regulator (AER), while the principal technical regulator is Energy Safe Victoria (ESV) and the Environment Protection Agency (EPA).

The legislative instruments under which JEN must operate and manage its assets are as follows:

- The Electricity Industry Act 2000;
- The Electricity Safety Act 1998 and Regulations;
- The Trade Practice Amendment Act;
- JEN's Victorian Electricity Distribution Licence;
- The Electricity Distribution Code (August 2008);
- The National Electricity Law;
- The National Electricity Rules; and
- The Bushfire Mitigation Code.

In addition to these, we also apply industry guidelines to the operation and management of the assets.

1.5.7 Expenditure Drivers

Several expenditure drivers influence the way the electricity network is operated, planned and managed. These drivers include but are not limited to:

- Growth and capacity demand;
- Supply reliability and quality;

- Compliance, safety and the environment; and
- Technological developments.

Growth and Capacity Demand

Aspects of growth and capacity demand that drive expenditure include the following:

- New customer connections, numbers and growth. JEN is obliged to connect new customers to its network, ranging from individual properties and urban residential developments through to new large commercial and industrial customers.
- Embedded generation and demand-side management initiatives, including Advanced Metering Infrastructure (AMI). This becomes relevant when existing and new installations influence demand levels and technical characteristics across the network in a dynamic and complex manner.
- Customer demand and energy forecasts. This becomes relevant when this directly and materially informs augmentation and required increases in capacity of the integrated assets.
- Maintaining supply and asset utilisation through augmentation. Predefined, risk-based planning criteria are used to assess the economic merit of investment compared with the potential for unserved energy. This informs the overall level of asset utilisation, which must be maintained at a level that ensures suitable supply following outages of key assets.

Growth in new connections is discussed in Chapter 7, while growth in demand is discussed in Chapter 8.

Supply Reliability and Quality

Aspects of supply reliability and quality that drive expenditure include the following:

- Supply reliability, quality and customer service standards. Prescribed service levels are mandated through license conditions and regulations;
- Maintaining the asset performance and condition of an increasing and ageing asset base. Supply reliability and quality is dictated by how the assets perform their intended functions. Failures can directly lead to customer interruptions;
- New failure modes for assets. As assets age and are subject to environmental conditions, new failure modes can arise, which must be managed based on the safety and reliability risks involved; and
- There is a service target performance incentive scheme (STPIS), also known as S-Factor scheme, which is a mechanism for the AER to financially reward or penalise for better or poorer service performance. The targets for a given year are approved based on the performance over the previous year regulated period.

Asset performance is further discussed in Chapter 6, with the impact on asset replacements discussed in Chapter 9.

Compliance, Safety and the Environment

Aspects of compliance and safety that drive expenditure include the following:

- Mandated compliance and safety obligations. Various standards relating to matters such as security and safety impact on both the design of existing and new plant and operational expenditure activities;
- Bushfire mitigation and vegetation management;
- Environmental obligations. This involves greenhouse gas emissions, noise, contaminants, vegetation, and bushfires;and
- Emergency response capability.

Specific compliance, safety and the environment issues are discussed in Chapter 9 for each asset class.

Technological Developments

Technological developments include the following:

- Information technology-based systems for network operations, engineering and capital works, customer management, retailer management, billing, and corporate services; and
- Network monitoring and control.
- Technological developments in the next period relate mainly to IT and are discussed in the Jemena Electricity Networks IT Asset Management Plan 2016-2020.

2 The Jemena Business Plan

This chapter provides a summary of the Jemena Business Plan and shows how the AMP relates to that Plan. The Plan provides:

- Strategic direction for Jemena's Asset Management Policy, Asset Management Strategy and Objectives, and Asset Management Plan by detailing the corporate vision, values, objectives, policies, and key success measures; and
- A reference guide and a source of strategic direction for the electricity network to ensure the network strategy and objectives and the asset management strategic approach are consistent with the corporate strategy as a whole.

2.1 Purpose and Vision

Jemena's purpose and vision is supported by a series of strategy directives and measurements of success that are intended to provide concrete guidance for achieving its aims.

Our Purpose

We deliver energy to our customers.

Our Vision

Vision	**"To be recognised as a world class owner and manager of energy delivery assets"**

Figure 2.1 Jemena Vision

2.2 Values

Jemena's values aim to support our vision to be recognised as a world class owner and manager of energy delivery assets. Figure 2.2 shows the five key elements that compose Jemena's values: health and safety, teamwork, customer focus, excellence, and accountability. Working 'the Jemena Way' is about doing what we say we're going to do and working as one team and following one way of doing things wherever possible.

Figure 2.2 Jemena's Values

Health and Safety

We care; we are successful when we identify risks and seek out healthier and safer ways to work, encourage questioning and entertain doubt, care for the physical and mental wellbeing of our people and ensure health and safety is considered appropriately in our decision-making.

Teamwork

We act as one team; we are successful when we value diversity and treat all people with dignity and respect, individually understand how the business works and the role that we play, work together to achieve better outcomes, ensure decisions are based on what is best for the whole business and are willing to sacrifice our own goals for the benefit of Jemena.

Customer Focus

We consider our customers in everything we do; we are successful when we seek opportunities to engage with our customers, hear, listen and think to understand what our customers want, deliver exceptional customer service in and beyond our work areas, evaluate decisions in terms of the impact on our customers.

Excellence

What we do, we do well; we are successful when we are committed to benchmarking ourselves against the world's best and set our standards accordingly, have an open mind to change, will look for better, simpler and a consistent way of operating, learn from our successes as well as failures and take active steps to improve performance.

Accountability

We do what we say we will do; we are successful when we do what we say we will do to meet deadlines and honour our commitments, encourage honest constructive discussions and are willing to learn from mistakes, are clear on roles and responsibilities and ensure our goals are SMART and we exercise appropriate initiative and judgment.

2.3 Objectives

Jemena has six main objectives:

- Embed a world-class safety culture;
- Be a high performing and engaged workplace that attracts, develops and retains industry leaders;
- Deliver operational and financial efficiencies aligned to business plan;
- Deliver energy services that are safe, reliable, affordable and responsive to our customers' preferences;
- Grow scale to be an influential market leader with strong customer, regulatory, stakeholder and community relationships; and
- Deliver financial performance that is superior to industry peers.

These objectives are supported by a strategy that establishes the core operations of the Jemena business, pursues industry leadership and extends the business to capitalise on new opportunities. In turn, the strategy is aligned to the objectives by which the business' performance is measured.

2.4 Strategy, Key Objectives and Measures

The Jemena strategy which links the vision, strategy and key success measures is detailed below in Figure 2.3. It summarises how Jemena plans to establish a strong foundation, become a leader in the energy delivery industry as a world class owner and manager and extend the business to capitalise on new opportunities.

	"ESTABLISH"	"LEAD"	"EXTEND"
Strategy	"Establish a strong foundation for Jemena"	"Lead the energy delivery industry as a World-Class owner and manager"	"Extend the business to capitalise on new opportunities"

Figure 2.3 The Jemena Strategy

The success of this strategy will be measured with five key success measures detailed below in Figure 2.4.

Key Objectives & Measurements	Safety:	People:	Performance:	Customer:	Growth:
	Top quartile industry safety performance	Top quartile employee engagement performance	Costs at or below regulatory allowance	Cost / Customer trending downward, with no deterioration in service levels	Additional growth value created over base business

Figure 2.4 Key Success Measures

3 Asset Management Policy, Strategy and Objectives

Jemena has established policies and objectives that impact on asset management. In this chapter the relevant policies and objectives are summarised.

3.1 Asset Management Policy

Jemena produces several key policy statement documents, one of which is the Asset Management Policy. This document provides a statement about Jemena's intentions and the principals for asset management as they are applied throughout the business. The Asset Management Policy document supports the Jemena Business Plan and Jemena Values. For more information about Jemena's Asset Management Policy, and other related policies see Appendix A.

3.2 Asset Management Strategy and Objectives

The JEN Asset Management Strategy and Objectives (AMSO) document provides Jemena's strategy for managing Jemena Electricity Network (JEN) assets to deliver the Jemena Business Plan. It details JEN's strategy and objectives, expenditure drivers, and network service levels (involving reliability of supply, customer service, and quality of supply), which considers the existing performance and condition of the asset management system and assets.

It also provides a guide to JEN's strategies, which consider existing asset utilisation and load growth capacity, new customer connections, existing asset performance and condition management, asset maintenance, refurbishment and replacement, and network safety and environmental risk management.

The AMSO aims to:

- Identify the electricity network and asset management strategies and objectives based on the overarching business drivers, the Jemena Business Plan and compliance requirements; and
- Provide governance within the business by providing the relevant plans with strategic direction.

The AMSO is used to inform key stakeholders about the asset management strategy for JEN and also facilitate the development of:

- Asset Class Strategies;
- Network Development Strategies;
- 20-Year Strategic Asset Management Plan;
- This document; and
- The Capital and Operational Work Plan.

3.3 National Electricity Rule Requirements

Sections 6.5.6 and 6.5.7 of the National Electricity Rules sets out requirements for forecast expenditures to be prudent and efficient. This AMP reflects the principles of prudency and efficiency as follows:

- A sound governance process for decision making has been established.
- Investments in unnecessary network are avoided through detailed forecasting requirements; new connections are based on sound principles and conducted by external specialists and forecasting of demand for electricity is conducted internally through a detailed systems study.
- The asset management system is accredited to international standard PAS 55, demonstrating that the asset management framework that has been established for the management of network assets is best practice.

- Standards have been set for the technical characteristics of new assets that reflect historical learnings and are expected to result in optimal life cycle costs.
- The impact on customers is considered with customer engagement and stakeholder forums conducted regularly.
- Procurement is managed strategically.
- Work practices for the maintenance of existing assets are based on good electricity industry practice, including the assessment of the impact of failure and the impact on lifecycle costs for each asset class.
- The decision to replace or maintain is embedded into work practices.
- Replacement of assets is based on a risk assessment basis – a condition assessment for high value assets, thus ensuring that assets are not replaced earlier than is necessary; low value assets that have a low impact of failure are allowed to run to failure, hence maximising asset life and lowering life-cycle costs.

4 Governance

This chapter discusses the governance within Jemena for development of this AMP as well as the methodologies used to monitor the performance of services and programs. This chapter also discusses risk management practices, capital program management, project economic evaluation and business case assessments, project and program cost estimating process, the capital and operational work plan, project management methodology, plan delivery, procurement, customer engagement and stakeholder forums.

The JEN Asset Management system and capital governance processes are certified to the PAS 55 standard. JEN is the third organisation to achieve certification to this international standard in Australia.

4.1 AMP Development Process

JEN's asset management processes aim to deliver optimal investment outcomes that provide due consideration of external influences, expenditure drivers, existing performance and risks, and asset management strategy and objectives.

The AMP is developed in accordance with the process described in Appendix C JEN AMP Development Process.

Capacity Demand

The following factors provide demand driven CAPEX:

- Connections;
- Network Augmentation projects; and
- Projects identified through existing asset utilisation and capacity to meet load growth.

Generally, connections are identified by:

- Medium term forecast which provides estimates of customer number growth for business and residential;
- Historical knowledge of specific customer projects, such as significant load increases by commercial and industrial customers, as well as those initiated by councils and Vic Roads; and
- Historical spend on various categories of projects and trends.

Network augmentation projects are identified by:

- Medium term forecast which provides estimates of customer number growth for business and residential;
- The application of planning criteria and demand forecasts as part of the annual transmission and distribution network planning processes;
- The implementation of network strategies; and
- Regulatory obligations.

Asset Replacement Projects

Asset replacement projects are identified within asset class strategies (see section 9) by:

- Programs required to meet regulatory compliance;
- 'Whole of Life' asset management;
- Application of appropriate risk assessment based on the asset criticality; and
- Review of the performance of the assets.

4.2 Risk Management

JEN recognises risk management as an integral part of its business operation and strategic planning. Risk management, including risk evaluation, treatment and documentation, is undertaken in a systematic manner in conformance with AS/NZS 31000:2009.

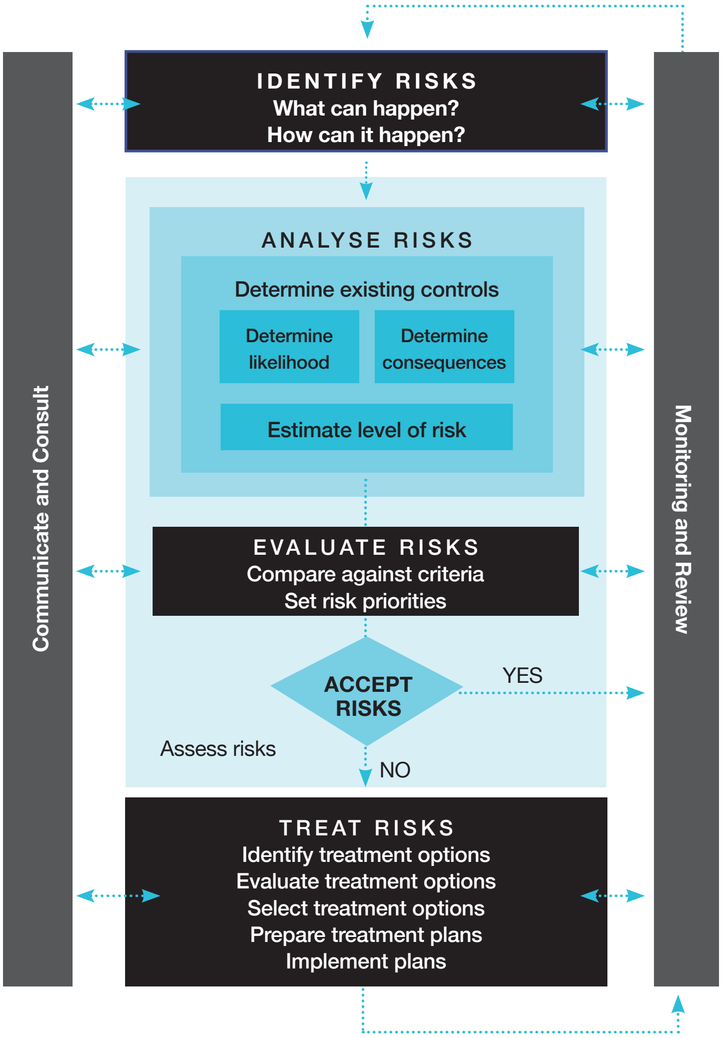


Figure 4.1 Jemena Risk Management Policy

All risk management activity within the company is governed by the Jemena Risk Management Policy.

It is recognised that complete elimination of risks is neither practical nor gives the best outcome to the business. However, it remains important for all credible risks to be identified, evaluated and appropriately managed. These operational risks are effectively and efficiently managed to ensure that they are mitigated to an acceptable level.

Risks are assessed in group workshops using risk criteria tables. Risk Action Plans are developed by the nominated risk owner to plan, monitor and report on the implementation of identified treatment actions.

Risks have been identified and are set out in risk registers. From the risk registers, risk mitigation is planned as being capital development, maintenance/operational enhancement, contingency planning or hold and review.

Since external events may impact on extended areas of the network, conveyance risk management also extends to consideration of catastrophic risk events (transmission failure, terminal station failures, system black, solar storms, subtransmission failure and major storms) and external supply transmission risks.

Investment based solutions to conveyance and other risks are not the only alternative considered.

Non-asset based factors such as procedures and work flow may be preferable to expensive capital solutions.

A conscious effort is made to integrate risk management into the culture of the organisation. Workshops are conducted on a regular basis to identify and assess risks and determine action plans. For each planned action, the responsibility for implementation is allocated to a member of staff. Progress on these is monitored at six-monthly intervals and more frequently in the case of critical tasks.

Risk assessments are also carried out when there are significant changes to processes, equipment or materials, as a part of change management. All significant projects undergo a risk assessment phase. Risk management concepts influence all decision-making processes within JEN, including contractor management. Field based activities completed by contractors are monitored through targeted, risk-based audits.

The concept of risk management influences the development of JEN's asset management strategies.

The risk matrix, contained in the Group Risk Management Manual, forms the basis of determining risk ratings for risks owned by JEN. A risk rating for a given risk is determined by the evaluation and assignment of a risk likelihood and risk consequence rating.

Once the risk rating has been determined, the management strategy of the risk is determined. Refer to the Group Risk Management Manual for more information on the measurement and management of risk.

4.3 Capital Program Management

An internal business process is used to rank projects that are proposed for inclusion in the Capital and Operating Works Program. The process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital and operational works and the principles of this approach articulate how JEN prioritises and optimises its investments.

The following are the high-level steps involved in the risk ranking process:

- Identify all potential capital projects including Connections, Asset Replacement and Network Augmentation;
- Identify projects that must be undertaken (mandatory), such as Connection projects and those that have commenced in the prior financial year;
- Define projects to a level that enables comparison for all remaining projects;
- Identify risks, threats, chronic losses, impact, controls, sensitivities and options for each project;
- Perform a 'design review' on each of the items identified in the step above;
- Apply the Project Prioritisation Methodology to each project to produce a priority ranking score;
- Rank the projects in order of priority ranking score;
- Eliminate or defer projects where the priority ranking score is relatively low and are not sensitive.

This process ensures an optimum investment plan to provide an integrated, coordinated and prioritised capital and operational program of works aligned to the corporate strategy and provides the maximum benefits and efficiency to customers.

4.4 Project Economic Evaluation and Business Case Assessments

The evaluation of projects is important to ensure that limited resources are used in the most efficient manner possible to the business at the time. Therefore all projects and investment decisions are evaluated in the light of the regulatory regime the business operates within, the tax system that applies to the business and the potential for projects to be unregulated.

All projects are evaluated to consider tax and depreciation to identify the true cost of investment that includes cost benefit analysis.

The evaluation considers:

- Capital inputs
  - Capital investment; and
  - Profit or loss on sale or disposal of assets.
- Benefits
  - Unregulated revenue;
  - Return on assets;
  - Regulatory incentive scheme benefits;
  - Reduction in fault restoration costs;
  - Impact on operational expenditure;
  - Avoided capital costs or brought forward capital;
  - Risk;
  - Value of lost load; and
  - List of intangible benefits.
- Non-capital costs
  - Unregulated costs;
  - Regulated costs; and
  - Regulatory incentive scheme costs.

4.5 Project and Program Cost Estimating Process

JEN uses four key inputs to estimate the cost of projects in the five-year Capital Works Program:

- Benchmarked prices;
- Actual costs of completed projects that are of a similar scope
- Input from experienced engineering, design and construction personnel; and
- Quotations from external service providers.

During the development of the Capital Works Program, benchmarked rates are consistently applied to the scope of a project using building blocks to develop the budget cost for each project. Where there are components of the project that are unique, or for where a benchmark does not exist, specific project estimates are developed. The estimated costs are developed by providing a design brief and functional scope to experienced engineering, design and construction personnel. Some projects are costed by obtaining quotations from external service providers.

These approaches ensure that various alternative options are investigated with the same rigour and transparency, in order to arrive at a recommendation for the preferred investment decision.

The Capital and Operational Works Program is also seasonalised to account for expenditure as it is incurred over the life of the project, given the necessary completion dates. There are various factors that are taken into consideration:

- Alignment of projects at the same location and with other distribution or transmission business requirements;
- Identification of projects that must be commissioned prior to summer;
- Network load constraints;
- Identification of plant items that have long lead times; and
- Commencement of identification and acquisition of land and easements.

To maximise efficiency, JEN aligns projects at the same location, usually a zone substation and/or terminal station. The alignment of projects at the same location is most common for asset replacement projects, such as switchboard and secondary equipment replacements. However this is equally applicable to many network augmentation projects such as additional transformation and safety and compliance projects where significant secondary equipment replacement is required.

JEN identifies projects that must be commissioned prior to summer and these are typically new transformers, new zone substations, new distribution feeders, augmentation of 66kV subtransmission lines, the establishment of tie lines between distribution feeders and the thermal uprating of distribution feeders.

Often projects such as zone substation switchboard replacements can only be performed during limited time windows. These projects often face network constraints at the distribution feeder level and are most often performed during winter and spring.

Zone substation transformers and switchboards replacement have long lead times. The duration between the time of placing an order and the delivery of the equipment can be up to 18 months. By factoring this into the seasonalisation of the Works Program, this ensures that the equipment is available at competitive price and the project is commissioned by the required date.

JEN commences the identification and acquisition of properties and easements for zone substations well in advance of construction of assets to ensure their availability and the certainty of planning permits. Some new zone substation sites will be required in established areas where land may be scarce or in high demand. Changing community and stakeholder expectations also requires consideration to be given to visual amenity, EMF exposure, perceived reductions in property value and environmental impacts.

JEN is committed to early and rigorous community and stakeholder engagement to provide transparency and to reinforce the need for and benefits of the proposed zone substation or powerlines.

The Capital and Operational Works Program is optimised using the risk ranking process, the seasonalisation factors and Jemena's strategic objectives.

4.6 Capital and Operational Work Plan

Annual forecasts of expenditure over the outlook period are presented in the Capital and Operational Work Plan. The Work Plan forms a key reference document within JEN's asset management system and progress against the Work Plan is continuously monitored. JEN's capex and opex is coordinated into categories, which align with the designated activities within the SAP works management system.

This Work Plan is developed taking account of resource requirements.

4.7 Project Management Methodology – Gate Process

To align the project management methodology across the business and to drive consistent improved project outcomes, a Project Management Methodology Strategic Plan has been developed. A standardised gating process has been implemented as described below.

A new PMM is being developed as part of a business transformation project within the business. In the interim, the existing process below will be maintained.

To drive investment efficiency, all projects and programs of work are controlled through a sequential gate process with review and approval at each of the following gates:

Gate 1 – Project Qualified;

Gate 2 – Feasibility Planning Reviewed;

Gate 3 – Detailed Plans Approved;

Gate 4 – Approval Obtained;

Gate 5 – Delivery Plan Approved;

Gate 6 – Project Technically Completed; and

Gate 7 – Project Closed.

The Gate process is a system by which each ‘gate’ provides authority to proceed to the next gate. This ensures the necessary checks and balances at critical stages of the project/program development and approval lifecycle. Thus the integrity of the business case is ensured on behalf of the board.

The Gate process provides the necessary checks and balances at critical stages of the project/program development and approval lifecycle. This is to ensure the integrity of the business case on behalf of the Board.

The key principle is that approval at each ‘gate’ provides authority to proceed to the next gate.

The staging of the gates is shown in Figure 4.2 along with the aims of each gate and the processes involved.

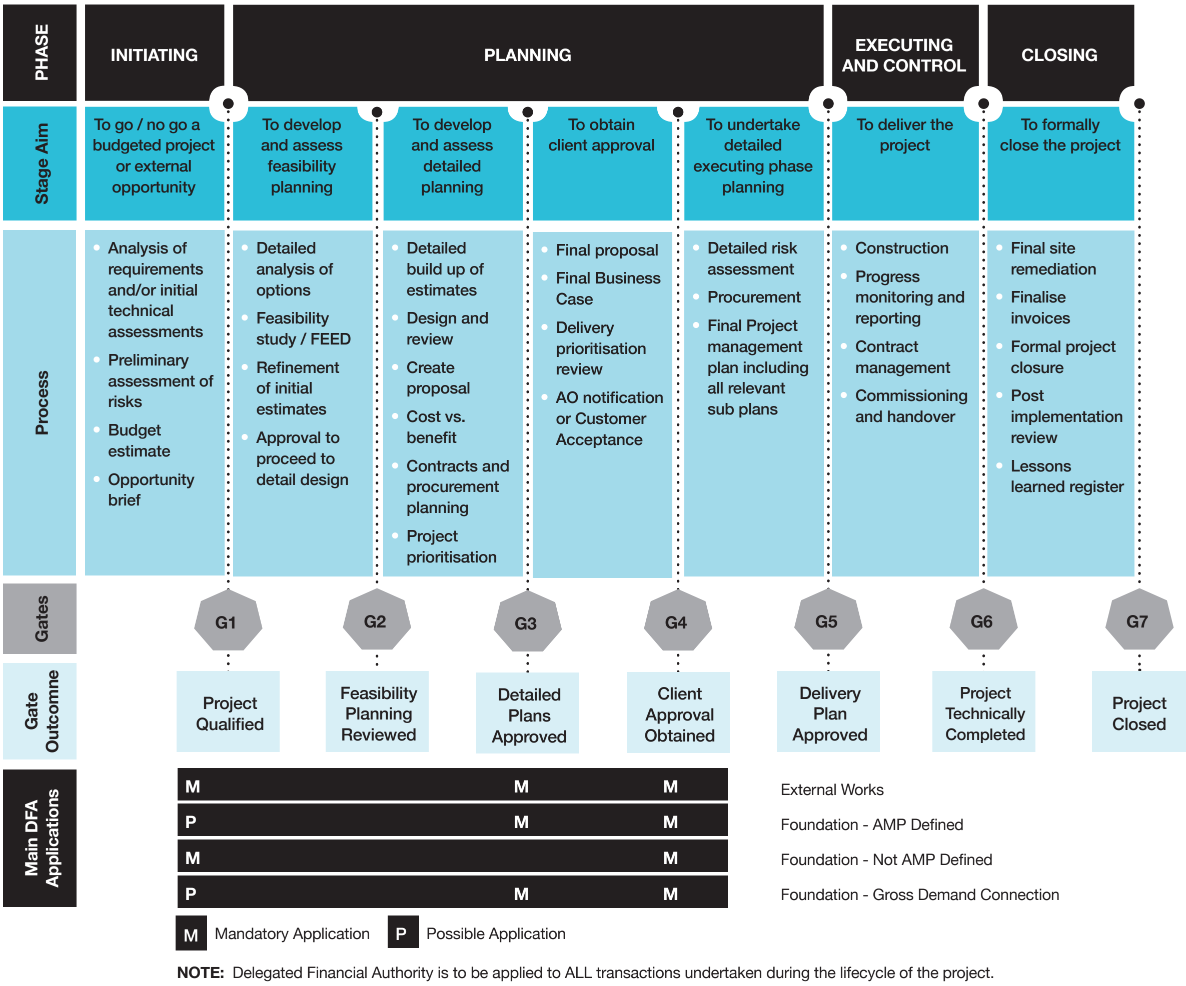


Figure 4.2 Project Management Methodology Gate Process

Gate 1 - Project Qualified

The purpose of the Review Gate 1 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘project qualification’ stage.

Gate 2 - Feasibility Planning Reviewed

The purpose of the Review Gate 2 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘feasibility assessment’ stage.

Gate 3 - Detailed Plans Approved

The purpose of the Review Gate 3 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘detailed planning’ stage.

Further DFA requirements or JEN approval, may need to be confirmed prior to any sign-off of the Gate 3 certificate.

The key output from Gate 3 is a developed business case which clearly identifies the preferred option to be pursued. The document should also clearly detail the benefits of undertaking the project and commit the Project Manager to deliver the project to the approved cost, scope and delivery targets of the project.

Gate 4 - Approval Obtained

The purpose of the Review Gate 4 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘obtain approval’ stage. Relevant supporting documentation is required and may be in the form of a business case or customer offer or connection agreement.

The key output from Gate 4 is the approved business case or customer offer. The approval of these documents will identify the preferred option to be pursued and the scope of how the work will be delivered. All of this information will be provided as part of the formal handover to Service Delivery.

Gate 5 - Delivery Plan Approved

The purpose of the Review Gate 5 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘delivery planning’ stage. Gate 5 concludes the planning phase of the project where a number of key project documents are generated and approval obtained for all project plans and designs.

A key outcome of the Review Gate 5 Requirements Process is that all the relevant documentation is completed prior to the commencement of construction. Some key documents that may be referred to in this process include risk management plans, signed drawings, health and safety plans and environmental plans.

The key deliverable of this review is the issuing of the design and construction orders. The approval of these documents will release the project to the relevant Construction Manager for commencement of the project construction.

Gate 6 – Project Technically Completed

The purpose of the Review Gate 6 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘executing and controlling’ phase and to verify that the project has been delivered.

During the executing and controlling phase, the key activity relates to the delivery, monitoring and reporting of the construction work. The key outcome of the gate 6 review process is that all relevant documentation has been adhered to and that the project is ready for commissioning and handover.

The key deliverable of this review is the commissioning and handover of the project. The approval of these documents will deem the project to be commissioned, recognising that project finalisation activities will continue until the project is formally closed at gate 7.

Gate 7 – Project Closed

The purpose of the Review Gate 7 Requirements Process is to confirm that all the necessary gate requirements have been satisfied during the ‘project closing’ phase and to verify that the project has been formally closed.

During the closing phase, a number of key tasks are undertaken including the financial settlement of the project and post implementation review. The key outcome of the gate 7 review process is that all relevant documentation has been adhered to during the closing phase and that the project has undergone formal project closure.

The key deliverable of this review is the formal closure of the project. The approval of this gate certificate will deem the project closed.

4.8 Plan Delivery

Materials

Jemena has established a Procurement Group performing the following two major functions:

- **Procurement –** this group is responsible for identifying procurement opportunities across the business that drive benefits through the aggregation of demand and the standardisation of ordering and logistics processes; and
- **Category Management –** this group supports the business in the development and implementation of contracts and service level agreements. Following standardisation of equipment specifications and tendering, period contracts have now been established for major plant items such as Cables (Underground and Overhead), Transformers and Kiosks, Electrical Conduits and Cover Slabs, Protective Clothing – Branded Items, Electricity Meters, RM6 Switchgear, Switchboards, Insulators, Gas Switches and High Voltage Fuses.

Outsourced Contracts

Jemena has partnered with service providers to supplement its internal workforce for delivery of Works Programs to JEN and other clients.

Competitive Tendering

It is standard practice to apply competitive tendering for the delivery of the major components of significant zone substation or distribution projects. The competitive tendering process exists to ensure optimal project cost control by engaging the market to ensure the most commercially and technically acceptable solution is implemented.

Efficient Works Program

Projects and programs are targeted for completion to deliver the best outcomes for the business and its customers. Drivers for works programming include timely construction to achieve maximum customer value for the initiatives. Programmed asset replacement projects are performed before forecast end-of-life and demand projects are completed to ensure that sufficient network capacity is in place to meet forecast loads immediately prior to the critical summer loading period.

Where practicable, works on adjacent networks, transmission; subtransmission and distribution assets, capital projects, maintenance and seasonalised Works Program are aligned to maximise cost efficiency.

An efficient Works Program balances business constraints with the needs of the network and customers. The ability to deliver the Works Program is dependent on business case production, project planning, tendering, material delivery and field construction resources.

To ensure that the Works Program is delivered, the following initiatives are in place:

- Capital and Operational Work Plan;
- Capital Works Program Governance Forum;
- Project forecasting and scheduling meetings;
- Business case and Gate progress status reporting; and
- Period contracts for major materials.

The purpose of these processes and meetings is to:

- Review the financial dashboard associated with the delivery of the Work Plan by major category: Connections, Asset Replacement, Network Augmentation, Non-Network and Maintenance;
- Review variances between the Work Plan and forecasts by these categories;
- Review timing of business case delivery where these are on the critical path for the Work Plan delivery;
- Review and confirm timing of forecast expenditure;
- Review progress of summer critical projects;
- Review progress of working through the gate process and obtaining project approval;
- Review progress of delivering against the Work Plan, and where required reforecast projects in the master Work Plan;
- Provide commentary for the end-of-month reporting;
- Ensure that resources have been scheduled for upcoming works; and
- Identify specific project issues.

4.9 Procurement

Efficiency in procurement is governed by the Procurement Group within Jemena. The Procurement Group is responsible for identifying procurement opportunities across the business that drive benefits through the aggregation of demand and the standardisation of ordering and logistics processes.

Strategic procurement is a proven method for managing large-scale, medium to long-term procurement activities. It has been adopted as standard practice by numerous organisations in Australia and internationally. Strategic procurement consists of two key capabilities - strategic contracting and category management. In strategic contracting, the emphasis is on developing a detailed knowledge base of the market and the category being sourced, and using this knowledge to develop optimal sourcing solutions. Category management focuses on managing contracts to ensure that the negotiated contract benefits are realised, and driving continuous improvement in contract benefits each year. Supporting the implementation of the policy are other policies, extensive good practice guidelines and comprehensive tools and templates, including standard contracts and tender documentation.

The structure of documentation and activities employed by Jemena's Procurement Group is presented in Figure 4.3.

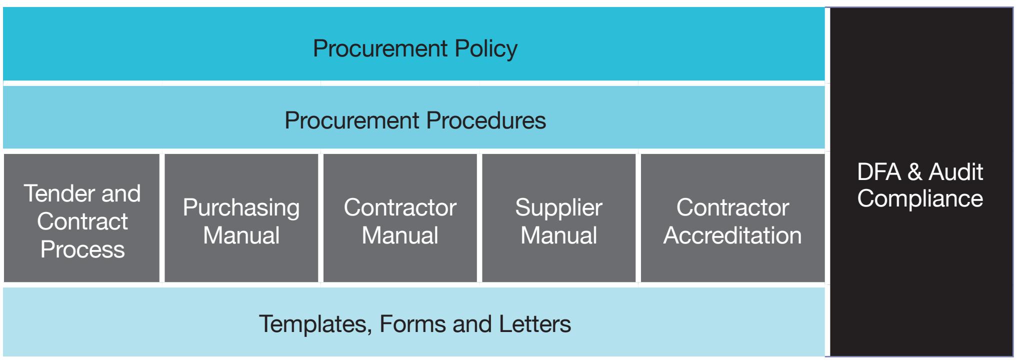


Figure 4.3 Strategic Procurement Framework

Items and Services Requiring Competitive Tender

JEN operates a competitive tender for the supply of all goods or services to be provided or supplied by third parties with a contract value in excess of a defined threshold for that item or class of items or service in any financial year. Irrespective of this threshold, JEN also ensures that all procurement processes have as their primary criteria, the cost effectiveness of the purchase.

4.10 Customer Engagement and Responding to our Customers' Expectations

This section provides information about how JEN is proactively engaging with its customers and other stakeholders. A component of this process involves JEN responding to customer expectations and the current focus includes monitoring potential future shifts in expectations. One of Jemena's Key Success Measures to deliver energy services that are safe, reliable, affordable and responsive to our customers' preferences. Jemena's Asset Management Policy states that Jemena will 'actively engage with customers and key stakeholders to understand and respond to their requirements to ensure outcomes are achieved that are in their long term interests (refer to chapter 3.1 or Appendix E).

This section explains what JEN has heard from our customers about their preferences and expectations for service levels. The remainder of this AMP sets out the asset management approach, processes and strategies which will be used to ensure that JEN is able to continue to deliver the service levels which customers have told JEN they value.

The remainder of this chapter/section is structured as follows:

- Our customer and stakeholder engagement objectives;
- Who our customers and stakeholders are;
- How we've engaged with our customers to determine their preferences in relation to our services over the long-term;
- What our customers' long-term preferences are; and
- How we plan to respond to customers' long-term preferences.

4.10.1 Our Customer and Stakeholder Engagement Objectives

Our customer engagement objectives are:

- To strive to understand and meet the reasonable expectations of customers and customer groups and reasonably balance their competing interests; and
- To ensure that customer and stakeholder engagement plays an important role in the prudent optimisation of our costs, services and prices.

4.10.2 Our Customers and Stakeholders

It is important that JEN consider and balance the competing interests of a range of customers, customer groups and other stakeholders. JEN's customers and key stakeholders include:

- End users of the electricity we distribute, including households and small, medium and large businesses;
- Stakeholders and groups who represent our end user customers, including various consumer advocacy groups and business associations;
- Local Governments, who are customers of our public lighting services; and
- Energy retailers, who collect revenue from small customers us on behalf of us.

The interests of other stakeholders including regulators, State and Federal Governments and energy ombudsmen must also be considered.

4.10.3 Engaging with our Customers on their Long Term Service Preferences

In the past, JEN's customers and stakeholders have generally had limited opportunities to engage with us about their long-term preferences and interests regarding our services. Although engagement activities have taken place at a range of different community and stakeholder levels, formal information gathering and discussions about customers' preferences regarding service levels have not taken place.

In 2014, JEN designed an in-depth engagement exercise to assess customers' preferences on a range of issues, including their preferences regarding the services we provide. This activity took the form of a deliberative forum and focus group, both of which were attended by a broadly-representative sample of residential and smaller commercial customers.

The JEN Customer Council, whose membership includes consumer advocates, industry associations representing large businesses, ombudsmen and local Government, was consulted on how to tailor questions to test customer preferences using our deliberative forum and focus group approach.

As part of this process, JEN also leveraged other engagement activities, including a forum with large customers and other stakeholders. These activities also formed one part of a broader customer and stakeholder engagement program throughout the year.

The deliberative forum involved educating customers about our business and the infrastructure and services we provide, emphasising the key elements we must consider as we make decisions which have long-term impacts on our customers. These three elements are summarised in the figure below.

Figure 4.4 The Interdependencies between Prices, Safety Levels and Service Levels

Our customers were informed that safety is non-negotiable for us, a point which was also strongly supported by our customers—and therefore our discussions predominately focused on the balance between our costs (and prices) and service levels. During the consultative process of developing the material for our deliberative forum, we identified four key attributes of our service:

- Reliability - making sure your electricity is available when you need it (refers to the number of supply interruptions (blackouts) experienced by customers);
- Responsiveness - minimising the time it takes to respond to blackouts;
- Customer empowerment - assisting customers to better manage their electricity use and costs; and
- Public amenity - considering the visual fit of our network with your local area.

The deliberative forum involved several sessions where we explained different attributes of our service to the group, including presenting options and the associated cost of differing levels of service over the long-term (i.e. up to 20 years). This was followed by facilitated round-table discussions and semi-quantitative voting by participants in response to specific questions around each of our four key service attributes (in addition to a range of other issues, such as their understanding of their electricity service and the industry and their preferences around how we communicate and engage with customers).

4.10.4 Our Customers' Long Term Preferences

JEN's key findings about our customers' long-term preferences for our key service attributes are explained below.

The Balance between Safety, Price and Service Levels

Customers considered that JEN had generally struck the right 'balance' between safety, price and service levels. Regarding the acceptability of the proposed view JEN presented around this balance in the plan period, the broad response from customers was that our proposal to broadly maintain the current balance was acceptable: a net of 85% thought it was at least moderately acceptable, with a substantial 68% seeing it as very or completely acceptable.

Safety Being Our Number One Priority

Customers strongly supported safety as JEN's number one priority. This was reflected in the almost universal agreement that safety should be the number one priority (net 96% agree strongly/somewhat). Discussions with customers recognised that safety was regarded as important not just for the benefit of the broader community, but also for JEN's employees.

"Safety is a non-negotiable and the most important priority." (Residential Customer)

Reliability

Customers generally considered JEN's supply to be reliable with a net of 88% rated the reliability as very good (64%) or quite good (24%).

Considering that reliability of supply was regarded as a key priority, several participants suggested that JEN should seek to improve reliability. Although some customers thought that in principle JEN should strive for continuous improvement (i.e. higher service levels over time), the cost of improving reliability was generally considered prohibitive, and as a result there was a strong preference to maintain similar levels of reliability in the future. Although participants recognised that some different types of customers may have different preferences and needs regarding the reliability of their supply, the overwhelming majority preferred to maintain the current level of reliability, noting the costs of providing a more reliable service and the relatively small gains that could be achieved for such costs.

"The cost of raising the level of reliability is not really worth it.
It's not in proportion." (Residential Customer)

When asked to vote for their option preference in terms of downgrading, maintaining or improving reliability, the overwhelming majority of customers preferred to maintain current levels of reliability. Therefore, when asked to rate the acceptability of JEN's proposed approach (to maintain current levels of reliability over the 2016-20 period), a strong majority (85%) considered this either completely or very acceptable, and a further 10% saw this as moderately acceptable equating to a net of 95% rating of customers this as at least moderately acceptable.

Responsiveness

Feedback revealed that no participants were willing to accept less responsiveness and that the vast majority (85%) would like responsiveness levels to remain the same. Discussions revealed that the main reason for voting for similar levels to now was the modelling which showed that the likely gain in responsiveness would be in the order of only five minutes, which participants felt was 'neither here nor there'.

*"It doesn't make sense to pay more to save a little bit of time.
Blackouts are going to happen. You can't control the weather." (Residential Customer)*

"I'm happy with the service at the moment and I don't want to pay an extra 60 cents or 70 cents to reduce the time from an average blackout by five minutes." (Residential Customer)

"Just stay the same as now." (Residential Customer)

Customer Empowerment

JEN is able to build on its investment in advanced metering infrastructure (AMI) technology to empower customers to be informed energy decision makers. This can be achieved through offering technologies and price signals which allow customers to make more efficient decisions about how they use (and in some cases, generate) electricity. Over time, these and new technologies could potentially reduce the amount of investment in new infrastructure required and allow us to deliver our services more efficiently.

Customers were generally supportive of JEN exploring new and innovative ways to reduce the need for future network investment. When given a choice between increasing network investment to cater for increased usage on peak demand days or offering incentives to consumers to decrease their usage at certain times to avoid the costs associated with building more poles and wires, the vast majority of customers (92%) preferred behaviour change incentives over infrastructure investment.

Customers also indicated an interest in participating in trials which utilise AMI technology for demand management. Potential trials discussed with customers included empowering customers with direct load control for air conditioning systems and incentives to reduce usage at peak times. There was strong support for JEN's proposal to explore various trials to help customers reduce their peak usage, and associated costs over the longer-term (85% thought this was either completely acceptable or very acceptable).

There was also support for JEN pricing our services to encourage customers to make more informed (and efficient) decisions about how they use our services and allow us to more efficiently provide services to our customers. The majority of participants (90%) indicated that they understood why JEN wants to move towards prices that better reflect the costs of delivering electricity to customers with different electricity needs. Participants felt positive towards JEN for thinking about ways in which it can help people save money, and some described the organisation as progressive and flexible.

"Flexibility is a good thing – they're thinking ahead. People do want to save money." (SME Customer)

Visual Amenity

The large majority of customers saw JEN's proposed approach to visual amenity over the 2016-20 period (that is, to generally not focus on improving the visual amenity of our services unless individual customers contribute to specific projects) as highly acceptable. Customers didn't place a high value on measures to improve the visual amenity of our network, instead placing more value on attributes other than this.

The majority of customers thought JEN's plan to do no more than it currently does regarding visual amenity was highly acceptable (net 64% completely/very acceptable) and that customers wishing to have improved visual amenity should be the ones that pay for it (net 75%). When it came to their willingness to pay for the visual amenity improvements, people's overall support for JEN's approach was further emphasised. Most were not at all willing to pay for the one-off costs of aerial cable bundling and insulation (83%) or undergrounding (80%) in the street of their premises. More than half (55%) felt the same way about more frequent tree pruning, and a substantial 46% also said this for more attractive substation design.

*"It is important to me, but when it costs that much just to get a little bit of a better visual, it's not worth it."
(Residential Customer)*

Customer Engagement – Customer Preferences

Customers indicated a solid interest in information and to a lesser extent being consulted; while participants appreciated JEN was informing and consulting them about relevant aspects of its future plans. Many participants said it useful to receive more information about JEN and what it does. They said it was empowering to have more information, and felt that JEN should continue to inform and engage with customers.

4.10.5 Responding to our Customers' Long Term Preferences

Customer engagement is an important step in the development of our asset management plans. Understanding our customers' long-term preferences is critical to us maintaining the relevance of our services to customers (and therefore viability as a business). Customer engagement is also an important way for us to give customers a say in how the network evolves and responds to new technology, giving us the opportunity to incorporate customer views into our long term strategic planning around this issue.

The key high-level findings regarding our customers' long-term preferences are:

- Customers want us to maintain safety as our top priority;
- Customers want us to maintain our current service levels. This includes in areas such as reliability, responsiveness and visual amenity; and
- Customers want us to explore new ways of more efficiently delivering our services and enabling them to use our services more efficiently. This involves leveraging of new AMI technology to better empower customers to more efficiently use electricity and also incentivise usage behavioural change to reduce traditional 'poles and wires' expenditure and focus more on smart technology use.

This AMP reflects and responds to these preferences by planning to maintain our current service levels over the next five years, and by laying a foundation for us to leverage and respond to new technology in the future and explore new ways to more efficiently deliver our services and enable customers to use our services more efficiently.

JEN is committed to proactively building on the engagement activities already undertaken using a range of engagement methods. This includes strengthening existing avenues allowing customers and stakeholders to provide feedback as well as exploring new ways of engagement with our customers and stakeholders, in line with their expectations. This will help ensure that we understand and respond to customers' and stakeholders' preferences and requirements in our planning, and that outcomes are achieved which are in their long term interests.

4.11 Stakeholder Forums

4.11.1 Jemena Asset Management System Review Committee (AMSRC)

The Jemena Asset Management System Review Committee (AMSRC) has responsibility for the asset management system across Jemena with the purpose of strengthening the Jemena asset management system by providing governance, alignment and review across Jemena.

4.11.2 Operational Forums

The Operational Forums are established to monitor the performance of the relevant service elements and programs.

- Non-routine capital management
  - Monitor the performance and progress of the JEN non-IT routine and non-routine capital program and KPIs including prompting business case approval for projects as required.
- Network Performance
  - Monitor the network performance of the JEN assets and KPIs including reliability, power quality and GSLs.

- Risk and Compliance
  - Monitor the performance of the JEN compliance functions including ESMS and ESV obligations, OH&S, Environmental, JCARS, audit program and risk register and KPIs as required.

The asset life required of the equipment used to construct and maintain the distribution network requires that a consistent risk-based approach be taken to the introduction of engineering changes and new technologies. Standard development and modification is undertaken by a number of specialist areas within JEN that have responsibility for particular asset groups.

New assets are constructed in accordance with a set of predefined technical standards in order to minimise the number of different assets across the network, and thereby reduce procurements costs, operational and maintenance costs (including responses to plant failure), as well as minimising the number of spares holdings.

For example, protection standards are developed by the protection and control group and primary plant standards are developed by the primary plant and distribution systems group. A system of standardisation committees has been used for the development of standard designs, policies and procedures associated with the design and construction of primary plant and distribution system assets elements. The standardisation committees comprise stakeholders from the Asset Management and Service Delivery groups to ensure a broad cross-section of input into the development of standards. These expert/ stakeholder committees undertake standardisation activity in a collaborative manner in accordance with the 'Standards Development and Modification Procedure'. Risk assessments form part of the standard development process.

4.11.3 Standardisation Committees

There are seven standardisation committees. The level of activity in each area determines committee meeting frequency and meeting formality. The membership of the committees can be varied dependent upon the issue under consideration and the expertise required. New committees can be established to address particular issues if required.

The seven standardisation committees are:

1. Cables and Ground Mount Substations Standardisation Committee.

The focus of this committee is the standardisation and design of underground cable systems and indoor, ground mount and kiosk type distribution substations. This includes the materials and equipment associated with these systems and the civil requirements for distribution substations.

2. Overhead Lines Standardisation Committee.

The focus of this committee is the standardisation and design of structures and engineering systems associated with the network. This includes the materials and equipment associated with these systems. The scope extends up to the customers service connection to the network.

3. Servicing Standardisation Committee.

The focus of this committee is the standardisation of the design and construction of overhead and underground servicing arrangements for customer installations and includes services supplied direct from substations.

4. Zone Substations Primary Standardisation Committee.

The focus of this committee is on the design and construction of primary plant and facilities associated with zone substations and terminal stations that contain JEN assets. This includes the material and equipment associated with these installations and the civil and structural requirements.

5. Protection and Control Standardisation Committee.

The focus of this committee is on the development and maintenance of secondary design standards for protection and control systems associated with primary plant and network lines and cables. This includes the definition of the required protection schemes and the implementation standards.

6. SCADA and Real Time Systems Standardisation Committee.

The focus of this committee is on the development of new technical policies, procedures, technical standards and material applications related to all SCADA and RTS issues. This includes the material and equipment associated with these installations.

7. Substation and Distribution Automation (SDA) Standardisation Committee

The focus of this committee is on the development and maintenance of the substation and distribution automation design and installation standard. This includes the definition of the substation and distribution automation technical policies, procedures and the implementation standards.

Engineering and Standardisation Issues

There are a number of areas that require further development of engineering standards. These include the following:

- Equipment Specifications - there is a significant amount of work being undertaken to standardise equipment specifications across all classes of assets so as to realise the benefits of standardisation and increase purchasing power; and
- Material and Equipment Developments - the continued developments that occur in material technologies and the availability of traditional materials means that there is a need to monitor these developments and assess their suitability for use on the distribution network.

5 Operating Environment

JEN operates in an environment which is impacted by the network characteristics, ownership and control, stakeholders, regulatory objectives and expenditure drivers. This chapter describes the key environmental factors that impact on the management of assets. These factors include:

- Aging assets presenting technical risks;
- Significant regulatory compliance obligations;
- Changes to the physical environment in which the assets are located;
- Assets located in areas of high bushfire risk;
- Assets capable of having adverse impacts on the environment;
- Changing nature of the key services provided by the network assets with an increase in connection of embedded generation, and the installation of smart metering devices.

5.1 Summary of Issues

The operating environment in which the network assets exist is changing. Rising network fault levels due to capacity expansion and the connection of embedded generators are resulting in increasing stress on parts of the network. Climate change is expected to continue to have a real and increasing impact on network performance, potentially lengthening the bushfire season and delivering conditions conducive to pole fire ignition, as well as the occurrence of more frequent wind storms and heat waves. Changing regulatory obligations will also impact on safety and compliance work plans.

JEN recognises that its network is ageing and that assets that were operating satisfactorily in the past, may not meet safety, compliance or service performance requirements as expected in the future because of these changes to the operating environment. Hence, JEN has a strategy to continually review its asset management strategies to ensure that assets continue to perform at a level that meets stakeholder requirements.

JEN will focus on maintaining its service performance in the next period. To achieve this, Jemena will continue to:

- Maintain network resilience to wind and extreme heat events;
- Implement changes to bushfire management;
- Manage preparedness and responses to extreme weather events;
- Respond to government climate change policy initiatives; and
- Leverage smart network technologies.

5.2 Technical Risks and Mitigation Plans

JEN's key technical asset risks (as discussed in further detail within the Asset Class Strategies and Section 9 of this AMP) are summarised in Table 5.1. These technical asset risks and the corresponding mitigating plans or resulting actions will result in additional volumes of work in the period to 2020 when compared to past work activities, in order to meet mandatory compliance and maintain overall asset risk.

Technical Asset Risk	Mitigating Strategy/Action
Bushfire ignition.	Install rapid earth fault current limiters in selected zone substations. Proactive replacement of end-of-life assets.
Tingles and shocks from household fittings/plumbing.	Condition based replacement of classes of low voltage service cables.
Pole fires and associated HV injections.	Condition based replacement of pole tops.

Technical Asset Risk	Mitigating Strategy/Action
Overloaded distribution substations resulting from increasing land utilisation (dual occupancies).	Overloaded substation upgrade program, conduct Substation Utilisation and Profiling (SUPS) studies – improved accuracy with the introduction of full interval metering data.
Zone substation transformer age profile and 66kV bushing failure.	Condition monitoring near end of life, plan to replace transformers and programs to extend transformer life including 66kV bushing replacements, oil reclamation program, transformer refurbishment, oil leak repair and OLTC replacements.
Zone substation circuit breaker age profile and metal clad indoor bus condition.	Increased condition monitoring near end of life and plan to replace.
Condition of steel, copper and ACSR conductors.	Targeted visual inspection depending on asset type, asset utilisation, age and condition, as well as fault interruption history and additional surveys following the occurrence of faults. Planned replacement of rusted steel and copper conductors.
Increased trend of underground cable failure.	Introduce new cable condition monitoring techniques and programmed replacement of end-of-life cables and trifurcating boxes.
Substation security – increasing number of break-ins and theft, Government consider as critical infrastructure.	Increased building security and lighting.
Environmental issues associated with noise, asbestos, PCB contamination SF_6 and EMF's.	On-going programs.

Table 5.1 Key Technical Asset Risks and Mitigation Strategies

Additional technical asset risks (as discussed in further detail within the Asset Class Strategies and section 9 of this AMP) are summarised in Table 5.2, where the mitigating strategy is opex related.

Additional Programs to Mitigate Technical Risks	Description of Additional Program
Early fault detection for Pole Fire Mitigation	Proposed step change for a program to deploy a limited number of pole top fire detection systems. The program will include leasing one pole-top fire detection system in 2016 and testing the systems on a limited number of feeders. This will include relocating the systems annually in order to cover more feeders. Deployment and testing of the technology on various feeders is necessary before a firm decision on rolling out the technology as a permanent solution can be made. Rollout of the technology, including its integration with JEN's SCADA system, is planned to occur during the 2021-2025 EDPR period.
Enclosed Distribution Substation Inspection and Rectification	The main driver for this step change is compliance with the Electricity Safety (Bushfire Mitigation) Regulations 2013. One third of JEN's distribution substations are non-pole type, comprising indoor, ground, kiosk / padmount, cubicle and underground substations. The program was designed to address risk to public safety and supply reliability by proactively inspecting and rectifying defects, rather than on an opportunistic basis.

Additional Programs to Mitigate Technical Risks	Description of Additional Program
Enhanced inspection of pole top assets - photography	Proposed step change for the capture and storage of high-quality photographic images of pole tops using a ground-based pole mounted camera (on an insulated telescopic operating stick). The driver is a focus on avoiding fire starts on electricity networks and reduction in pole top fires, which are a significant industry issue. Detailed photography of the pole top will assist maintenance planners in making the appropriate decision on rectifying a defect.
Overhead switch inspection	Proposed step change for a routine program of visual inspection and functional tests of all overhead air break switches. The introduction of an inspection program would give a better view of the true condition of switch health and allow a more efficient replacement program of only replacing switches that represent a true danger to reliability and safety therefore maximising the cost/benefit of the replacement program. The benefits of increased condition based asset data will feed into the CBRM model to more accurately predict future replacements and more effectively tailor future replacement programs to maintain network reliability.
Underground cable testing	Proposed step change to continue testing early XLPE underground cables for signs of premature failure. This program is required to maintain the supply security in areas with a high penetration of these cables. Defective cables identified by this program will be replaced under the proactive cable replacement program.
Public lighting switch wire removal	Public lighting switch wires have been largely redundant since the mid 1980's as lighting control was transferred to photo electric switching on each lantern. In the JEN network, the switch wires were not removed when luminaires were replaced and in many areas have remained in place for over 30 years as an unmaintained asset. The objective of this step change is to remove the remaining public lighting switch wire to reduce operating inefficiencies and eliminate the risk associated with the ongoing degradation of unmaintained assets.
Service Inspection and Testing Program	Proposed step change to resume inspection and testing of customer service lines. Required by the Electricity Safety (Management) Regulations 2009 and JEN's ESMS to ensure that the neutral impedance of service lines on the network is more than 1 Ohm to earth. A step change is required because the costs incurred in JEN's base year (calendar year 2014) is not representative of typical annual costs.
Rectification of earths in non CMEN areas following test program	Proposed step change to rectify HV earth in non-Common Multiple Earthed Neutral (CMEN) areas that are found to be above standard resistance. This is required to rectify the unacceptable measurements so that they are at an acceptable standard. The main driver of is compliance with JEN's Electricity Safety Management Scheme, which includes reference to the superseded Electricity Safety (Network Assets) Regulations 1999.

Additional Programs to Mitigate Technical Risks	Description of Additional Program
Assessment of soil contamination within zone substations	JEN commissioned a preliminary environmental assessment of contaminated soils within six electrical zone substations in 2014. The study identified varying levels of contamination and concluded that it was likely due to the substations used as operational sites containing bulk quantities of hydrocarbons and historic use of PCBs (Polychlorinated Biphenyls). This step change involves further targeted soil testing based on individual sites' risk characteristics, which will quantify the lateral and vertical limits of contamination. While there have been no changes or increases to relevant regulatory or external requirements, the preliminary asbestos assessment has identified risks which if not managed correctly may result in safety issues and the breach of existing legislation.
Network asbestos management	JEN commissioned and conducted preliminary asbestos audits in 2014 on zone and distribution substations. The audits identified asbestos containing material within the network. However, locations that were not accessible due to network restrictions were not assessed—these are deemed potential asbestos hazards. While there have been no changes or increases to relevant regulatory or external requirements, the preliminary asbestos assessment has identified risks which if not managed correctly may result in safety issues and the breach of existing legislation.
Vegetation management	Proposed step change to address new regulatory obligations, which the ESV has released.

Table 5.2 Key Technical Asset Risks and Opex Strategies

5.3 Compliance and Safety

JEN's plan to meet safety standards is detailed in this section.

JEN's long term objective for network safety and management of network asset related risks is to develop and maintain an environment where JEN's duty of care in terms of its responsibilities with regard to the safety of the public, employees and contractors is demonstrated through achievement of:

- Appropriate network safety key performance indicators;
- Continual reduction in network incident trends;
- Compliance with applicable law, regulations and codes;
- Management of key stakeholder regulatory relationships; and
- Management of reputational risk.

Aspects of JEN's compliance and safety procedures are described in the Electricity Safety Management Schemes (ESMS). Electricity Safety Management Plans (ESMPs) have been developed to address key compliance risks.

5.3.1 Drivers and Objectives

There are two primary drivers for network safety; regulatory compliance, and the exercise of a duty of care to employees, contractors and the general public. These are examined in further detail below.

Regulatory Compliance

Regulatory compliance revolves around the obligations to comply with all of the acts, codes, and regulations administered by the ESV, and other regulatory bodies such as WorkSafe, the EPA and VicRoads.

The main regulations that govern safety are the Electricity Safety (Installations) Regulations, the Electricity Safety (Management) Regulations, the Bushfire Mitigation Code and the industry documents, the 'Blue Book' and the 'Green Book'.

These regulations cover areas such as design clearances of live conductors to people and other structures, requirement of construction industry personnel to obey temporary minimum clearances i.e. 'No Go Zone' publications; the safe working requirements for people working on the network and the requirements for regular inspection and testing of the assets.

The Electricity Safety Act 1998 (ESA) makes provisions for the safety of electricity supply in Victoria. JEN is required to comply with the provisions of the ESA and supporting regulations or standards for the design, construction, operation and maintenance of a distribution network.

JEN supports the Victorian Government's strategic direction for safety in all areas.

The Electricity Safety Act was amended as at 1 April 2014. Under this amendment, it allows the Electricity Safety (Management) Regulations to be changed. The change makes it mandatory for electricity distribution businesses to develop and maintain an Electricity Safety Management Scheme (ESMS) or 'Safety Case'.

This change in the Act and regulations represents a shift away from highly prescriptive regulation where compliance with the regulatory requirement provided a defence, to a regime where the risk burden for safe management of the network resides even more so with the Major Electricity Company (MEC).

Under the previous scheme the Electricity Safety (Network Asset) Regulations (ESNARS) 1999 (superseded in part by the Electricity Safety (Installations) Regulations 2009), were the principal regulations governing the design, construction, maintenance and operation of electricity distribution networks within Victoria. The regulations were administered by Energy Safe Victoria (ESV). The objectives of the ESNARs were to:

- Prescribe standards for the design, construction, operation and maintenance of network assets; and
- Protect persons from risk, and property from damage, associated with network assets.

JEN demonstrates its operational case for safety through an Electricity Safety Management Scheme (ESMS) that has been developed specifically for its unique facility, operations and situation.

The ESMS sets out the adequacy of the safety management system by specifying measures as well as strategies for reducing the effects of risks and incidents.

The scope of the regulations included general obligations of the network operator, supply system standards, aerial and underground lines and services, electrical substations, generators, earthing and electrical protection. JEN's compliance with the regulations is subject to an annual voluntary audit regime, as part of the ESMS, conducted for the ESV.

Under the new Electricity Safety (Management) Regulations 2009, it is mandatory for network operators to implement an ESMS that will describe:

- The standards for the design, construction, operation and maintenance of network assets; and
- The systems to protect persons from risk, and property from damage, associated with network assets.

This shift in regulation away from prescribed regulations (provided as a safety blanket by the regulator), to a system underpinned by identification and management of risks associated with the facility assets to a level that is 'As Low As Reasonably Practicable', (ALARP). JEN supports the ESMS approach to safety management for networks, and the principle that risks should be as low as reasonably practicable , and has implemented an ESMS that has been approved by ESV.

The ESMS format is consistent with a future nationally consistent regulatory framework and with the performance-based safety management systems (also known as a 'safety cases') currently operating in most States and Territories.

This light-handed regulatory instrument will overlay a minimum compliance burden, but at the same time, an increased risk burden on network operators to implement safe working solutions to maintain and continuously improve community and worker safety standards. Companies that do not effectively formulate and implement their ESMS to ensure a safe network risk losing their licence to operate.

To explore this concept further, 'rule compliance' under a prescriptive regulatory regime may have previously satisfied the best endeavours of a reasonable person test in the event of an incident. Under a risk based ESMS regime where the level and reduction of risk is measured against ALARP, a risk that was previously tolerable because the asset met a regulatory requirement, may no longer be tolerable if implementing further prudent action may reduce the risk to 'ALARP' and could reasonably have been expected to prevent the incident.

Duty of Care

JEN has a duty of care to provide a safe environment for the community, employees and contractors. Extensive risk, safety and work practice programs have been developed to identify and minimise risks associated with the interaction between people and JEN assets. JEN will use its best endeavours to ensure compliance with applicable acts, codes and regulations.

Figure 5.1 is intended to depict the interrelationships between legislative changes, risk management, the electricity safety management scheme, asset management plan and asset class strategies.

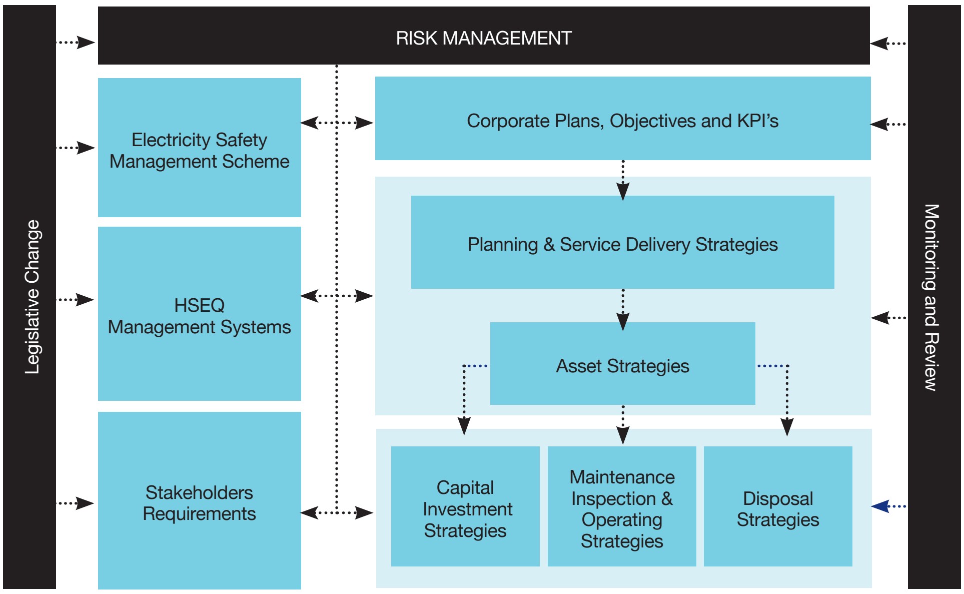


Figure 5.1 Integration of Electricity Safety Management Schemes into Asset Management

5.3.2 Expenditure Implications

JEN supports the Electricity Safety Management Scheme approach to network safety management.

ESMPs have been developed and implemented to address four areas of non-compliance with the ESNARs. Since 2001 quarterly reports have been provided to the ESV on the status of each program.

The ESMPs are:

- Overhead service heights clearance;
- Pole-mounted substations clearance;
- Neutral Service Testing Program; and
- Additional programs involving the installation of 'Breakaway Devices' on 'low overhead services', and the replacement of Neutral Screen services have also been developed and implemented to address specific safety risks.

A brief description of each plan is as follows:

Overhead Service Height Clearance

The 1999 revisions to the ESNAR have rendered a significant number of service installations across network, installed prior to 2000, non-compliant. Prior to 1999, the prescribed minimum height for service lines over driveways and other ground traversable by vehicles was 3.9 metres. When the ESNAR's were revised, the minimum height for new service lines was increased to 4.6 metres with effect from 1 January 2000. For various reasons, many existing services fail to meet the amended minimum height criteria.

In the case of service clearance heights, risk assessments have been undertaken, and programs have been completed to replace all identified critical services. The focus now is on identifying all non-compliant services and addressing the remaining higher risk locations. Work to replace medium and low priority installations will continue, but most will be actioned after the higher risk locations have been addressed. New and replacement services are installed in accordance with the 1999 ESNAR or ESMS requirements.

In the event of a service failure, while it may be initially reinstated at its current height in order to restore supply, the service is either fitted with a 'Breakaway Device' or is recorded in the maintenance program for attention at a later date based on the allocated priority attached to its height above the ground.

In Victoria, distributors and component manufacturers have worked together to develop innovative solutions, such as clean-break devices, which electrically and mechanically isolate a service, to reduce the level of risk to the public and the network when a service fails or is damaged through contact by vehicle, tree or debris. The PLP Disconnect Device (blade type) is used on the JEN.

JEN proposes to continue the program of rectifying non-compliant service heights in a prioritised manner.

Pole Mounted Substation Clearance

A program was implemented to inspect all pole mounted substations on the network to identify any that were non compliant to the ESNAR 22 (3) ground clearance requirements. This program was implemented in addition to the three-four year cyclic pole inspection program, and resulted in the identified non conforming pole substations being classified based on a prioritised basis.

All non-compliant pole type substations have been identified and will be addressed over the next 35 years on a prioritised basis in accordance with the Electricity Safety Management Plan (ESMP).

Neutral Service Testing Program

Under the ESNARs, JEN was required to test the continuity of service neutrals connected to its network. The associated ESMP program to address this compliance requirement progressively tested all connected services over a 10-year period.

JEN will continue to undertake a range of compliance related programs including those listed in Table 5.3.

Compliance	Progress to Date	Future Approach
Service height clearance	An inspection and replacement program for service lines has seen all Priority 1 & 2 outstanding services completed.	Implement the service replacement program.
Clearance heights for pole mounted substations	An inspection and replacement program for substations has seen all Priority 1 & 2 outstanding substations completed.	Address remaining clearance height issues in line with program.
Testing of LV service neutrals	All service neutrals have been tested.	Test service neutrals, investigate, develop and implement innovative solutions for the testing of LV service neutrals.
Earthing systems and electrical protection	The implementation of CMEN (Common Multiple Earthed Neutral) and earth testing has continued.	Continue with earth testing for those assets outside of the CMEN footprint.
Actions to Reduce Customer Electric Shocks		
Tree Clearing	Cyclic tree clearing program	Increase the clearing of trees from around LV services to prevent damage to service neutrals.
Customer Awareness	There are several limited customer safety awareness programs in place.	Improve and increase the customer safety awareness programs (Trees, No Go Zones, Reporting Tingles, Private Poles).

Table 5.3 Compliance Programs funded under the current Regulatory Determination

Under the requirements of the ESMS, JEN must work to continually improve its systems and safety performance. The capital expenditure benchmarks included in this Plan reflect the cost to JEN of continuing the approach to achieving network safety where risks are ALARP.

The safety and compliance plan for the period to 2015 includes the following work activities. It is proposed that these continue in the plan period.

Service Neutral – Continual Monitoring Program

In addition to service neutral testing programs which represents a test of the continuity of the service neutral at a point in time (currently tested every ten years), JEN plans to roll out a program of continual service neutral monitoring. This continual monitoring will proactively alert Jemena to a problem before high impedance or hot joints fail and provide an improved safety outcome as a result of being proactive, rather than reacting, after the customer has experienced a shock. When an alert occurs, the service will be tested and replaced as a matter of priority.

Asset Design and Innovation

JEN is continually researching new designs, materials and work practices to improve the safety of its supply system, enabling it to build safer and smarter structures to deliver electricity to customers. It also supports the activities of a range of industry bodies, in particular Energy Safe Victoria (ESV), in developing initiatives to improve and promote electrical safety.

The network safety strategy can be separated into seven separate strategies:

- Regulatory Compliance;
- Work Practices;

- Training;
- Contractor Safety;
- Structures and Plant;
- Corporate Initiatives; and
- Risk Management.

CMEN (Common Multiple Earthed Neutral)

JEN implemented a program to rollout CMEN schemes throughout all high risk, well frequented areas on the network. Clause 23 (2) of the ESNAR 1999 requires un-insulated metal and concrete, that is accessible to people, must be appropriately earthed and comply with clause 10 of the Guidelines for Design and Maintenance of Overhead Distribution and Transmission Lines, HB-C(b)1 issued jointly by the Electricity Supply Association of Australia, and Standards Australia.

High risk, well frequented areas are defined as public urban areas:

- Associated with a city or town;
- Within school grounds or children's playgrounds;
- Within public swimming pools;
- At a popular beach or water recreation area; and
- Within 100m of the above locations.

JEN will complete the program in 2017 to bring these areas into compliance with clause 23 (2) of the ESNAR 1999.

Distribution Structures

This particular strategy is to improve the safety of JEN's network by building safer and smarter structures to transmit electricity to consumers.

Some examples of improvements that have been made are:

- Using wood poles for every HV structure, to reduce the possibility of high step and touch potentials on poles during fault conditions;
- Using only steel HV crossarms to reduce the possibility of pole and crossarm fires due to higher than normal leakage currents across faulty insulators or poorly tightened bolted connections. This will result in less HV injections over time due to a reduction in events where the wood crossarms burn through and the HV conductors drop into LV conductors underneath;
- Using insulated covers over bare HV conductors at supporting structures such as HV transformer bushings, HV dressing down insulators and the tops of HV fuse units;
- Adopting 'Cold Shrink' technology for cable terminations and joints, which removes the need for gas bottles and flames, which were required with previous 'Heat Shrink' technology;
- The replacement of parallel groove clamps with Ampact connectors to eliminate the risk of clamp failure;
- Implementation of business-wide common multiple earth-neutral systems (CMEN) to extend the size of the earthing systems and reduce the risk of electrocution through the failure of the earth connection; and
- The implementation of a program involving VESI (Victorian Electricity Supply Industry) accredited contractors and auditors to improve the standard of civil work related to JEN underground electricity infrastructure (VEDN Victorian Electricity Distribution Network).

These initiatives require constant research and development effort, regular standards group meetings and updating of field design and construction manuals.

Additional work activities that are new or will result in significant volumes of work in future include:

- Replacement of non-preferred services;
- Raising of pole transformer height to meet the minimum standard required by ESNAR;
- Upgrade of deteriorated earthing grids in zone substations;
- Upgrade of security lighting within zone substations;
- Refurbishment of zone substation grounds;
- Noise reduction of zone substation;
- Oil leak repair of zone substation transformers;
- Public lighting switch wire removal;
- CMEN implementation within East Preston (EP) and Preston (P) zone substation areas;
- Augmentation of selected distribution substations and LV overhead to maintain supply capacity;
- Installation of triple interceptors for oil containment at zone substations (one per year);
- Installation of Rapid Earth Fault Current Limiters (REFCL); and
- Replacement and installation of additional power quality meters.

These activities are further discussed in the asset class strategies where appropriate.

Works Practices Risks

The strategy of improving work practices centres mainly around initiatives to improve the safety of personnel by providing smarter and safer ways of conducting work on the network.

Some of the previous initiatives include:

- Providing linesmen with Live Line Glove and Barrier training and then equipping them with the appropriate personal safety apparel to allow them to use this method at every opportunity when working on JEN assets;
- Utilising Elevated Work Platforms (EWPs) that have longer telescopic booms, more versatile baskets, Live Line capable lifting hoists with insulated lifting ropes, and approved Glove and Barrier gear that will allow full utilisation of the Glove and Barrier training;
- Utilising single man EWPs that provide faster fault response and the ability to operate on the system by a single man;
- Progressively increasing the number of linesmen who are trained up to network operator capability;
- Conducting regular mandatory insulation testing of all of the above equipment to ensure safety standards are maintained;
- Implementation of lineworker registration and the development of the VESI Skills Passport;
- Refining and standardising refresher training across all VESI network operators; and
- Publication of a new VESI Fieldworker Handbook in 2006 and an updated version in 2009.

Future initiatives will involve investment in documenting, improving and training on works practices procedures to improve compliance and safety and reduce risks.

Training – Employee and Contractor Safety

JEN manages the network assets through the following general principles:

- Every contractor must have a signed contract that includes provisions that cover mandatory training and Occupational Health and Safety;
- Every person employed by a contractor that works on the JEN must have suitable training for the task;
- Audits are conducted to ensure compliance with industry codes and regulations; and

- JEN supports the Victorian Electricity Distribution Networks (VEDN) initiative to improve the quality of work undertaken by civil contractors on underground electrical infrastructure, both through completion of the training program and the implementation and maintenance of HSEQ management systems, and auditing.

Due to the highly hazardous work environment, investment in training which results in a highly skilled, highly competent workforce is essential to support and maintain a viable safety case. The training strategy goes hand in hand with the work practices initiatives outlined above.

Over recent years, the principal training driver for qualified lineworker personnel has been the Live Line Glove and Barrier training, and the Network Operator training. This program continues today and all lineworkers now become qualified in Live Line Glove & Barrier within four years of completing their apprenticeship. Live line refresher training includes an annual, independently audited program.

All line workers are required to be trained in the use of a Neutral and Supply tester and to perform tests to ensure that connections to installations are safe. This testing regime meets the requirements of regulation 23(11)(a) of the ESNAR.

In addition to these programs, there is the mandatory technical refresher training in safety related skills such as LV live working, rescue techniques, traffic management and LV servicing.

There is an active program to update the Victorian Electricity Supply Industry (VESI) manuals, some of which are no longer relevant in today's work environment, to comply with the new standards. This meant the development of a new HV Operations Manual and a new Live Line Manual. As previously mentioned, the VESI Fieldworker Handbook was updated in 2006 and 2009.This Handbook is currently being updated and a new version will be released in 2015. In addition, there are many Occupational Health and Safety programs for all employees, not just linesmen, and these programs include regular workplace inspections, health and safety programs concentrating on employee wellbeing and health.

In 2004, the VESI introduced a Skills Passport which is now a cornerstone of the VESI refresher training and authorisations programs. The Passport provides portable evidence of the currency of the Passport Holders' training, inductions and network authorities. In 2008, an ENA committee was established to develop and implement a similar scheme on a national scale.

The national passport will be supported by nationally consistent training packages that have been developed by EE-OZ Training Standards for energy generation, transmission and distribution and which reference nationally consistent standards. These national qualifications are now supported by standardised refresher training descriptors which will support the national passport as being the recognised qualifications across jurisdictions.

Changing work practices have been targeted at improving system reliability, safety and business efficiency. Live line glove and barrier techniques and first response crews have required significant investment in training, plant and equipment. Maintenance of these skills requires ongoing refresher training while plant and equipment requires regular testing and replacement to ensure that it is maintained in safe working order. Similar ongoing refresher training is required in many other areas of work practices.

JEN also has an overall responsibility for safe work practices and requires all contractors engaged on its assets to be appropriately trained and authorised. Internal and external audit programs are conducted to ensure safe work practices are maintained.

Indicators

There are two indicators that are used to measure performance in this area. They are:

- Fatal, serious or minor incidents associated with contact with the network; and
- Environmental infringement notices issued.

Significant resources are allocated to respond to emergency situations. In most cases these incidents are handled with no further impact. However, in particularly severe cases or where there is a risk to safety it is a requirement that a written report be submitted to the technical regulator detailing the issues.

It is important that the electricity network is operated and maintained so as to minimise the safety risk to members of the public as well as employees. Therefore the target is to have zero fatalities and zero environmental infringements. JEN's safety and environmental performance measurement against key indicators is presented in Table 5.4.

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Fatalities due to contact with the network	0	0	0	0	0	0	0	1	0	0	0
Environmental infringement notice issues	0	0	0	0	0	0	0	0	0	0	0

Table 5.4 Historical Safety and Environmental Performance (Actual)

5.4 Climate Change

Climate change has emerged as an issue of key focus for the world. JEN understands the importance of minimising the risk to its assets and customers due to the effects of climate change, and the importance of contributing to solutions to help solve the climate change problem. As part of its strategic objectives for ensuring the long-term sustainability of its network and associated operations, JEN plans to assess climate change infrastructure impacts by monitoring latest development in climatic models, and working closely with other public service infrastructure provides and relevant government departments on adaptation options. This section provides the approach to the key climate change challenges faced by the JEN.

5.4.1 Expenditure Implications

The following is a list of initiatives relating to climate change adaptation that are being considered by JEN:

- Initiate a number of studies to better inform JEN on the required changes to asset design requirements and asset capability as a result of projections in climate change;
- Manage network resilience to wind and extreme heat events;
- Implement changes to bushfire mitigation;
- Management of extreme weather events;
- Respond to government climate change policy; and
- Proactive management of greenhouse gas abatement.

Preventative Measures

Preventative measures are available to minimise the impact of extreme events. The following initiatives are being implemented by JEN:

- Improve communication to customers during widespread supply emergencies; and
- A capital expenditure program aiming to maintain the safety performance of the network.

The program includes the replacement of undersized poles that are known to break at high wind speed, the installation of Rapid Earth Fault Current Limiters (REFCL), pole-top fire mitigation and pole replacement:

- Continuation of the Distribution System Augmentation program to replace overloaded distribution substations to ensure network capacity is available; and

- A program to opportunistically retrofit insulation and air conditioning to zone substation control buildings where sensitive electronics equipment are installed.

Other impacts on electricity networks caused by the extreme weather pattern which may need addressing include:

- The de-rating of network infrastructure and reduction of asset lives due to increases in peak summer temperature and extended sequences of high temperature days, drought and changes in load pattern;
- Droughts and its effect on soundness of asset foundation, and earthing system conductance;
- Flooding and its effect on electricity infrastructure; and
- Increased bushfire risks including loss of electricity infrastructure and increased vegetation management costs.

These additional factors will be addressed as part of the on-going asset management process.

Greenhouse Gas Emission Management

Management of greenhouse gas emissions in the form of distribution losses occurring from the use of the network, public lighting emissions management and future use of SF_6 insulated switchgear will be a key focus for JEN going forward. JEN's stand-alone environmental policy demonstrates the increased emphasis on the environmental performance of the assets it operates. Minimising carbon footprints, identifying innovative environmental solutions and developing environmentally sustainable purchasing principles will assist in driving better environmental performance of JEN's assets.

JEN plans to investigate the economics of the following measures for reducing greenhouse gas emissions:

- Review conductor sizing to potentially reduce distribution network losses;
- Consider the installation of power factor correction capacitors on distribution feeders to reduce distribution network losses;
- Dynamic optimisation of the network by actively adjusting open point positions on a regular basis to optimise losses, reliability and demand;
- Quantifying the impact of harmonics and voltage unbalance on network losses and trialling technologies to reduce harmonic distortion levels;
- Facilitation of distributed generation connections to reduce network losses; and
- Investigation of non-SF_6 alternatives such as dry-air switchgear to reduce our reliance on SF_6 as an insulating material.

5.5 Emergency/Contingency Planning

There are emergency response management arrangements in place for JEN, which articulate the key processes for notification, escalation and mobilisation in the event of an emergency. The intent of the emergency response arrangements is to ensure that the initial response to an emergency is to protect people and assets from immediate harm; to ensure processes, controls and resources are immediately available so that JEN can continue to meet its operational capabilities and that appropriate recovery mechanisms are in place to ensure that all JEN's critical functions are re-established as soon as practicable to meet ongoing operational demands.

Periodic reviews and emergency exercises are conducted, and where necessary, emergency preparedness and response procedures are revised in accordance with a continuous improvement approach to emergency management.

As well as simulation and exercise program in place for JEN, the extreme events of a storm (April 2008), extreme heat (January 2009) and devastating fire conditions (February 2009) in JEN's network area, have tested the full application of emergency management arrangements for JEN under real and sustained conditions, demonstrating the capacity of the emergency response system to effectively manage JEN assets under conditions of significant threat.

5.6 Bushfire Management

JEN has a Bushfire Mitigation Plan in place to reduce the effects of bushfires in the network area. The plan is developed in line with regulatory requirements. The creation of the Bushfire Mitigation Plan and associated policies and procedures demonstrate the commitment from all levels of management within JEN to the minimisation of bushfire risk due to electricity assets.

Whether the terms minimisation or prevention are used, the aim of the plan is to be a primary reference for all bushfire related policies and procedures and to manage the bushfire ignition risk using approved techniques.

The policies and procedures have been developed over time and are carefully tailored to meet the specific needs of the JEN electrical assets in the Hazardous Bushfire Risk Areas as designated by the Country Fire Authority (CFA). These policies and procedures are communicated to all relevant employees and contractors and stringently enforced at both the design and construction phases of maintenance and network augmentation work. Regular bushfire mitigation audits are carried out to ensure compliance.

The objectives of the plan are:

- To demonstrate JEN's level of commitment to meeting its bushfire mitigation responsibilities;
- To define JEN's approach to management of the risk of bushfires caused by electricity assets; and
- To consolidate policies and procedures relating to bushfire mitigation activities in a referenced document.

5.6.1 Drivers and Objectives

The purpose of the bushfire mitigation policy is to minimise the risk of fires caused by electricity assets and to ensure compliance with legislative and regulatory requirements. The objectives of the bushfire mitigation policy are to:

- Ensure public safety;
- Ensure that the Electric Line Clearance Management Plan balances safety, reliability and community requirements with conservation values in the best interests of its customers and everyone in JEN's area of supply;
- Minimise vegetation related electricity interruptions to JEN's customers;
- Establish a standard of care that must be observed by our employees and contractors as well as our customers in relation to JEN assets where power lines are near vegetation;
- Ensure JEN's management procedures will minimise the effects of power lines on vegetation and over time achieve a sustainable environment unaffected by power lines;
- Ensure electricity distribution assets are maintained to the standard required to ensure the system is fire safe in hazardous bushfire risk areas; and
- Ensure that there are no outstanding maintenance items for the duration of the declared fire danger period.

The following is a list of JEN's initiatives relating to bushfire mitigation for the next period. They are to:

- Continue to deliver the existing well established and effective bushfire mitigation strategies;
- Monitor the potential lengthening of the gazetted fire season as a result of climate change and any impact that this may have on the ability to deliver works programs, particularly vegetation management and maintenance services;
- Accelerate the replacement of wooden crossarms with steel crossarms to mitigate the risk of fire start as a result of pole fires;
- Install Rapid Earth Fault Current Limiter (REFCL) (resonant earthing) to further reduce fault current in high exposure bushfire substations;
- Identify and prune or remove trees that lie outside of the compliance clearance area but remain a risk of contacting overhead lines;

- Implementation of engineering solutions such as asset relocation and replacement in order to achieve electric line clearance regulatory compliance when clearing of vegetation is not feasible.
- Replace non-preferred services to reduce the possibility of fire starts; and
- Retire low voltage bare overhead main conductors.

The following map in Figure 5.2 shows the land to which the Bushfire Mitigation Plan applies with respect to the JEN Electricity Networks distribution area. The map identifies the Hazardous Bushfire Risk Areas in green.

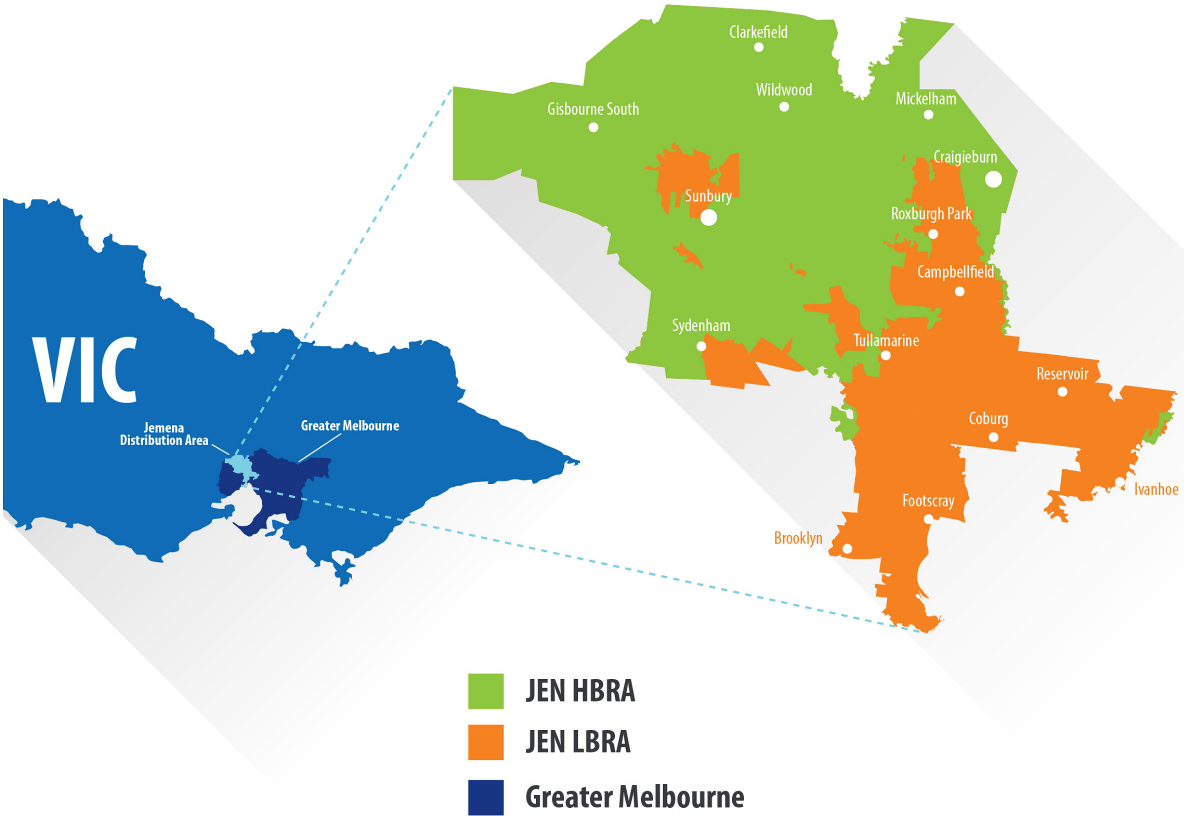


Figure 5.2 Hazardous (Rural) and Low (Urban) Bushfire Risk Areas

The Powerline Bushfire Safety Taskforce was established by the Victorian Government, through Energy Safe Victoria, in response to the findings of the 2009 Victorian Bushfires Royal Commission.

Its role is to investigate the full range of options available to reduce the risks of catastrophic bushfires from electricity infrastructure and to quantify the benefits and cost, taking into account all measures already taken by Government.

Its final report, which was completed in 30 September 2011, recommended a 10-year plan to reduce bushfire risk, including costings.

Strategies

The core bushfire mitigation strategies adopted by JEN are:

- Rigorous management processes - policies and procedures are documented and understood by all relevant employees and contractors, and systems are in place to monitor and review the effectiveness of the processes;
- Preventative programs - these are based on the analysis of fire risk and the implementation of appropriate instructions and programs;
- Asset condition monitoring - the condition of the assets are closely monitored through a program of inspection, testing and recording; and

- Procedures for days of total fire ban - appropriate operational procedures are maintained and implemented on days of total fire ban.

Bushfire Mitigation Management System

The purpose of the Bushfire Mitigation Management System is to combine JEN's Bushfire Mitigation management processes and procedures into a formal management system to ensure effective management of assets and activities in the Hazardous Bushfire risk area. The objectives of the system are to:

- Identify and document the management processes, procedures and activities (and the relationships between them) associated with managing the risk of bushfires; and
- Identify the management control mechanisms for the activities critical to the management of fire risk.

Audit and Review

The purpose of the audit and review procedures is to ensure the ongoing effectiveness of the Bushfire Mitigation Management System. The objectives of the audit and review are to:

- Ensure that bushfire mitigation procedures are followed and are meeting their objectives;
- Ensure the timeliness and effectiveness of responses; and
- Review the value of performance measures.

Management Structure

It is important to ensure that there is a clear understanding of the responsibilities for the implementation and control of all activities related to bushfire mitigation. The objectives of the management structure are to:

- Have in place a formal, documented management structure for bushfire mitigation;
- For each position, to have clearly identified responsibilities with assigned authority and accountability; and
- Identify the inter-relationships between those that manage, perform, record and verify bushfire mitigation activities.

Management Reporting

Management reporting is required to ensure that personnel engaged in bushfire mitigation are kept informed of the status of JEN's fire season preparedness. The objective of management reporting is to:

- Provide appropriate and timely reports to all levels of the bushfire mitigation management structure.

Reporting to ESV

An important component of the Bushfire Mitigation Plan is to ensure that Energy Safe Victoria (ESV) is informed of relevant matters associated with bushfire mitigation. The objective of the reporting to the ESV is to:

- Ensure that ESV is provided with all necessary information required by them, in relation to bushfire mitigation activities.

Systems for Measuring and Validating Performance

Systems are in place to ensure that the status of the bushfire mitigation program and the effectiveness of the management system are measured and validated. The objectives of the systems are to:

- Establish appropriate measures and targets;
- Record the status of the bushfire mitigation program; and
- Evaluate the effectiveness of the bushfire mitigation management system.

Bushfire Mitigation Plan

The purpose of the Bushfire Mitigation Plan is to plan and document JEN's approach to managing the fire risk. The objectives of the Bushfire Mitigation Plan are to:

- Prepare a plan covering the identification of the risks, the environment, the works program (including auditing), communication and required actions; and
- Meet legislative and regulatory requirements.

Technology Implementation

The adoption of available technologies to minimise the fire risk is an important component of the plan. The objectives are to:

- Implement available technologies to minimise the risk of fires from electricity assets, where the investment is prudent; and
- Work towards creating an environment where Electric Line Clearance is minimised.

Step Change to Industry Practice

It is important that changes to established practices and procedures will not increase the bushfire risk. The objectives are to:

- Ensure that a rigorous process is followed for the implementation of step changes to industry practices; and
- Ensure that key stakeholders (e.g. ESV and insurers) are consulted.

5.6.2 Expenditure Implications

Preventative programs are based on analysis, including a risk assessment and will be either:

- Responsive - for damaged or defective equipment identified during routine inspection and testing or reported by other means; and
- Routine/cyclic - for replacement, modification and maintenance at set intervals of time.

Specific programs focused on bushfire mitigation include:

- Electric line clearance management;
- Network monitoring;
- Private overhead electric lines management; and
- Other bushfire mitigation strategies.

These programs are the key drivers of expenditures, as discussed below.

Electric Line Clearance Management

Electric Line Clearance Management includes both tree clearing and preventative activities. JEN has Electric Line Clearance responsibilities in both Hazardous Bushfire Risk Areas (HBRA) and Low Bushfire Risk Areas (LBRA). The purpose is to ensure that adequate clearances are maintained between vegetation and network assets.

The objectives are to:

- Maintain programs for achieving statutory clearances at all times between vegetation and network assets; and
- Have in place an Electric Line Clearance Management Plan, approved by ESV.

The responsibility for Electric Line Clearance management is defined in the Electricity Safety (Electric Line Clearance) Regulations 2010 and associated Code of Practice for Electric Line Clearance.

Generally, in the LBRA, Electric Line Clearance management of street trees in urban areas is the responsibility of the local council. In the HBRA, Electric Line Clearance management of street trees in urban areas is the responsibility of JEN.

Electric Line Clearance management of private trees encroaching on JEN assets is JEN's responsibility in both the urban and the hazardous bushfire risk areas. The responsibility for trees approaching private electric lines or service lines over private property lies with the property owner.

The vegetation management contractor, in accordance with the detailed Electric Line Clearance Management Plan, will inspect the whole of the JEN fire area, including private electric lines each year. The vegetation management contractor will arrange power lines clearance in accordance with the Code prior to the anticipated start of the fire season.

Network Monitoring

Asset Management Systems

The purpose of the asset management information systems is to maintain a database of information to enable the effective management of all of the JEN assets in the HBRA with the objective of being able to:

- Identify every item of the electricity network; and
- Record information about each item. The asset management systems:
- Identify and locate all network assets;
- Record the condition of the assets;
- Record the date of network asset assessments;
- Identify assets subject to approved replacement, modification or maintenance programs; and
- Generate action reports, assigning the category of the priority where maintenance or repair works are required.

The asset information management systems comprise several components, some of which include the Works Management System, the Geographical Information System and Field Data Capture capability. Refer to Section 9 'Asset Class Strategies (Life Cycle Management)' for further information.

Asset Inspection and Assessment

The purpose of asset inspection and assessment is to assess and record the condition of network assets in hazardous bushfire risk areas. The objectives of the asset inspection and assessment strategy are to:

- Assess by inspection and, where appropriate by testing, the condition of network assets; and
- Assess by inspection the clearances between vegetation and network assets.

Private Overhead Electric Lines

Private Overhead Electric Lines (POELs) are inspected on a regular basis to ensure that they are maintained in a safe and serviceable condition. The objectives of the POEL policy are to:

- Manage the assessment of POELs; and
- Manage the rectification and replacement of defective POELs.

While POELs are primarily the responsibility of the property owner, JEN inspects them on a cyclic basis; notifies the owner of any defects found and monitors the process of fault rectification. The rectification of defects is the responsibility of the owner of the line. The POELs will also be inspected annually prior to the declared fire risk period for clearance from trees.

JEN requires that POELs are made safe before the bushfire season, and will disconnect supply on total fire ban days if repairs are not completed.

Where a POEL is found to be defective and is to be replaced, the replacement service will be the most appropriate type, either an underground service or a HV line and substation. As required by Regulation 403 of the Electricity Safety (Installations) Regulations 2009, (and its subsequent replacement), POELs in need of substantial reconstruction will be replaced with underground consumer mains.

From 2011, JEN inspects all POEL's on a 37-month cycle.

Additional Bushfire Mitigation Policies

Additional bushfire mitigation policies that JEN has in place include:

- Liaison with other organisations relevant to Bushfire Mitigation activities through the sharing of knowledge, skills and resources;
- Ensuring that all employees and contractors engaged in bushfire mitigation activities have the appropriate knowledge and skills to carry out their work through maintaining an effective system for the assessment and training of employees and contractors;
- Ensuring the currency, retention and security of bushfire mitigation records through the secure storage of up-to-date information with controlled access and that the appropriate level of management approves bushfire mitigation policies and procedures;
- Taking appropriate action and learning from each fire ignition involving network assets or incidents with the potential to cause fire ignition through responding to, reporting, investigating and analysing every fire ignition involving network assets and reported situation with the potential to cause fire ignition;
- The assessment of risks and causes or potential causes of fire ignition from electrical assets to enable appropriate action to minimise the risk through a rigorous risk assessment and implementation of appropriate actions;
- The removal or minimisation of the causes of fire ignition by electrical assets through the establishment and implementation of preventative programs for assets identified as a fire risk or potential fire risk; and
- The maintenance of a system of operational instructions, maintenance procedures and technical standards for activities in hazardous bushfire risk areas, in the preparation for and during the declared fire danger period. This is achieved through the maintenance of a system of operational instructions for inspection, testing and assessment of network assets and a system of standards for the design, construction, operation and maintenance of the network.

These policies are in line with Regulatory requirements and exhibit good industry practice by:

- Ensuring that equipment and services procured for the network do not compromise JEN's bushfire mitigation programs. This is achieved by ensuring that contractors providing services in hazardous bushfire risk areas meet the same standards as JEN employees and that equipment purchased for use in hazardous bushfire risk areas has been assessed in relation to the risk of fire ignition;
- Enhancing public awareness of bushfire mitigation issues by increasing community awareness of the risks of POELs and of work and vegetation near lines and increasing the contribution by the community to minimising the risk of fires; and
- Having plans prepared for actions to be taken on days of total fire ban or in the event of fires.
  The objective is to be prepared such that the appropriate actions will be implemented on days of total fire ban or in the event of fires. Operational Contingency Plans are also in place which set out actions that, will be taken to secure the safety of network assets, where preventative program works are incomplete or extra ordinary environmental conditions exist.

Quantification of Network Impacts due to Climate Change

It is estimated that climate change will have an impact on the number and severity of bushfires. JEN's asset management practices must be able to adapt to meet the potential challenges of:

- Increase in the number of extreme fire risk days;
- Potential changes to bushfire risk areas; and
- Potential lengthening of gazetted fire seasons.

Management Practices to address increasing Bushfire Risk

Given the advice of an increasing likelihood of more intense fires in the JEN region, it is prudent for JEN to take additional measures to avoid fire starts. It is concluded that prudent actions may include:

Additional Management of Hazard Trees

Hazard trees are trees that are outside of the compliance cutting area but still pose a threat to the network assets. The threat may be in the form of coming into contact with lines particularly during periods of high wind. Management actions include identifying hazard trees and undertaking pruning or other activities to reduce the threat they pose to network assets.

Reduction of Incidence of Pole Fires

There is a demonstrated relationship between dry conditions and the incidence of pole fires. With projected long term increases in dry conditions, the risk of fire ignition from pole fires is also expected to increase. Acceleration of existing programs of wooden cross arm replacement will provide a beneficial mitigation to the risk of fire start from JEN assets.

Earth Fault Current Reduction

Consideration shall be given to upgrading the electricity distribution network zone substation transformer earthing from direct and Neutral Earthing Resistor (NER) earthing to resonant earthing to reduce the fault current. Given the large improvements in performance from a fault energy perspective (resonant earthing being a factor of 1.7 million times less likely to start a bushfire than direct earthing) and the recent bushfire experienced in Victoria, a program will be implemented to introduce resonant earthing within all high exposure bushfire zone substations.

Installation of Insulated Conductor Systems

Insulated conductor systems provide additional protection to live electricity wires to prevent and minimise the impact of events such as line clashing in high winds, vandalism, wind blown debris and impacts from hazard trees. All of these impacts have the potential to start a fire and therefore the use of insulated conductor systems has a beneficial impact in the prevention of bushfire starts from electricity assets, as well as minimising the likelihood of customer outages.

There are different options available in insulated conductor systems:

- Aerial Bundled Cable (ABC) - refers to bundling of multiple low voltage overhead lines into one single insulated cable. ABC is more resilient than bare conductor to the impacts of wind and contact from vegetation reducing the risk of fire starts from electrical lines; and
- Covered conductor is a standard power line wire which incorporates an insulated plastic cover. The cover helps prevent localised faults that result from powerlines clashing in the wind or from debris, such as small tree branches, being blown or falling onto powerlines.

The benefits of selectively installing insulated conductor systems such as ABC and covered conductors to mitigate the increasing risk of bushfires will be further investigated.

A study will be undertaken to identify locations where significant bushfire risk mitigation may be achieved through the application of insulated conductor systems.

5.7 Environmental Management Plan

JEN manages its assets responsibly through an Environmental Management System (EMS). Such a system assures that the many activities and programs that are undertaken are documented and controlled to minimise any impact on the environment. A diligent EMS demonstrates that JEN manages its environmental responsibilities and duties of care.

The environmental objectives are to:

- Be recognised as an environmentally responsible company;
- Demonstrate responsible and diligent governance of its operations in the environment in which it operates; and
- Limit adverse environmental effects in providing for the efficient, safe, and reliable distribution and supply of energy and energy related services.

The drivers for environmental management are to:

- Comply with all applicable laws and regulations;
- Safeguard the environment for communities within which JEN operates through prevention of environmental impact and the considered risk management of all activities;
- Continuously improve the EMS;
- Identify innovative environmental solutions for services delivered;
- Ensure that all significant environmental hazards and risks are identified, assessed and controlled; and
- Ensure employees and contractors understand their responsibility for the environmental performance of their activities.

5.8 Embedded Generation

There are a number of existing embedded generators connected to the JEN HV distribution network. There are also on-going enquiries for the connection of embedded generators. On the LV networks, an automatic connection standard has facilitated the connection of small embedded generators, primarily roof-top photovoltaic (PV) systems. PV penetration is now over 5% of JEN's customer base.

The key technical issues associated with these units include:

- Network support;
- Fault level contribution;
- Protection schemes;
- Islanding;
- Intermittent generation;
- Network security;
- Compliance issues; and
- Customer expectations and associated rule changes.

5.8.1 Expenditure Implications

The following is a list of initiatives relating to embedded generation that are planned for the next period. These include:

- Reviewing fault level mitigation technologies to overcome fault level limitations impeding the connection of embedded generators;
- Developing business process to embed the consideration of viable embedded generation technologies in non-network option analysis of major network augmentation projects;
- Opportunistic protection upgrades for adaption to active two-way network;
- Development of standard connection agreement and connection procedures for embedded generation;

- Modelling and determining the critical mix of embedded generation technologies and penetration levels needed before proactive measures are needed to maintain service quality within limits specified in relevant technical standards, particularly for intermittent generation clusters on the LV networks;
- Reviewing generator islanding restrictions to establish a possible migration path for micro-grid concepts;
- Determining whether a need exists to audit micro-embedded generation installations for compliance with JEN's connection requirements;
- Establishing a dedicated resource for processing and handling generator connection applications;
- Reviewing the method for calculation of electrical losses for business cases; and
- Implement Chapter 5 and Chapter 5a rule changes.

5.9 Advanced Metering Infrastructure Plan

The Victorian Government's order in Council (OIC) gave JEN an obligation to deploy 100% of Advanced Metering Infrastructure (AMI) meters to all electricity consumers who use less than 160 MWh per annum. This objective has been achieved in mid-2014.

5.10 Smart Network Plan

Smart networks combine advanced communication, sensing and metering infrastructure with existing energy networks. This enables a combination of applications that can deliver a more efficient, robust and consumer-friendly electricity network.

JEN has been developing and applying smart network compatible technologies to its distribution network over many years. JEN's long term strategic objective for smart networks is to continue to embrace new and innovative technologies which present net tangible benefits for application within the network.

JEN also plans to leverage the infrastructure provided by the AMI program to further develop a smart network and improve its service delivery to customers.

A smart network will deliver service improvement and empowerment to customers who want flexibility in using power efficiently, priced effectively, and in an environmentally sustainable manner. Adoption of smart network concepts will help JEN to maintain a market leading position and to provide a platform for innovation to meet changing customer needs. As such smart network concepts are included in the asset management decision making process.

Whilst smart networks are a paradigm change, a building block implementation is planned by JEN rather than a transformational change. The concept of smart networks is and will be a continuously developing one and its success hinges on JEN being continuously aware of customer and societal expectations.

In 2016-20 JEN will focus on the following aspects of smart network implementation:

- Roadmap formulation – to develop a roadmap to guide the development of operational technologies (OT);
- Data analytics - to analyse network data (AMI data, SCADA data) to develop intelligence and insight for more efficient and effective management and operation of the Jemena electricity network;
- Demand management and non-network alternatives – to develop the capability for Jemena to undertake economic non-network alternatives to meet customer load demand, through demand response, embedded generation, energy storage and other technologies;
- Deliver network benefits by leveraging Advanced Metering Infrastructure (AMI) – incremental investment in AMI meter firmware/backend system upgrade and integration with Outage Management System to deliver improved operational efficiency, enhanced asset safety, improved supply reliability and quality, and better customer service;

- New network technologies - provide early warning of impeding pole top fires, enhance network bushfire performance by implementation of Rapid Earth Fault Current Limiter (REFCL) technology in zone substations supplying into high bushfire risk areas, and implementation of IEC61850 substation automation technology;
- Facilitate the connection of renewable energy resources – address the current issues caused by the connection of photo-voltaic systems and to trial technologies that will increase the hosting capacity of the distribution network for renewable energy resources.

Specifically, the program of work for 2016-20 includes:

Year	Project
2015	Formulate 10-year development roadmap of operational technologies (Opex)
2015	Installation of first pole top fire early detection system on BY11 22kV feeder (Opex)
2015	Installation of first Rapid Earth Fault Current Limiter (REFCL) technology in SHM zone substation (Capex)
2015	Commissioning of first IEC61850 technology at new BMS Zone Substation (Capex)
2015	Commissioning of IEC61850 technology at new TMA Zone Substation (Capex)
2016	AMI meter firmware/backend systems upgrade to deliver profiling capability and broken neutral detection (Capex)
2016-20	Installation of additional pole top fire early detection system and rotation of the two systems to a number of 22kV feeder sites (Opex step change)
2017	Outage Management System upgrade and integration with AMI outage detection (Capex)
2017	LV smart diagnostic tools development (Opex and Capex)
2018	Distribution Management System Implementation (Capex)
2018	REFCL in SBY Zone Substation (Capex)
2019	REFCL in CBN Zone Substation (Capex)
2020	REFCL in COO Zone Substation (Capex)
2016-17	Trial - managing peak demand through customer engagement (DMEGCIS)
2016-17	Trial - distributed grid energy storage (DMEGCIS)
2016-17	Trial - demand response field trial (DMEGCIS)
2017-19	Trial - direct load control trial (DMEGCIS)
2018-20	Trial - efficient connection of micro embedded generators (DMEGCIS)
2019-20	Trial - technology and economic assessment of residential energy storage (DMEGCIS)

6 Asset Performance

JEN has established key Level of Service Indicators for:

- Reliability of supply;
- Customer service; and
- Quality of supply.

This chapter sets out the required levels of performance and their impacts on the management of the assets. Key outcomes for the 2016-2020 period are:

- Reliability of supply and customer service will be maintained at current levels; and
- Quality of supply will be maintained within regulated requirements.

6.1 Approach

JEN regularly carries out detailed analysis of the network to identify performance and capability shortcomings. This includes mathematical modelling of the total network to determine its ability to meet the forecast requirements (loading and performance), including the state of individual components with respect to line loading and voltage levels under normal and contingency conditions. Results of this modelling are used to identify when and what potential inadequacies are likely to arise in the future and determine which network augmentation or operational options are feasible to satisfy the requirements. This informs the technical compliance expenditure category in asset replacement (Chapter 9).

All viable network augmentation and operational options are considered, balancing performance risk against costs to identify optimal solutions to meet forecast requirements. The options are also risk evaluated for performance and reliability in an integrated system. Accurate modelling requires a high level of understanding of the complex behaviour of all network elements such as lines, transformers and capacitors.

This section outlines the performance targets and measures used as the basis for the planning activities. Regular reporting in relation to a significant number of KPI's is undertaken. These measures, in total, document the overall performance of the network.

Level of Service Indicators covers the following areas:

- Reliability of supply;
- Customer service; and
- Quality of supply.

Service provision is best understood to include the reliability of electricity supply to customers, the timely performance of customer works, and the responsiveness to customer communications. An important principle in the context of service provision is that of balancing costs with risks. To provide the 'best solution to customers' requires that this balance is maintained such that the level of service provided to customers is optimised against the cost of providing that service.

This section identifies the projects and expenditure that are designed to contribute to the achievement of JEN's asset management strategy objectives through maintaining and improving the level of service that JEN provides its customers.

The asset performance that underpins JEN's service levels is largely determined by factors such as the historic design, age, location and condition of the distribution network as well as the changing operational environment that causes variation in asset performance from year to year. To manage these factors, JEN conducts regular detailed analysis of the network and develops appropriate and cost efficient responses to ensure that aggregated network performance targets are met.

For the period covered by this AMP, JEN has an objective to maintain reliability performance at the average historical level, to deliver improved customer service during major emergency events, as well as continue to foster a positive customer service business culture.

6.2 Key Issues

Equipment failure is the key cause of network outages. JEN has implemented a process of investigating failures of subtransmission and zone substation equipment and implementing plans to prevent recurrence and avoid systemic failures. On the distribution network, JEN identifies the true cause of high-voltage network faults and uses this information to target preventive programs, remedial work and maintenance.

The installation of Power Quality Meters on the network has enabled JEN to identify and manage power quality issues. This will result in a better understanding of current and emerging issues and will result in an initial increase in the number of instances when remedial work is required to bring power quality performance within Victorian Distribution Code limits.

6.3 Reliability of Supply

Reliability of supply is a key component of service provision and refers to the degree to which the network avoids outages (interruptions to customers' electrical connection) and provides as continuous a supply as possible.

The international reliability indicators SAIDI, SAIFI, CAIDI and MAIFI used in the following sections are defined as:

- SAIDI (System Average Interruption Duration Index) – the total minutes, on average, that a customer is without electricity in a year;
- SAIFI (System Average Interruption Frequency Index) – the number of occasions, on average, each customer would experience an outage in excess of one minute;
- CAIDI (Customer Average Interruption Duration Index) – the average time taken for supply to be restored when an outage greater than one minute has occurred; and
- MAIFI (Momentary Average Interruption Frequency Index) – the total number of momentary interruption events (less than one minute) that a customer would experience in a year, on average. The small letter 'e' stands for 'event' where an event consists of one or more momentary interruptions occurring sequentially in response to the same cause that does not result in a sustained loss of supply.

These reliability indicators are the primary methods by which reliability is measured and are continuously monitored by JEN. This section summarises the current level of reliability performance, identifies the target levels of future performance and sets out the plan for management of the network in order to achieve those targets.

6.3.1 Current Levels of Service

The current level of service of JEN's network with respect to reliability performance is summarised in Table 6.1 and is put in context by comparison to historical levels.

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
SAIDI – Total	66	81	99	76	76	98	80	76	71	83	86
SAIDI – Unplanned	59	74	91	67	66	88	62	55	50	60	59
SAIDI – Planned	7	7	8	9	11	10	18	20	21	24	27
SAIFI – Unplanned	0.98	1.36	1.37	1.30	0.95	1.29	0.94	0.90	0.92	1.11	0.96
CAIDI – Unplanned	60	55	66	52	69	68	67	61	54	54	61
MAIFI	0.79	0.75	0.99	0.90	0.66	1.02	0.97	0.80	0.70	0.77	0.79

Table 6.1 Current and Historical Network Reliability Performance (excluding upstream events and major event days)

The following figure gives the details of the reliability performance of the network as measured by the supply reliability indices. The red line is shown which indicates the regulation target. The blue bar represents the impact of excluded events.

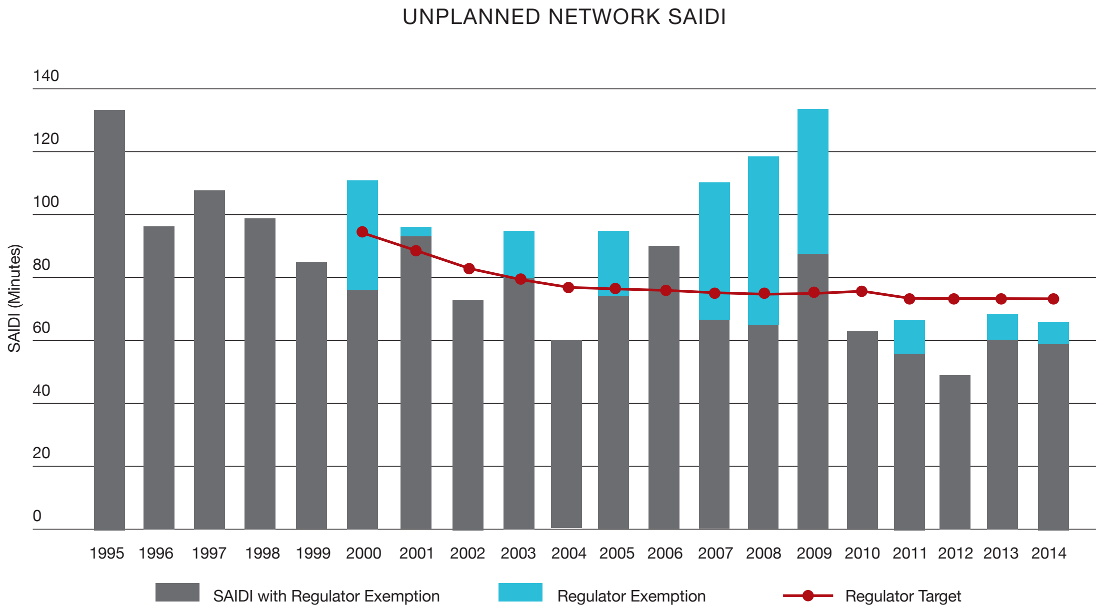


Figure 6.1 Unplanned SAIDI trends

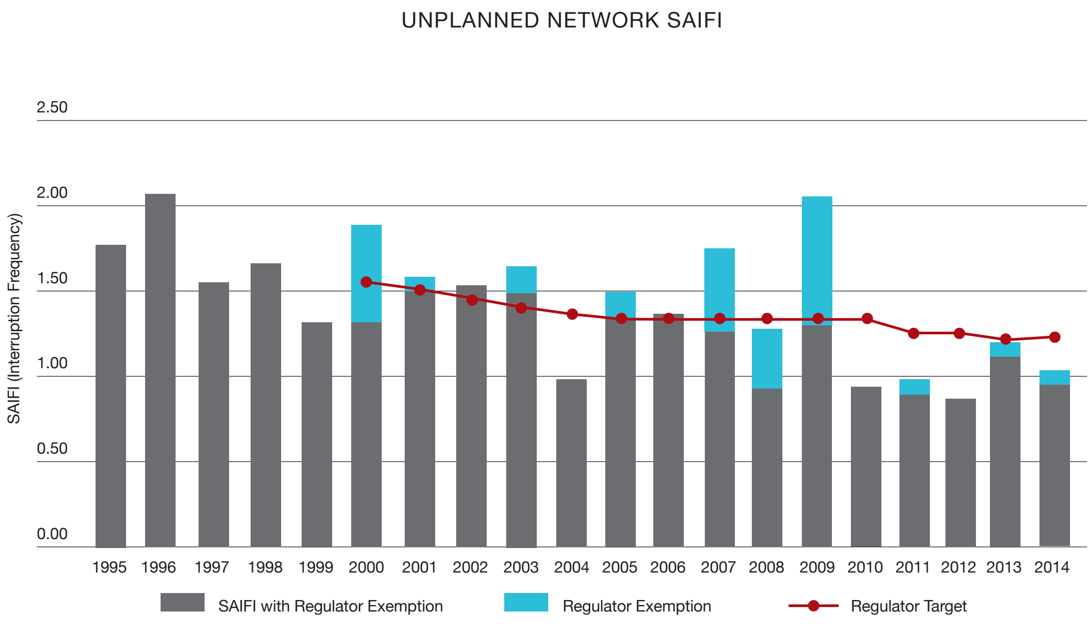


Figure 6.2 Unplanned SAIFI trends

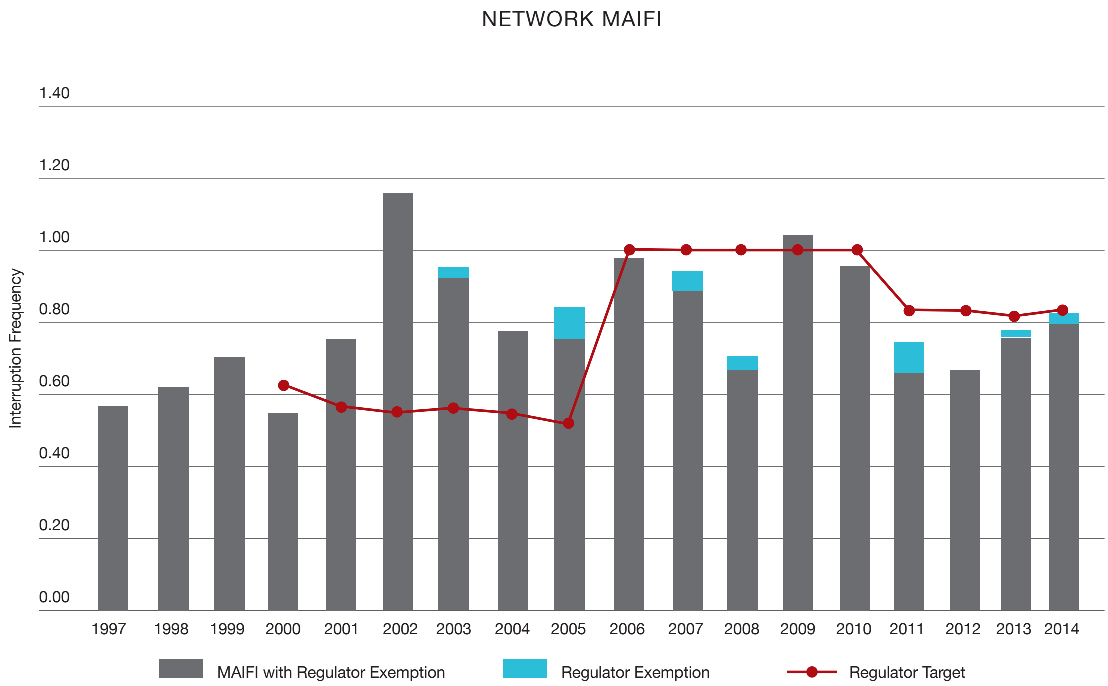


Figure 6.3 MAIFI trends

Figure 6.1 shows historical SAIDI reliability performance, with the blue bars representing ESC approved excluded events (which include both upstream events and major event days). Yearly performance, however, has varied considerably from a low of 50 minutes in 2012 to a high of 91 minutes in 2006.

The reasons for variations in performance are:

- 2004, 2010, 2011, 2012 and 2013 were years of mild weather with correspondingly good performance;
- 2006 had a significant volume of underground cable faults and many major feeder faults occurring during off-peak hours when resources were stretched. Other major contributors were pole fire events (7.9 minutes), high wind events (8.3 minutes) and lightning events (11.9 minutes);
- 2008 was a year when weather conditions resulted in a significant volumes of pole fires; and
- 2009 was a year of poor performance due to a range of factors: heat wave (14.4 minutes), pole fires (8.4 minutes), high winds (8.4 minutes), third party (4.5 minutes), lightning (3.9 minutes), underground asset failures (3.9 minutes), overhead conductor connector failures (3.3 minutes), and surge arresters (1.4 minutes).

Unplanned CAIDI is dependent on the type of faults that occur, the nature of the resultant damage and resource availability at the time of faults. CAIDI has been consistent over the years at around 60 minutes (excluding major events). The years 2006, 2008, 2009, 2010 and 2011 were above the average performance mainly due to significant volumes of underground cable faults in 2006 (underground cables typically have long repair times) and many major feeder faults occurring during off-peak hours when resources were stretched; significant volumes of pole fires in 2008, and pole fires and the extreme heat wave in 2009.

MAIFI has increased significantly since the introduction and commissioning of auto circuit reclosers (ACRs) in mid 2002 and has averaged around 0.9 interruptions per annum. As a result of the current initiatives of reducing secondary damage and hence maintaining SAIFI performance, it is expected that MAIFIe may increase.

The largest single influence on the variability of the reliability performance of a mainly overhead network is the environment in which it operates. Weather and associated events such as storms, drought and bushfires together with the effect of third party interference results in large variances in the year-to-year reliability performance of the network.

Preventative maintenance and asset replacement plans are focused on optimising the required expenditures against service performance outcomes to ensure that only prudent and efficient expenditures are made. Details of asset replacement plans are covered in Section 9.

Specific asset replacement initiatives to address reliability performance impact are summarised below:

- **Underground Cable Replacement –** JEN has introduced a new condition monitoring technique to detect the conditions of aged cables and will prioritise the replacement of end-of-life cables;
- **Pole and Pole Top Replacement –** there is a priority to replace poles and pole tops that are at their end-of-life; and
- **Overhead Line Replacement –** steel and copper overhead line conductors are showing increasing trend of failure due to age/corrosion. A replacement program is planned in this period.

JEN can influence reliability levels through control of the following aspects of asset management:

- The condition of the network elements;
- The level of redundancy built into the network;
- The design standards of the network;
- The standard of day to day network management, monitoring and response times; and
- The level of innovation applied to finding solutions to ongoing network issues.

6.3.2 Reliability Plan

Investment to maintain reliability in the past few years has been mainly on reducing the impact of faults by installation of auto circuit reclosers, remote controllable switches and overhead line fault indicators such that fewer customers are off supply and supply restoration times are shorter. The projects have been prioritised in terms of the criticality of the feeders and effectiveness of SAIDI and SAIFI reduction.

The initiatives put in place as part of this plan are discussed below:

- **Feeder Fault Mitigation on Rogue Feeders.** An Asset Performance Review meeting is held every month to review the performance of different aspects of the network and make recommendations. This involves investigations into individual feeder faults and performance monitoring to identify and rectify poorly performing feeders. The focus of this program is on identifying and rectifying declining performance.
- **Conductor Clashing Mitigation.** JEN has developed a conductor clashing mitigation policy as a step-by-step approach to address the issue and prevent reoccurrence after fault. The policy includes a proactive approach to identify potential conductor clashing sites and re-design these sites. This re-design is undertaken in conjunction with the protection settings review using the Conductor Clashing Simulator model for new ACR installation projects and zone substation transformer upgrade projects that would result in a significant increase in fault levels.
- **Pole Fire Mitigation.** Analytical studies into the critical factors contributing to pole fire ignition have identified and ranked high-risk assets and geographical locations. JEN has implemented a long-term program to inspect and tighten or replace hardware at these sites over a number of years.
  This program is planned to increase in volume as climate change and other external environmental factors result in climatic conditions conducive to pole fires. The aim is to maintain existing levels of performance despite the increase in adverse climatic conditions.

Investment will continue on projects that would reduce fault impact cost effectively. In addition to the installation of ACRs and overhead line fault indicators, remote control switching and monitoring on indoor and kiosk substation switchgear will be installed in modest volumes.

In accordance with this plan, JEN has targeted the following average levels of reliability performance which have been set by the AER for 2016-2020, based on the historical performance of 2011 to 2015.

Annual Reliability Targets (2016-20)	Target	Urban	Short Rural
Total minutes off supply (SAIDI)	93	87	201
Unplanned minutes off supply (SAIDI)	57	55	91
Planned minutes off supply (SAIDI)	36	32	110
Unplanned interruption frequency (SAIFI)	0.97	0.95	1.23
Unplanned interruption duration (CAIDI)	59	58	74
Momentary interruption frequency (MAIFI)	0.78	0.76	1.63

Table 6.2 2016-2020 Reliability Targets

6.4 Customer Service

Customer service is an important part of JEN's role as a distribution network service provider. JEN monitors a range of customer service indicators in order to track and improve service performance. Customer service is best understood as the level of timely completion of works that have been agreed with customers and the responsiveness of JEN to customer communications, particularly via JEN's call centre.

The Electricity Distribution Code and the Public Lighting Code specify guaranteed service levels (GSL) for meeting customers' appointments on time, for making supply connections and for fixing public lights within specified time frames. Customer service is also measured in terms of the number of distribution complaints received by the distributors and the Energy & Water Ombudsman of Victoria, and in terms of call centre performance (timeliness in responding to telephone calls).

6.4.1 Current Levels of Customer Service

JEN's historical performance against GSLs is summarised in Table 6.3.

Performance Indicator %	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011*	Actual 2012*	Actual 2013*	Actual 2014*
Appointments on time	99.81	99.98	99.92	99.92	99.69	99.89	98.58	98.72	99.21	99.39	98.52
New connections on time	99.86	99.88	99.91	99.81	99.50	99.11	99.89	99.98	99.87	99.93	99.92
Street lights repair on time	95.81	93.13	98.86	99.11	97.26	83.79	95.09	99.98	99.65	99.87	99.46

* Appointments on time exclude Appointments (AMI rollout) for consistent comparison.

Table 6.3 Historical Performance against Guaranteed Service Levels

JEN's historical level of call centre performance is summarised in Table 6.4. JEN's historical level of customer complaint performance is summarised in Table 6.5.

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Calls to call centre fault line - total number	88,315	115,267	120,330	121,791	122,714	137,988	104,691	105,682	112,878	132,673	115,621
Calls to fault line forwarded to an operator (%)	61.4	48.5	62.8	64.2	71.7	69.5	80.5	78.0	85.4	82.4	83.6
Calls to fault line answered within 30 seconds (%)	73.8	75.2	77.4	79.9	73.1	77.4	77.2	60.05^	64.23^	62.95^	73.60^
Calls to fault line – average waiting time before call answered (seconds)	74	98	60	68	65	55	72	69	63	69	38
Calls abandoned	801	5,301	8,092	16,057	31,771	31,273	31,687	29,943	36,737	41,408	35,173
Call centre – number of overload event	0	0	0	2	2	47*	29*	9*	3*	1*	0*

* Call Centre number of overload event definition changed from 2009.

^ Calls to fault line answered within 30 seconds (%) definition changed from 2011.

Table 6.4 Historical Performance for Call Centre Performance

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011*	Actual 2012*	Actual 2013*	Actual 2014
Complaints - total per 1,000 customers	1.34	1.73	1.55	1.47	1.42	2.43	4.16	1.69	2.20	2.26	2.78
Complaints – connection and reinforcement	75	83	52	48	81	120	258	51	64	80	48
Complaints – reliability of supply	23	65	50	45	48	104	118	17	39	18	48
Complaints – technical quality of supply	122	139	180	222	173	159	187	117	101	167	143
Complaints – administrative process or customer service	64	37	42	26	50	58	266	208	120	48	339
Other complaints - distribution	91	79	170	132	100	299	457	137	392	407	308

* 2011 Complaints excluded complaints (AMI rollout) for consistent comparison.

Table 6.5 Historical Customer Complaint Performance

6.4.2 Future Targets for Customer Service

The AER has proposed that call centre performance (% of calls answered within 30 seconds) continues to be included in the STPIS for the regulatory period from 2016-20, and that targets be set based on the average of the last five years' performance. The benchmark set for the 2016-2020 regulatory period under the AER definition is 61.16%.

Annual Call Centre Performance Targets (2016-2020)	Target
Calls to fault line answered within 30 seconds (%)	64.235%

Table 6.6 2016-2020 Call Centre Performance Targets

The forecast number of GSL payments for not meeting customer service measures, and customer complaints per year for the period 2016-20 are shown in the tables below.

Annual Customer Service Targets (2016-2020)	Forecast number of payments p.a.	Target %
Appointments on time	147	> 98.8%
New connections on time	16	> 99.8%
Street lights repair on time (within 2 business days)	18	> 98.8%
Supply offers received by customers within 20 days (unless agreed with customer)	-	> 99.8%

Table 6.7 2016-2020 GSL Payments and Performance for Customer Service Measures Targets

Annual Customer Complaint Forecast (2016-2020)	Forecast
Complaints – total per 1000 customers	2.23
Complaints – connection and reinforcement	61
Complaints – reliability of supply	31
Complaints – technical quality of supply	132
Complaints – administrative process or customer service	179
Other Complaints – distribution	311
Average number of working days to resolve complaints	20

Table 6.8 2016-2020 Customer Complaint Performance Forecast

6.5 Quality of Supply

Quality of supply includes the accuracy of the supply voltage, the shape of the voltage waveform as measured by harmonic distortion, and momentary changes in supply voltage such as sags, swells and transients. JEN's long-term strategic objective for quality of supply is to provide supply voltages to all JEN's customers that comply with mandated regulatory quality of supply limits.

6.5.1 Current Levels of Service

Power quality is becoming an increasingly important issue for electricity customers, suppliers and manufacturers. The widespread development and adoption of power electronic equipment by consumers and its interaction with the delivery of electricity within the supply network has also raised the profile of power quality with regulators.

While supply reliability primarily focuses on the presence (or absence) of electricity supply, power quality focuses on the aspects of electricity supply which affect electrical apparatus' performance, and in some cases, life expectancy. Parameters such as voltage magnitude, phase unbalance, harmonics and momentary changes (sags, swells, transients and flicker) are factors affecting power quality. Both utilities and consumers of electricity are becoming increasingly concerned about the quality of electric power and as such, Power Quality has become one of the most debated issues within the power industry today.

There are six major reasons for the growing concern:

Increased Sensitivity of Customer Electrical Equipment

Equipment is more sensitive to power quality variations than equipment applied in the past. Many new devices contain microprocessor-based controls and power electronics that are sensitive to many types of electrical disturbances. Power quality impacts the performance and reliability of these devices.

Reduced Equipment Life and Performance

More research is required into the effects of increased harmonics, transients and negative phase sequence voltages on the life expectancy and capability of customer equipment and network equipment. Increases in network electrical losses may also result through overheating and noise generation associated with poor power quality. This is a risk that needs to be explored and quantified.

Increased Penetration of Non-Linear Loads

Increasing emphasis on overall energy efficiency, production efficiency and management of greenhouse gas emissions has resulted in the growth of power electronic devices such as high-efficiency lighting, adjustable-speed motor drives and switched-mode power supplies. The non- linear nature of these loads (only drawing current during part of the supply cycle) results in increasing harmonic distortion levels.

Increased Penetration of Airconditioning and Intermittent Generation

Increased usage of air-conditioning contributes adversely to voltage flicker as a result of the duty-cycle when air-conditioners switch on and off. The most immediate impact experienced by customers connected in close proximity is the repetitive dimming of lights. When connected as single phase units, air-conditioners can also impact voltage unbalance performance. This can lead to three-phase equipment loss of life due to excessive heating from the negative phase sequence currents and higher electrical losses. Potential flicker situations also occur from other variable loads and is expected to increase from forecast higher penetrations of intermittent embedded generation sources.

Equipment Mission and Immunity

Non-linear and intermittent loads emit disturbances when they are connected to the supply network, which can in turn affect other sensitive electrical equipment. The supply network is required to be designed in such a way to meet minimum power quality standards so that equipment can be immune from malfunctioning (immunity standards), but this can only be achieved if equipment emission standards are enforced. Currently there is no mandatory requirement for consumer electrical equipment to meet emission standards before they can be offered for sale in Australia.

Increasing Customer Awareness

Customers are becoming better informed about such issues as interruptions, sags and switching transients and are challenging electricity utilities to improve the quality of supply delivered. Being able to deal with customer concerns means appropriate power quality monitoring is required. Further monitoring will also assist with regulatory compliance and reporting.

6.5.2 Power Quality Plan

The aim of the power quality plan is to:

- Maintain power quality levels within regulated requirements;
- Address any emerging issues identified as being associated with power quality with appropriate mitigations;
- Minimise interruptions to customers due to network induced voltage disturbances;
- Minimise damage to customer and network equipment caused by power quality issues;
- Reduce the level of network losses generated by voltage unbalance and harmonics; and
- Monitor and participate in industry development of power quality standards and strategies.

JEN also plans to identify and mitigate power quality issues from the collected data to address issues of:

- Steady state voltage variations by progressively reviewing and rectifying the areas where voltage violation has been revealed — fixing local issues identified with an expectation that more issues will be revealed via the introduction of AMI meters with voltage quality monitoring function, coupled with a more globalised network approach to voltage correction.

Harmonics and the need to consider the use of tuned reactors and harmonic filtering equipment to deal with the increasing penetration of non-linear connected loads:

- **Voltage sags.** JEN plans to trial control schemes to minimise voltage sags during network faults; and
- **Unbalanced loads.** JEN plans to progress with a proposed amendment to the Distribution Code so the Code aligns with international standard for unbalance limits, and to balance network loads where excessive unbalance is identified.

JEN plans to become more proactive in managing the quality of supply on its network into the future because of these emerging issues.

Historical performance is shown in Tables 6.9 and 6.10.

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Voltage variations – steady state - feeders	Not available	15,715	56,252	21,514	14,587	7,264	2,897	1,091	3,428	3,392	1,622
Voltage variations – steady state – zone substations	79	234	414	318	214	323	396	143	214	72	148
Voltage variations – 1 minute	0	0	0	0	0	0	0	27	46	38	39
Voltage variations – 10 seconds	0	0	57	54	70	54	48	1,377*	1,395*	850*	760*

* Includes all voltage variations that have minimum voltage below 0.9 of set point voltage

Annual Voltage Variation Forecast (2016-2020)	Forecast (2016-2020)
Voltage Variations – Steady State Feeders	2,486
Voltage Variations – Steady State Zone Substations	195
Voltage Variations – 1 Minute	30
Voltage Variations – 10 Seconds	886

Table 6.9 2016-2020 Voltage Variation Performance Forecast

Note: Annual voltage variation forecast data for 2016-2020 is based on five year averages.

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
Low voltage supply	46	50	43	45	53	31	39	27	16	30	29
Voltage dips	17	16	17	14	10	11	15	12	13	9	10
Voltage swell	3	0	0	1	0	0	0	0	2	1	1
Voltage spike (impulsive transient)	0	0	0	0	0	2	2	0	2	1	1
Waveform distortion	0	0	1	2	0	0	0	0	0	0	0
Other	56	73	119	180	110	114	127	78	68	126	102

Annual Voltage Level Forecast (2016-2020)	Forecast
Low voltage supply	26
Voltage dips	10
Voltage swell	1
Voltage spike (impulsive transient)	1
Waveform distortion	0
Other	94

Table 6.10 2016-2020 Voltage Level and Distortion Performance Forecast

JEN initiatives for power quality include:

- **Measurement and Simulation.** Monitoring power quality performance to identify existing problem areas or worsening trends by using information from the power quality monitors is one of JEN's key objectives. Simulation of the network and customer loads under various scenarios will enable JEN to identify potential trouble-spots and apply suitable proactive mitigation actions. These simulations will involve the use of steady state, dynamic, and fault level network simulation software.

  Further, use of harmonic simulation software and flicker calculations will be required. Understanding the differences across both three-phase and single-phase networks will be needed. Correlation of simulated results with measured data will be required to test power quality models and to determine the key influences that impact quality of supply levels. Understanding causes of harmonic resonance and the characteristics of the load through load modelling and monitoring will be instrumental to implementing an effective power quality strategy.

- **Analysis of Smart Meter Voltage Quality Data.** The mandated program covers all customers consuming under 160MWhr per annum, essentially all residential customers, small commercial and industrial enterprises. The smart meters are linked by two-way communication network to a central back office system. Apart from 30-minute energy consumption, the meters also monitor voltage quality.

  The mass rollout of smart meters with voltage monitoring capability has therefore provided voltage sensing at every consumer supply point. JEN is in the process of analysing the smart meter voltage quality data to pinpoint areas where voltage delivery can be improved.

- **Refine Power Quality Standards.** JEN will seek to actively influence the development of national and international quality of supply standards through participation in industry and standard committees. A key requirement in the medium term will be to influence new code and regulatory requirements relating to quality of supply to ensure JEN can respond to new regulatory environments and to ensure suitable projects are incorporated into price review submissions.
- **Application of Technologies.** JEN plans to adopt and apply new technologies on the network to mitigate power quality issues. This will be achieved by trialling the latest technologies on offer and to gather information on the performance of customer equipment under non-ideal voltage supply conditions.
- **Research and Training.** JEN will research the issues associated with power quality. This will include literature searches and correspondence with other utilities and training in the subject of power quality. Liaison with consultants and parent/sister companies may be useful to gauge different perspectives and to obtain an international exposure.
- **Customer Education.** JEN plans to educate commercial and industrial customers about the interaction between customer equipment and the supply network. This will ensure that appropriate equipment standards can be specified before the equipment is purchased and, for existing equipment, suggestions will be made of how equipment immunity can be improved. For consumer electronics, work will be undertaken with equipment manufacturers to improve equipment immunity to match typical Australian distribution network characteristics.

7 Connections

This chapter sets out the asset management plan for new connections to its electricity network. A forecast of JEN's Connections expenditure from 2016-2020 is included in Table 7.1.

Regulatory Category $2015 Real, $000	2016	2017	2018	2019	2020	Total (2016-20)
Connections	45,068	44,235	48,072	43,596	46,832	227,803
Total	**45,068**	**44,235**	**48,072**	**43,596**	**46,832**	**227,803**

Table 7.1 Connections Capex for 2016-2020

This expenditure provides for a forecast average growth rate of 1.3%, representing some 4,000 new connections per year. Residential customers are forecast to grow by 1.3% per annum, small business customers by 1.1% per annum and large business customers by 3.0% per annum. The forecast expenditures ($2015, '000) for each of the connection types are:

Expenditure Activity	Total (2016-2020)
Business Supply >10kVA	126,016
New KTS-MAT 66kV Line	11,083
Dual & Multiple Occupancy	56,814
Medium Density Housing URD/PURD	33,394
Low Density/Small Business Supplies <10kVA	496
Total	**227,803**

Table 7.2 Connections Capex by Expenditure Activity

7.1 Requirements

JEN complies with its responsibilities to connect new customers under its Electricity Distribution Licence and Electricity Industry Guidelines. In accordance with its published Customer Connection Guide, and following receipt of a written request for a new connection and all required information, JEN will within 20 business days, provide a written offer for the proposed works. JEN will provide in the offer the full cost of the new works and network augmentation, JEN's contribution towards the work and the price payable by the customer.

Connection capex accounts for a significant proportion of JEN's total network capital expenditure, historically in the order of 40%. Connections capex is not directly controllable by JEN in that JEN must respond to a variable level of customer project demand. The predicted value of Connections capex is therefore derived through an analytical process that combines economic forecasts of JEN's customer base with the unit rates that JEN anticipates for discrete capital works activities. The JEN document titled Customer Capital Forecasting Procedure details this methodology and provides for a transparent and consistent application of the process.

7.2 Key Issues

The number of customer connections is expected to grow at an average rate of 1.3% over the 2016-2020 period.

JEN relies on economic forecasters to provide long term estimates and on short term data trends based on actual data.

7.3 Forecasting Methodology

The basic approach to forecasting Connections capex is to draw heavily from historical experience, where the number of connections across the network is known, as well as the typical cost. The unit costs are then applied to forecast connections across each of the connection types.

As Connections capex projects are made up of a large number and a broad range of projects types, where the cost can range from several hundred to several million dollars, the derivation of work volume takes two key external inputs:

- Forecasts (provided by ACIL Allen Consulting) for residential customer numbers; and
- Forecasts (provided by Construction Forecasting Council) (CFC) for expenditure in different industry categories including commercial, industrial and infrastructure.

The growth rates of these external forecasts are then applied to JEN's actual Gross Demand Connection volumes from the most recent financial year to arrive at five-year forecasts of volumes for each work activity within the following SAP categories:

- Medium Density Housing URD/PURD;
- Public Lighting;
- Dual and Multiple Occupancy;
- Business Supply > 10kVA;
- Low Density/ Small Business Supplies < 10kVA;
- Special Capital Works, Customer Contribution – Non-Supply; and
- Service Wire.

The residential customer number forecasts are used to derive the Medium Density Housing, Public Lighting and Dual and Multiple Occupancy forecast volume growth rates. CFC expenditure forecasts for the non-residential sector (industrial, other commercial and miscellaneous) are used to derive Business Supply and Low Density/Small Business Supplies forecast volume growth rates. CFC expenditure forecasts for the infrastructure sector (roads, bridges, railways, harbours) are used to derive Special Capital Works and Recoverable Works forecast volume growth rates.

Unit rate forecasts for each activity are developed by breaking down historical expenditure into the categories of materials and labour and applying economic escalation factors for each category.

Forecasts for annual Gross Demand Connection capex expenditure over the next five-year period are then developed by applying these unit rates to the forecast volumes for each activity.

For the purposes of detailed budgeting and planning, these annual forecasts are seasonalised into monthly forecasts according to JEN's average Gross Demand Connection expenditure profile of the previous three years.

7.3.1 Base Forecasts

Forecasts, as at September 2014, of residential customer numbers underpinning the Connections capex forecasts are shown in Table 7.3.

Year	Residential Customers	Small Business	Large Business
2014	288,997	26,331	1,419
2015	293,028	26,599	1,460
2016	297,134	26,881	1,504
2017	300,815	27,167	1,549
2018	304,556	27,455	1,596
2019	308,357	27,747	1,645
2020	312,220	28,041	1,696

Table 7.3 Customer Number Trend - ACIL Allen (September 2014)

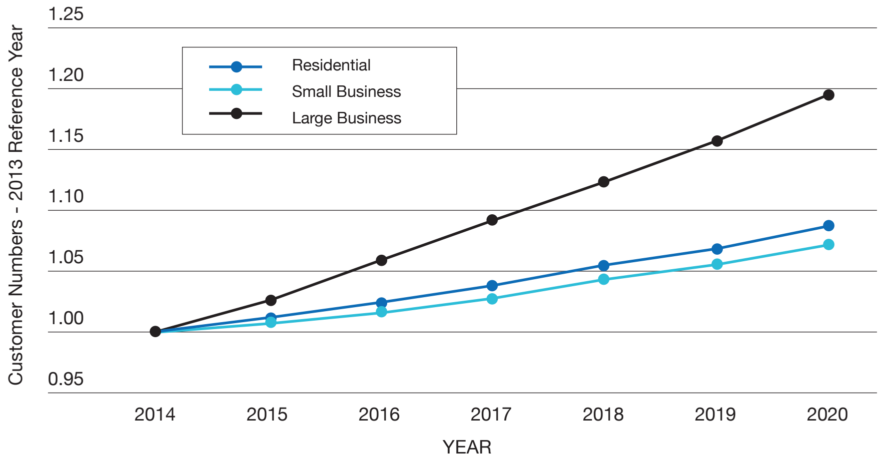


Figure 7.1 Customer Number Trend (September 2014)

The CFC forecasts of expenditure ($M) underpinning the Connections capex forecasts are based on the CFC data published on its website in May 2014, as shown in Table 7.4.

Year	Non Residential – Other Commercial (Melbourne)	Non Residential – Industrial (Melbourne)	Non Residential – Miscellaneous (Melbourne)	Engineering – Roads (Victoria)	Engineering – Bridges, Railways & Harbours (Victoria)
2014-15	230	1,757	460	2,146	1,322
2015-16	330	1,797	564	2,116	1,255
2016-17	311	1,836	554	2,144	1,227
2017-18	299	1,839	551	2,150	1,213
2018-19	312	1,848	571	2,181	1,210
2019-20	307	1,865	574	2,203	1,195

Table 7.4 CFC Forecast of Expenditure ($M) (May 2014)

7.3.2 Large Load Changes

Confirmed major new customers, as at September 2014, within the next five years include:

- On-going commercial/industrial estates outside Melbourne Airport land (5MVA);
- Melbourne Airport Business Park development (up to 60MVA) over the next 10 years;
- On-going industrial developments in Broadmeadows (5MVA);
- CSL HV supply upgrade in Campbellfield (4MVA);
- Northcorp Food Processing Factory in Campbellfield (2MVA);
- Food Plastic Factory in Campbellfield (2.5MVA);
- Metrolink Business Park in Campbellfield (2MVA);
- Summerhill Village Shopping Centre in Reservoir (3MVA);
- Coburg North shopping centre (4.5MVA);
- Essendon Airport Redevelopment (1.5MVA);
- Blue Cross Community Centre in Preston (1.5MVA);
- In the residential area there are several URD estates, which are currently being constructed or about to commence, e.g. Valley Lake Estate, Highlands Estate, River Valley Estate, Pentridge Estates, Coburg Hill, Edgewater Estates and Aston Estates;
- Load increase of ANZ Tullamarine Data centre (1.5MVA);
- Donnybrook Road Quarantine Facility (3.4MVA);
- Yarra Trams new traction substation in Preston (2.7MVA); and
- Yarra Trams new traction substation in Regent (1.4MVA).

High probability of proceeding major new customers, as at September 2014, within the next five years include:

- Footscray Central Activities Area Development (5MVA);
- Paper manufacturing plant in Preston (2MVA);
- Pascoe Vale Shopping Centre (1.5MVA);
- CSL new facility in Campbellfield (2MVA);
- Epworth Hospital in Coburg South (4MVA);
- Bega Cheese supply upgrade in Coburg South (2MVA);
- Steelforce Australia in Coolaroo (2.7MVA);
- Residential and commercial development in Flemington area near to Flemington Racecourse (up to 4.5MVA);
- Residential and commercial development in Amcor paper mill site Alphington (6MVA in December 2015 increasing up to 9.3MVA by the end of 2020);
- Residential and commercial development in Pentridge, Coburg (up to 11MVA) over the next 10 years; and
- New tram substations in Newmarket, Travancore, Essendon, Essendon North, Airport West, Moonee Ponds and Coburg (9.6MVA).

Proposals under consideration, as at September 2014, include:

- Further development in the Craigieburn and Mickleham area covered by the Northern Growth Corridor (possible ultimate of up to 130MVA) over the next 30 years;
- Further development within Footscray Central Activities Area (total of approximately 40-50MVA) over the next 30 years;

- Latrobe University HV supply increase (up to 7MVA) over the next 12 years;
- Austin Hospital HV supply increase (5MVA);
- Further re-development of Essendon Airport site (5MVA);
- Further development on Austrak site (4MVA); and
- Data centre in current the Age building West Meadows (up to 8MVA).

These estimates include changes in existing customer loads and loads associated with proposed new developments. Zone substation load forecasts are based on feeder loadings, which have been appropriately diversified to take into account the feeder maximum demands occurring at different times of the day.

Note that only loads associated with confirmed new developments or development proposals that have a high probability of proceeding are included.

7.4 Customer Contribution Policy

The customer contribution policy is developed in accordance with Guideline 14 of the ESC.

8 Network Augmentation

This chapter sets out the asset management plan for upgrading existing network assets and adding new network assets. A forecast of JEN's augmentation expenditure from 2016-2020 is included in Table 8.1.

Regulatory Category $2015 Real, $000	2016	2017	2018	2019	2020	Total (2016-20)
Augmentation	25,436	56,751	52,399	30,636	11,534	176,756
Network Property	-	3,888	-	-	2,046	5,934
Total	**25,436**	**60,639**	**52,399**	**30,636**	**13,580**	**182,690**

Table 8.1 Augmentation Capex for 2016-2020

Major works that form this plan are described in the Capital and Operating Work Plan and include:

- Preston (P) zone substation conversion to 22kV Stages 4 to 6;
- East Preston (EP) zone substation conversion to 22kV Stages 3 to 5;
- Establish Craigieburn (CBN) zone substation including 4 feeders from the zone substation and extension of 66kV loop to the zone substation;
- Redevelopment of Fairfield (FF) and Flemington (FT) zone substations; and
- Redevelopment of Sunbury (SBY) zone substation and reconfiguration of KTS-MLN-SBY No. 2 66kV line.

8.1 Requirements

The National Electricity Rules (NER) and Victorian Electricity Distribution Code outline the need for each electricity distribution business operating in the National Electricity Market (NEM) to submit and publish an annual report – the Distribution Annual Planning Report (DAPR) – detailing plans to ensure its subtransmission lines, distribution lines and zone substations meet predicted demand over the following five-year period.

The key drivers for network augmentation capex investment are:

- The growing demand for electricity (typically over the summer period), whether through new customers connecting, or existing customers increasing their load;
- Safety - overloaded electricity plant and equipment poses a significant health and safety risk;
- Supply reliability and quality - as a last resort, overloaded plant can be managed by shedding supply to customers, thereby causing interruptions that lead to increases in SAIDI and SAIFI measures;
- Environment - heavily loaded plant incurs both real and reactive power losses; and
- Economic merit, where the cost of investment is completely offset by benefits in the form of a quantified reduction in energy at risk.

The intention of this section of the AMP is to leverage JEN's annual distribution network planning process and indicate how the process and its outcomes are integrated across the wider network to ensure optimised asset investment decisions are made.

This section outlines the philosophies and methodology used to plan the augmentation of the Jemena Electricity Network to meet predicted load demand for electricity over the following five years. It also provides information about load demand forecasting, assessment of the distribution network capacity, and proposed augmentation plans for the network. This augmentation plan is a major component of the capital investment plan.

8.2 Key Issues

Summer peak demand is forecast, as at September 2014, to grow by an average of around 1.4% per annum from summer 2014-15 to summer 2020-21.

The Victorian Government's metropolitan planning group predicts that one of the largest growth areas in the state over the next six years falls within our network boundary—the Northern Growth Corridor, encompassing Craigieburn and developments around Donnybrook and the Hume freeway.

To meet this level of growth, JEN will be required to:

- Establish new zone substations;
- Install or upgrade transformers in existing zone substations; and
- Undertake the re-arrangement, upgrade and installation of significant components of the subtransmission and distribution network.

This level of investment requires careful consideration as to the prudence of the timing of project works and the ability to deliver increased work activities.

A consistently high utilisation of the network is important to ensure that proposed investments do not result in customers bearing increased costs. Careful attention to planning and design of the network is required.

Eight embedded generators (greater than 1MW) are currently connected to the system. Opportunities for the connection of additional embedded generation or demand side solutions are sought through the issue of annual planning reports. Rising fault levels will increase the complexity in assessment and costs of new generator connections or demand side solutions.

The processes to forecast local overloads of distribution substations using the SUPS system have been improved to reduce overload failures and to enable better targeting of localised demand related capital expenditure.

For more detailed information about key issues, refer to JEN's Regional Planning documents as listed in Appendix B.

8.3 Network Augmentation Objectives

JEN's specific objectives for distribution network planning are to:

- Provide safe, cost effective, efficient, reliable electricity supply that meets target levels of performance;
- Maximise utilisation of existing assets; and
- Determine the most cost-effective means of developing the network to meet future loading requirements and customer needs.

A project aimed at alleviating a distribution system constraint should proceed if it minimises the cost to customers, having regard to the:

- Relative costs and benefits, including any change in supply reliability, of network augmentation and non-network alternatives to the augmentation;
- Uncertainty of assumptions that must necessarily be made in the decision analysis;

- Total asset life cycle costs; and
- Need to comply with environmental and land-use planning standards, health and safety standards, and applicable technical standards.

Distribution system planning is integrated and optimised to meet the demands of load growth and renewal of the ageing, poor performing parts of the network. It includes a commitment to maximise utilisation of assets and to use non-network solutions where they are cost effective. The investment planning process is a key part of overall asset management in that it strongly influences how new assets are acquired.

On an annual basis, all short to medium term expenditure on the network (capital and operating) is evaluated and ranked on a consistent basis to ensure an optimum investment plan and budget allocation. The investment planning and risk management processes are integrated to ensure that investments provide the maximum benefits and efficiency to customers at the lowest lifecycle cost.

8.4 Network Augmentation Planning Methodology

The network augmentation planning methodology is principally focused on an annual process that is summarised by the following steps.

- A post-summer review of actual performance and operation of the network assets is undertaken, where actual loading levels are monitored;
- Network models are updated accounting for recent network changes and new investments, including a review and determination of the applicable plant ratings. Assets are typically grouped and analysed according to function in line with the following categories:
    - Transmission connection points;
    - Sub transmission lines;
    - Zone substations;
    - High voltage lines; and
    - Low voltage assets.
- A range of spatial peak demand and energy forecasts are developed for the ten-year planning horizon, including cross-referencing with independent forecasts and neighbouring distribution networks;
- Year-by-year system studies and power flow modelling is carried out with all plant in service. This is a comprehensive assessment across each category of assets in order to test each piece of equipment thermal capacity to supply the demand forecasts. JEN systematically carries out load flow studies, examines transformer loading, voltage constraints and fault levels;
- Year-by-year system studies and power flow modelling are also carried out under deterministic network outage (N-1) conditions. This is a more onerous assessment across each category of assets in order to test each piece of equipment's thermal capacity to supply the demand forecasts assuming a critical piece of plant is unavailable;
- Identification of preliminary deterministic based constraints and timing given the power flow modelling;
- A preliminary risk assessment is undertaken for each constraint, accounting for the duration of potential overload, the number and type of customers affected, the back-up (load transfer capability and contingency plans) available within the specific network area, and the likelihood (probability) of the event occurring;
- For each of the constraints, engineering analysis allows the identification of technically and economically feasible network solutions to alleviate the potential overloads – this analysis is coordinated with asset replacement programs, and draws from wider experience in areas such as protection, system performance, network control and local asset planners;
- Preliminary project costs are determined, and an indication of the lead time to deliver the network augmentation is estimated. This information allows a preliminary preferred solution to be selected based on least cost principles;

- A ten-year growth-related capex plan is developed, and the five-year DAPR document is published in order to provide transparency and information to the wider energy industry, with a specific objective of seeking opportunity for non-network solutions to defer the need for network investment;
- A formal business case is prepared in time to ensure the preferred network solution can be implemented prior to the risk of potential overloads exceeding acceptable levels. The business case includes a detailed risk assessment looking at all feasible options, including more accurate project costs estimates, coupled with a comprehensive technical and economic assessment, including cost benefit analysis based on the probability of the event occurring and the potential energy at risk. The views of interested stakeholders, such as customers, other DNSPs, AEMO or AusNet Services are incorporated into the evaluation process; and
- The business case is critically reviewed as part of executive approval, prior to the project being implemented in accordance with the business procurement policy and project management policies.

In general, this planning methodology and process reflects the planning strategy that the JEN network has adequate capacity to meet anticipated maximum demand, even under extreme summer conditions. There is, however, a risk of inadequate supply capacity in some parts of the network if there is simultaneous occurrence of extreme summer temperatures and an unexpected outage of critical plant.

8.5 Network Planning Criteria

Network planning criteria are the predefined set of technical rules and guidelines that inform the need for network augmentation investment within the distribution network.

JEN's planning criteria are documented in detail within:

- JEN Planning Manual, March 2013;
- JEN Network Planning Criteria, December 2014; and
- JEN Instruction Manual, Network Demand Forecasts, June 2006.

These documents cover: access to historical loading data; load forecasting processes; rating standards for connection assets, sub transmission assets, feeders and zone substation plant; planning criteria and risk management; the regulatory environment; interfaces across the business; and the technical analysis processes undertaken.

JEN applies a probabilistic approach to planning its distribution network. The probabilistic approach is regarded as a key aid to judgement rather than the sole determinant of network augmentation plans. The key principles of JEN's distribution planning criteria are summarised in the following statements.

- Zone Substations - a probabilistic approach is adopted, where loading above and beyond a deterministic N-1 loading level is permitted on the provision that the expected energy at risk is less than the cost to augment. In order to evaluate the need for investment, the amount of expected energy at risk (EE@R) is quantified in dollar terms by multiplying the consequential overload amount (measured in MWh's based on its magnitude and the duration of the event) by the likelihood/ probability of the event occurring, and then multiplying this product by the Value of Customer Reliability (VCR) measured in $/MWh. Based on this economic assessment and appropriate sensitivity studies, investment is deemed prudent and efficient in the year that the value of the benefit in terms of reduced EE@R exceeds the annualised cost of the investment. This planning approach has the benefit of deferring major investment compared to a deterministic N-1 planning approach, especially if the growth rate is relatively low and the characteristic of the load duration curves is such that it is very peaky. The principle is that it is suitable to take a greater degree of risk under such peaky conditions on the basis that it is only for a relatively low number of hours per annum and the likelihood of an unplanned failure occurring coincidently with the high demand situation is relatively low. This approach does however implicitly include the risk that plant can be overloaded for a short time and that load shedding may be an acceptable and economic alternative to network investment. This is not the case with more conservative N-1 deterministic criterion.

- HV Feeders - a probabilistic approach is also adopted, however for feeder assets a nominal utilisation level of around 85% of a feeders rating is adopted as this provides for some margin across the feeders to ensure that load can be transferred away from the outage to an adjacent feeder to minimise the medium-term outage consequences.

JEN undertakes its planning studies under the medium economic growth scenarios and for both the 50% PoE and 10% PoE weather conditions. JEN also adopts a composite VCR of $38,400 ($2014) for its distribution planning risk assessments.

In summary, the planning criteria adopted by JEN allows for some discretion to be made in regards to the specific timing of its network augmentation investment to allow a risk-based balance between benefits and costs of distribution services – this is generally shown as the optimised level of supply reliability in Figure 8.1.

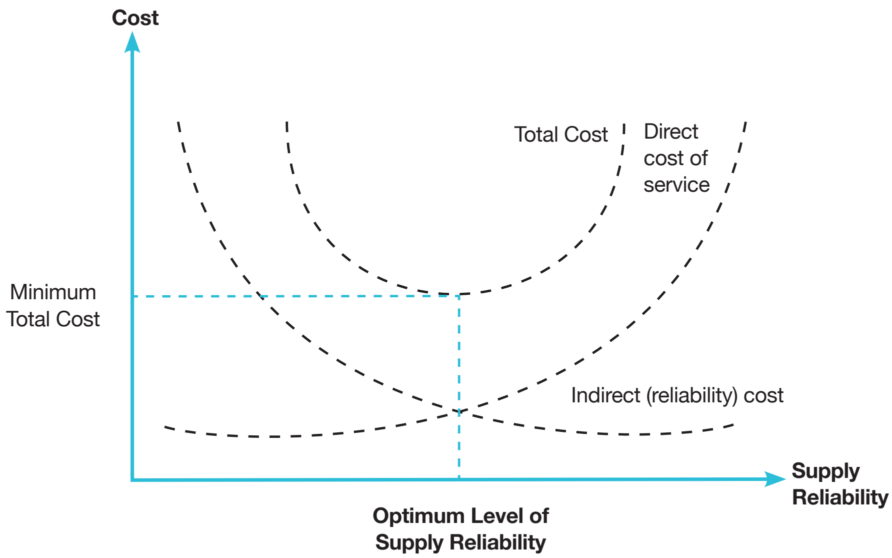


Figure 8.1 Balancing the direct cost of service and indirect cost of interruption

The extent to which investment should be committed is made considering:

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

8.5.1 Valuing Energy at Risk

In order to determine the 'economically optimal' level and configuration of connection capacity (and hence the supply reliability that will be delivered to customers), JEN adopts the same value of energy at risk, known as 'Value of Customer Reliability' or VCR, as adopted by AEMO. The VCR for electricity is a measure of the cost of unserved energy. The VCR will also be used in future regulatory test assessments for planned augmentation of the JEN[1].

The VCR is determined by AEMO, through a customer survey approach that estimates direct end user customer costs incurred from power interruptions at the sector and state levels.

1 The same VCR is also used in the AER's Service Target Performance Incentive Scheme.

8.6 Network Load Growth (Demand)

The most critical input to the network augmentation planning process is the electricity demand forecasts.

JEN's ten-year coincidental demand MW forecasts is shown in Figure 8.2 and Table 8.2, which indicates that JEN's peak summer demand is considerably higher than the winter demand levels.

It is forecast that the summer peak demand would grow by an average of around 1.4% per annum for the next ten years.

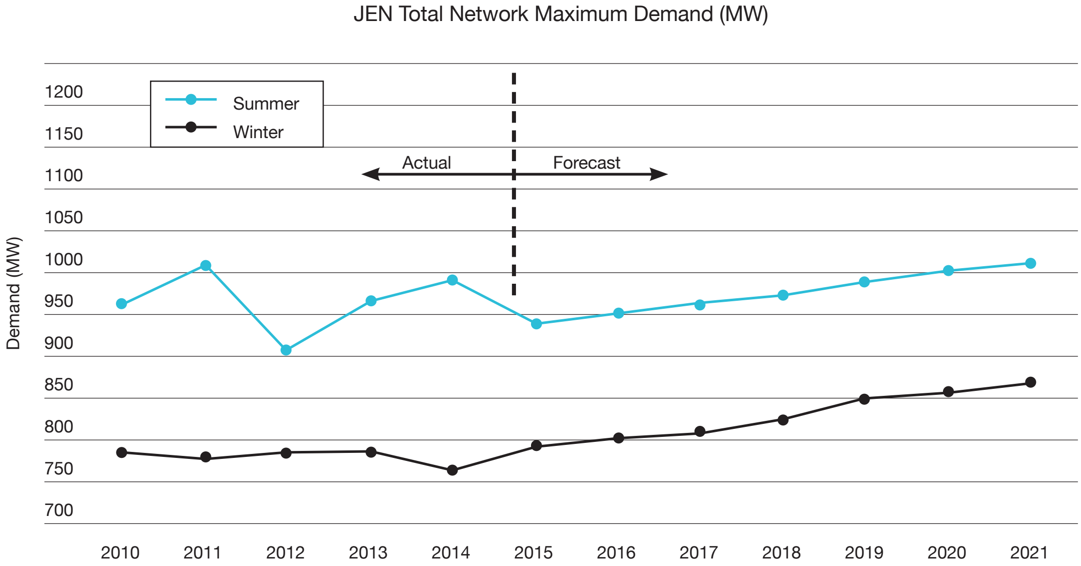


Figure 8.2 JEN Coincident Maximum Demand, Ten Year Forecast (MW) (September 2014)

Demand (MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Summer (50 POE)	962	1014	913	966	995	936	947	959	973	986	1002	1015	1,210	1,233
Winter (50 POE)	778	773	777	778	761	788	800	814	827	843	858	872	946	961

Table 8.2 JEN Coincident Maximum Demand (September 2014)

These forecasts form the basis of JEN's forecast network augmentation capex projects.

The process undertaken to prepare these forecasts involves two independent sets of demand forecasts being prepared annually, one by JEN's Network Planning team and the other by an independent forecasting consultant, ACIL Allen.

- JEN's forecasts are built up from a feeder level to zone substation level and finally to terminal station level, i.e. using a 'bottom up' approach. The forecasts are based on trends identified by looking backwards at historical data and also by looking forwards at drivers in the future that influence load growth. The forward looking drivers include known future loads, knowledge of local information such as proposed major industrial and commercial developments, predicted housing and industrial lot releases, proposed embedded generation and other things such as economic forecasts and council planning. Two forecast scenarios are produced for summer and winter peak demand conditions – a 50% probability of exceedence (POE) forecast and a 10% POE forecast.
- ACIL Allen's forecasts include a summer and winter demand forecast at each JEN terminal station as well as the total network demand for the 10%, 50% and 90% probability of exceedence (PoE) levels.

In preparing these forecasts, ACIL Allen uses national, state and regional economic projection models to drive the forecasts, i.e. a 'top down' approach. The information that ACIL Allen considers includes:

- The Australian GDP growth rate (%);
- Medium term outlook for the world and Australian economies;
- Economic outlook for Victoria and the JEN supply area;
- Government policies which impact on electricity demand and consumption. PeakSim model incorporates the impacts of Federal and State Government's energy and environmental policies on demand, energy prices from policy measures such as the proposed Emissions Trading Scheme and the expanded Mandatory Renewable Energy Target, and other policy measures such as changes to Minimum Energy Performance Standards (MEPS) - e.g. effect on lighting and air conditioners, as well as taking into account the roll out of smart meters and electric cars and the phase out of electric resistance hot water heaters; and
- Variations in temperature patterns.

Prior to finalisation and application of the forecasts, the terminal station forecast from JEN bottom-up forecast is compared against ACIL Allen's top-down forecasts and any material discrepancies are investigated, with the forecasts adjusted if necessary to ensure consistency and accuracy. JEN adopts its bottom-up forecast for the purpose of planning its network, as this provides detailed information at the feeders and zone substations levels.

Individual zone substation load forecasts are based on feeder load forecasts, which have been appropriately diversified to take account of different feeder load profiles.

8.6.1 Demand-Side Response (DSR)

DSR schemes have the potential to reduce peak demand on the electricity network and so defer network augmentation projects. This can be achieved by customers shifting their usage to off-peak and/or by using high efficiency, low energy, appliances and reducing energy wastage or curtailing their demand at peak times.

DSR schemes could include:

- Off-peak usage incentives (reduced price); and
- Interruptible load at reduced electricity price, covered by a supply agreement that the load can be interrupted during network emergencies.

If such schemes were established, their effectiveness would depend on the extent of customer uptake.

Demand would also be reduced through the encouragement of the use of high efficiency appliances and energy efficient designed homes and buildings (insulation, natural lighting, etc).

Opportunities for non-network solutions are published in annual planning reports and proponents are invited to contact JEN for further discussions.

8.6.2 Embedded Generation

Embedded generation can be an alternative for the alleviation of network inadequacies and constraints and thus defer the need for major substation or line augmentation projects. The embedded generation would be connected to, and supply into the subtransmission and / or distribution networks.

Possible embedded generators could include the following types:

- Gas turbine power stations;
- Co-generation from industrial processes; and
- Generation using renewable energy, for example land-fill or wind turbines.

There are eight embedded generators inter-connected to the network – Somerton Power Station in Somerton, Brooklyn Landfill in Brooklyn, Bolinda Landfill in Broadmeadows, Austin Hospital in Heidelberg, Latrobe University and Bioscience Research Centre in Bundoora, Mini Hydro in Preston and Visy in Coolaroo.

In forecasting peak demand for zone substation with embedded generation, it is assumed that the generators are running at peak load periods unless otherwise specified.

Table 8.3 shows the capacity and year of installation of the eight embedded generators inter-connected to the network.

Embedded Generator	Capacity (nominal)	Year Installed	Zone Substation
Austin Hospital	3.8MW	1991	NH
Bioscience Research Centre	1.5MVA	2011	NH
EDL - Bolinda Landfill	6.4MW	1993	BD
EDL - Brooklyn Landfill	3.0MW	1st unit in 2002 2nd unit in 2004 3rd unit in 2007	TH
Latrobe University	6.0MW	Early 1990s	TT
Preston Mini Hydro	2.0MW	2008	CN
Somerton Power Station	150MW	2002	Somerton Switching Station (SSS)
Visy	4.1MW	2012	VCO

Table 8.3 Embedded Generator Details

8.7 Network Augmentation Plan

The outcome of the network augmentation planning process described above is a detailed asset investment plan. A detailed listing of the network augmentation capex is set out in the Capital and Operating Work Plan.

The following is a list of key initiatives relating to future demand planning for the next five years:

- Continue the strategic plan of converting the Preston and East Preston network from 6.6kV to 22kV to increase transfer capability as well as replacing aging assets;
- Flemington – project was originally planned during 2011-15 period. Significant customer supply risk already exists. Redevelop zone substation prior to 2017/18;
- Sunbury – Transformation capacity (66/22kV) reaches capacity in 2017. Redevelop zone substation including transformer replacement prior to summer 2018/19;
- Establish new Craigieburn (CBN) zone substation. Existing supplies from Somerton (ST) and Coolaroo (COO) zone substations, both some distance away from the load centre, exceed capacity in 2019. New supply point (zone substation) needed prior to summer 2019/20 to mitigate customer supply risk;
- Install or upgrade new power transformers within existing zone substations to increase transfer capacity;
- Undertake the re-arrangement, upgrade and installation of significant components of the overhead subtransmission line and distribution feeder network;
- Review and update distribution substations and LV network management process to maintain network performance especially during summer heatwaves;
- Assess impacts on network and update planning philosophies in response to climate change and resultant Government policy initiatives, new technologies such as increasing penetration of distributed generation; and
- Develop and incorporate demand management strategy into network planning processes.

8.8 Utilisation

JEN calculates and analyses two measures of network utilisation to test the performance and overall capacity of the distribution system from a top-down perspective. One measures the utilisation of zone substation plant, and the other measures the utilisation of high voltage feeder capacity. Historical utilisation can vary significantly as weather changes from year to year as this influences maximum demands.

Zone substation utilisation is calculated by dividing the measured maximum demand at the zone substation by the nameplate rating of the zone substation transformer. This measure gives an indication of unused capacity in the network. (There will always be some unused capacity due to redundancy requirements.) When all the transformer capacity is used at times of peak demand this measure will approach 100%. The formula is:

Zone Substation Utilisation = Summation of maximum demand at JEN zone substations (excluding customer owned or other DNSP owned stations) / Summation of transformer nameplate ratings at JEN zone substations.

Feeder utilisation is calculated by dividing the maximum demand supplied by the feeder by the feeder's rating. It is an indicator of unused capacity in the network and at times of peak demand, this measure may approach 100%. The formula is:

Feeder Utilisation = Summation of maximum demand at JEN feeders / Summation of JEN feeder ratings.

The historical network loading, capacity and utilisation of high-voltage feeders are shown in Table 8.4 and Table 8.5, respectively.

Performance Indicator	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Summation of maximum demand at JEN feeders (MVA)	1,034	1,037	1,069	1,117	1,224	1,275	1,287	1,222	1,167	1,241	1,291
Summation of JEN feeders ratings (MVA)	1,978	2,016	2,039	2,048	2,106	2,178	2,208	2,206	2,217	2,282	2,311
Feeders utilisation %	52.3%	51.4%	52.4%	54.5%	58.1%	58.6%	58.3%	55.4%	52.6%	54.4%	55.9%

Table 8.4 Historical Network Loading, Capacity and Utilisation of HV Feeders

With feeder capacity augmentation planned to meet the growing demand over the next five years, the forecast feeder utilisation is projected to remain around 55%.

The historical network loading, capacity and utilisation of JEN zone substations are shown in Table 8.5.

Performance Indicator	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Summation of maximum demand at JEN zone substations (MVA)	848	832	855	912	988	1,070	1,031	1,025	937	1,016	1,042
Summation of transformer nameplate ratings at JEN zone substations (MVA)	1,441	1,441	1,474	1,458	1,524	1,557	1,571	1,604	1,633	1,633	1,644
Zone substation utilisation %	58.9%	57.8%	58.0%	62.5%	64.8%	68.7%	65.6%	63.9%	57.4%	62.2%	63.4%

Table 8.5 Historical network loading, capacity and utilisation of JEN zone substations

With zone substation capacity augmentation planned to meet the growing demand over the next five years, the forecast zone substation utilisation is projected to remain around 65%.

The measures of utilisation are at the desired levels and provided capacity continues to be added to the network to meet predicted growth then the forecast utilisation will remain at acceptable levels consistent with the present levels.

8.9 Fault Levels

Typical maximum fault levels for the 66kV loop system is 2,500MVA (21.9kA).

The typical maximum fault levels that can be expected at the zone substations are:

- 22kV - 500MVA (13.1kA);
- 11kV - 350MVA (18.4kA); and
- 6.6kV - 250MVA (21.9kA).

These fault levels relate to standard ratings to which plant and equipment have been historically designed, and are the safety limits set in the Distribution Code. The fault level will reduce along the distribution feeder with the distance from the zone substation and depend on factors such as the type of fault, impedance of the fault and impedance of the network.

JEN intends to keep network fault levels below maximum limits as stated above while the network capacity is expanded to meet customer’s increasing electricity requirements. Embedded generators have the potential to add to fault levels and may cause the fault level limits to be exceeded in localised areas. As part of the generator connection process, JEN will be monitoring closely fault level contributions from embedded generators.

Apart from the requirement to limit fault levels to within equipment design rating, there are other considerations that will favour reduced fault levels.

Resonant earthing has the capacity to reduce an earth fault current to such a low level that transient earth faults become self clearing without the need to disconnect customers. As a result of this significant reduction in fault current, the risk of fire ignition is substantially reduced.

There are no other technologies available that can reduce the fault current to such low levels as resonant earthing. The only alternative to installing a resonant earthing would be to insulate or underground all conductors from a zone substation to ensure they did not have the potential to initiate a fire. Given the extremely large costs in undergrounding an entire distribution network, this option has not been considered further.

8.10 Power Factor

From a network capacity perspective, 'Power Factor' is a measure of the proportion of the electrical current that is carrying energy and is primarily driven by customers' load characteristic. Poor power factor effectively means inefficient use of network capacity and will also result in increased network losses for the same amount of energy supplied to customers.

JEN considers the option of power factor correction at zone substations as part of its network augmentation planning. For the parts of the network with poor power factor, power factor correction can be a cost effective way of maximising network utilisation and deferring more expensive network augmentation such as an installation of a transformer.

8.11 Steady State Voltage Regulation

JEN is responsible for the management of voltage levels on the high voltage and low voltage networks. On the high voltage network, voltage control is done automatically by the use of automatic voltage regulators (AVRs) at each zone substation. These units control the operation of on-load tap changers fitted to the zone substation transformers. The AVRs respond to the variations in voltage that occur as network loads vary by causing the operation of the on-load tap changers. The on-load tap changers effectively vary the transformation ratio of the zone substation transformers to compensate for the changes in network load and maintain voltage levels within the required tolerances.

Voltage control on the low voltage network is managed by design in terms of the design load limit and the network length (voltage drop calculation) and the use of off-load tap changers on the distribution transformers. Voltages are set at the time of installation so that the variations that occur with load remain within the allowable operating range. The automatic voltage control that occurs on the high voltage network is critical to the maintenance of appropriate voltage levels on the low voltage network.

Power quality monitoring equipment in place has revealed that in some instances the steady state supply voltage is outside the regulatory limit some of the time. Through the voltage quality reporting from the AMI meters, JEN has also obtained indication of customers experiencing steady state voltages outside of the regulatory limits, particularly those marginally outside the limits where the impact on customer equipment may not be discernable so as to cause customer complaints. JEN is presently assessing the feasibility and cost/benefit for proactive voltage quality management process based on AMI meters.

9 Asset Replacement

This chapter sets out the asset management plan for the maintenance and replacement of network assets. A forecast of JEN's expenditure from 2016-2020 is included in Table 9.1.

Regulatory Category $2015 Real, $000	2016	2017	2018	2019	2020	Total (2016-20)
Asset Replacement	49,255	51,760	50,303	68,999	73,160	293,477
General Equipment	706	771	771	771	771	3,788
Fleet and Vehicles	3,878	3,257	3,302	5,155	3,379	18,973
Total	**53,839**	**55,788**	**54,376**	**74,925**	**77,310**	**316,238**

Table 9.1 Asset Replacement Capex for 2016-2020

The expenditure allows for:

- 19 subtransmission installation replacement projects;
- 18 projects for subtransmission communications and protection replacement;
- 28 separate projects/programs for high voltage installation replacement;
- Condition based pole replacement including the replacement or reinforcement of undersized pole or LV poles with HV raiser brackets;
- Pole reinforcement in preference to replacement;
- Condition based pole top structure replacement including removal of public lighting switchwire;
- Condition based overhead line replacement;
- Condition based underground cable replacement;
- Proactive condition based replacement program for non-preferred services; and
- Defective public lighting lanterns replaced in accordance with the Public Lighting Code.

9.1 Approach

The overall approach for asset replacement is based on the outcomes of asset class strategies, and in consideration of the lifecycle management, including key issues and plans for managing the assets.

JEN produces individual strategies for each of its asset classes that provide information about the:

- Asset class profile, which includes information about the type, specifications, life expectancy and age profile;
- Asset strategy, which includes key strategies and plans that support the Jemena Business Plan, asset management policy, and asset management strategies and objectives, as well as informing expenditure plans and programs of work;
- Asset risk, which includes information about asset performance objectives and measures, criticality and condition-based analysis;
- Asset performance, which provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with the management of the asset; and

- Asset expenditure assessment, which provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as historical and forecast operating expenditure (OPEX) and capital expenditure (CAPEX). This also includes decisions about whether to renew or dispose of assets that have reached the end of their economic life based on their performance, risks and/or supply security or service level requirements.

The asset class strategies are summarised in sections 9.6 to 9.28 below. The asset class strategies use leading asset management techniques to ensure an appropriate balance of capital and operational expenditure through the consideration of total lifecycle management costs. JEN's aim is to ensure that the network and assets are managed optimally to the benefit of the customer.

9.1.1 Asset Replacement Methodology

Asset creations occur in relation to projects to maintain reliability (covered in Section 6), gross demand connections (covered in Section 7) network augmentation (covered in Section 8), and asset replacement. The latter type of asset creations first requires a decision on whether to maintain or replace. Such decisions are made based on the asset reliability and network risk considerations and anticipated cost implications. Consequently, different asset classes have different lifecycle management strategies applied to their management. To this end, the component parts of the network have been divided into approximately 25 different asset classes. Table 9.2 shows the asset replacement methodology adopted for these asset classes.

9.2 Asset Maintenance Strategy

Number	Asset Class	Asset Replacement Methodology		
		Age Based	Failure Rate Based	Condition Assessment Based
1	Poles			✓**
2	Pole Tops			✓**
3	Conductors & Connectors	✓	✓	✓
4	Overhead Line Switchgear		✓	✓**
5	Automatic Circuit Reclosers		✓	✓**
6	Public Lighting	✓	✓	
7	HV Outdoor Fuses	✓	✓	✓
8	Surge Arresters	✓	✓	✓
9	Pole Type Transformers		✓	✓**
10	Non-Pole Type Distribution Substations		✓	✓**
11	Earthing Systems			✓
12	Underground Distribution Systems	✓	✓	
13	LV Services	✓	✓	
14	Substation Grounds			✓
15	ZSS Capacitors			✓
16	ZSS Circuit Breakers			✓**
17	ZSS Instrument Transformers			✓
18	ZSS Disconnectors & Buses			✓**
19	ZSS Transformers			✓**

Number	Asset Class	Asset Replacement Methodology		
		Age Based	Failure Rate Based	Condition Assessment Based
20	ZSS DC Systems			✓
21	ZSS Protection Systems			✓
22	PQ Assets		✓	
23	Metering	✓	✓	

** CBRM (Condition Based Risk Management)

Table 9.2 Asset Replacement Methodology by Asset Class

9.2.1 Practical Approach to Asset Management

JEN's practical approach to asset management is based around various strategies that implicitly account for the appropriate balance of capex and opex through the consideration of total lifecycle management costs. Asset management practices include:

- Run to failure for high volume/low cost/low risk assets;
- Routine inspections and testing;
- Targeted inspections and testing;
- Combination of condition-based and time-based preventative maintenance;
- Corrective maintenance;
- Emergency planning and maintenance, including for severe events;
- Condition-based replacement;
- Some degree of age-based replacement, where appropriate; and
- Identification and holding of strategic spare plant and materials.

9.2.2 Defect Policies

The defect principles and policies dictating when plant is replaced or maintained are contained within JEN's detailed Asset and Enclosed Substation Inspection Manuals and Asset Class Strategies.

9.2.3 Spares

Critical primary and secondary spares for strategic assets are held to secure the operation of the network. These spares relate to zone substations and elements of the subtransmission lines. A limited number of major spares are held in case of major plant failure involving long-lead time items such as circuit breakers and HV bushings.

In general terms spares are not held for the distribution network as failed assets are replaced with the current standard materials and designs.

Currently JEN does not hold a spare 66kV/22kV or 66kV/11kV transformer. The loss of a transformer at a zone substation is a credible risk - particularly in an ageing network. Supply security at zone substations is dependent upon the provision of a full compliment of transformers. Given the age profile of 66/22kV transformers, a 66kV/22kV transformer spare is not considered to be prudent at this time.

9.2.4 Replacements

Age Based Replacement

While actual asset replacement decisions may include a condition assessment, forecast volumes for planning and regulatory approval purposes may be based on an age or failure rate assessment only.

Age based replacement is a combination of run to failure and age based replacement.

Failure Rate Replacement

Failure rate based replacement is a result of analysis of failure rate trends. Any particular families of assets that show increased rates of failure are managed separately with an accelerated replacement program.

Condition Based Assessment

Condition based assessment can be either invasive or non-invasive or a combination of both. Non-invasive assessment includes activities such as inspections, infra-red surveys and limited testing procedures. Invasive assessment includes activities such as oil sampling and equipment overhauls. Invasive assessment is usually associated with a greater range of inspections and testing procedures.

Condition Based Risk Management (CBRM) models have been applied to ten of the asset classes. JEN uses CBRM to identify poorly performing assets that will affect the service delivered.

Critical CBRM inputs include:

- Engineering knowledge and practical experience of the assets;
- Asset specification, history (faults, failures, generic experience, maintenance records), duty, environment, test and inspection results;
- An understanding of degradation and failure modes; and
- Experience of building CBRM models.

CBRM outputs include:

- Part 1 – Condition, which provides health indices, health index profiles, probability of failure (POF) and failure rates, and estimates of future failure rates with different interventions; and
- Part 2 – Risk, which provides quantification of current and future risk for asset groups with different interventions (expressed as a monetary value), criticality involving changed priorities within an asset group, and comparison/optimisation across asset groups.

9.3 Key Issues

Many network assets have known integrity issues that are being addressed through a range of strategies and processes. These strategies and processes aim to minimise expenditures and maximise performance.

Emerging issues have also been identified. These issues are due to:

- Ageing assets;
- Increasing asset failure rates; and
- Increasing external impacts such as climate change.

They are expected to result in increased expenditures when compared to historical levels. In detail, they include:

- The age profile of poles indicates that the rate of pole condemnation will rise slightly over the next five years, before beginning to rise significantly;
- Low strength poles and poles fitted with HV raiser brackets make up a group of poles that have been identified with girth measurements that do not comply with pole testing criteria. A program has commenced to identify and prioritise these poles for replacement;
- The potential for pole fires is expected to increase as climate change and other external environmental factors result in climatic conditions conducive to pole fires. Hence the volume of pole top remedial work resulting from line inspections is forecast to increase;

- The volume of pole tops reaching the end of economic life is forecast to rise substantially over the next five years;
- All Whipp & Bourne ACRs have been installed since 2000 and although under normal circumstances would not require replacement in the immediate future there are a number that are leaking SF_6 gas.
- As a result of the inspection and testing program that is required by the ESMS, an increasing number of LV overhead services have been identified as requiring replacement;
- Preventative maintenance programs to ensure that substations and easements are maintained in appropriate condition are increasing;
- Harmonic resonances between capacitor banks and the distribution network can result in overheating and damage to capacitor bank installations. The increase in non-linear loads on distribution networks is an emerging problem and capacitor bank reactors need to be selected to prevent this type of resonance;
- Augmentation of the transmission system by AusNet Services has resulted in increasing fault levels at zone substations. The interrupting capability of circuit breakers has to be monitored in the light of these increasing fault levels to ensure that the interrupting capability of the circuit breakers is adequate; and
- A significant percentage of JEN's relay population was installed in the 1960s and have reached the end of their life. As a result, a considerable volume of relay replacement work is planned for the next five year period.

9.4 Overview of Assets

Table 9.3 summarises the asset quantities within the JEN asset base as at December 2014.

Asset Class	Population	Asset Class	Population
Automatic Circuit Reclosers	108	PQ Systems	52
Communications Equipment	462	Public Lights	67,539
Communications Cables (Metallic and Fibre)	300km	Surge Arresters	6,002
HV Outdoor Fuses	5,738	Underground Cable (excluding services)	1,719km
LV Services and Terminations	179,597	ZS Capacitor Banks	36
Monitoring Applications	1	ZS Circuit Breakers	415
Non-Pole Type Distribution Substations	1,971	ZS DC Systems	82
Overhead Conductor (excluding services)	4,440km	ZS Disconnectors	737
Overhead Line Switchgear	1,911	ZS Instrument Transformers (non-integral)	201
Poles	97,813	ZS Protection Relays	1,503
Pole Top Structures	118,809	ZS Transformers	63
Pole Type Transformers	3,991		

Table 9.3 Asset Quantities

In addition to adding to or reinforcing the network to meet customer's requirements for increased load, it is necessary to focus on maintaining the functionality of the existing network.

Assets are replaced either when they fail or, for assets where the consequence of in-service failure is unacceptable, replacement occurs when they have reached the end of useful life. End of useful life is assessed based on a number of established criteria. This includes assessments made via a range of condition monitoring activities.

Over the past 10 years significant effort has been put into assessing the condition of assets by undertaking monitoring and inspection programs. The condition of assets is generally well understood and techniques such as reliability centred maintenance have been used to optimise the performance of assets and to optimise the timing of replacement. Asset maintenance and inspection programs are established for all relevant classes of assets. These are undertaken in a timely and cost-effective manner.

An indicator used to measure performance in this area is the number of feeder and ACR faults per 100km of line due to equipment failure.

JEN's performance against this asset condition indicator is shown in Table 9.4 which shows a decreasing trend of asset deterioration.

Performance Indicator	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
No. of feeder and ACR faults per 100km of line due to equipment failure*	3.2	3.3	4.4	4.5	4.6	3.8	2.9	2.3	2.5	3.3	

* Includes sustained and momentary interruptions.

Table 9.4 Historical Asset Condition as indicated by Feeder and ACR Faults

The number of unplanned outages due to equipment failure is indicative of the overall condition of the network. While outages may be caused by external factors such as weather, bushfire and natural disasters, the frequency is likely to increase if an area of the network ages to a point where it becomes more unreliable and is not subject to sufficient maintenance or replacement. Figure 9.1 shows the historical performance of the network in terms of equipment failures resulting in high voltage outages.

High Voltage Equipment Failures resulting in Feeder and ACR Outages

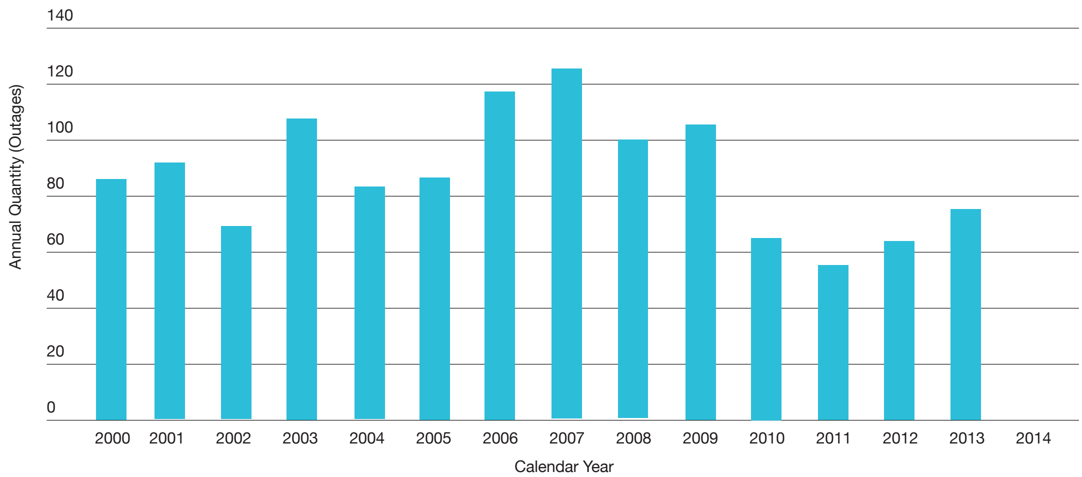


Figure 9.1 High Voltage Equipment Failures resulting in Outages (includes sustained and momentary interruptions)

Analysis of root cause or failure mode of failed equipment has led to approaches to mitigate against faults due to equipment failure. There are programs in place to address the following:

- Pole and crossarm fires; and
- Underground cable failures.

The rate of underground asset failure has shown an increasing trend over recent years. Underground cable condition assessment equipment was introduced in 2014 to assist with the condition assessment of underground cables. The intent is to establish the condition of problematic cables and prioritise mitigation actions.

9.5 Overview of Asset Management Practices and Performance

The following strategies outline asset management practices that are incorporated into JEN's lifecycle management activities. These include:

- Poles are periodically treated with chemical preservatives and reinforced with steel stakes when appropriate to extend pole life;
- Poles are inspected based on either a three or four-year cycle and some 'limited life' designated poles are inspected annually;
- Line inspection incorporates the pole inspection and inspection of all other assets attached to the pole structure such as the pole top, surge arresters, switchgear, transformers etc;
- Inspection zones are defined to facilitate efficient inspections based on regional location;
- Thermographic surveys of overhead conductors and connections are programmed on one, two or three year cycles, subject to feeder criticality and performance history;
- Mercury vapour lamps used for residential public lighting are bulk relamped every four years;
- High pressure sodium lamps used for main road lighting schemes are patrolled three times per annum and replaced on failure;
- HV outdoor fuses are maintenance free; some families are targeted for replacement due to age and performance criteria, e.g. fault level clearing capability, bushfire performance;
- Surge arresters are replaced based on performance history, which is related to age;
- Mandatory earthing systems and distribution protection equipment inspections are programmed every ten years, except for CMEN systems and fuses;
- Current injection testing is undertaken periodically on all zone substation earth grids;
- 66kV underground cables have their sheaths tested every two years;
- Oil filled cables are monitored through an oil pressure monitoring system;
- Mandatory inspection and testing of LV services is undertaken every 10 years;
- Outstanding work notices are grouped by geographical areas through IT systems to ensure work is packaged into efficient bundles;
- Field computing is used to ensure data integrity and immediate application;
- Zone substations are subjected to routine monthly visual inspections, annual engineering inspections and civil audits based on a three-year cycle;
- Preventative maintenance of circuit breakers and transformer tap-changers is based on a combination of elapsed time and condition. This is informed through operations and fault interruptions;
- Zone substation circuit breakers and transformers are individually ranked based on technical risk (condition and performance);
- Preventative maintenance of zone substation protection and communication equipment is carried out on a regular time basis, based on type; and
- The maintenance program is managed via a computerised maintenance management system (SAP).

9.6 Overview of Inspection and Maintenance Practices

The inspection and maintenance practices across the key asset classes are summarised in Table 9.5.

	Asset	Current Inspection and Maintenance Practice
Subtransmission and Distribution Network	Underground Distribution Systems (JEN PL 0035)	66kV sheath test – two-yearly.
	Electric Line Clearance Management Plan	Two-year cyclic cutting and pruning.
	Connector & Conductor (JEN PL 0026)	Thermal surveys – annual, one, two and three-year cycle. Targeted aerial inspection via camera. Line inspection program.
	Poles, attachments, lines & pole top structures (JEN PL 0024 & JEN PL 0025)	Line inspection program – four-yearly non-fire, three-yearly fire area.
	HV Outdoor Fuses (JEN PL 0026)	Per line inspection program. Thermal surveys – annual, one, two and three-year cycle.
	Surge Arresters (JEN PL 0031)	Per line inspection program.
	Automatic Circuit Reclosers (JEN PL 0028)	Per line inspection program. Replace batteries – five-yearly.
	Public Lighting Minor (JEN PL 0029)	Re-lamp – four yearly and eight yearly PE cells.
	Earthing Systems (JEN PL 0034)	Test – 10 yearly in non-CMEN areas.
Distribution Substations	Non-Pole Type Distribution Substations (JEN PL 0033)	Inspect two yearly. Earth resistance test (non-CMEN) – 10 years.
	Pole Type Transformers (JEN PL 0032)	Per line inspection program.
	Overhead Line Switchgear (JEN PL 0027)	Inspect – airbreak and remote controlled switches five-yearly, manual gas switches 10 yearly.
Zone Substations	Grounds and Domestic Management of Zone and Non-Pole Substations (JEN PL 0037)	By operators – monthly, By engineer – yearly.
	DC Systems (JEN PL 0023)	Maintain – LAPP six-monthly, VRLA 12 monthly, chargers 12 monthly.
	Circuit Breakers (JEN PL 0039)	Maintain on service duty and time Functional test annually if the CB has not operated.
	Disconnectors and Buses (JEN PL 0041)	Maintain disconnectors – six yearly.
	Transformers (JEN PL 0042)	Monthly inspection Oil test annually.
	On Load Tap Changers (JEN PL 0042)	Maintain on service duty and type.
	Supervisory Cables (JEN PL 0004)	Electrical inspect – four yearly.
	Capacitors (JEN PL 0038)	Maintain – six yearly.
	Earthing Systems (JEN PL 0034)	Continuity test – five yearly, Design/injection test – 10 yearly.
	Protection and Control (JEN PL 0021)	Maintain – three and eight yearly cycles.

Table 9.5 Inspection and Maintenance Practices for each Asset Class

9.7 Poles

Please refer to document JEN PL 0024 for more detailed information on Poles.

9.7.1 Asset Description

Concrete poles, wood poles and some steel structures are used to support the overhead network. Steel poles are almost exclusively used to support public lighting infrastructure. The total number and type of poles in JEN's asset portfolio is shown in Table 9.6.

Poles	
Wood	60,849
Concrete	19,635
Steel	17,329
Total	**97,813**

Table 9.6 Number and Type of Poles – December 2014

The pole age profile is shown in Figure 9.2. The oldest poles on JEN were installed in the 1930s, however nearly all poles have been installed since 1950. The vast majority of poles are wood poles and these are made up of a variety of different wood types, generally referred to as durability Class 1, 2, and 3. The expected asset life differs for each durability class of wood pole due to differences in the species of wood used. Pole life may be extended by the use of preservative treatments at the time of pole harvest/manufacture, historically by impregnation of sapwood with creosote and more recently with Copper Chrome Arsenate (CCA).

Currently CCA treated hardwood poles are almost exclusively used for all new/replacement works. These poles have a life expectancy of 35 to 55 years. Improved treatment procedures mean that poles will be expected to last longer than this in the future. Further life extension is achieved by use of chemical preservative treatment at the time of inspection to inhibit deterioration of wood, mainly at the ground-line.

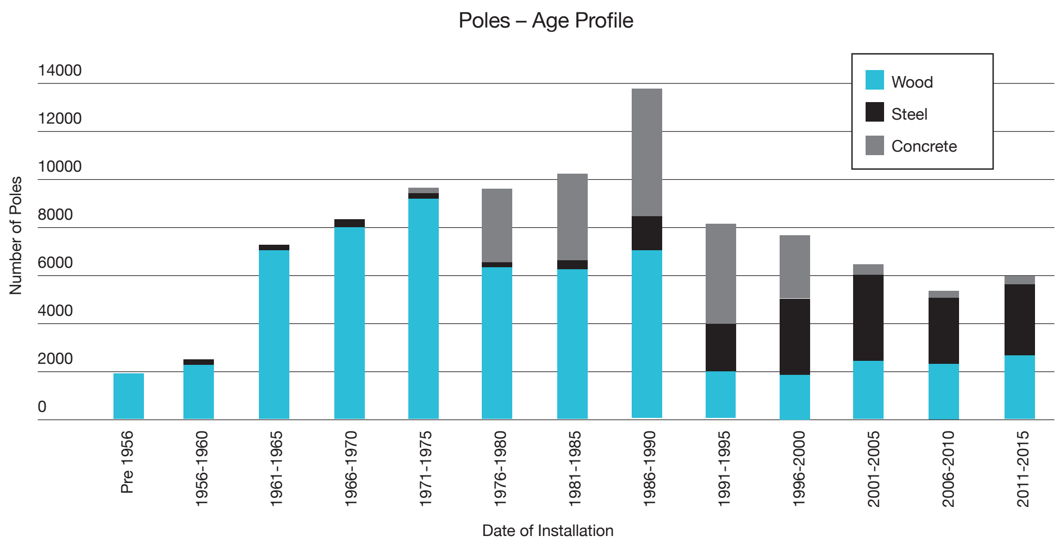


Figure 9.2 Pole Age Profile

9.7.2 Inspection and Testing

Pole replacement and reinstatement occurs as a result of a cyclic condition monitoring program that involves inspection and testing of poles to determine their operational condition. This inspection is undertaken on a four-year cycle in the LBRA (low bushfire risk area) and on a three-year cycle in the HBRA (hazardous bushfire risk area).

For subtransmission poles, the inspections are arranged on a subtransmission line basis and for all other poles the inspections are arranged on an inspection zone basis.

The condition of the lines, poles, pole top substations and associated hardware is assessed using the guidelines in the Asset Inspection Manual. All wood poles are treated with ground line preservative in accordance with the requirements of the Asset Inspection Manual.

9.7.3 Asset Failure Risk

The key risks associated with pole failures are third party personal or property damage, loss of supply and potential fire starts.

9.7.4 Integrity Issues

Wood poles suffer ground line fungal timber rot and this is the main failure mode for wood poles. The application of localised wood preservative treatments can extend the service life of wood poles significantly. Poles are treated as part of the preventative maintenance program. Current trends indicate an increase in pole condemnation rates per number inspected.

Where circumstances permit, the replacement of unserviceable poles is deferred by pole reinstatement techniques, currently by utilisation of steel stakes. This technique is now applied to poles classified as limited life that would otherwise require annual inspection, resulting in further reduction in pole replacement rates.

Concrete poles are affected by high salt levels in areas where there are problems associated with rising water tables. This may lead to corrosion of the reinforcing systems and subsequent concrete spalling. JEN is not experiencing problems of this nature although there have been minor occurrences of concrete degradation needing to be repaired.

Concrete poles are conducting structures and consequently their use in the high voltage network has to be managed so that they are appropriately insulated from the high voltage and low voltage conductors that they support. Early use of these poles tended to apply the same insulation systems that were used on wood poles and as a result there have been some supply reliability issues associated with the use of concrete poles, particularly those installed early in the roll out of concrete poles. These issues have mostly been resolved by utilising bird covers or longer length insulators to prevent flashovers caused by wildlife.

Steel poles are treated with bitumen paint over the galvanised finish to help reduce the effects of ground line corrosion. Poles are monitored in service and corrosion assessed. The incidence of ground line corrosion of steel poles is increasing with the age of the asset group and the rate of replacement of steel poles has increased in recent years and is forecast to continue to increase over the next five years. As most of these poles are used in underground estates as public lighting poles the security of the cable access cover on the pole is a high priority to prevent access to live cables. These covers have been tampered with from time to time and the inspection program includes this aspect.

9.7.5 Emerging Issues

The age profile of poles indicates that the rate of pole condemnation will rise significantly in subsequent regulatory periods.

In 2010, the ESV directed the Victorian electricity supply industry to inspect all POELs on a regulated 37-month interval. POELs in the designated Hazardous Bushfire Risk Area (HBRA) were already inspected on a three-year cycle in line with JEN owned poles. As a consequence, approximately 600 POELs in the Low Bushfire Risk Area (LBRA), are now inspected on a three-year cycle instead of the four-year cycle applicable to the JEN owned poles in the LBRA.

The network contains a significant number of poles that have a smaller girth than the standard defined in the Asset Inspection Manual. These poles are typically 5kN rated LV poles installed by previous network owners. Until 2011, undersized poles were allowed to remain in service provided there was sufficient sound wood and no external decay. The failure of three undersized LV poles during a wind storm in 2008 has indicated that these ageing poles required replacement some 10 to 20 years sooner than a standard pole. A program to stake or replace these poles over a ten-year period was implemented in 2011. The ratio is estimated to be 80:20 staked to replaced.

Similarly there are a significant number of LV poles with HV raiser brackets installed on JEN. These are poles that were designed as LV poles and some time after installation were converted to HV poles by the installation of steel raiser brackets to support a HV crossarm above the LV. This was done by previous network owners rather than replacing LV poles with HV poles. These poles are targeted for replacement for similar reasons to the undersized poles. The extra height gained by the use of the raiser bracket effectively decreases the pole strength rating due to the increased bending moment. There are also safety concerns as modern HV crossarms are steel and as the wooden HV crossarms are replaced the pole top becomes a conducting supporting structure on an otherwise non-conducting pole with clearances around the LV conductors associated with a non conducting structure.

9.7.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Programs are in place to extend wood pole life and to reinstate wood poles by ground line staking wherever possible. These programs have resulted in an estimated increase in wood pole life by approximately 15-20 years.

All unserviceable poles that meet the criteria in the Asset Inspection Manual for pole reinstatement are staked. All limited life poles that are suitable will be reinstated to full service by means of staking when identified.

All other poles are replaced based on condition.

The condition based replacement of approximately 6,000 poles is forecast for the 2016-2020 period. Additionally, approximately 2,150 undersized poles or LV poles with raisers will be replaced.

9.7.7 Asset Disposal

Wood poles that have been treated with CCA can only be disposed in land fill, unless they are less than 10 years old and not damaged, in which case they are reused. Other treated poles may be recycled, but not used for burning. Untreated wood poles can be recycled or burned. Concrete poles are reused but those that are damaged are recycled.

9.8 Pole Top Structures

Please refer to document JEN PL 0025 for more detailed information on Pole Top Structures.

9.8.1 Asset Description

Pole top structures consist of crossarms, insulators and associated hardware. Historically all crossarms were made of Class 1 durability timbers. Steel crossarms were introduced in the early 1980's for use on high voltage and subtransmission poles. Current construction standards require the exclusive use of steel crossarms on high voltage and subtransmission poles. Wooden crossarms continue to be used exclusively on the low voltage network to facilitate safe work practices.

Condition monitoring and replacement work ensures the crossarm population is maintained in a good condition.

The life expectancy of a wooden crossarm is 45 years. The life expectancy for a steel crossarm is 70 years. Analysis of crossarm age at replacement indicates that on average a crossarm is replaced at the age of 38 years. Therefore, it is assumed that every pole older than 45 years will have had the crossarm along with the insulators changed at least once. Furthermore, it is assumed that all high voltage and subtransmission crossarms installed after 1980 are steel.

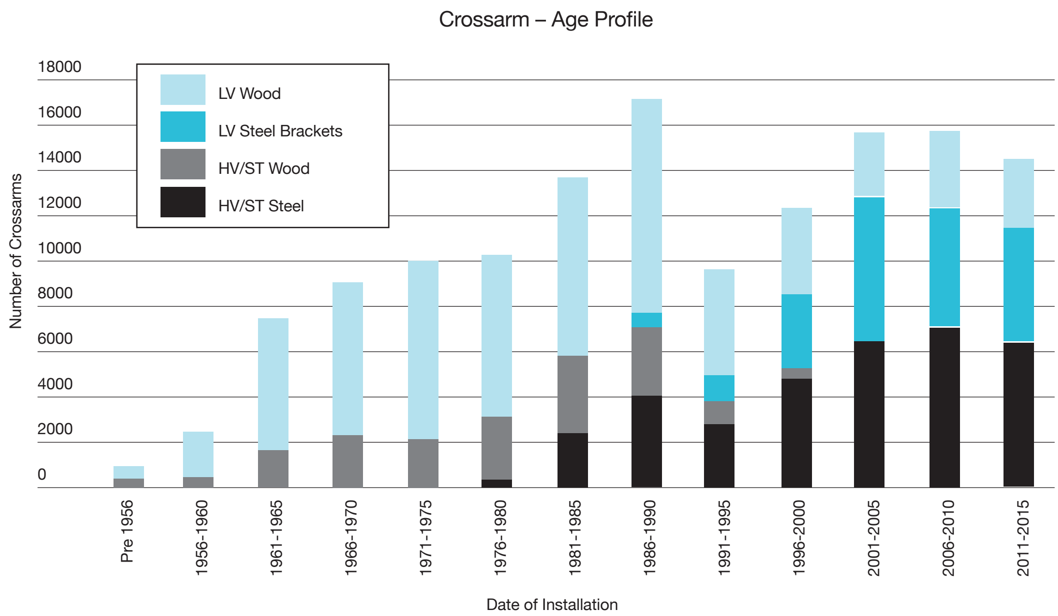


Figure 9.3 Pole Top Structures Age Profile

9.8.2 Inspection and Testing

The condition of pole tops is monitored in conjunction with the pole inspection and testing program; that is on a four-year cycle in the LBRA and a three-year cycle in the HBRA.

The criteria for the inspection of all pole tops are set out in the Asset Inspection Manual and this covers crossarms, insulators, ties, braces, pole caps, bird covers, switchgear, surge arresters etc. The results of these inspections drive the pole top asset replacement programs.

9.8.3 Asset Failure Risk

The key risks associated with a pole top failure are third party personal safety or property damage, high voltage injection, loss of supply, pole top fires and potential fire starts.

9.8.4 Integrity Issues

Crossarm failure is limited to wooden crossarms due to the nature of the material. JEN has no history of the failure in service of a steel crossarm. Wood crossarm failure results from the deterioration of the wood due to weathering, fungal attack and occasionally termite attack. The extension of the life of wood poles by the use of pole reinstatement systems and pole preservative treatments has meant that the rate of pole top replacement is increasing. The condition of crossarms is monitored as part of the routine condition assessment program of asset inspection.

Pole or crossarm fire is a significant issue, and is a consequence of the combined effects of environmental conditions and pole top design that utilises wooden crossarms. A build up of airborne particles on insulators is generally the cause of pole top fires. When moisture is added to this, usually in the form of light rain or fog, the particles may conduct electricity. This may cause arcing at the base of the insulator and ignition of the pole or crossarm.

The factors, which increase the likelihood of a pole top fire, are particle build up on insulators and the 'dryness' of the pole and crossarm. The greater the build up of particles and the drier the pole, the more likely a fire is to occur when moisture is introduced.

Bird and other animal strikes on pole tops are a significant cause of supply reliability problems. This is particularly the case when an earth is introduced at the top of the pole as occurs with the application of concrete poles. Phase to phase and phase to earth clearance at pole tops is critical to the supply reliability and supply quality performance of the network.

Modern designs pay particular attention to these issues and programs have been run to improve the performance of particular structures that have been identified to be at risk from bird or other animal strike.

9.8.5 Emerging Issues

The potential for pole fires is expected to increase as climate change and other external environmental factors result in climatic conditions conducive to pole fires. Hence the volume of pole top remedial work resulting from line inspections is expected to increase.

Given the age profile, the volume of pole tops reaching the end of economic life will rise substantially over the next five years.

9.8.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Pole top replacement involves the replacement of submission, high voltage and low voltage pole top assemblies that have reached the end of their economic life, including those on poles that have been reinstated. Work to eliminate identified sources of television interference that involves pole top replacement is also included in this program. In total, approximately 19,000 crossarms are forecast to be replaced in the 2016-2020 period, based on condition.

There are no effective preventative maintenance programs that extend pole top life. With the exception of targeted pole top fire mitigation programs to address identified high-risk pole fire locations, there are no bulk replacement programs for the replacement of pole top components.

The pole and pole top hardware inspection and maintenance program has been reviewed as a part of developing the pole fire mitigation strategy. Emphasis is placed on visually identifying the contributing factors to pole fires. The pole fire mitigation strategy focuses on the use of modern pole top design that utilises steel crossarms. These structures are specifically designed to prevent pole and crossarm fires. Approximately 3,200 crossarms are forecast to be replaced in the 2016-2020 period as part of the targeted pole fire mitigation strategy.

9.8.7 Asset Disposal

There are no specific asset disposal requirements.

9.9 Connector and Conductors

Please refer to document JEN PL 0026 for more detailed information on Connector and Conductors.

9.9.1 Asset Description

Conductors

Overhead conductors are of mixed age (Table 9.7) and are in relatively good condition. The majority of the conductors are installed on the LV network. Conductors are made of aluminium, copper or steel.

The most common bare conductor type used on the overhead network is aluminium. The bare aluminium conductor is in two forms, either all aluminium conductor (AAC) which is comprised of an aluminium alloy or aluminium conductor steel reinforced (ACSR) which is comprised of a steel core for tensile strength surrounded by aluminium conductors.

Copper conductor and copper cadmium conductor was used extensively in the older parts of the network. The main disadvantages of copper conductor relate to cost and weight.

Steel conductor is used in rural areas where large distances and small loads are involved. Because of its strength long spans can be constructed. This assists in keeping construction costs low in rural areas. Its current carrying capacity is limited and consequently its application is restricted to areas with low load density.

Conductor Type	Installation Years	Life (Years)
Copper Conductor	1920 - 1960	60
Cadmium Copper	1960 - 1975	60
Steel (Sc Gz)	1960 - present	50
Aluminium Steel Reinforce (ACSR)	1960 - 1975	50
Aluminium (AAC)	1975 - present	60
Aerial Bundled Conductor (ABC)	1990 - present	60

Table 9.7 Periods of installation of different conductor types

Connectors

Connectors are used to join conductors and must provide physical strength and electrical conductivity.

There are hundreds of non-tension and full tension connectors on every HV feeder and many thousands on the associated low voltage networks.

Non-tension connectors used on the network include compression sleeves, PG clamps, D clamps, U-Bolt connectors, split bolts and the recently introduced fired wedge Ampact connectors. They are installed wherever conductors need to be joined, such as at strain poles, tee off poles, cable head poles and anchor poles.

Fired wedge (Ampact) connectors are the only approved non-tension connector for use on the high voltage network and provided a reliable connection.

Full tension type connectors used include compression sleeves, McIntyre sleeves and automatic line splices. They are used to join conductors under tension.

No new automatic line splices are permitted due to poor electrical connection at low stringing tensions and copper McIntyre sleeves are being phased out in favour of compression sleeves.

Aluminium and copper compression sleeves are the only type of full tension connector approved for use on both the HV and LV networks.

9.9.2 Inspection and Testing

The condition of subtransmission and distribution conductors and connectors is monitored through thermographic surveys on a predefined basis, every one, two or three years. Depending on feeder criticality, asset type, asset utilisation, age and condition, as well as fault interruption history, additional surveys will be carried out following the occurrence of faults. A targeted inspection program is commencing to identify deteriorated small cross-section copper, AAC and steel conductors.

9.9.3 Asset Failure Risk

The major risks associated with conductors and connectors are equipment damage, outages, claims and damage to customer's equipment from HV injections.

9.9.4 Integrity Issues

Corrosion of steel conductor and steel reinforced conductor (ACSR) is monitored to ensure mechanical integrity is maintained. A program has been implemented to condition monitor, identify and replace rusty conductor and rusty steel tie wire.

Most secondary damage caused by HV fault current occurs at connectors. They are inspected via thermal surveys. Despite the thermal inspection that does detect deteriorated connectors, there are parts of the network that perform badly in this respect with failures occurring that involve high voltage parallel groove (PG) clamps and U-bolt connections.

9.9.5 Emerging Issues

A number of incidents are known to have occurred while work crews have been performing glove and barrier work on 7/2.5 and 7/3.0 AAC conductors. The risk assessment made by the field crew prior to working live on the conductor does not identify the damage until the conductor is untied and lifted from the insulator.

It is forecast that increasing amounts of deteriorated small cross-section copper and AAC conductor will require replacement as it is identified through inspection and condition assessment over the next five years.

9.9.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

A range of non-tension connections used on the subtransmission and high voltage networks were identified as failing to withstand the passage of fault current. This means that in the event of a network fault secondary damage was occurring which prevented successful reclose and prolonged supply restoration.

A program will be completed in 2017 aimed at replacing poor performing non-tension connections with properly engineered connections on feeders ex Broadmeadows zone substation.

These underperforming non-tension connectors are replaced with fired wedge connectors along the backbone of high voltage feeders determined by I^2t calculations. Also, full tension automatic line splices need to be identified and replaced using standard compression full tension connectors.

Conductor replacement normally occurs as a result of asset inspection, network upgrades to address performance issues, capacity issues or as a result of conductor damage caused by third parties.

Conductors are replaced as a result of having reached the end of their service life. An example of this are the spans of steel conductor exhibiting evidence of rust degradation. Programs are in place to identify and replace this conductor as its condition is identified.

Overhead line replacement work involves replacement of sections of overhead conductor. This work is generated from a number of sources including:

- Defect reports resulting from the line inspection program;
- Failure of conductor as a consequence of system faults or mechanical fatigue;
- Installation of low voltage aerial bundled cables (LVABC) to overcome tree and other clearance problems, and where overhead assets have reached the end of their economic service life; and
- Degraded conductor such as steel and old copper identified by targeted inspection and assessment programs.

Approximately 50km overhead conductor is forecast to be replaced in the 2016-2020 period.

9.9.7 Asset Disposal

All metal such as aluminium and copper conductor and steel is sold as scrap. Conductor should not be reused.

9.10 Overhead Line Switchgear

Please refer to document JEN PL 0027 for more detailed information on Overhead Line Switchgear.

9.10.1 Asset Description

Overhead line switchgear includes air break switchgear, gas insulated switchgear and disconnectors (isolators). The number of air break type switches installed on the network is approximately 1,080.

In addition there are 805 gas insulated switches of which approximately 140 are automated. In past years the number of air break types has decreased as redundant air break switches and disconnectors have been removed and others replaced with gas insulated switches. No air break type switches have been installed on the JEN since approximately 1995.

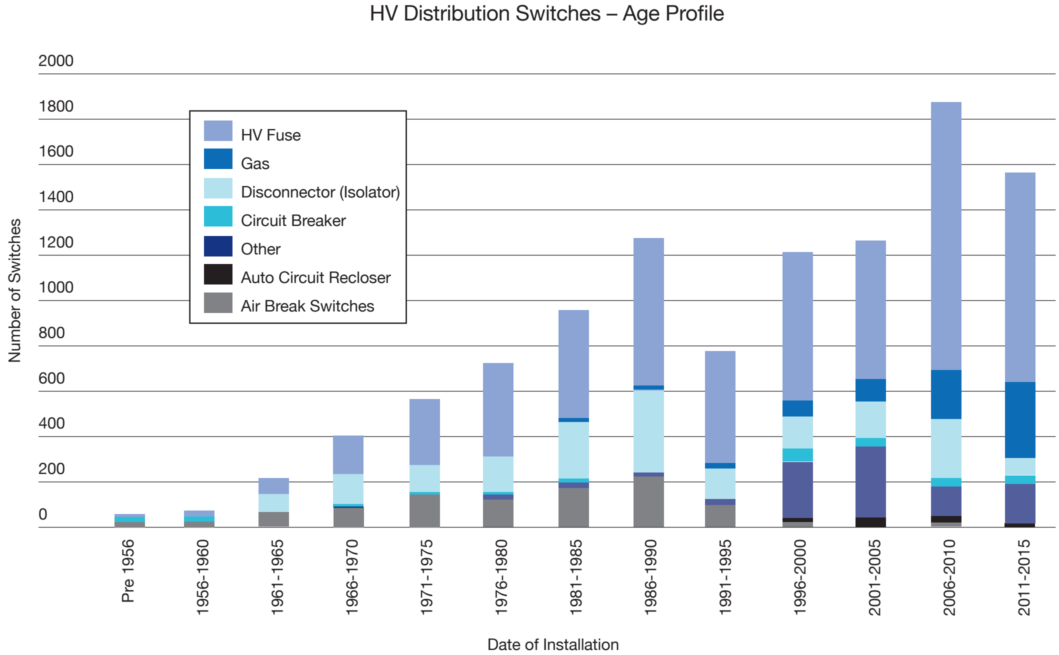


Figure 9.4 HV Distribution Switches Age Profile

9.10.2 Inspection and Testing

A new targeted inspection program for HV air break switches and disconnectors will commence in 2016 in addition to the normal asset inspection program. Remote controlled gas switches are inspected every five years in conjunction with battery maintenance. Manually operated gas switches are inspected as part of the asset inspection program.

In addition to the visual inspection, all switches and disconnectors are included in the regular thermal survey of overhead lines. It is expected that some hot connections and contacts will be detected, and shall be programmed for repair.

9.10.3 Asset Failure Risk

Failed switchgear and disconnectors reduce operational flexibility and can result in additional customer interruptions during planned and unplanned work activities.

If operated, failed switchgear can result in an electrical flashover, potentially harmful to persons in the immediate vicinity.

9.10.4 Integrity Issues

Air break switches fitted with arc chutes can be prone to misalignment, corrosion, stiffness and breakage of components, thus requiring regular inspection and corrective maintenance of any defects found.

Air break switches fitted with flicker blades or horn deflectors and arc chute switches have limited load breaking capability and are also prone to misalignment and deterioration. Air break switches fitted with expulsion interrupters can also become out of adjustment and thus require checking.

Disconnectors (isolators) are simple devices with their primary problems being loose mounting bolts, burnt button contacts, hot connections and tracking insulators.

The need to replace high voltage air break switches is identified when the switches are operated or via inspection. Any switch that is found to be inoperable or that requires extensive maintenance will be assessed for operational requirement and possible replacement with a gas insulated switch.

There have been a number of incidents of premature failure of overhead high voltage single blade isolators. This has been associated with the failure of one or both supporting porcelain insulators. These failures have been associated with a family of ABB isolators manufactured prior to 1999. A replacement program prioritised by the age of the isolators will retire this family of isolators by the end of 2015.

9.10.5 Emerging Issues

No emerging issues are known.

9.10.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The necessity for any maintenance on overhead line switchgear is determined by the results of the scheduled inspections. Any switch that fails the inspection criteria is deemed defective (or inoperable) and is categorised as CRO (Caution Re Operating). The switch is subsequently scheduled for minor maintenance or replacement.

Only minor faults on HV air break switches are repaired. If major damage has occurred to an air break switch it is replaced with a gas switch, after consideration of the operational need for the switch. Approximately 560 high voltage and low voltage switches are forecast to be replaced in the 2016-2020 period.

9.10.7 Asset Disposal

Switchgear containing SF_6 gas is disposed of in accordance with EPA requirements.

9.11 Automatic Circuit Reclosers

Please refer to document JEN PL 0028 for more detailed information on Automatic Circuit Reclosers.

9.11.1 Asset Description

An automatic circuit recloser (ACR) is a self contained light duty circuit breaker complete with overcurrent earth fault and sensitive earth fault protection and automatic reclose functionality. They are used on high voltage distribution feeders generally with a high frequency of both permanent and transient faults and with many or critical customers. Upon detecting a fault current greater than its programmed setting, the ACR will open and reclose automatically in order to attempt to restore supply. If the fault is permanent, the ACR will lock-out after a pre-set number of reclose operations (rural two-three, elsewhere, one) and isolate the faulted section of line from the remaining system.

There are 108 three-phase ACRs installed on the network (one installed as a zone substation bus tie).

9.11.2 Inspection and Testing

The condition of ACR's is monitored in conjunction with the asset inspection program, that is on a four-year cycle in the LBRA and a three-year cycle in the HBRA.

9.11.3 Asset Failure Risk

Failure of an ACR may result in the loss of customer supply and the release of SF_6 gas.

9.11.4 Integrity Issues

ACRs are generally very reliable devices with no evidence of in-service equipment failure in the past.

9.11.5 Emerging Issues

A number of Whipp & Bourne ACRs are leaking SF_6 gas. All the Whipp & Bourne ACR's have been installed since 2000 and will be monitored and any gas leaks managed.

9.11.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Whipp & Bourne ACRs require periodic monitoring of gas pressure, contact wear and battery condition. Faulty or defective ACRs are repaired wherever economically acceptable.

There is no plan for ACR refurbishment. Seven ACRs are forecast to be replaced and 27 new ACRs installed in the 2016-2020 period.

9.11.7 Asset Disposal

ACRs containing SF_6 gas are disposed of in accordance with EPA requirements.

9.12 Public Lighting

Please refer to document JEN PL 0029 for more detailed information on Public Lighting.

9.12.1 Asset Description

There are more than 67,000 public lights across the network. The public lighting system generally consists of three sub network elements:

- Lighting of main roads – mostly high pressure sodium (HPS) fittings;
- Lighting of minor roads – mostly mercury vapour (MV) fittings; and
- Watchman or security lighting.

Lighting of car parks, parks and monuments is normally provided by either shopping centre management or municipal councils.

Public lighting systems are generally supplied directly from the low voltage distribution network. Control of public lighting lanterns is generally via individual PE (photoelectric) switches integral to the lantern. In some older installations, control is provided via a PE switched contactor, which controls a number of lights. The use of a centralised control cascaded switch wire system was discontinued in the mid 1980's with the introduction of the PE cell switching controlled luminaires

The age profile is shown in Figure 9.5.

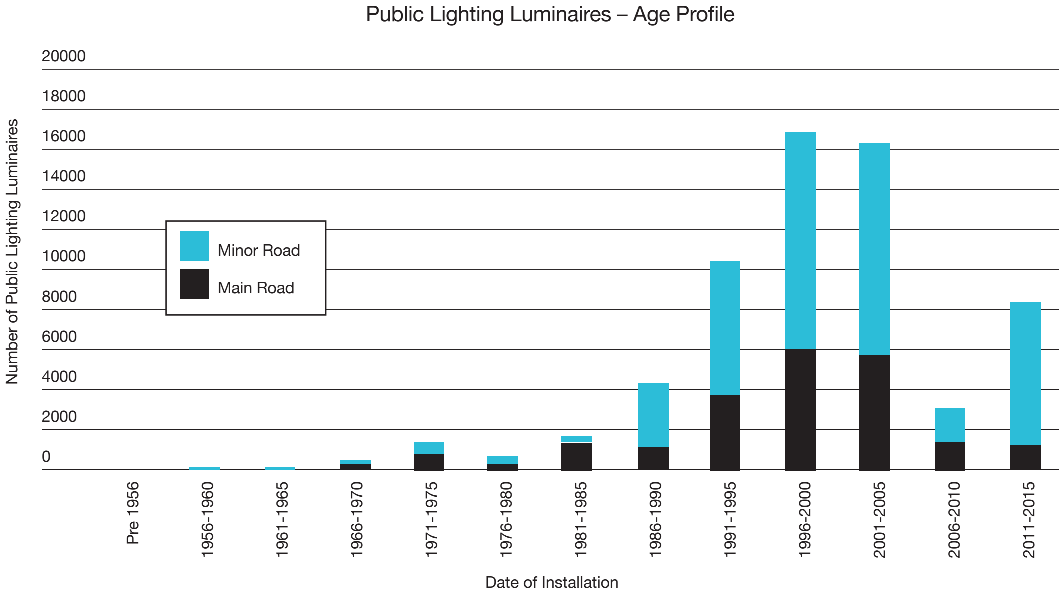


Figure 9.5 Public Lighting Luminaires Age Profile

9.12.2 Inspection and Testing

Main road lights are inspected and tested three times a year as part of the maintenance program. Defective lights are identified and rectified.

All other public lighting assets are inspected as part of the asset inspection program.

9.12.3 Asset Failure Risk

The major risks associated with the public lighting system are public perception/liability, and environmental risk associated with asset disposal and energy consumption.

9.12.4 Integrity Issues

Two types of lantern are generally used. Mercury Vapour lamps and lanterns are used for residential public lighting. High Pressure Sodium lamps and lanterns are used for main road lighting schemes. Each has different failure modes and characteristics. Consequently a bulk lamp replacement program is used to maintain the performance of Mercury Vapour public lighting schemes to ensure that light output remains within Australian Standards and complies with the Public Lighting Code.

High Pressure Sodium lamps however, are run to failure because their light output is maintained over the operating life of the lamp. Main road lights are patrolled three times per year for faults since non-operating lights tend not to be notified by the public.

9.12.5 Emerging Issues

Low emission lighting is being adopted by public lighting customers. A number of high efficient minor road lighting luminaires are approved for use. A small number of High Pressure Sodium lamps have been identified as experiencing burning of the control unit. This has been investigated and will be monitored to identify trends. In 2012, a program was implemented to re-lamp all HPS lights in Hazardous Bushfire Risk Areas (HBRA).

9.12.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Street lighting equipment is replaced based on age and failure rates. The age profile for street lighting luminaires reflects the large scale replacement of minor road lighting in the late 1990's. This will have an impact on the replacement activity for these assets as they will be approaching end of life at the end of this planning period.

These assets have a relatively short operational life by network standards (approximately 20 years). Asset replacement is required when the optical systems deteriorate which results from environmental exposure and the effects of long term vibration.

The integrity of main road and residential road lighting is maintained by application of the Public Lighting Code.

Asset replacement programs centre on bulk replacements for lamps and control equipment. The rollout of low-energy high-efficiency sustainable lighting systems has started to drive replacement programs for minor road lighting. Approximately 1,850 major road and 2,500 minor road lights are forecast to be replaced, based on condition, in the 2016-2020 period.

Sustainable Public Lighting

As a result of environmental concerns over Green House Gas Emissions (GHGE), considerable interest has been expressed by Municipal Councils and the Victorian Department of Sustainability and Environment (DSE) for more energy efficient lighting. Over 50% of all council GHGE can be attributed to public street lighting.

Most of the existing technology uses Mercury Vapour (MV) and High Pressure Sodium (HPS) lamps.

New technologies currently used to replace MV lamps include a number of approved fluorescent and LED luminaires. Electronic control equipment (ballasts, igniters and photocells etc) could also improve the efficiency of HPS lamps. These technologies could reduce energy consumption by 50% or more.

Public Lighting Maintenance

On main roads, defective lights identified through inspection are rectified. In addition, the general public reports defective public lights. These are repaired so that Guaranteed Service Levels (GSL's) relating to the repair of public lights are achieved. These GSL's require that defective lights are repaired within two days of being reported.

On minor roads, inspections are not undertaken. Minor road lights are bulk re-lamped on a four-year cycle and have their PE cells replaced at an eight-year interval. Defective lamps are replaced in response to reports from the general public. In order to meet the GSL, residential public lights are repaired within two working days of being reported as defective.

Security Beam and Flood Lighting Maintenance

Defective Security Beam (Watchman) and Flood Lighting that is reported by the public or customers is treated in the same way as public lighting in regard to the public lighting GSL and is fixed within two working days of the defect being reported.

9.12.7 Asset Disposal

Mercury vapour light globes are disposed of in accordance with EPA requirements for the recovery of mercury. Public Lighting Control boxes containing PCB insulated capacitors are disposed of using licensed waste contractors in accordance with EPA requirements.

9.13 HV Outdoor Fuses

Please refer to document JEN PL 0030 for more detailed information on HV Outdoor Fuses.

9.13.1 Asset Description

HV fuses are used to isolate network faults and protect the upstream network form unnecessary outages. Approximately 5,700 sets of outdoor fuses are installed mostly to protect cables, transformers and spur lines.

Three types of HV outdoor fuses are used; Expulsion Drop Out (EDO) fuses, Powder Filled (PF) fuses and Boric Acid (BA) fuses. These fuses are fitted on pole type substations, cable head poles and spurs (branch circuit isolation).

The only approved fuse types for new installations and replacement works are the BA (preferred) and PF fuses (for use where fault levels exceed the capability of the BA fuse). No new installations of EDO fuses are permitted on the network. Boric acid fuses are now used as the standard for new pole type substations because they provide full range protection as well as being lighter and more suitable for operation from ground level.

9.13.2 Inspection and Testing

HV fuses are included in the regular cycle of thermal surveys and asset inspection. When opportunities arise, such as repair of overhead conductor faults, all fuses are inspected for cleanliness, signs of tracking, cracks on fuse mounts and carriers and that the lead connections and bird and animal covers are secured.

9.13.3 Asset Failure Risk

The major risks associated with HV Outdoor Fuses are loss of supply due to equipment failure and the risk of fire ignition.

9.13.4 Integrity Issues

EDO type fuses may 'hang up' and PF fuses may 'candle' when interrupting low fault currents.

9.13.5 Emerging Issues

No emerging issues are known.

9.13.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

EDO, PF and BA fuses are considered to be maintenance free. They have an expected life of 30 years provided they are properly installed.

Corrective maintenance is used to repair defects and faults identified during inspections or problems that occur during service.

All unacceptable fuses are to be replaced. In particular all old brown porcelain EDO mounts are replaced opportunistically.

In areas where fault levels are over 2kA, EDO fuses are to be removed and replaced by BA fuses.

For the 22kV and 11kV system, the BA fuses are the standard fuse for all new installations due to their full range operation and suitability for hook stick operation. However, BA fuses cannot interrupt fault currents above 10kA and hence are not recommended to be used within 1km of a zone substation due to the associated higher fault currents. In this scenario, PF fuses are recommended. No fuse replacements have been forecast for the 2016-2020 period.

9.13.7 Asset Disposal

There are no specific asset disposal requirements.

9.14 Surge Arresters

Please refer to document JEN PL 0031 for more detailed information on Surge Arresters.

9.14.1 Asset Description

Surge arresters (sometimes called surge arresters or lightning arresters) are used extensively across the network to protect equipment from damage caused by overvoltages associated with lightning strikes and network operational activities.

Surge arresters have an expected life of 25 to 30 years provided they are properly installed.

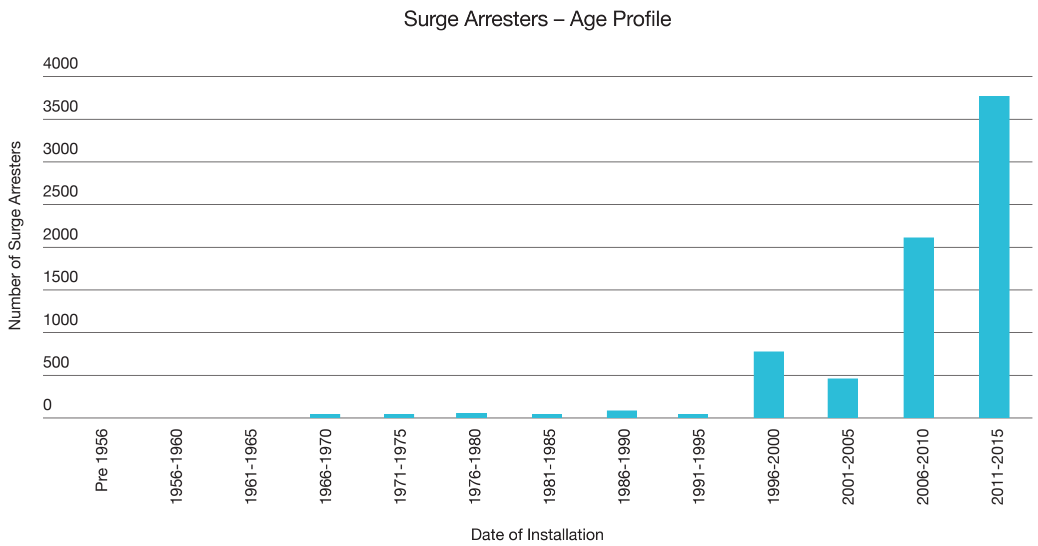


Figure 9.6 Surge Arresters Age Profile

9.14.2 Inspection and Testing

Inspections are carried out in conjunction with pole and line inspection and consequently on the same cycle.

9.14.3 Asset Failure Risk

The major risks associated with surge arresters are safety to people through shattered porcelain and third party liability due to litigation claims. Other risks include equipment failure resulting in bushfires.

9.14.4 Integrity Issues

Modern polymeric surge arresters are reliable with few failures recorded in service. Surge arresters have featured in animal strikes on the network due to the reduced phase to earth clearances associated with their installation. Consequently particular care needs to be taken in the design of structures that incorporate surge arresters and the specification of animal caps purchased with the surge arrester. Historically porcelain and early versions of polymer housed surge arresters did suffer a range of in service failures.

9.14.5 Emerging Issues

Porcelain surge arresters in excess of 20 years of age are starting to fail in service under fault conditions. The increase in failure rate is small but noticeable and is being monitored.

Similarly, there are some early versions of polymeric housed surge arresters that are showing signs of premature failure associated with their installation in areas affected by elevated environmental pollution levels. These are being monitored and some targeted replacement programs have been implemented.

9.14.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Surge arresters are considered to be maintenance free. Surge arresters are replaced on failure or programmed for replacement when found to be of unacceptable type or condition. When opportunities arise such as repair of pole top structures as well as during the normal asset inspection program, all surge arresters are inspected. Replacement programs targeting porcelain housed surge arresters and EDMP housed surge arresters that are deteriorating prematurely will be completed in 2016.

Approximately 1,200 surge arresters are forecast to be replaced in the 2016-2020 period.

9.14.7 Asset Disposal

No specific asset disposal requirements.

9.15 Pole Type Transformers

Please refer to document JEN PL 0032 for more detailed information on Pole Type Transformers.

9.15.1 Asset Description

Pole type transformers are outdoor transformers mounted on wood or concrete poles. Their primary purpose is to convert electrical energy from 22kV, 11kV or 6.6kV to service voltages of either 433/415V for a three-phase systems or 240/480V for a single phase system. They range in size from 10kVA to a maximum of 500kVA.

Transformers are the most critical network components. They have low failure rates, but high failure consequence for safety and supply reliability. The total number of pole mounted transformers on the JEN is 3,991.

Of the pole transformers, at least 30% are over 30 years old. The age profile for pole transformers is shown in Figure 9.7.

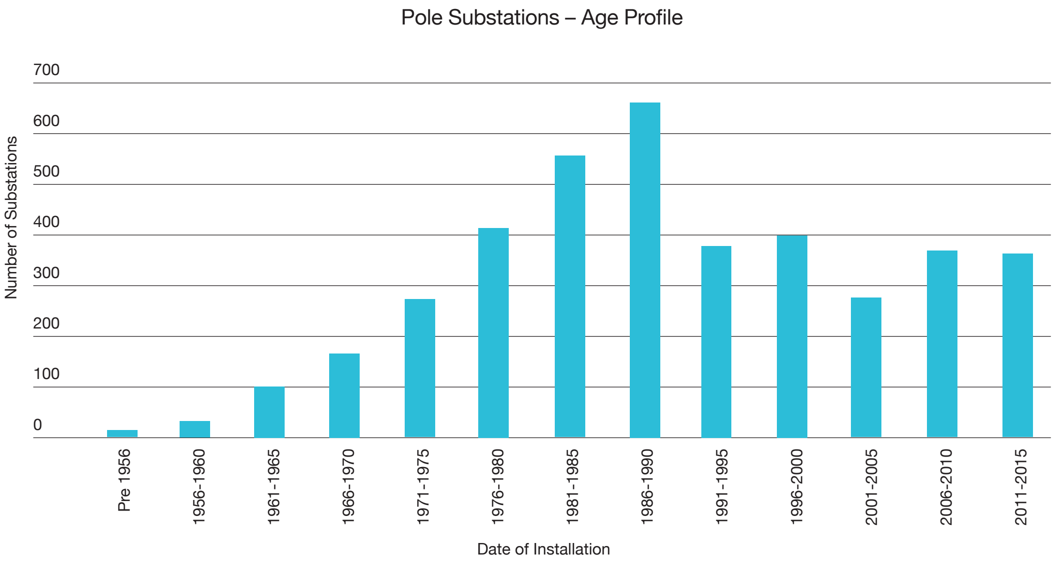


Figure 9.7 Pole Transformer Age Profile

9.15.2 Inspection and Testing

Inspection of transformers is to be carried out as part of the normal asset inspection program.

All assets in the Hazardous Bushfire Risk Areas are inspected every three years, and in the Low Bushfire Risk Areas every four years. Transformers and connections are also included in the regular overhead line thermal survey cycle.

9.15.3 Asset Failure Risk

Transformers are generally very reliable with a low probability of failure. The major risks associated with pole type transformers are environmental with respect to potential equipment failure and the impact of an oil spill.

9.15.4 Integrity Issues

Generally the pole top transformer population is in good condition.

There have been a small number of catastrophic premature winding failures in distribution transformers. These transformers have been returned to the manufacturer for analysis and replacement. Age related failure is quite small but can be expected to increase as these assets approach end of life. Distribution transformers are also replaced when load exceeds transformer ratings and an augmentation program is in place for highly loaded transformers.

9.15.5 Emerging Issues

An increase in load related failures may be occurring. The distribution transformer replacement programs have been increased to address this issue.

9.15.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Transformers are generally maintenance free.

Defective units are inspected and tested to determine repair requirements. The decision to repair is based on the age of the transformer, the cost of repair, and the likelihood of the repaired units being returned to service.

When transformers are removed from service for reasons other than defect repair, such as load growth, load decrease, redundancy or maintenance, the opportunity is taken to carry out condition assessment, testing and refurbishment.

Transformers are replaced because of:

- Transformer failure; and
- Transformer cyclic rating is likely to be exceeded.

There are no known problems with the existing transformers in terms of their design and operation and no proactive planned replacement programs are therefore required.

Approximately 140 transformers are forecast to be replaced in the 2016-2020 period.

9.15.7 Asset Disposal

Transformers must be oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately. Transformers are disposed of through a recycling company.

9.16 Non-Pole Type Distribution Substations

Please refer to document JEN PL 0033 for more detailed information on Non-Pole Type Distribution Substations.

9.16.1 Asset Description

Non-pole distribution substations include indoor, kiosk, or ground mounted (compound) type substations. Indoor substations are generally installed within a customers building, kiosk substations are installed on easements within various public areas and subdivisions or on customers property, whilst ground mounted substations are installed within a chain wire mesh enclosure generally on a customer property.

Distribution substations transform the distribution voltages (22kV, 11kV or 6.6kV) to 415/230V for local distribution to customers via the low voltage network. There are 194 ground type substations, 447 indoor type substations and 1,330 kiosk substations, as well as a number of switch cubicles and metal shells.

The components that make a distribution substation include high voltage switchgear and associated protection equipment (high voltage fuses or protection relays controlling high voltage circuit breakers), a transformer or transformers and low voltage switchgear and associated protection equipment (generally fuses). It includes an earthing system and is constructed to ensure unauthorised access to the equipment by the general public is prevented.

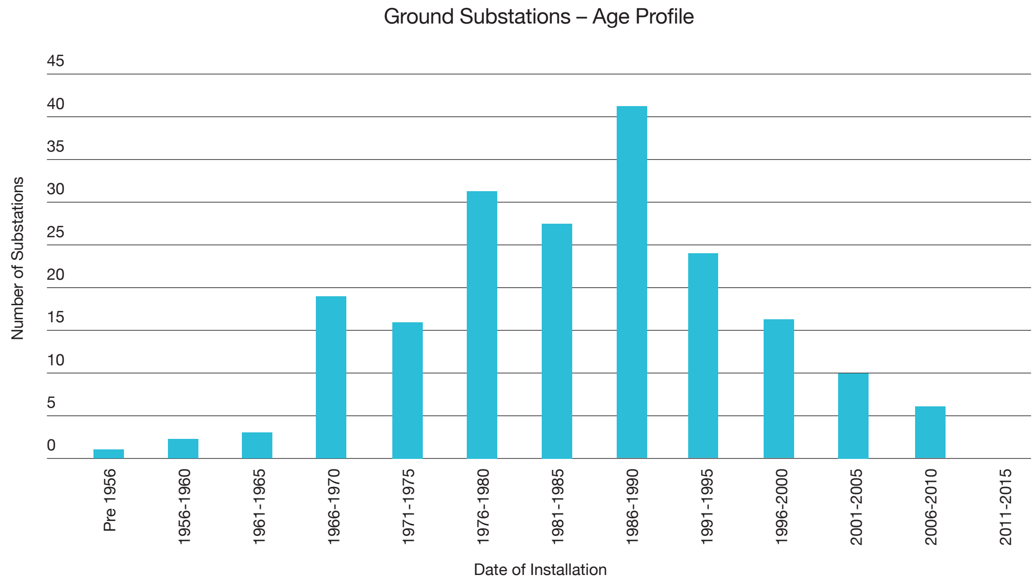


Figure 9.8 Ground Substations Age Profile

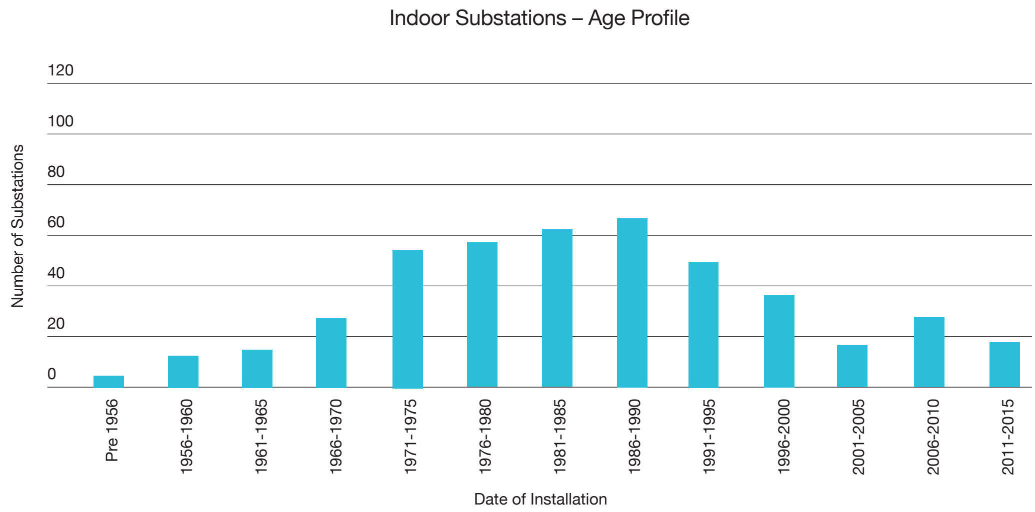


Figure 9.9 Indoor Substations Age Profile

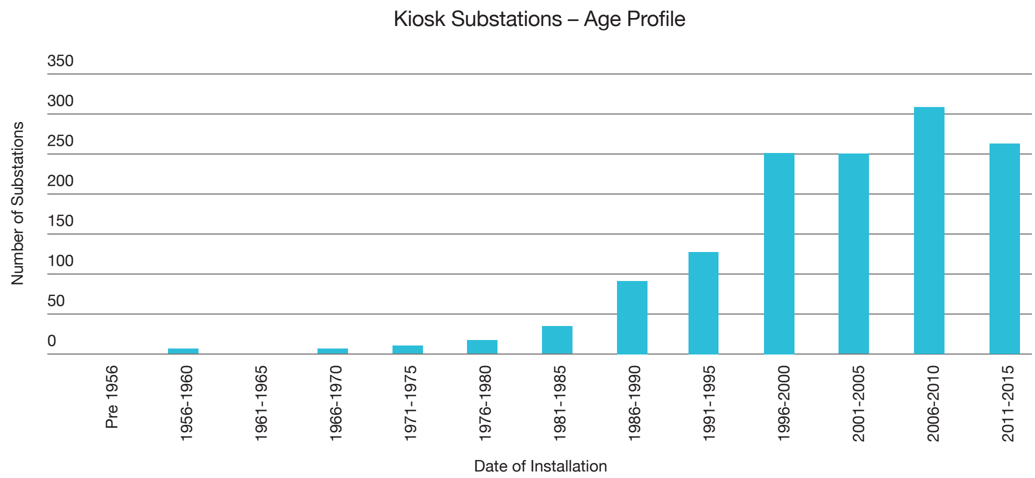


Figure 9.10 Kiosk Substations Age Profile

9.16.2 Inspection and Testing

The inspection requirements for this class of distribution substation are set out in the Enclosed Substation Inspection Manual and include as a minimum the following: visual inspection of SF_6 gas gauges and photographs of pressure gauges with abnormal levels, thermal scanning, corrosion, abnormal audible discharge, cable conditions, transformer and switchgear oil leaks and oil levels, security checks, weeding, cleaning etc. The inspection is to be undertaken by suitably qualified personnel and a detailed inspection report prepared.

9.16.3 Asset Failure Risk

The major risks associated with non-pole substations are failure of the major assets contained within the substations such as switchgear, transformers and cables resulting in a loss of supply.

9.16.4 Integrity Issues

Distribution substations are generally in good condition with no significant condition or replacement issues. However, it is anticipated that the programmed substation inspections will result in increased identification of defects and issues associated with ageing HV switchgear and LV distribution boards.

There is an issue associated with integrity of gas insulated ring main unit switchgear commonly used in kiosk type substations in underground distribution systems and indoor substations. A number of units have been detected with low gas pressure and have had restrictions placed on their operation.

There is a larger issue related to the life expectancy of this type of equipment and it is expected that the rate of replacement of this type of switchgear will increase over time.

9.16.5 Emerging Issues

Identification of substations with gas insulated RMU's without a gas pressure gauge will occur as part of the substation inspection program. There have been a small number of catastrophic failures of the older gas insulated ring main switches (manufactured between 1983 and 1987) believed to have been caused by loss of gas. These do not have a gas pressure gauge and hence it is not possible to determine their condition accurately. These will be programmed for replacement as they are identified.

There have also been several catastrophic failures of the Calor Emag switchgear installed in indoor substations. This switchgear also exhibits operating problems associated with dry lubricants. Following the completion of the data collection program associated with the substation inspection program a prioritised replacement program has been developed.

9.16.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The condition of non-pole type distribution substations and associated hardware is monitored following the guidelines set out in the Enclosed Distribution Substation Inspection Manual. These inspections are programmed periodically and address substation security, easement condition, substation access issues and the condition of the HV switchgear, cable terminations, LV distribution equipment and the transformers. Inspection includes thermal survey of the plant.

Approximately 93 ground mounted kiosk substations are forecast to be replaced in the 2016-2020 period. Additionally, approximately 90 kiosk substations are forecast to be refurbished.

9.16.7 Asset Disposal

Switchgear containing SF_6 gas is disposed of in accordance with EPA requirements. There are no other specific asset disposal requirements. Transformers must be oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately. Transformers are disposed of through a recycling company.

9.17 Earthing Systems

Please refer to document JEN PL 0034 for more detailed information on Earthing Systems.

9.17.1 Asset Description

Earthing and electrical protection systems must safely manage abnormal supply network conditions to avoid risk to people, or damage to property.

Earthing systems must be made of corrosion resistant, high conductivity materials, specifically manufactured for the earthing of electrical installations. These materials include copper, copper alloy, aluminium, and stainless steel. All metal and concrete structures located within 2.4 metres on the ground that support high voltage conductors and can be made alive in the event of primary insulation failure must be effectively earthed.

The age of earthing systems is typically the same as the asset to which the earth is applied.

9.17.2 Inspection and Testing

In accordance with the ESMS, it is required that earthing systems, except Common Multiple Earthed Neutral (CMEN) earthing systems, and electrical protection equipment, except fuses, must be inspected and tested at least every 10 years for compliance with the regulations.

The strategy aims to maintain an effective distribution earthing system through periodic integrity checks and the establishment of CMEN in high risk areas to ensure safety to personnel and public, and compliance with the ESMS. An integral part of this strategy is the CMEN strategy.

In non-CMEN areas periodic inspection and testing is required to be undertaken on substations, HV switches, isolators, ACRs, HV fuses, surge arresters, cable terminations, concrete poles and HV metering installation earths to coincide with other scheduled maintenance. Earthing systems covered by CMEN do not require periodic testing.

9.17.3 Asset Failure Risk

The major risk associated with earthing systems is public safety. Higher than required resistance in the earthing system can result in step and touch potentials hazards leading to electrical shocks or delayed protection system operation.

9.17.4 Integrity Issues

Damage to the earthing system by the passage of fault currents or through physical damage by third parties can lead to loss of functionality.

9.17.5 Emerging Issues

No emerging issues are known.

9.17.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The required earthing resistance for the various earthing arrangements shall be as specified on the appropriate earthing diagram for the particular installation and equipment.

Replacement of earthing system equipment would normally only be required if periodic inspection and testing reveals degradation such as conductor and connector corrosion, mechanical fatigue, vandalism or inadvertent breakage through excavation.

Earthing system augmentation will be required where earth resistance test results exceed the maximum specified limits.

Zone Substations

In order to ensure all zone substation earth grids comply with safety criteria a design review program has to commence on all zone substations. This involves recalculating actual and allowable step and touch potentials through theoretical modelling and/or current injection tests. If step and touch potentials are outside allowable limits, earth grid augmentation is undertaken.

At 10-year intervals the following is undertaken in zone substations to ensure earth grids continue to comply with safety criteria.

- A physical integrity inspection is undertaken of all above ground structure earth to earth grid connections of all HV and LV equipment;
- Sample inspections of underground conductors and conductor joints shall be conducted to check for any corrosion or damage. As part of this check, a ‘transfer hazard check’ shall be conducted to ensure no new underground pipelines, metallic communications cables, and unauthorised connections have been made to the perimeter fence;
- A grid continuity test shall be conducted. This test can use portable instruments and measure between a main earth grid reference connection and each structure earthing point. This is particularly important for high energy dissipation points such as surge arrester, portable earth, and earthing switch earth connection points; and

- Replacement of earthing system equipment would normally only be required if periodic inspection and testing reveal degradation such as conductor and connector corrosion, mechanical fatigue, vandalism or inadvertent breakage through excavation. Earthing system augmentation will be required where earth resistance test results exceed the maximum specified limits.

9.17.7 Asset Disposal

There are no specific asset disposal requirements.

9.18 Underground Distribution Systems

Please refer to document JEN PL 0035 for more detailed information on Underground Distribution Systems.

9.18.1 Asset Description

66kV Subtransmission Cable

The subtransmission underground cable system consists of 66kV oil filled cable and 66kV cross-linked polyethylene cable. 66kV underground cable has been used mainly as the entry and exit cable for zone substations, in some cases for freeway crossings and in more recent times for environmental and aesthetic reasons.

The majority of oil-filled cables were installed during the 1960's and the balance in the 1970's. There is a mixture of both British and Japanese manufactured cables utilized on the subtransmission network. In the last decade, all of the cables that have been installed are XLPE insulated. These periods can be seen in the age profile in Figure 9.11.

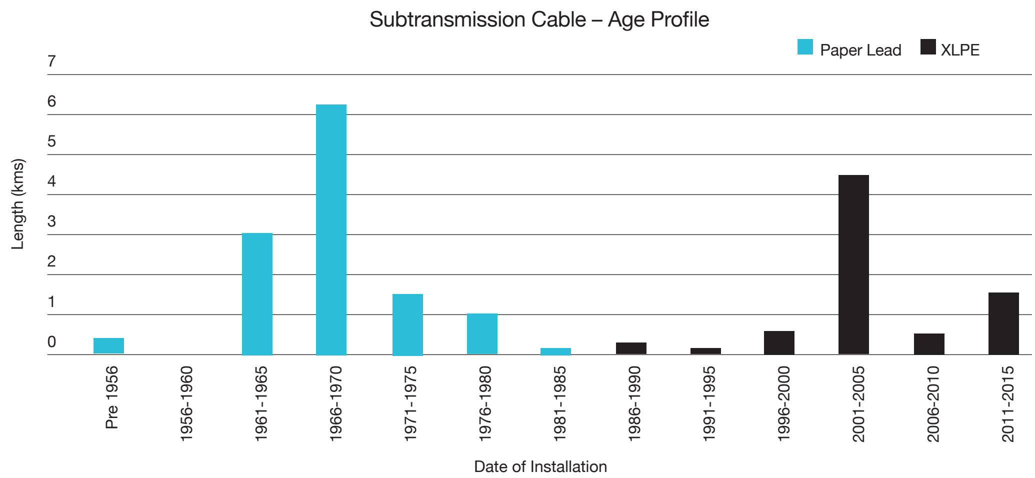


Figure 9.11 Subtransmission Cable Age Profile

22kV, 11kV and 6.6kV High Voltage Cable

Paper-lead cable was used up to the mid 1980's to construct the underground network. From that time on, XLPE insulated cable has become the preferred cable type for the construction of the high voltage underground network. The simplicity and flexibility of XLPE insulated cable has given rise to the introduction of elbow connectors. This has allowed the development of compact HV switchgear systems and as a result the kiosk type substations that are the basis for the design of modern underground distribution systems. In the last decade all of the high voltage cable used has been the XLPE insulated type.

Paper-lead cable has good service history and while a cable life of 70 years can be expected for this type of cable, there are cables in the network that have been operating for 90 years. Early versions of XLPE insulated cable are predicted to have a serviceable life nearer to 40 years. However, current XLPE cable designs are expected to attain longer service lives. The age profile for HV cable is shown in Figure 9.12.

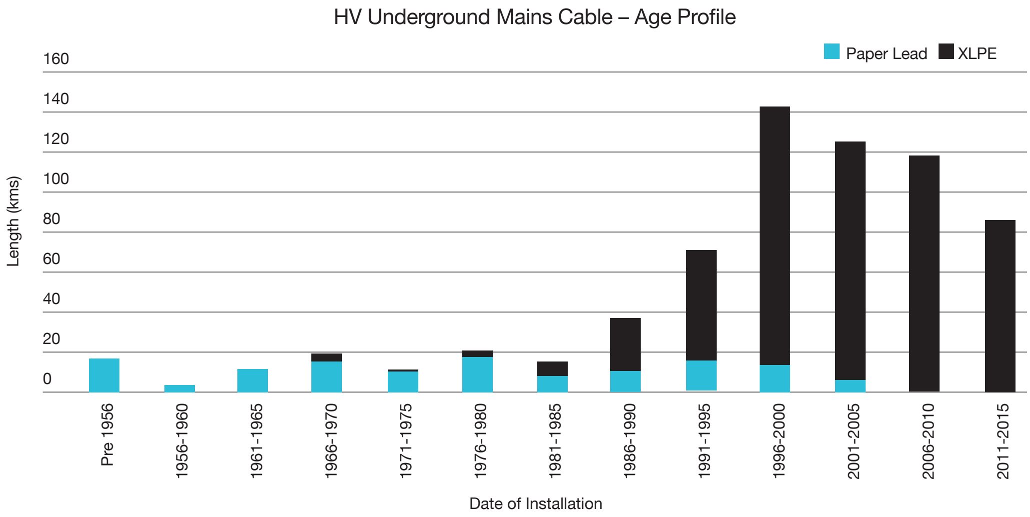


Figure 9.12 HV Cable Age Profile

Low Voltage Mains Cable

Like the HV cable systems, originally paper lead cable was used for the construction of low voltage underground mains. Modern cable systems are constructed using 185mm^2 and 240mm^2 solid sector aluminium conductor XLPE insulated cable. This cable is direct buried and fitted with service tee-joints to supply customer load. This cable system is the basis for the construction of all modern underground residential distribution networks.

The length of cable installed from year-to-year is closely related to the number of new housing lots developed.

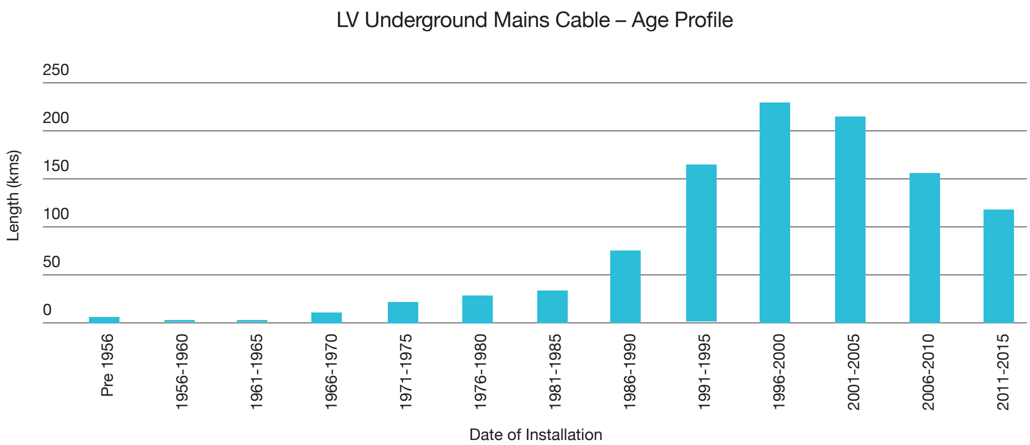


Figure 9.13 LV Cable Age Profile

Underground Services

The point of supply for underground systems is normally in a pit or pillar located on or near the customer's property boundary. The customer owns the cable from the pit/pillar to the building. JEN owns the cable upstream of the service pit or pillar. This is the service cable referred to in this section. New service cables consist of 16mm^2, 35mm^2 and 50mm^2 stranded copper XLPE insulated cable.

The age profile of the underground service asset is shown in Figures 9.14, 9.15 and 9.16.

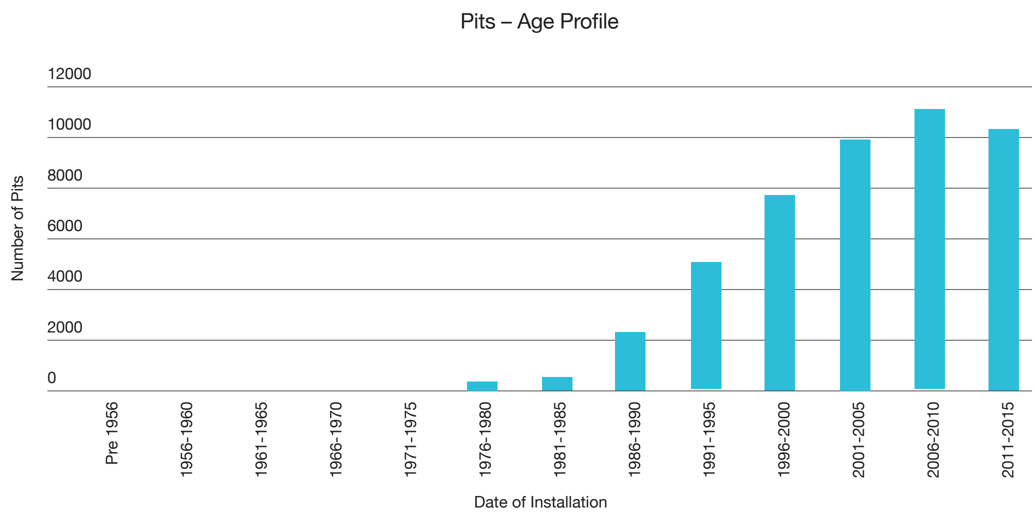


Figure 9.14 Underground Service Pit Age Profile

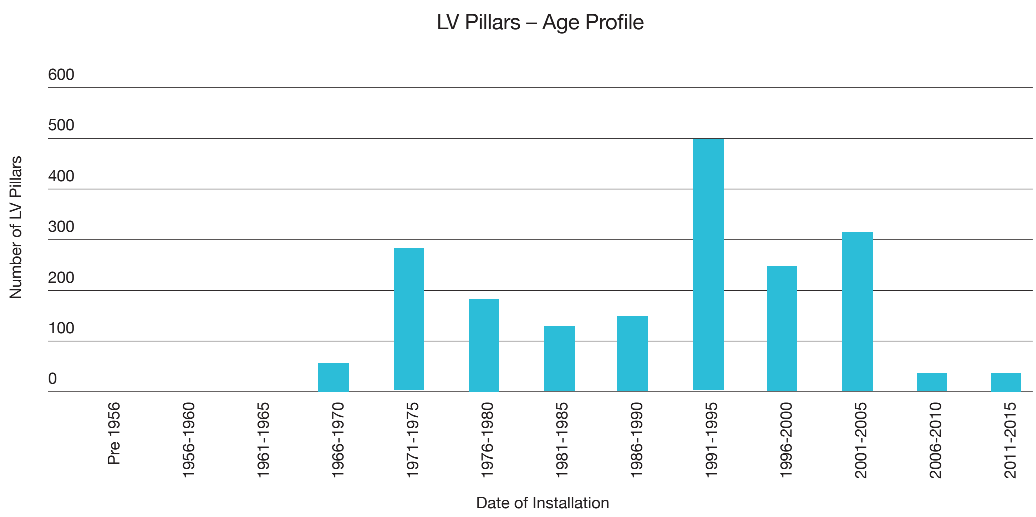


Figure 9.15 Underground Service Pillar Age Profile

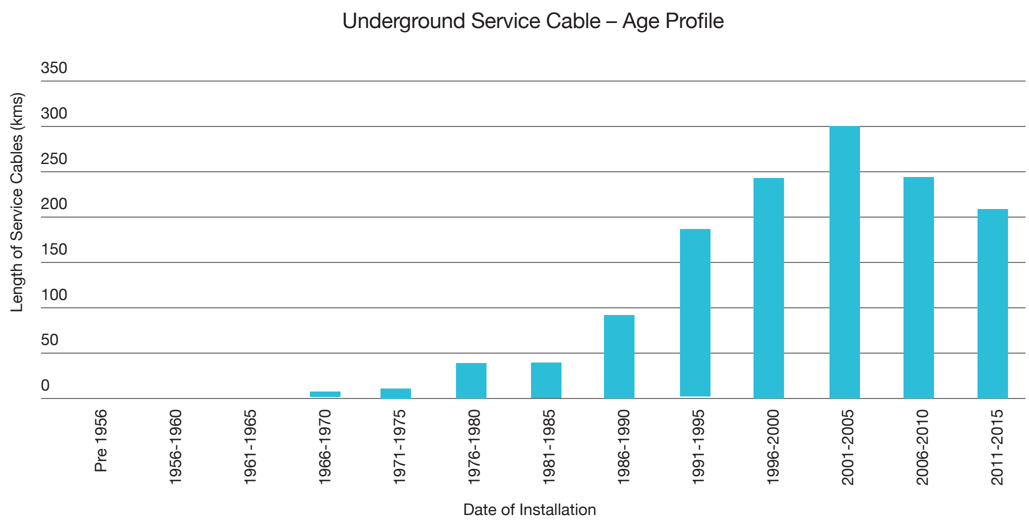


Figure 9.16 Underground Service Cable Age Profile

9.18.2 Inspection and Testing

Sheath testing of 66kV is performed every two years. No other routine inspection or testing of underground assets is performed aside from visual inspection of terminations as part of the asset inspection programs. The assessment of underground high voltage cable condition via partial discharge survey is currently being evaluated.

9.18.3 Asset Failure Risk

The major risks associated with underground distribution systems are public safety and reliability of supply.

9.18.4 Integrity Issues

Cable faults generally constitute a very small percentage of network faults. There are few cable faults experienced each year that are the result of damage resulting from digging or drilling. However, there is some indication of premature failure in early XLPE high voltage cables generally attributed to the immature manufacturing process that involved the steam curing of the insulating material. There is also some experience of failures in low voltage cable joints generally associated with poor workmanship.

Modern XLPE cable insulation systems can suffer from water and electrical treeing and this can be initiated by high voltage DC tests and lead to premature cable failure. Care needs to be exercised when cable tests are performed. Condition monitoring of significant cables using new techniques is planned to be introduced in 2016.

The low voltage underground cable network makes extensive use of pillars and pits to terminate cables and provide service connections. Pillars are prone to damage by vehicles and vandals. An extensive inspection program has been undertaken to ensure that all pillars are secure and appropriately locked.

9.18.5 Emerging Issues

Increasing failure rates are forecast as cables and cable joints and terminations age.

The incidence of explosive failure of metal housed compound filled overhead trifurcating boxes on HV cable is being monitored with a program for replacement of these terminations is planned over a 10-year period which commenced in 2013.

9.18.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

In conjunction with other works or projects, underground cables that have reached the end of their economic life are replaced. This work includes the removal of older technology compound filled cable termination boxes. Recent experience with early installations of high voltage XLPE cable has indicated a developing issue with possible extended failure of insulation resulting in the potential need to replace complete sections of cable. Replacement of high voltage cable will continue to be driven primarily through analysis of fault history.

Underground services are generally repaired when damaged with replacement being a low frequency unplanned activity.

Cable replacement only occurs if a history of cable faults is evident that are related to cable condition related failure. Underground cable systems constructed of paper lead cable have achieved exceptional reliability and longevity, with high voltage cables known to exceed 90 years in service.

Cable systems are managed by monitoring and controlling operating conditions. Faulted cables generally are repaired and returned to service. The condition of cable terminations is monitored by visual and thermographic inspection. Cables that are connected to the overhead system, identified as having degraded insulation due to the effects of ultraviolet light, will be assessed, and where necessary are replaced. The performance of old cast iron and fabricated metal cable termination boxes will be monitored and a 10-year program for replacement of these terminations commenced in 2013.

The condition of oil-filled subtransmission cables is monitored constantly by virtue of the oil pressure monitoring system linked to the SCADA system. Should the integrity of the outer sheath of the cable be compromised, then a loss of oil will occur and an alarm will be raised.

These cables have a routine inspection cycle to monitor the integrity of their outer sheath and to test the sheath voltage limiters.

Replacement joints, terminations and cables are held centrally. Because most of the oil-filled cables are relatively short in distance and the lack of expertise in oil-filled jointing in Australia, if an oil-filled cable was to fail, it is most likely that the circuit would be replaced with a new XLPE cable.

In order to minimise third party damage to cables, cable locating services are proactively promoted to contractors. To minimise damage of cables during installation, inspection of contractors during the laying of cables is carried out.

Although there has been no effective condition-monitoring system available for installed high voltage and low voltage cable systems, emerging partial discharge mapping technology is being investigated with a view to the development and implementation of a program to monitor and assess in-service cable condition in 2016.

Cable systems are generally protected from corrosion due to electrolysis by insulated cable sheathing materials. Some older lead sheathed cables can be damaged however.

For subtransmission cables, alarms are fitted to give early warning of low oil pressure and levels via the SCADA system. Immediate investigation and rectification of the problem follows any oil alarm.

Approximately 3.5km of HV and 1.0km of LV underground cables are forecast to be replaced in the 2016-2020 period.

The condition of high voltage and low voltage cables is monitored through the analysis of failures. The modes of failure primarily include:

- Third party damage; and
- Failure of terminations and joints.

To manage these issues the following actions are taken:

- Pro-active promotion of the 'Dial Before You Dig' service (MOCS – Melbourne One Call Service); and
- Thermographic and ultrasonic monitoring of terminations.

Approximately 28,000 inquiries for asset locations are received per annum. The majority of these calls are generated from MOCS. Others are received directly from the public and some from internal sources. Where there are assets in the vicinity of the inquiry, cable plans are sent to the inquirer. In some situations it is necessary to provide assistance on site to locate the underground assets.

9.18.7 Asset Disposal

There are no specific asset disposal requirements.

9.19 LV Overhead Services

Please refer to document JEN PL 0036 for more detailed information on LV Overhead Services.

9.19.1 Asset Description

Overhead services connect the low voltage (LV) system from a pole to the point of supply at a customers' electrical installation.

Services are upgraded to current standards in conjunction with other work such as network augmentation, pole replacement, re-conductoring, and asset relocation. Particular attention is paid to open wire, red lead and aluminium neutral screened services. Overhead services have a life expectancy of 40 years.

Overhead services operate in an environment where they are subjected to the effects of weathering and many are impacted by vegetation. There are various types of services installed in the distribution network and based on the type of service, the age can be estimated. There are some types that are not considered serviceable any longer and are targeted for replacement.

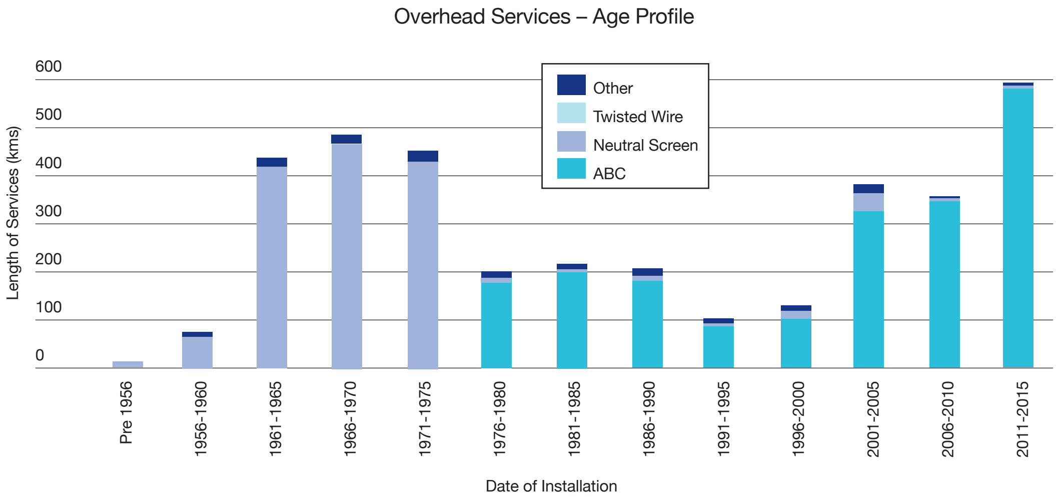


Figure 9.17 Overhead Services Age Profile

9.19.2 Inspection and Testing

An inspection and testing program has been implemented as required by the ESMS. All overhead services are physically checked and a neutral integrity test is performed. This inspection program is on a 10-year cycle. In addition overhead services are inspected as part of the programmed three and four-yearly asset inspection program.

9.19.3 Asset Failure Risk

The key risk of failure of an LV service is the potential for electrical shocks or electrocution, which can occur through direct contact with a damaged cable or within the electrical installation when the neutral connection is broken.

9.19.4 Integrity Issues

Aluminium has been used as a service conductor for many years due to its low cost and light weight.

Care needs to be taken however when using aluminium to ensure that connections and joints are properly engineered to ensure the integrity of the joint is maintained over the life of the installation.

In addition, the use of PVC insulation in conjunction with aluminium conductor can result in corrosion problems if water penetrates the insulation.

Particular care is taken with aluminium service cables to ensure that water ingress is prevented. Water ingress can result from abrasion of the cable by contact with trees. Corrosion of the aluminium conductor can lead to loss of the neutral conductor, which can result in an unsafe situation in a customer's installation. There are a number of service cables in use that are particularly susceptible to this mode of failure.

Over the years a variety of regulations have been applicable to the installation of service cables. These have specified minimum ground clearances and these specifications have varied over time.

Current regulations set new requirements and largely provide no ‘grandfather’ provisions for service cables erected in accordance with superseded regulations. Consequently there are a large number of service cable installations that are not in strict compliance with current regulations. Policies have been developed and implemented to achieve full compliance over time. The introduction of the breakaway device has greatly assisted in this endeavour.

9.19.5 Emerging Issues

During the AMI roll out, a precise measurement of the service neutral resistance was undertaken. In addition, the AMI installation process has identified defective services that require replacement. The regulatory obligation for the testing of service neutrals every 10-years will occur between 2016 and 2020.

9.19.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The following preventative maintenance is performed:

- Tree clearing as identified by the vegetation management program;
- Opportunistic replacement of superseded low voltage overhead services (as per replacement guidelines) during pole or cross arm replacement, or during investigation of voltage complaint, etc. initiated by the customer;
- Planned replacement of non-preferred service types; and
- Repair or replacement for height related issues as identified during the inspection cycle, from faults or during the performance of other maintenance.

All defective low voltage overhead services shall be replaced. Replacement of an LV service will occur according to the following guidelines:

- Service is defective;
- Where the service fails an NST test, and repair is not viable;
- Where minimum clearances are not maintained, and the service is not suitable to be raised; and
- When a service disconnect device is used for low services, the service will require replacement with ABC (XLPE).

A dedicated service replacement program has been developed to target replacement of overhead services of non-preferred service types. The program is planned to continue until all non-preferred service types have been replaced. In total, approximately 50,000 non-preferred services are forecast to be replaced in the 2016-2020 period.

The following actions that support the removal of non-preferred low voltage overhead services shall be undertaken when servicing work is required to be carried out at the customer’s premise or during maintenance activities on JEN assets:

- Bare Neutral Open Wire and Braided Red Lead service cables; to be replaced with the current standard service cable;
- Aluminium Neutral Screened service cable; to be replaced with the current standard service cable;
- Copper Neutral Screened service cable; shall be replaced with the current standard service cable if in poor condition;
- PVC insulated service cable (grey twisted); to be replaced with the current standard service cable only if in poor condition; and
- When working on a pole any service cable found with a ‘temporary’ repair or non standard connection shall be replaced with the current standard service cable.

9.19.7 Asset Disposal

There are no specific asset disposal requirements.

9.20 Communications Cables

Please refer to document JEN PL 0004-0010 for more detailed information on Communications Cables.

9.20.1 Asset Description

Communications networks, systems and equipment are broad and varied in type and age profile. The oldest remaining active services were established some 60 years ago by the State Electricity Commission of Victoria in the form of copper twisted pair supervisory cables. The original supervisory cable network was used for protection signalling, monitoring and telephony. Over time the communications systems have evolved to include SCADA and have expanded across the state until the SECV was privatised in 1995. More recent additions to the communications infrastructure assets are radio and ethernet networks extending to pole top devices and zone substations.

Enclosure Device	Installation Years	Units	Expected Life
Fibre Optic Supervisory Cables	2000-Current	127 cables 235.8km	50
MDS iNET Radio	2003-Current	96	15
VF Inter-tripping Equipment	1963-1980	96	30
RTUs	1990-Current	28	15
RuggedCom Ethernet Switches	2005-Current	37	15
AVARA DFX	2007-Current	3	15
Sixnet EtherTRAK Ethernet I/O Gateway	2003-Current	20	20
Moxa NPort Serial Device Servers	2003-Current	80	15
Cisco Routers & Switches (Primary: BD, backup: ES)	2011-Current	12	10
BT PABX	2005	2	15
Firewall	2011-Current	5	10

Table 9.8 Communication Equipment Asset Profile

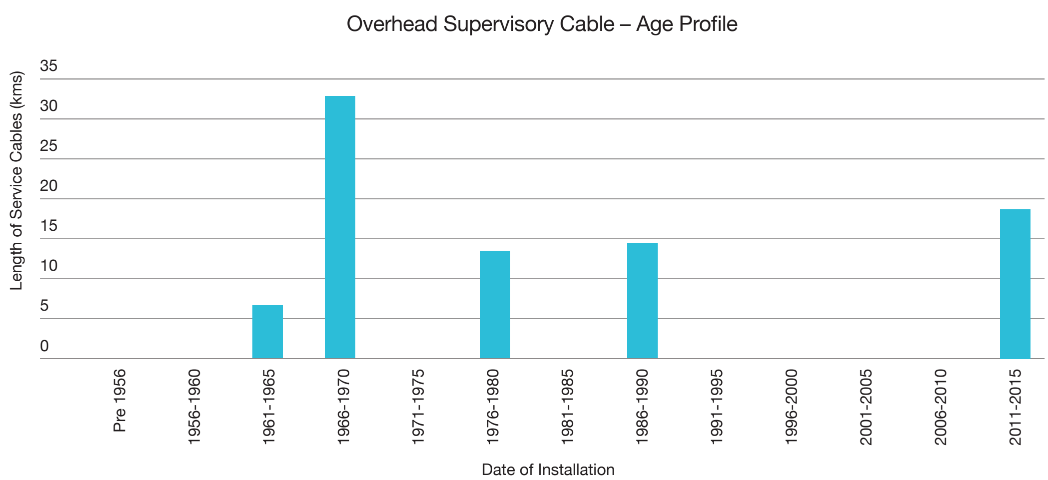


Figure 9.18 Overhead Supervisory Cable – Age Profile

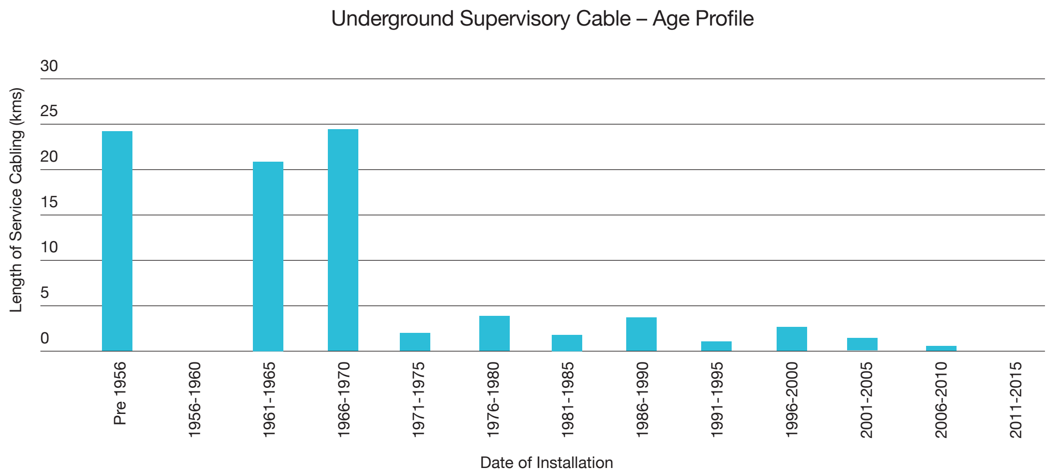


Figure 9.19 Underground Supervisory Cable – Age Profile

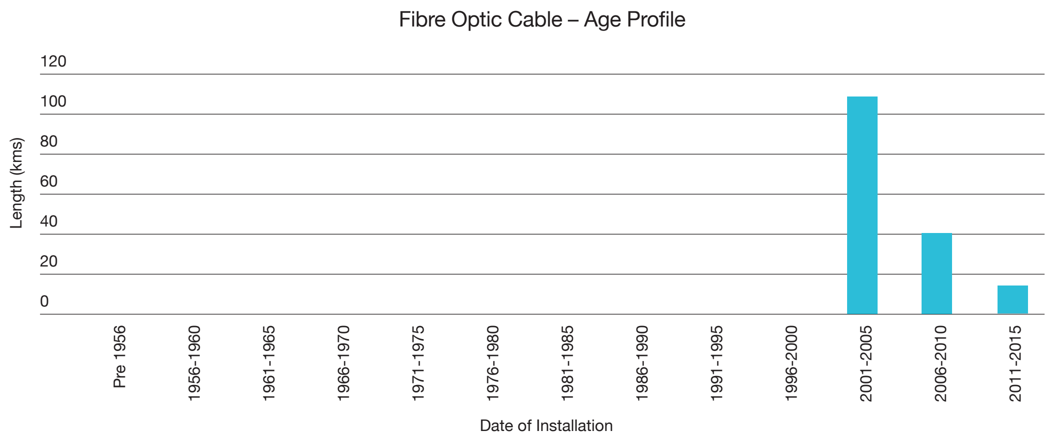


Figure 9.20 Fibre Optic Cable - Age Profile

9.20.2 Inspection and Testing

Routine inspection is required for communications assets present in public areas and for communications cables that are attached to distribution poles.

Fibre optic supervisory cables with aerial construction require routine inspection. These communications assets, their attachment to poles and accessories are to be visually inspected as part of the three and four-yearly inspection cycle as dictated by the Asset Inspection Manual.

Fibre optic cable condition can be assessed by an Optical Time Domain Reflectometry (OTDR) test. These tests measure the optical path losses through a fibre core and can indicate loss events along the cable length with high accuracy of location. Each fibre optic cable deployed has had a base line OTDR test conducted on each core with results archived for future reference. A test and inspection cycle of five years is prescribed where each fibre optic cable segment shall be OTDR tested and the results analysed for at least two cores within each cable bundle.

Fibre terminations and splicing points in pits and on poles are to be inspected visually. Reports and recommendations are made for any corrective works required or identified as part of the inspection cycle.

Electronic monitoring of communications circuits, systems and networks permits early detection and identification of failing or failed systems. Monitoring is particularly important for systems that are redundant and the failure of a circuit may not be evident when redundant systems are activated. Each communications circuit deployed is required to be capable of asserting a remote alarm if that communications circuit suffers a hard failure. It is further desirable if a circuit can assert a warning for a degraded communications circuit. A protection or signalling system communications circuit or equipment failure will generate a SCADA alarm (via the RTU) if its communications link fails. Protection communications alarms are thus received by the Coordination Centre (CoC) and an appropriate maintenance or investigative response is required.

SCADA communications alarming and monitoring functions are internal to the SCADA host platforms where extended failures of devices (multiple message loss) are indicated as alarms or warnings to the CoC and SCADA support team.

Ethernet networks are periodically and automatically tested by monitoring applications and tools that are designed for managing IT systems. Ping and Simple Network Management Protocol (SNMP) tools permit interrogation of devices and capturing of alarm events in close to real time. Presently the 'SNMPC' monitoring tool is used for SCADA network monitoring. Corporate communication links are actively SNMP monitored by the Information Services (IS) help desk.

JEN owned communications infrastructure leased to third parties are provided unmonitored. It is the responsibility of the third party to monitor their own data links. JEN is required to monitor neighbouring channels where they are present in the same infrastructure as third party leased services.

9.20.3 Asset Failure Risk

Communications systems for infrastructure themselves are predominantly components of risk mitigation systems. For instance, current differential protection signalling relies on communications so that comparative measurements can be made across subtransmission lines to reveal and make safe faults quickly, and thus reduce the risk of damage to plant, equipment and life. In doing so, the risk of operating the distribution network is itself reduced.

Backup voice communication systems are used to ensure continued communications to field crews in the event of a primary voice communications system failure, which in turn allows a central coordinated approach to managing field resources during normal or extreme scenarios.

As communications systems are designed to reduce the risk and increase the efficiency of operations, loss of one or more communications systems increases the risk profile of the distribution asset and/or reduces the efficiencies that are realised through applications that rely on communications infrastructure.

9.20.4 Integrity Issues

Communications infrastructure assets can be adversely affected by:

- Deterioration of aged assets (for example, water ingress into repeater pits and cable junctions);
- Civil works and ground disturbance including cable physical damage (severed, bent or crushed);
- Aerial cable damaged by trees, wire down, car into pole and fire; and
- Radio frequency interference.

9.20.5 Emerging Issues

- Zone Substation RTUs of type Invensys Foxboro C225 and C25 have reached end of life. These RTUs were installed in 1987-1990 and had a predicted service life of 15 years. Modern SCADA protocols are not support by these RTUs. An RTU upgrade program is in place which will replace these aging RTUs with modern replacements. Aged RTUs are also opportunistically upgraded as part of secondary and primary equipment upgrades and augmentations.

9.20.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The key management strategies are:

- Utilisation of the communications system assets to their maximum recommended lifecycle;
- Apply prudent and efficient asset management practises to ensure reliability and availability of the communications system assets;

- To replace or retire legacy communications systems with modern alternatives in a timely manner to avoid failures due to ageing of the assets; and
- To actively monitor the condition and analyse the performance of the communication systems asset over the lifecycle.

The proactive preventative maintenance requirement is very low to moderate for communications infrastructure assets. The inspection cycles have elements of preventative maintenance.

Corrective maintenance is usually required in response to a defect identified by one of the following:

- A direct report from the Coordination Centre, communications failure of systems reported by SCADA or other source;
- A direct report from field crews investigating a secondary fault;
- Alerts from automated monitoring systems (SCADA and communications monitoring systems);
- Reports from routine inspection, poles or communications assets; and
- Faults raised by third parties.

Identified faults and defects are to be addressed with a timely response as is appropriate for the affected systems. Refurbishment of RTUs and communications systems assets may be possible to extend the life and functionality. Where an upgrade path is available and the equipment still has a viable life, that equipment will be upgraded in conjunction with other capital work at that site.

9.20.7 Replacement

Aged RTUs

The zone substations are remotely controlled via SCADA and remote terminal units (RTUs). Some of the installed RTUs are obsolete and are unsupported by the manufacturer. Further to this, the legacy RTUs cannot support modern feeder protection relays or protocols used within SCADA. To minimise the operational impact of any failure, these ageing RTUs must be replaced. The replacement is aligned with relay replacement projects. Recovered legacy components are to be utilised as spares to support the remaining RTUs in service.

Replacement of PQM Comms

Telstra GSM (GPRS) network is used to dialup zone substation BMI power quality meters (PQM). As per Telstra's strategy to migrate to a faster and more reliable mobile platform (from GSM to LTE/HSDPA) they will discontinue the GSM by 2014. Sixteen zone substation power quality meters are utilising this communication media and must be replaced.

SNMPc Replacement

SNMPc is a network management tool currently used to monitor and manage the JEN IP network and equipment. This application is outdated and does not support all new functionalities required. A replacement system is under investigation and negotiation.

9.20.8 Asset Disposal

There are no specific asset disposal requirements.

9.21 Grounds/Domestic Management of Zone Substations and Non-Pole Type Substations

Please refer to document JEN PL 0037 for more detailed information on Grounds/Domestic Management of Zone Substations and Non-Pole Type Substations.

9.21.1 Asset Description

There are 25 zone substations and more than 1,970 other substations consisting of:

- Cubicle substations;
- Ground type substations;
- Indoor substations;
- Kiosk substations; and
- Underground substations.

9.21.2 Inspection and Testing

Inspection and maintenance shall be performed on grounds and external surfaces of Zone Substations, Distribution Substations and Switching Cubicles. These inspections shall identify and rectify substation/switching cubicle defects which are likely to create a safety or environmental hazard or detract from the appearance of the installation.

The maintenance of distribution substation enclosures and easements was conducted on a corrective basis up until 2009. This has proved to be unsatisfactory as it failed to appropriately address housekeeping and security of distribution substation enclosure and easements. A preventative maintenance program has been implemented to ensure that substations and easements are maintained in appropriate condition and that defects are identified and corrected in an appropriate time frame.

A civil and structural engineering audit shall be conducted on a three-year cycle to monitor the integrity of all buildings and structures associated with zone substations. Any deteriorated structures or buildings found shall be programmed for refurbishment.

A program of annual inspection of all fall arrest equipment installed on zone substation plant, equipment and buildings has been implemented. This equipment has been installed as a result of new working at heights regulations.

The inspection program has been implemented to ensure ongoing compliance with OH&S regulations relating to working at heights. This is to be carried out by external contractors.

9.21.3 Asset Failure Risk

The major risks associated with the surrounds and housings of substations are:

- Safety to employees during operation and maintenance;
- Supply reliability due to lack of access for operation;
- Equipment failure due to animals/birds/insects;
- Poor public perception due to appearance if in an unkempt state;
- Vegetation covering vent holes might also result in equipment overheating;
- Access by unauthorised persons;
- Vandalism;
- Water leaks; and
- Environmental oil loss.

9.21.4 Integrity Issues

Distribution Substations

The easements and enclosures associated with distribution substations require ongoing maintenance to ensure their appearance and security is maintained. There are numerous examples of rubbish and household waste being left on easements and attacks on substation enclosures by vandals (particularly graffiti).

Zone Substations

There have been a number of issues detected as a result of audits undertaken of the condition of buildings, grounds and structures in zone substations. The effect of long term drought on building and structure foundations has meant that some remedial works have been necessary to address building and structure damage at a small number of locations. This work has included the underpinning of foundations.

Asbestos has been used as a building material in many of the older substations and this issue needs to be managed whenever building modifications are considered.

As the wooden framed asbestos clad buildings age, maintenance needs increase. When significant asset replacement of the equipment housed in these buildings is required, the suitability and integrity of the existing building structures needs to be critically assessed before proceeding with these projects.

In some cases the existing buildings may require replacement to facilitate major asset replacement works.

Zone Substation Building Replacement Plan

The replacement or major refurbishment of zone substation buildings will be triggered by the condition of the building and the need to replace protection and control equipment, not by the age of the buildings alone.

The nominal life of zone substation buildings is 50 years for wooden and 90 years for masonry type buildings. Civil and structural inspections of the buildings will indicate the need for repairs or refurbishment. Buildings at Coburg North (CN), Preston (P) and Sunbury (SBY) zone substations are forecast to requirement upgrading or replacement in the 2016-2020 period.

The issue of asbestos within buildings remains a potential health and safety risk. The selection criteria for replacement or major refurbishment of zone substation buildings may be governed by legislation changes in the future, requiring the safe removal of all asbestos within specified timeframes.

Control buildings containing microprocessor based protection and control equipment are required to operate within a temperature controlled environment. The provision of air conditioning to zone substation buildings will involve the installation of two commercial air conditioners, doors to segregate the protection room and thermal insulation. These installations will be implemented in conjunction with major project work.

9.21.5 Emerging Issues

There are no emerging issues associated with the grounds/domestic maintenance of zone or non-pole substations.

9.21.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The lifecycle management strategy applied to zone substation assets comprises condition monitoring, preventative and corrective maintenance activities. The primary condition monitoring activities comprise routine visual inspection on a monthly basis, annual engineering inspections and civil audits on a three-year cycle. The preventative maintenance program is primarily a housekeeping program. Corrective maintenance is carried out as required and includes maintenance of site security and minor civil repairs. The lifecycle management strategy also includes life extension programs associated with the buildings and planned building replacement programs based on condition, age and building type.

9.21.7 Asset Disposal

Many of the older buildings contain asbestos or are asbestos clad and these need to be managed and disposed of in accordance with EPA guidelines.

9.22 Zone Substation Capacitors

Please refer to document JEN PL 0038 for more detailed information on Zone Substation Capacitors.

9.22.1 Asset Description

Zone substation capacitor banks comprise capacitors, reactors and earth switches. This is reliable plant that has inert and long life equipment with a modest need for routine maintenance.

Capacitors are installed in zone substations to reduce system losses, maximise asset utilisation and to provide reactive power compensation for heavy load conditions. The capacitor banks vary from 4MVAR to 12MVAR and they are time or VAR controlled and automatically or manual switched.

There are 36 capacitor banks within 20 zone substations with a total capacity of approximately 264MVAR. The capacitor banks date from 1962. All capacitors installed between 1962 and 1978 are of the large ‘bathtub’ type.

9.22.2 Inspection and Testing

Inspections of capacitor banks are performed monthly by operators as part of the zone substation inspection program. In addition capacitor banks are viewed as part of the annual zone substation engineering audit.

Whenever access to the capacitor bank is required for repairs, the opportunity is used to inspect the entire installation.

Thermographic surveys of capacitor banks are also included in the annual surveys.

9.22.3 Asset Failure Risk

The major risks associated with capacitors are environmental due to potential failures leading to oil spills. Capacitor banks are generally reliable and the risk of failure is considered to be low.

9.22.4 Integrity Issues

Some families of series reactors installed within capacitor bank installations have been found to be defective due to severe cracks appearing in the epoxy resin body. These will be scheduled for replacement when identified. This type of defect is monitored during monthly zone substation inspections.

Noise can also be generated by older capacitor bank installations. This is emitted by the large iron cored inductors that form part of these installations. New installations are designed to meet the requirements of the EPA regulations.

Capacitor bank enclosures at a number of zone substations have deteriorated. The galvanized coating on the chain wire mesh panels have deteriorated and rust has developed as a result. These will be scheduled for replacement.

Most high voltage capacitors on the network are known to be PCB free, however there is a small number of one type of older capacitor which can only be tested destructively. It has previously been confirmed that these contain PCB contamination at non-scheduled levels.

9.22.5 Emerging Issues

Harmonic resonances between capacitor banks and the distribution network can result in overheating and damage to capacitor bank installations. The increase in non-linear loads on distribution networks is an emerging problem and capacitor bank reactors need to be selected to prevent this type of resonance, in addition to limiting the inrush current when energised.

9.22.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The lifecycle management strategy applied to capacitor banks comprises condition monitoring, minimal preventative maintenance and corrective maintenance. This strategy is applied because the plant is very reliable and the consequence of failure is minimal. The principal condition monitoring activities applied to capacitor banks comprise visual inspection and infra-red thermal imaging.

The preventative maintenance activities are mainly targeted at capacitor banks installed indoors as they can be affected by the accumulation of dust on insulating surfaces, and on the maintenance of earth switches. In addition, the lifecycle management strategy also includes a replacement program based on condition and age.

Replacement Plan

A program for the replacement of capacitor banks, prioritised by condition is planned. One is planned to be replaced in the 2016-2020 period.

The larger bathtub type capacitors are of an age where there are no spares and these have been found to be PCB contaminated. Failure of a bathtub element of a capacitor bank will result in the replacement of the entire installation.

Small can type capacitors are individually replaced on failure. Some capacitor can families are suffering increasing failure rates. As these are identified, they will be programmed for replacement.

9.22.7 Asset Disposal

Capacitors must be oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately.

9.23 Zone Substation Circuit Breakers

Please refer to document JEN PL 0039 for more detailed information on Zone Substation Circuit Breakers.

9.23.1 Asset Description

Circuit breakers (CBs) are devices that operate automatically to interrupt current flows under network fault conditions. The expected life of a CB is 45 years for outdoor circuit breakers and 50 years for indoor CBs. Of the current population of 415 HV CBs there are 50 CBs over 50 years old.

The CB population age profile (Figure 9.21) show that a large number of CB's have been in service beyond their expected life and this situation will be managed over the next 10 years.

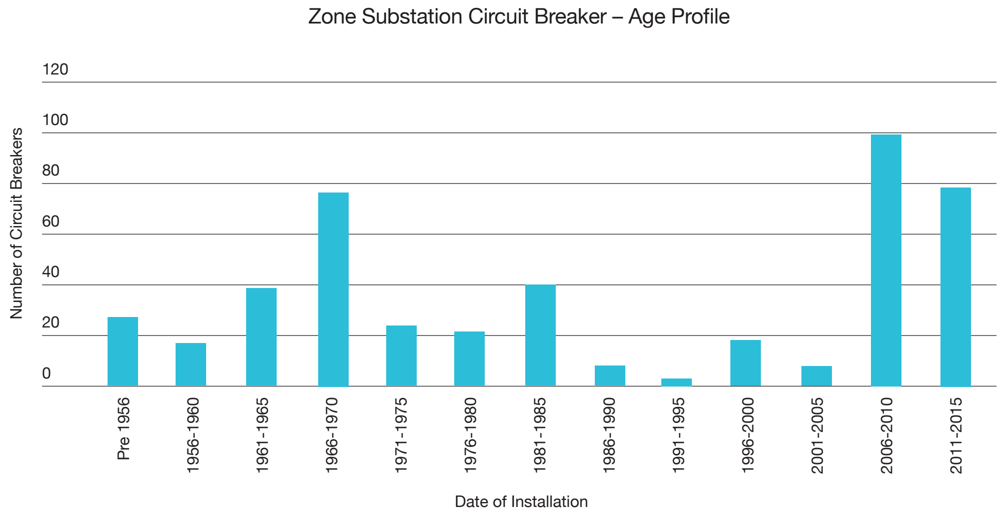


Figure 9.21 Zone Substation Circuit Breaker Age Profile

9.23.2 Inspection and Testing

Operators visually inspect circuit breakers when visiting substations. Engineers conduct whole of substation audits at least annually identifying any obvious defects. Thermographic surveys are conducted annually and cover all zone substation electrical assets.

To determine mechanism operating reliability a trip/close coil monitor (Kelman) instrument is used to record current versus time information. From this information slow operation can be detected. It is planned to capture the first operation at a scheduled maintenance and for CBs with some history of problems, recordings at intervals between maintenance.

In addition a functional check is to be performed on each CB annually (open –close operation) if the CB has not been operated during this period. Many CBs are not called on to operate for extended periods and this functional test will check the control systems from the control room to the CB and in addition exercises the lubrication on the CB mechanism and thus reduces the likelihood of slow or sticking operation.

For indoor switchboards, once over 40 years old, a comprehensive set of condition monitoring tests (Insulation Resistance, Partial Discharge, Dielectric Dissipation Factor and Capacitance) are conducted on the fixed cubicle buses. These tests are conducted at five-yearly intervals unless results are showing rapid degradation over time. In this case, tests shall be conducted at more frequent intervals.

Additionally, equipment that measures Transient Earth Voltages (TEV) with metal enclosed switchgear is utilised for on line condition monitoring. Any switchgear that shows high readings shall then be subjected to the more comprehensive test described above.

TEV tests shall be applied to all indoor switchgear irrespective of age. TEV surveys are a switchgear condition monitoring technique scheduled to be performed routinely to assist in monitoring the condition of the ageing switchgear population.

9.23.3 Asset Failure Risk

CB's are installed to fulfil critical functions associated with the safe and reliable operation of the HV network. CB's can experience tripping defects and in rare circumstances catastrophic failure can occur. The dominant CB failure modes that impact on the reliability of the network are as follows:

- Failure to insulate;
- Failure to interrupt fault currents;
- Failure to carry load due to high resistance connections resulting in thermal overheating; and
- Failure to trip due to mechanism problems that prevent the CB from opening or may result in slow operation. This will cause back up protection to operate which may result in the loss of supply from a bus or whole zone substation and the CB may be damaged.

9.23.4 Integrity Issues

A small number of failures of CBs have been experienced that have been related to operational duty. These CBs have been switching capacitor bank installations on a daily basis. These CBs are in excess of 40 years old. This type of operation far exceeds the operation of a normal zone substation CB. Mechanical failures have occurred in the primary contact drive systems. The monitoring of the condition of CBs with similar duty cycles has been modified to detect evidence of this type of failure.

Bushings on some families of outdoor CBs are leaking insulating compound and will eventually fail if left unattended, interrupting supply to customers. A program has been developed to replace all bushings in order of priority as leaks are detected.

Condition assessments have been undertaken on indoor metal clad switchgear and this has revealed that some families are suffering age related deterioration of the insulating systems. This is related to the ageing of the synthetic resin bonded paper bushings used extensively in some families of metal clad indoor switchgear.

In addition, worn mechanisms and availability of spare parts are an issue with some performance problems being experienced related to mechanism age. This is being reflected in relatively high maintenance costs. As a result of the ageing switchgear, an ongoing program of condition monitoring and life assessment tests is being conducted so as to identify, prioritise and plan for necessary asset replacement.

Sulphur Hexaflouride (SF_6)

SF_6 is an insulating gas commonly used in relatively modern switchgear and is a powerful greenhouse gas. JEN's longer term objective is to investigate the use of alternate insulation mediums where technically acceptable to reduce the use and loss to atmosphere of SF_6 gas.

Switchgear Issues

The 22kV 345GC circuit breakers within various outdoor zone substations have been undergoing a bushing refurbishment program due to a history of pitch leaks. This refurbishment program will maintain the major insulation of the circuit breaker. To date the CB mechanism have also suffered some minor defects particularly with capacitor bank CB's.

This issue has been managed successfully. The main contact pull rod has had a relatively short failure history. The maintenance schedule has been modified to remove the class 2 overhaul at 12 years and implement a class 2 overhaul at six years to identify the fractured pull rods. Generally this failure mode is associated with capacitor bank switching and the onerous duty on the mechanism components.

9.23.5 Emerging Issues

Augmentation of the transmission system by AusNet Services has resulted in increasing fault levels at zone substations. The interrupting capability of CB's has to be monitored in the light of these increasing fault levels to ensure that the interrupting capability of the CB's is adequate.

9.23.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

A number of different CB technologies have been utilised over the course of time. These include bulk oil, minimum oil, SF_6 and vacuum technologies. Each of these CB types has different maintenance requirements and needs. The lifecycle management strategy applied to CBs comprises condition monitoring, preventative and corrective maintenance programs that are tailored for the various types of circuit breakers deployed on the network.

The preventative and corrective maintenance programs are based on a combination of elapsed time and CB wear as assessed by operations and fault interruptions. These strategies are designed to address the deterioration of lubrication systems in the CB mechanisms that occurs with time and the wear that occurs on main contacts, arcing contacts and arc interrupting systems in the chambers of the CBs due to operations and fault interruptions.

In addition, the lifecycle management strategy includes life extension programs designed to address CB components that are deteriorating prematurely and a planned prioritised replacement program based on condition and age. The strategy also incorporates the specification of new plant that utilises low maintenance technologies and the latest advances in arc fault containment to provide operator protection.

The principal condition monitoring tools applied to the CBs include:

- The recording of operations and auto points to determine the condition of the fault interrupting systems;
- Kelman circuit breaker analyser;
- Electrical tests;
- DDF, partial discharge and capacitance tests on indoor switchboards;
- Thermal imaging;
- Functional tests;

- Monthly inspections; and
- Monitoring of load.

Maintenance Strategy

The basic philosophy is that CBs should only be maintained when they need to be. This is a simple philosophy, but not really easy to achieve in practice. Preventative maintenance should only be performed when the condition of the CB indicates that maintenance is required.

To assess the condition of any particular CB and determine when maintenance is necessary, three condition indicators are used. Fault interruption duty, the number of switching operations performed and elapsed time are used to determine when maintenance should be carried out. In addition, new techniques are being researched to give improved condition data.

Replacement Plan

A program of planned replacements based on a range of factors including failure and defect history, maintenance costs, spare parts availability, failure probability and consequences and suitability of ratings has been established.

A priority ranking, together with any load growth requirements, is used to determine which specific items are to be replaced. Units removed from service will be utilised as spares for items of the same type still in service.

66kV CBs at Broadmeadows (BD), Coburg North (CN), Footscray East (FE), Footscray West (FW) and Heidelberg (HB) zone substations and are forecast to be replaced in the 2016-2020 period.

Indoor metal clad switchgear at Footscray East (FE) and Footscray West (FW) are also forecast to be replaced.

9.23.7 Asset Disposal

All CBs containing oil are oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately. CB's containing SF_6 gas are disposed of in accordance with EPA requirements.

9.24 Zone Substation Instrument Transformers

Please refer to document JEN PL 0043 for more detailed information on Zone Substation Instrument Transformers.

9.24.1 Asset Description

Instrument transformers are located in the 25 JEN zone substations. They comprise 66kV, 22kV, 11kV and 6.6kV current and voltage transformers. These transformers are installed within indoor switchrooms or outdoor switchyards for metering and protection purposes.

As an asset class instrument transformers have proved to be very reliable. The introduction of polymeric bushings should further enhance the performance of 66kV instrument transformers by reducing the consequence of in service failures.

In each zone substation, VT's and CT's are deployed on the subtransmission plant and on the medium voltage plant to satisfy the requirement of various protection schemes such as over-current, earth fault and directional protection schemes.

CT's and VT's can be grouped as follows:

- Oil immersed types inside bulk oil circuit breakers;
- Oil immersed free standing post types;
- Oil immersed types inside power transformers;

- Dry synthetic cast resin types supplied together with metalclad switchboards; and
- Low voltage wound toroidal types installed over HV bushing in metalclad switchboards.

9.24.2 Inspection and Testing

Although there are many instrument transformers in the system, the service reliability has been high. Their performance can be maintained with minimal work as described below.

Operators visually inspect instrument transformers external to major plant items, when visiting substations, to detect any obvious defects. Checks are to be made for signs of oil leaks, tank distortion, and damage to bushings and leads. Also engineers conduct whole of substation audits at least annually identifying any obvious defects.

Thermographic surveys are conducted annually and cover all zone substation electrical assets. A detailed inspection is to be conducted as part of the maintenance of the associated circuit breaker, bus or line as appropriate.

The population of zone substation instrument transformers is ageing. For those transformers that exceed 40 years of age, a new program of condition assessment tests are to be deployed to assess the condition of the plant and assist in making decisions on the planned retirement of the plant.

9.24.3 Asset Failure Risk

Instrument transformers are generally very reliable and risk of their failure is considered to be low. The major risks associated with Instrument Transformers are public safety from potential failures and reliability of supply.

9.24.4 Integrity Issues

There have been some incidents of the explosive failure of a particular variety of 66kV current transformers (CT's) in the Victorian Electricity Supply Industry due to a design defect. These have all been replaced on the JEN network.

9.24.5 Emerging Issues

No emerging issues are known.

9.24.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

This category of plant comprises discrete voltage and current transformers operating at subtransmission and distribution voltages installed in zone substations. These devices are the primary measurement devices that drive the protection, control and monitoring systems in zone substations. This type of plant is generally very reliable with little need for routine maintenance. The lifecycle management strategy applied to instrument transformers comprises condition monitoring, minimal preventative maintenance and corrective maintenance.

The primary condition monitoring tools used are visual inspection and thermal imaging. This type of plant is not designed for intrusive routine maintenance and in fact it has been shown that this can lead to premature deterioration of instrument transformers due to the disturbance of seals which results in the ingress of moisture. The preventative maintenance consists principally of the washing of insulating surfaces. The lifecycle management plan also includes a planned replacement program based on age and condition. The strategy also incorporates the specification of new plant that incorporates CT's and VT's in switchgear wherever possible and this has significantly reduced the use of discrete instrument transformers.

The maintenance strategies aim to identify, repair, maintain and replace faulty instrument transformers to:

- Avoid possible explosive failure of porcelain type transformers;
- Avoid secondary damage to other station equipment;

- Mitigate hazards to personnel in the station; and
- Remove a unit for repair through planned process.

Replacement Plan

Instrument transformers are replaced on condition.

Instrument transformers that are an integral part of metalclad buses, transformers, circuit breakers, and capacitor banks will be replaced together with the major asset. This also applies to outdoor CT's attached externally to CB's.

Oil filled VT's and CT's fitted with porcelain bushings or housings, are to be tested to establish their condition for planned replacement as the need arises.

No Instrument transformers are forecast to be replaced in the 2016-2020 period.

9.24.7 Asset Disposal

There are no specific asset disposal requirements.

9.25 Zone Substation DC Supply System

Please refer to document JEN PL 0023 for more detailed information on zone substation DC supply systems.

9.25.1 Asset Description

A zone substation DC supply system comprises of battery bank, battery charger, distribution board and associated cabling and wiring and is used for the following functions within the zone substation:

- All high voltage circuit breaker closing and tripping operations;
- Auxiliary supply for protection, control, metering, communication and SCADA equipment;
- Local status indications and alarms;
- Control room emergency lighting system; and
- Miscellaneous systems including smoke detectors and security systems.

The DC supply system is therefore critical to the safe and reliable operation of the zone substation.

The DC supply system must support the standing and momentary DC loads of the zone substation. Under normal operating conditions, the battery charger supplies the DC loads and keeps the battery bank fully charged. In the event of charger failure or AC supply failure (abnormal operating condition), the battery bank must seamlessly and continuously support the zone substation DC loads for extended periods of time. The nominal design carryover time for all zone substation DC supply systems is 10 hours.

The battery bank cannot be allowed to discharge beyond its rated design capacity as this may damage the batteries and will invariably compromise the reliable operation of zone substation protection and control equipment. Furthermore, the battery bank cannot be switched out of service without the zone substation being shut down. This is not desirable and procedures have been developed for safely replacing faulty batteries while the battery bank remains in service.

The standard DC supply system voltage for all new construction is nominally 110V. A number of other legacy supply system voltages exist including 24V, 30V, 36V, 50V and 240V.

All new DC systems are required to be fully duplicated consisting of 'X' & 'Y' battery banks and 'X' and 'Y' chargers with monitoring facilities, in accordance with the Zone Substation Secondary Design Standard (JEN ST 0600), with the objective of enhancing the availability of DC systems and increasing the operational reliability of secondary systems at zone substations.

There are presently 82 DC supply systems (comprising battery bank and charger) installed across 25 zone substations, one high voltage switching station and two high voltage customer substations including spare battery banks located at Coburg North (CN), Pascoe Vale (PV), and Heidelberg (HB) zone substations.

Lead acid batteries have proven to be an extremely reliable source of standby energy and are exclusively used in all zone substation applications across the network. Traditionally, only flooded or lead acid pasted plate (LAPP) type batteries were used. More recently, some sealed or valve regulated lead acid (VRLA) type batteries have been installed at substations having major refurbishments. Approximately 82% of the battery population is LAPP; while 18% is VRLA.

The average age of the battery bank population is currently 8.5 years. The age profile for all (flooded and VRLA type) batteries is shown in Figure 9.22.

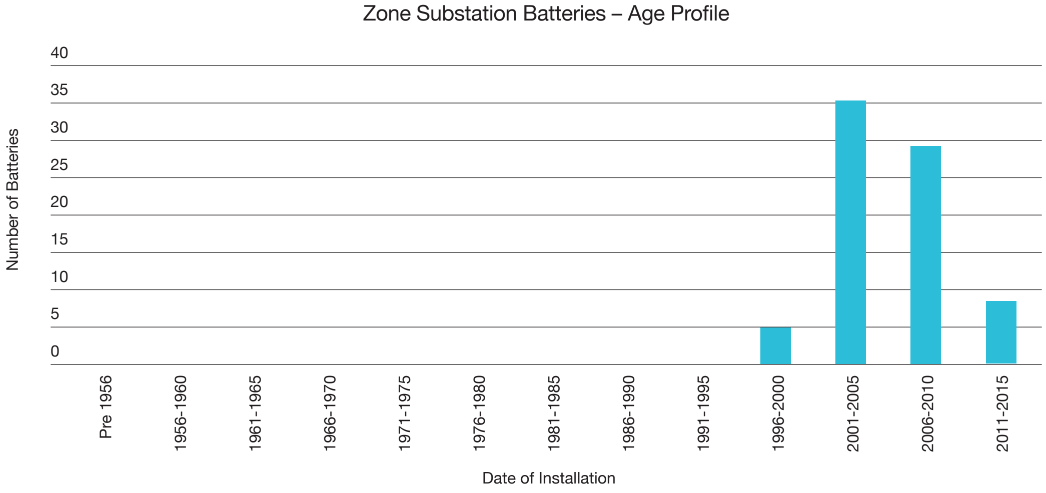


Figure 9.22 Zone Substation Battery Age Profile

The average age of JEN's battery charger population is currently 14 years. The battery charger age profile is shown in Figure 9.23.

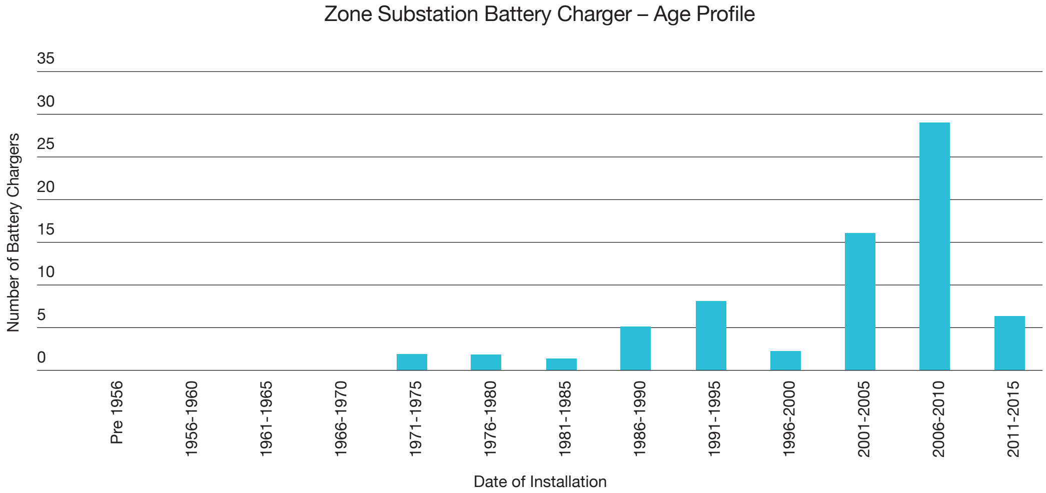


Figure 9.23 Zone Substation Battery Charger Age Profile

Although adequate spares are held for flooded (LAPP) batteries and chargers, spares for VRLA batteries are to be procured and held in stock.

9.25.2 Inspection and Testing

Inspection and testing is performed within the routine maintenance programme.

9.25.3 Asset Failure Risk

The major risks associated with a zone substation DC supply system failure are:

- Battery rupture and associated acid spill;
- Loss of protection, control and communications functionality; and
- Inability to automatically trip high voltage circuit breakers and isolate network faults.

The consequences of not isolating network faults includes widespread supply interruptions, significant damage to high voltage plant and equipment, possible bushfire initiation and increased risk to the health and safety of both operating personnel and the general public.

9.25.4 Integrity Issues

The following are issues relating to the ongoing reliable operation of zone substation DC supply systems.

- Non-redundant DC systems at most substations;
- Diversity of equipment from various suppliers;
- Inadequate spare VRLA batteries; and
- Inadequate record keeping of maintenance test results.

9.25.5 Emerging Issues

No emerging issues are known.

9.25.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The zone substation DC supply system is critical to the safe and reliable operation of the network. Accordingly, the lifecycle management strategies applied to this group of assets centres around:

- Close, and in some cases continuous monitoring of asset condition and availability;
- Comprehensive preventative maintenance; and
- Conservative asset replacement strategies.

Planned Replacement

The critical nature of this type of equipment and the consequence of failure means that a conservative approach to asset replacement is taken as detailed below. The replacement strategy applied to zone substation DC supply systems is principally time based. The replacement policy is to replace at end of useful life, or earlier based upon condition.

DC chargers at Coburg North (CN), Footscray West (FW), Flemington (FT) and Preston (P) zone substations require replacement in the 2016-2020 period.

Preventative Maintenance

This strategy aims to minimise routine preventative maintenance as far as is practicable and maintenance intervals have been aligned with current industry standards. Maintenance requirements have been customised depending upon the battery type and/or battery charger technology. Once maintained, it is assumed that the DC supply system will perform reliably at least up until the time that it is next maintained.

If a particular type or family of battery / battery charger begins to exhibit symptoms of performance degradation, it is closely monitored. This may require an increase in the preventative maintenance frequency and possibly modifications to the standard maintenance tasks in order to address a specific issue or issues. Furthermore, if aged DC supply system equipment is not replaced at its nominated end of useful life, routine preventative maintenance cycles may also need to be reduced on a case by case basis.

Routine preventative maintenance is performed on a six and twelve-monthly cycle for batteries; and on a twelve-monthly cycle for battery chargers.

Corrective Maintenance (Defects)

Defects are defined as issues or problems that do not represent an immediate threat to the performance and/or intended operation of the DC supply equipment. While defects need to be addressed promptly, they are not necessarily urgent. Defects would typically be identified during routine preventative maintenance or opportunistic inspection. All defects are investigated in an effort to identify and understand the root cause or failure mode.

Corrective Maintenance (Faults and Emergency)

Faults are typically identified as a result of an investigation arising from some abnormal operation or lack of operation. They may also be identified during routine preventative maintenance or via some form of health condition monitoring with an alarm received in the Co-ordination Centre via SCADA.

Faults are addressed as a matter of urgency as they represent issues or problems that will or have affected the performance and/or intended operation of the DC supply system. Furthermore, the reliable operation of all equipment connected to the DC supply system including protection and control relays may be compromised. The fault is to be resolved and the affected equipment returned to service within a period not exceeding 24 hours.

This shall be achieved via either:

- Repair, or where there is not possible; or
- Replacement with a spare.

The faulted equipment is returned to the manufacturer for post failure analysis (if this option is available) and repaired wherever this is practical and economically prudent. If the faulty equipment cannot be repaired, then it is disposed of accordingly.

Like defects, all equipment faults shall be fully investigated in an effort to identify and understand the root cause or failure mode.

9.25.7 Asset Disposal

Currently when the batteries are retired or replaced, these are packed in accordance with procedure for packing and transportation as recommended by Jemena's recycling service provider. Batteries are then transported and disposed by recycling service provider. There are no specific asset disposal requirements for chargers.

9.26 Zone Substation Disconnectors and Buses

Please refer to document JEN PL 0041 for more detailed information on Zone Substation Disconnectors and Buses.

9.26.1 Asset Description

This group of assets refers to the outdoor air insulated bus systems and the associated disconnectors, isolators and earth switches. Typically in a zone substation that utilises outdoor type equipment, there are about 40 22kV and nine 66kV disconnectors. These are simple mechanical devices which can be repaired without significant delays providing that a replacement unit or spare parts are available.

A disconnector is capable of opening and closing a circuit (being operator dependent), in which negligible current is made or broken.

Disconnectors provide the physical and visible isolation of HV plant and feeders in zone substations. They are normally fitted with earth switches or earthing receptacles to facilitate the earthing of the isolated plant. In many older substations, 66kV line disconnectors rated at 800A were installed. These units can impose limits on 66kV line ratings. These are identified in the capital load growth planning process and where necessary, they are upgraded to 1250A to match modern line ratings. Many old disconnectors are no longer manufactured and therefore spares are no longer available.

Indoor air insulated type, 66kV buses are maintained at the same time as disconnectors, whereas outdoor buses are inspected and insulators washed using live line techniques. Maintenance work involves close inspection, checking of connections, and cleaning of insulators, earth switches, surge arresters and wall bushings. The maintenance of disconnectors includes disassembly, cleaning, lubricating, adjusting and functional testing.

Zone substation bus installations on the network date from 1956.

9.26.2 Inspection and Testing

This group of assets will be inspected as part of the monthly operational inspection. In addition, they will be inspected as part of the annual substation engineering audits.

Infra-red thermographic surveys covering all HV plant such as disconnectors, isolators, buses and associated connections, surge arresters and wall bushings shall be performed annually.

9.26.3 Asset Failure Risk

The major risks associated with disconnectors are related to failures due to high resistance connections and insulation breakdown.

9.26.4 Integrity Issues

There are no significant integrity issues associated with bus systems generally. There has been one incident of deterioration of a foundation supporting an outdoor bus but this is an isolated event.

Many old disconnectors are no longer manufactured and therefore spares are no longer available. High resistance connections are not uncommon in some families of older disconnectors. These are detected by the annual infra-red inspections of the outdoor bus systems. A replacement program is targeted at these poor performing families of disconnectors.

The ‘duo-roll’ type of 66kV disconnector has a history of high contact resistance and corrosion between the clevis and the blade (aluminium tube) and between the blade and beaver tail moving contact. These types of problems lead to overheating and eventually fail if left unattended.

ABB Isolators in zone substations have now been replaced. Although only one isolator with cracked porcelain has been found, there have been several failures in the distribution network. In each case throughout the distribution network, the porcelain insulator has broken and was either found to be hanging from the HV conductor tail, or in some circumstances has resulted in the isolator blade collapsing during field switching.

In addition to this recognised failure mode associated with the porcelain insulator, all ABB isolators installed within zone substations have an inferior latching mechanism which has a history of failure and is in need of replacement. The failure of the latch to keep the isolator closed could allow it to open during heavy loads or while carrying fault currents.

9.26.5 Emerging Issues

No emerging issues are known.

9.26.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

This plant is very reliable, uncomplicated equipment with minimal maintenance requirements. The lifecycle management strategy applied to this equipment comprises condition monitoring, preventative and corrective maintenance. The principal condition monitoring tool is thermal imaging and this is the major driver of the corrective maintenance activities. The preventative maintenance activities consist primarily of cleaning. The lifecycle management strategy also includes a planned replacement program based on age and condition. Modern zone substation design utilises indoor distribution equipment so the only outdoor equipment specified is for the 66kV bus.

Routine Preventative Maintenance

Routine preventative maintenance shall include cleaning, checking of contacts, spring tension and resistance measurement, lubrication and functional tests and is to be performed as part of an outage of the associated major plant items (e.g. bus, line, feeder, transformer).

Regular monthly inspections to identify defects and annual thermal surveys to detect high resistance connections of all plant and equipment will be scheduled in SAP. Any abnormalities identified either during inspection audits or during switching, should be reported, to assess asset performance and adjust maintenance intervals.

Corrective Maintenance

Corrective maintenance is performed to repair defects identified during in-service inspection or routine maintenance and by thermal surveys.

Refurbishment

Refurbishment of disconnectors shall be undertaken in situ where possible. If it is necessary to remove a disconnector from service to refurbish it in a workshop then consideration shall be given to its replacement.

Replacement Plan

Replacements are generally identified as part of the load growth capital planning review each year. At 66kV the most likely units to be replaced will be line disconnectors whose ratings impose limits on the associated line. At 22kV some transformer disconnectors may be inadequately rated for transformer cyclic or emergency ratings and will therefore be replaced. Units with recurrent defects are programmed for replacement. The age profile of this class of assets indicates that a large percentage of the population is approaching end of life. Projections based on modelling of the population indicate an increase in the rate of age related replacement. Approximately 59 disconnectors at Airport West (AW), Broadmeadows (BD) and Coburg North (CN) zone substations are forecast to be replaced in the 2016-2020 period.

9.26.7 Asset Disposal

There are no specific asset disposal requirements.

9.27 Zone Substation Protection and Control Systems

Please refer to document JEN PL 0021 for more detailed information on Zone Substation Protection and Control Systems.

9.27.1 Asset Description

Protection and control equipment (commonly referred to as secondary equipment) is installed within zone substations and is connected to both the instrument transformers for sensing current and voltage signals, and to switchgear and plant equipment for monitoring and control.

The secondary equipment is designed and configured to detect the presence of network faults and/or other abnormal operating conditions and to then automatically initiate action to either isolate the faulted network by the opening of appropriate circuit breakers, or to correct the abnormal operating condition by initiating some pre-defined control sequence.

The type of secondary equipment applied varies from simple time delayed over-current relays to more complex differential and distance protection schemes depending upon the primary asset being protected or controlled, the type of fault to be detected and other considerations such as speed of fault isolation.

There are approximately 250 unique models of main protection and control relays in service across the network with a total population of approximately 1,500 relays. This count excludes auxiliary relays and other ancillary secondary equipment such as trip relays and repeat relays that are commonly associated with the main protection and control scheme.

Approximately 35% of JEN's relay population is electro-mechanical technology. These relays were installed some 30 to 40+ years ago and were mostly imported from countries such as the United Kingdom with some being manufactured locally in Australia including some by the former State Electricity Commission of Victoria (SECV).

Given their age, very few remaining spare parts exist, however, as a result of recent relay replacement projects, some spares have become available for a number of relay models.

The remaining population (65%) comprises relays based upon electronic technologies, with approximately 14% being analogue electronic relays and 51% being digital or numerical electronic relays. The vast majority of these relays have been imported from the United States of America, United Kingdom and other European countries including Germany and France.

The average age of electro-mechanical type relays is 38 years with some relays now approaching 50 years of age as shown in Figure 9.24.

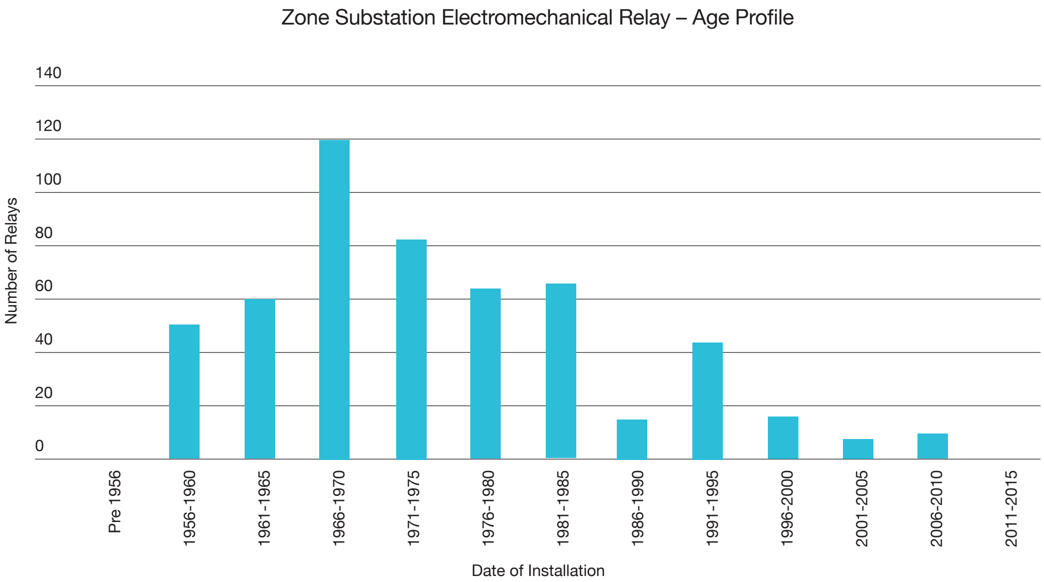


Figure 9.24 Electromechanical Relay Age Profile

The average age of analogue electronic type relays is currently 11 years while the average age of the new digital/numerical relays is only six years. Some of the earlier analogue electronic relays are now approaching 40 years of age as shown in Figure 9.25.

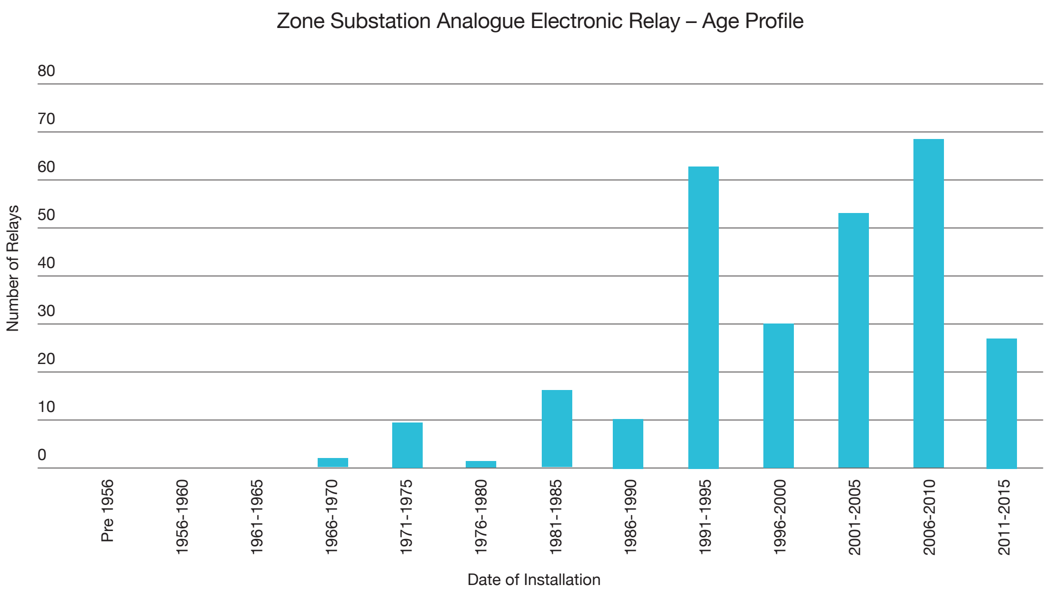


Figure 9.25 Electronic and Digital/Numerical Relay Age Profile

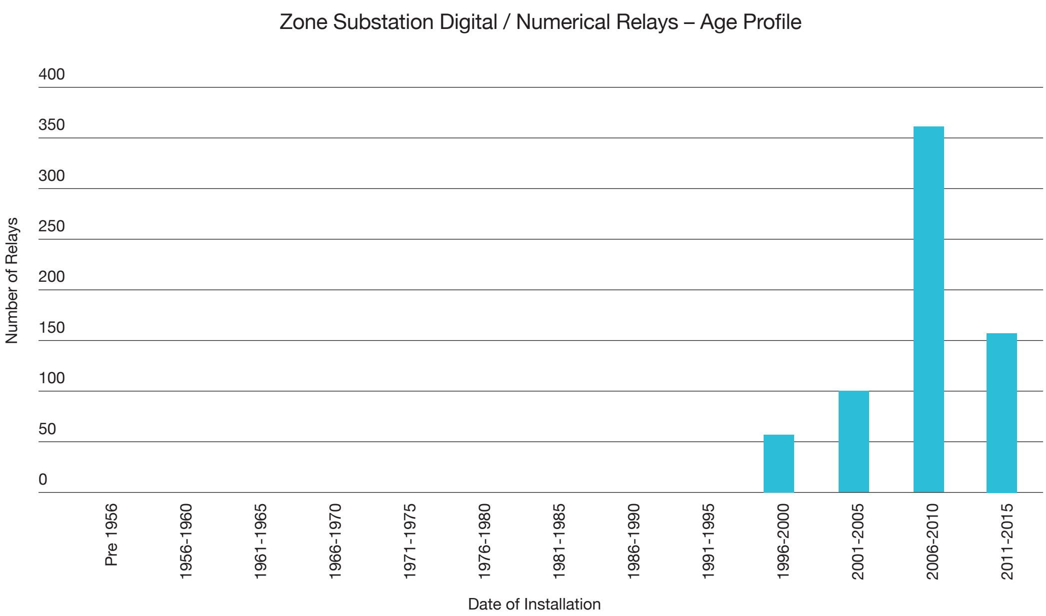


Figure 9.26 Zone Substation Digital / Numerical Relays - Age Profile

9.27.2 Inspection and Testing

Close, and in some cases continuous, monitoring is performed. Digital relays contain self-monitoring and provide alarms that are sent through the SCADA system (where the station contains suitable communications). Analogue relays are not monitored.

9.27.3 Asset Failure Risk

Protection schemes in particular are designed to detect the presence of faults or other abnormal operating conditions and to automatically isolate the faulted network by the opening of appropriate high voltage circuit breakers. Failure to isolate faults will invariably result in severe damage to high voltage apparatus and present a serious health and safety hazard to both operational personnel and the public.

9.27.4 Integrity Issues

Protection and control relays and other secondary equipment have traditionally been very reliable as demonstrated by extremely low failure rates. Ongoing monitoring of in service relay performance has not identified any significantly high failure rates within the useful life period of the relay's lifecycle. However, certain electro-mechanical and analogue electronic relay types are exhibiting performance issues most notably at or near their deemed useful life expectancy.

9.27.5 Emerging Issues

A significant percentage of JEN's relay population was installed in the 1960s and is nearing end of life. As a result, a considerable volume of relay replacement work is planned over the next five to ten year period. The risks associated with deferring any planned relay replacements must be closely monitored and continually reviewed so as to ensure that the reliable performance of the asset is not unduly compromised.

9.27.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Secondary systems are critical to the safe and reliable operation of the network. Contingency and redundancy is designed into the application of protection schemes such that all plausible faults are detectable by at least two separate and independent protection relays.

It is also required by regulations that all plausible network faults are to be isolated by automatic devices in the shortest possible time. Control and monitoring schemes are also very important for the safe, reliable and efficient operation of the network.

Accordingly, the lifecycle management strategies applied to this group of assets centre around:

- Close, and in some cases continuous, monitoring of asset condition and availability;
- Comprehensive preventative maintenance; and
- Conservative asset replacement strategies.

The total population of JEN's protection and control equipment has been grouped into three main relay types or technologies, namely electro-mechanical, analogue electronic and digital/numerical. As a result, the maintenance and replacement planning varies depending upon the technology. However, fundamentally the same lifecycle management strategy is adopted for all protection and control relays.

Replacement

The replacement plan has been optimised in an effort to smooth out the volume of work and therefore the capital expenditure profile over the next ten years without adversely affecting the risk profile of asset failure. In doing so, the replacement of some aged secondary equipment has been pushed out by a number of years while others have been brought forward.

A number of electro-mechanical relays have outlived their nominal life expectancy and are nearing 50 years of age. These relays have been targeted for replacement within the next five years. No allowance for additional maintenance has been included in this lifecycle management plan on the basis that the planned replacement proceeds as recommended.

Aged relays at Airport West (AW), Broadmeadows (BD), Braybrook (BY), Coburg North (CN), Footscray West (FW), North Heidelberg (NH) and Sunbury (SBY) are forecast to be replaced in the 2016-2020 period.

Preventative Maintenance

This strategy aims to minimise routine preventative maintenance as far as is practicable and maintenance intervals have been aligned with current industry standards. Maintenance requirements have been customised depending upon the relay type and other factors including the relay age profile.

Once maintained, it is assumed that the secondary equipment will perform reliably at least up until the time that it is next maintained.

If a particular type or family of relay begins to exhibit symptoms of performance degradation, that relay population will be more closely monitored. This may require an increase in the preventative maintenance frequency. The maintenance tasks may also be customised accordingly to address a specific issue or issues.

Routine preventative maintenance is to be performed at nominal eight-year intervals on electro-mechanical type relays, analogue electronic type relays, and on digital and numerical type relays.

Corrective Maintenance (Defects)

Secondary equipment defects are defined as issues or problems that do not represent an immediate threat to the performance and/or intended operation of the equipment. While defects need to be addressed promptly, they are not necessarily urgent. Defects would typically be identified during routine preventative maintenance. All secondary equipment defects shall be fully investigated in an effort to identify and understand the root cause or failure mode.

Reactive Maintenance (Faults and Emergency)

Secondary equipment faults are typically as a result of an investigation arising from some abnormal operation or lack of operation. They may also be identified during routine preventative maintenance or via some form of health condition monitoring with an alarm received in the Co-ordination Centre via SCADA.

Faults are addressed as a matter of urgency as they represent issues or problems that will affect or have affected the performance and/or intended operation of the equipment. The fault is to be rectified and the protection and control relay returned to service within a period not exceeding 24 hours.

Asset Spares

The availability of spare secondary equipment is a critical element of the effective management of the protection relay asset class. Spare equipment is required in the event of a defect or failure so as to re-instate full or part functionality of the secondary scheme in the shortest possible timeframe. This ensures the associated risks are minimised.

The recommended minimum and maximum number of secondary spares are to be maintained at all times

Given the critical role of protection systems, a comprehensive protection setting review is periodically required.

9.27.7 Asset Disposal

Electro-mechanical relays removed from service are held for as spares as required. There are no other specific asset disposal requirements.

9.27.8 Introduction of IEC 61850

The new IEC 61850 international standard for distribution substation is not just defining a new protocol, but also introducing abstract model of primary and secondary distribution substation equipment and communication equipment. Merging the communication capabilities of all IEDs in a substation can provide data gathering as well as remote control. Multiple IED sharing data or control commands results in eliminating much of the dedicated control wiring in a substation.

In early 2013, JEN approved the IEC 61850 Strategy and Roadmap which is a commitment to the use of IEC 61850 technology to enhance substation automation. Power utilities around the world are currently adopting IEC 61850 as standard protocol for substation automation due to the numerous benefits that this technology offers, namely:

- Interoperability between different vendor IED's;
- Reduced configuration costs;
- Simplified application development;

- Improved condition monitoring;
- Reduced wiring costs; and
- Installation of equipment to facilitate the smart grid landscape.

The IEC 61850 Strategy and Roadmap concludes that the adoption of this technology would require sufficient investment with skilling up internal workforce and amending technical standards and work practices before cost efficiencies would outweigh the additional implementation costs. This paper suggests that the IEC 61850 program is expected to break even (i.e. Cost efficiencies would exceed the value of implementation cost in present value terms) following the implementation of five zone substations.

9.27.9 Business Opportunities for Introduction of IEC 61850

JEN is currently expanding the network with two new zone substation constructions namely Broadmeadows South (BMS) and Tullamarine (TMA). JEN for the first time will be implementing IEC 61850 technology at these two zone substations which are expected to be commissioned in early 2015.

There are also condition based relay replacement projects planned in the 2016-2020 period. These projects provide an opportunity for the business to implement IEC 61850.

9.28 Zone Substation Transformers

Please refer to document JEN PL 0042 for more detailed information on Zone Substation Transformers.

9.28.1 Asset Description

JEN has a total of 25 zone substations equipped with power transformers. The age profile for zone transformers is shown in Figure 9.27. The total installed transformer capacity is approximately 1,550MVA. The major power transformers are fitted with voltage regulating equipment to maintain the required supply voltage under all loading conditions.

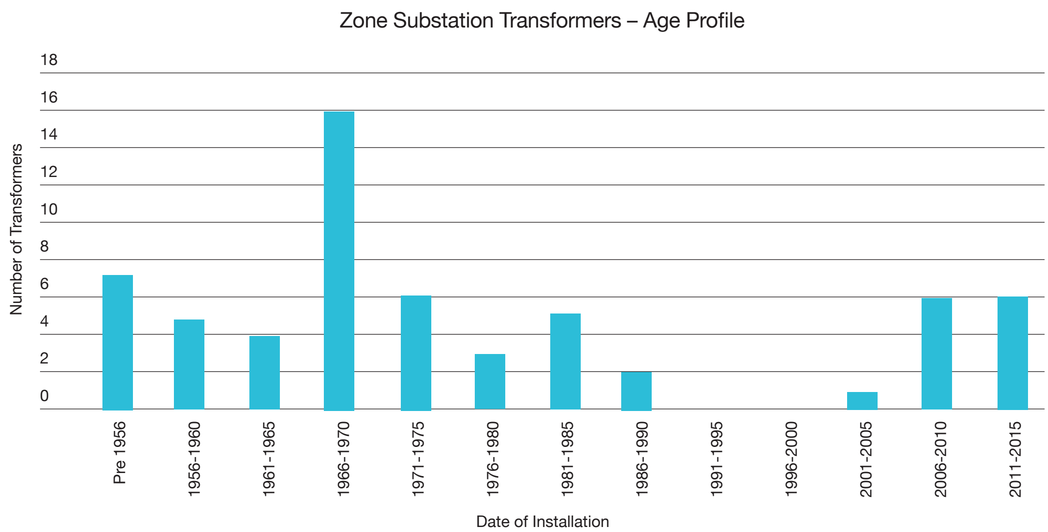


Figure 9.27 Zone Substation Transformer Profile

Zone substation transformers are critical elements in the distribution network because of their high replacement cost, their strategic impact on customer supply and their long lead time for repair or replacement.

An urban zone substation typically has two or three off 20/33MVA naturally cooled transformers with some transfer capacity between adjacent stations. Generally these types of transformers are also fitted with fans and pumps to increase their output capacity to 27MVA or 33MVA. In rural areas where customers are spread over a large area, smaller 10/16MVA transformers may be used.

Typically a three-transformer zone substation supplies between eight to twelve feeders and up to 30,000 residential customers.

The majority of transformers on the network operate at a primary voltage of 66kV and with secondary voltages of 22kV, 11kV or 6.6kV dependent on their geographical location. There remain a small number of transformers that operate with primary voltages of 22kV and secondary voltages of 11kV and 6.6kV and this is a reflection of the age of these assets.

There are currently 13 transformers in excess of 50 years of age. As the expected average life of a transformer is 55 years, the ageing condition of these transformers is being monitored.

9.28.2 Inspection and Testing

The monthly zone substation inspections conducted by operating personnel and annual engineering audits shall identify any obvious defects via visual inspection. Inspection activities include checking for general cleanliness, oil levels, signs of oil leak, corrosion of tank/cooler/conservator, tank distortion, broken porcelain, tracking on bushings and surge arresters, observing hot spot and top oil temperature indication, operation of auxiliary equipment such as the transformer cooling systems and any unusual noise.

The principal condition monitoring tools applied to the power transformers include:

- Annual oil sampling and testing that includes; dissolved gas analysis, physical and electrical properties, furan analysis, particle counts and moisture measurement;
- Age assessment using dielectric response measurement;
- Thermal imaging;
- DDF tests of high voltage bushings;
- Monitoring of the on-load tap changer operation counters;
- Monitoring of temperature alarms and load; and
- Monthly inspections.

The major contributor to the ageing of zone substation transformers is moisture content of the insulation system. Management of the moisture content extends the operational life of the transformer. Two on-line oil dryout units (Trojan) have been purchased to treat zone substation transformers with high moisture contents. The units are moved from transformer to transformer on an ongoing basis and over time effectively reduces moisture levels in the insulation systems of older transformers. This extends the life of the transformers by slowing the rate of ageing of the insulation systems and represents efficient trade- off between capex and opex. A program has been developed to deploy the Trojan systems on older transformers.

Furthermore, as the rate of ageing of a zone substation transformer is primarily determined by the moisture content in the insulation system, the ageing condition can be assessed by the Degree of Polymerisation (DP) of the cellulose material in the insulation system of the transformer. In order to assess the ageing condition, a new set of dielectric response measurements are being used to measure the moisture content in the insulation system and to estimate the DP of the paper insulation system. This is proposed to be carried out on older transformers to assist with the assessment of their ageing condition so that decisions can be made about replacement and or refurbishment of transformers.

In addition to the dielectric response measurements discussed above, a wider program of conventional electrical tests is being applied to ageing transformers to further assist with the assessment of the condition of the older transformers on the network.

9.28.3 Asset Failure Risk

Transformers are generally very reliable and risk of their failure is considered to be low. The major risk associated with transformer operation has been identified as personnel safety in the event of potential failures. As transformers age however the risk of failure increases. Tests on JEN's older transformers are indicating an increased risk of failure linked to the degradation of material properties.

9.28.4 Integrity Issues

The oldest of the transformers on the network date from 1949 (65 years old). Over the next five to ten years many of the transformers operating on the network will reach an age where assessments and decisions on age related retirement will need to be made. These decisions will be made based on condition assessments and are designed to balance the risk of failure against the deferral of capital expenditure.

These transformers are carefully monitored to assess the condition of the plant and managed to ensure that they are not subject to overloading. The primary insulation system used in the manufacture of power transformers consists of oil and paper. The condition of the paper insulation system is the principal indicator of the overall condition of the transformer. Paper ageing is an irreversible process and measures are taken to slow the rate at which paper ageing in transformers occurs. The major indicators of the condition of a transformer are the strength of the paper insulation, the moisture content of the insulation system and acidity of the oil in which it is immersed. There are a number of power transformers on the network that are ageing.

The condition and operating environment of the ageing transformer population is monitored closely and plans are being developed for their refurbishment and ultimate retirement and replacement.

Programs are in place to dry transformers using online equipment and oil reclamation/refurbishment programs are in place to address oil acidity and thus slow the degradation of the paper insulation system and thus extend the life of the transformers. In addition tests are undertaken on older transformer to determine the ageing condition of the paper insulation systems.

Transformer life extension through on-line moisture removal and oil reclamation or refurbishment has been successfully employed. This life extension work enables the deferral of replacement expenditure for as long as possible while maintaining the reliability availability and capacity of the transformation assets.

The risks associated with the ageing transformer population have highlighted the need for the development of a methodology for the estimation of transformer ‘End of Life’ based on asset condition. There has been some preliminary work done in this area. This has become increasingly important because there are a large number of transformers past their design life.

Noise

Power transformers at zone substations tend to generate more noise as they age due to the loss of core clamping pressures. In addition, at times of peak load additional noise can be generated by the operation of auxiliary cooling systems (fans and pumps). While new zone substations are constructed so that noise is kept within allowed limits, older substations may not comply and noise attenuation measures may be required. Such an example are the transformers at Fairfield (FF) zone substation.

Insulating Oil

Large volumes of insulating oil are contained in zone substation transformers. Zone substation power transformers vary in size but a typical oil volume in a new transformer is 18,000 litres.

Action has been taken to reduce the risk of the escape of this oil, particularly through the construction of bunds for all power transformers.

Minor leaks from power transformers at zone substations are not uncommon and a major loss of power transformer oil has not occurred in recent years however, a small possibility of loss of transformer oil from a zone substation remains. A major escape of oil from a zone substation could result in significant clean up costs and lead to prosecution by the Environment Protection Authority.

PCBs

All zone substation power transformers on the network have been tested for PCB contamination.
Four transformers have been found to contain low concentrations (non-scheduled) PCB contamination.

PCB contamination is defined as ‘scheduled’ (> 50 parts per million and 50 g PCB) or ‘non-scheduled’ (>2 and <50 parts per million).

9.28.5 Emerging Issues

There has been a number of 66kV transformer bushing failures across the Victorian Electricity Supply Industry over the past 15 years. Although none of the failures have occurred on JEN the population of bushings affected is common across Victoria. The condition of all transformer bushings is now monitored by a program of routine testing of the dielectric dissipation factor (DDF).

Rising fault levels are occurring in some areas of the network. In addition to traditional current limiting devices, neutral reactors, Rapid Earth Fault Current Limiter (REFCL) (resonant earthing) has been added to transformers to further reduce fault current in high exposure bushfire substations. In the period 2016-2020, REFCL devices are forecast to be required at Craigieburn (CBN), Coolaroo (COO), Sunbury (SBY) and Sydenham (SHM) zone substations.

9.28.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

Power transformers are the major plant item in any zone substation. They are expensive long lead time items of plant. In addition, a transformer is made up of discrete components such as the core and coils, cooling system, on-load tap changer and the high voltage bushings all of which have differing condition monitoring and maintenance needs. Consequently the lifecycle management strategy applied to this plant involves a comprehensive suite of condition monitoring activities, together with preventative maintenance programs, and corrective maintenance activities targeted at the various components of the transformer. Because of the value of the plant and the long lead times associated with its replacement, the lifecycle management strategy also includes life extension programs and an asset replacement program based on condition assessment.

The strategy also incorporates the specification of new plant with features designed to decrease the rate of ageing of the plant by reducing the exposure of the transformer oil to air borne moisture and oxygen and the specification of vacuum type on-load tap changers with little to no maintenance needs.

The strategy also includes the procurement of strategic spare transformers to mitigate the network risk associated with the ageing transformer population, the failure of a transformer and the long lead times for the supply of this type of plant.

Oil reclamation to reduce oil acidity levels and on-line dry out of transformer insulation systems presents an opportunity to slow the degradation of the paper insulation and extend the life of the transformers. Programs are being developed for the application of these techniques to selected transformers.

Modelling of transformer life based on age, loading history, and a number of condition measurements are being undertaken. This is used in conjunction with other drivers for replacement such as noise and network augmentation to assist with the prioritising and proactive forecasting of transformer replacement included in this plan.

The zone substation transformer asset class strategy includes time based inspections, condition based (operations or time) preventative maintenance, defect maintenance and condition monitoring to identify incipient faults, establish remnant life and the need for replacement or overhaul. Both corrective and preventative maintenance is applied to zone substation transformers and their ancillaries.

Preventative maintenance is performed on tap changers, including mechanisms, diverter and selector switches, based on the number of tapping operations, with an overriding time interval. Any defects or faults are repaired as and when they occur.

The asset class strategy adopted for transformers centres around close monitoring of asset condition, comprehensive preventative maintenance programs structured in accordance with Reliability Centred Maintenance (RCM) methodologies and asset life extension works. Where possible a comprehensive range of spare parts is kept for these assets.

Preventative Maintenance

Transformer and on load tap changers are scheduled for preventative maintenance based on their operational duty (number of tap changer operations) or by an overriding maximum time interval.

Condition Monitoring

A comprehensive condition monitoring regime is fundamental to the lifecycle management of zone substation transformers. The condition monitoring methodologies that are applied to transformers include; oil sampling and the electrical and chemical analysis of properties, dissolved gas analysis, infra-red thermal imaging and a range of diagnostic electrical tests, including inspection.

Replacement Plan

Programs are in place to assess the condition of older transformers. The replacement and retirement of transformers is driven by both the need for network augmentation and the need for replacement due to age and condition. In a number of locations these drivers align. Transformer retirements and replacements are planned at Essendon (ES), Heidelberg (HB), North Essendon (NS) and Fairfield (FF) in the 2016-2020 period. All of these transformers are in deteriorated ageing condition but this is not necessarily the single driver for these replacements and retirements. In addition the condition of the transformers at Newport (NT) are also being monitored as tests indicated deteriorated insulation systems.

The roof on transformer enclosures at Footscray West (FW) and Heidelberg (HB) also require replacement.

9.28.7 Asset Disposal

Transformers must be oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately. Transformers are disposed of through a recycling company.

9.29 PQ Systems

Please refer to document JEN PL 0022 for more detailed information on PQ Systems.

9.29.1 Asset Description

JEN has three separate power quality monitoring systems that continuously monitor the voltage supply at zone substation 6.6kV, 11kV and 22kV buses and at strategic 240/415V buses (end of feeder locations) within the distribution network. They are:

- Zone substation system using BMI 8010 power quality metering equipment;
- Zone substation system using ION 7650 power quality metering equipment; and
- End of feeder system using EDMI MK6 power quality metering equipment. The systems record the following information:
- Steady state rms voltage levels;
- Short duration voltage disturbances including sags, swell and transients;
- Voltage harmonics; and
- Voltage unbalance.

The systems are also programmed to capture voltage and current waveforms associated with any power quality excursion outside preset limits. These disturbance waveforms provide additional information which is particularly useful when analysing specific power quality disturbances in the network.

Each system comprises power quality meters permanently installed throughout the network. Within zone substations, the power quality meters monitor the network via suitably rated voltage and current transformers. Within end of feeder distribution substations, the power quality meters are connected directly to the low voltage network without the need for voltage transformers. Monitoring of load current is generally not implemented in end of feeder applications due to the limited availability of current transformers in distribution substations.

The power quality meters installed in zone substations consist of 13 ION 7650 PQ Meters and 15 BMI 8010 PQ Meters. The power quality meters installed in Distribution Substations (End of Feeder) consist of 24 EDMI MK6 PQ Meters.

The average age of JEN's power quality meter population is as shown below:

- ION 7650 PQM: average age is 10 years.
- BMI 8010 PQM: average age is 12 years.
- EDMI MK6 PQM: average age is 10 years.

9.29.2 Inspection and Testing

The integrity of a power quality meter is assessed through the daily communication check process. No other routine inspection or testing is performed.

9.29.3 Asset Failure Risk

The major risk associated with the failure of any power quality monitoring system is regulatory non-compliance.

9.29.4 Integrity Issues

Power quality metering equipment has traditionally been very reliable as demonstrated by extremely low failure rates.

However, there has been a significant number of communication related performance issues experienced over the past ten years. On average, upwards of six or more dial-up modem communication failures are experienced annually. The failure modes are defined below:

- Modem lock up requiring a power down/up cycle to reset;
- Modem failure requiring replacement;
- Telstra phone line damage e.g. due to third party damage;
- Modems left unplugged by field staff working on site;
- Telstra 4G SIM cards faulty and/or disabled by mobile phone communications service provider; and
- Other failures within the PSTN and GSM networks.

There are a number of current issues relating to the ongoing reliable operation of the power quality monitoring system. These are listed below:

- Reliability of dial-up modem communications;
- Database management including trimming and archiving of data;
- Obsolescence of BMI 8010 meter; and
- EDMI MK6 meter has limited functionality to analyse power quality data.

9.29.5 Emerging Issues

A routine maintenance policy is now recommended for these meters to ensure they remain in reliable service. A maintenance frequency of five years is recommended for those power quality meters that rely upon a sealed lead acid battery for backup power supply in the event of loss of AC mains supply i.e. BMI 8010 type meters installed within zone substations.

The maintenance frequency recommended for all other power quality meters is eight years.

9.29.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The lifecycle management strategies applied to this group of assets centre around:

- Close monitoring of asset condition and availability;
- Comprehensive preventative maintenance;

- Availability of spare equipment; and
- Conservative asset replacement strategy.

Planned Replacement

The replacement strategy applied to zone substation and strategic end of feeder power quality meters is principally time based. The replacement policy is to replace at end of useful life, or earlier based upon deteriorating performance. Replacements of power quality meters are planned for North Heidelberg (NH), Somerton (ST) and Tottenham (TH) zone substations in the 2016-2020 period.

Preventative Maintenance

This strategy aims to minimise routine preventative maintenance as far as is practicable and maintenance intervals have been aligned with current industry standards. Once maintained, it is assumed that the power quality metering equipment will continue to perform reliability at least up until the time that it is next maintained.

Corrective Maintenance (Defects)

Defects are defined as issues or problems that do not represent an immediate threat to the performance and/or intended operation of the power quality metering equipment. While defects need to be addressed promptly, they are not necessarily urgent. Defects would typically be identified during routine preventative maintenance.

All defects shall be fully investigated in an effort to identify and understand the root cause or failure mode. All details shall be captured in the defects database for future analysis and trending.

Reactive Maintenance (Faults and Emergency)

Faults are typically as a result of an investigation arising from some abnormal operation or lack of operation. They may also be identified during routine preventative maintenance. Faults must be addressed as a matter of urgency as they represent issues or problems that will or have affected the performance and/ or intended operation of the power quality metering equipment.

The fault shall be resolved and the power quality meter returned to service within a period not exceeding 24 hours. This shall be achieved via either:

- Repair, or where this is not possible; or
- Replacement with a spare.

The availability of spares is a critical element of this lifecycle management plan.

9.29.7 Asset Disposal

There are no specific asset disposal requirements.

9.30 Electricity Metering

Please refer to document JEN PL 0045 for more detailed information on Electricity Metering.

9.30.1 Asset Description

JEN operates electricity meters as part of its asset base. Metering assets and their classification is as specified in Table 9.9 below. There are currently more than 320,000 LV meters installed in the network. These assets are relatively low cost items individually, but as an asset class, they represent a significant investment. Each customer installation has a meter installation to record their consumption of electricity. This data is gathered by interval meters except for a small number of accumulation meters which are gradually being replaced. Interval meters record usage in 30-minute intervals. Accumulation meters only keep track of the total accumulated electricity usage.

JEN is an accredited Meter Provider and Metering Data Provider for Type 5 and 6[1] metering installations. In addition, JEN as a Local Network Service Provider (LNSP) has an obligation under the NER to provide metering to all customers with annual consumption energy of less than 160MWh.

JEN also maintains and operates the cross-boundary HV metering installations within its zone substations, in accordance with the NER.

Advanced Interval Meter Rollout

In July 2005, the Victorian Government together with the Victorian Electricity Distribution Businesses and a range of electricity retailers commissioned a study on Enhanced Interval Meter Communications. This study assessed the costs and benefits of adding remote communications to the interval metering rollout program (IMRO) and concluded that there was a positive business case for not only adding communications to interval meters but also accelerating the rollout.

The Victorian Government in conjunction with the industry and the Essential Services Commission (ESC) facilitated the development of a set of minimum functionality requirements that were mandated across distribution businesses.

JEN started the rollout of Advanced Metering Infrastructure (AMI) in 2009 and this project officially came to a close at the end of June 2014. The smart meter rollout of five years involved the meter exchange for more than 320,000 customers on the Jemena Electricity Network.

Jemena's smart meter network negates the necessity of manual meter reads through remote meter readings, thereby reducing estimated meter reads to a minimum. JEN customers have the benefits of being able to arrange remote reconnections and disconnections and have access to their real time usage data through Australia's first online electricity usage portal, the Jemena Electricity Outlook Portal.

1 Types of metering installations are defined in Chapter 7 of NER. These mainly relate to annual energy throughput through the connection points. In VIC the Type 5 & 6 metering installations refers to connection points with annual consumption of energy less than 160MWh.

JEN Metering Assets

Asset Categories	Assets	Years	Units	Expected Life
Electricity Meters	AMI Meters – Direct Connected Single Phase	2009 - Current	288,975	15 years
	AMI Meters – Direct Connected Three Phase	2009 - Current	32,330	15 years
	AMI Meters – LV CT Connected Three Phase	2009 - Current	307	15 years
	Legacy Meters – Single Phase	1975 - 2012	4,699	15 years
	Legacy Meters – Three Phase	1975 - 2012	2,389	15 years
	HV Meters	1992 - 2012	15	15 years
Meter Communication Assets	AMI Communication Devices – Access Points	2009 - Current	90	15 years
	AMI Communication Devices – Relays	2009 - Current	346	15 years
	AMI Communication Devices – Battery Packs	2009 - Current	436	5 years
Instrument Transformers	Instrument Transformers – LV CTs	1975 - Current	5,175	30 years
	Instrument Transformers – HV CTs	1975 - Current	45	30 years
	Instrument Transformers – VTs	1975 - Current	15	30 years

Table 9.9 JEN Metering Asset Volumes

Notes:

1) Backend systems are explained in the JEN IT Asset Management Plan 2016-20.
2) AMI local meter reading tools, software and antennas are managed with the metering assets and are not separately listed in the table above.
3) HV Meter Communication Devices are managed with HV meters as they are integral part of the meters and are not separately listed in the table above.

The following figures present the annual number of installations of various assets of AMI meters since 2009.

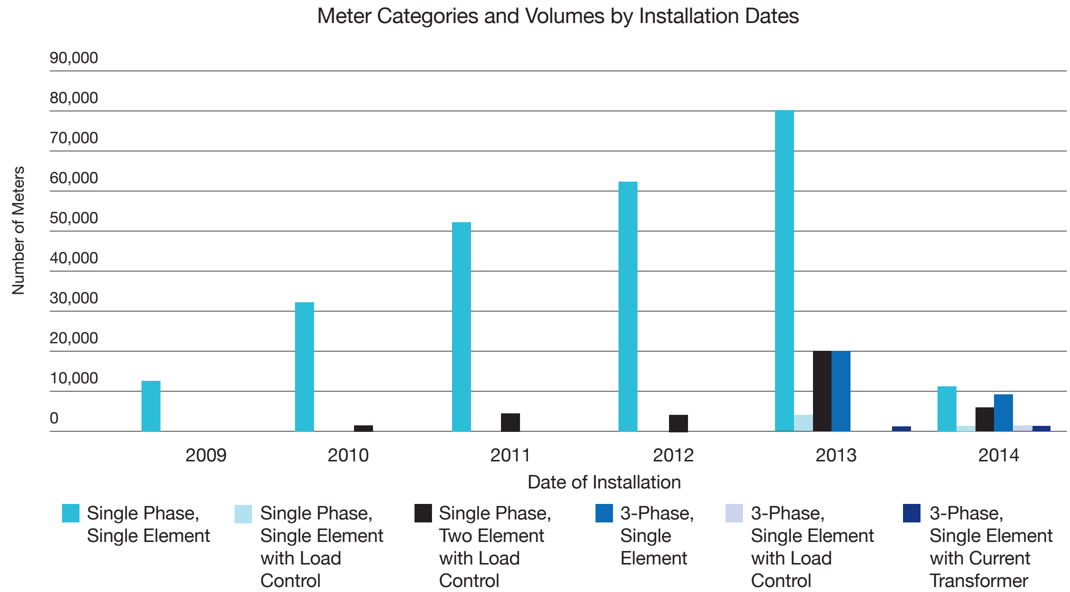


Figure 9.28 Meters volumes by installation dates and meter categories

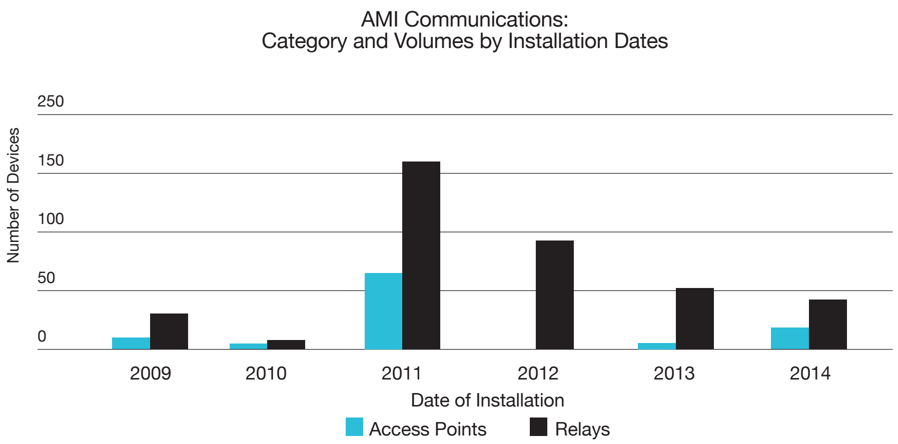


Figure 9.29 AMI Communication: category and volumes by installation dates

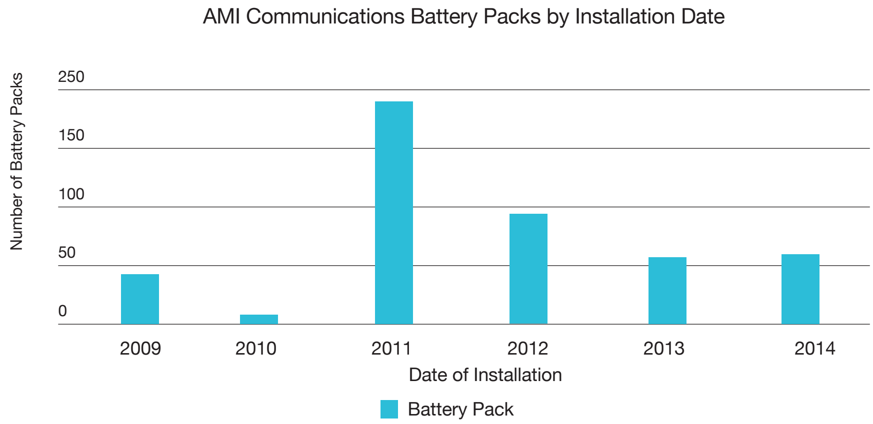


Figure 9.30 AMI Communications battery packs by installation date

9.30.2 Inspection and Testing

JEN undertakes inspection and testing of the metering assets in accordance with its Metering Asset Management Strategy and Plan approved by AEMO. This plan sets out the program for meter asset inspection, testing and replacement based on meter condition and performance. JEN's maintenance programs are reviewed annually in light of changes to product offerings, historic asset performance, changes to policies and regulatory requirements. Any changes to the Metering Asset Strategy or Plan will trigger the resubmission to AEMO for re-approval.

The testing and inspection of Type 2 to 4 metering installations shall be carried out in accordance with the requirements of chapter 7 of the 'National Electricity Rules'. It should be noted that there are no Type 1 metering installations on the JEN network.

Work undertaken as part of the maintenance plan is predominantly the routine inspection and testing of metering and current transformer installations together with maintenance of metering equipment in response to regulatory obligations set out under the NER. Any meter family that is found to be non-compliant is either recalibrated or retired.

The plan lays out the requirements for the sampling and testing of the different classes of meters and instrument transformers and covers the following areas:

- Type Testing / Pattern Approval;
- Pre-Installation Testing;
- Meter Installation Inspections;

- Direct Connected Meter Sample Testing;
- HV and LV CT Connected Meter Testing;
- LV CT Sample Testing; and
- HV CT & VT Testing.

Type Testing / Pattern Approval

Jemena ensures that all new meter types conform to the relevant codes and specifications and that no new metering equipment is installed unless appropriate type tests and pattern approvals have been reviewed and accepted.

All new metering equipment purchased has National Measurements Institute's Pattern Approval from an accredited laboratory recognised under the International Certification Scheme under the 'National Measurements Act'. Relevant approval certificates and type testing results as per Australian Standards are procured from meter and communication vendors and are maintained within JEN.

Pre-Installation Testing

Jemena ensures that all metering equipment has been tested to an appropriate standard before installation and is fit for purpose.

The requirement is that an accuracy test shall be performed on all new metering equipment to ascertain whether the new equipment meets the relevant minimum standards either:

- Prior to installation, on each individual active energy meter, reactive energy meter, current transformer and voltage transformer; or
- At the time of commissioning, on the installed metering equipment.

Metering Installation Inspections

Jemena ensures that all metering installations are inspected in accordance with the requirements of Schedule 7.3 of the NER. As per the requirement all Type 2 and 3 CT and VT connected HV metering installations are inspected every two and a half years. All Type 4, 5 and 6 meters are inspected at the time they are tested.

An inspection includes checking of all seals, comparison of pulse counts, comparison of direct reading meters, verification of metering parameters and physical connections and CT ratios and connections.

Direct Connected Meter Sample Testing

Jemena tests direct connected meters in accordance with AS1284.13 - Electricity Metering, In-Service Compliance Testing. For this purpose, direct connected meters are sampled and tested based on representative families or populations of meters. Meters are grouped into populations based upon meter manufacturer and meter design or pattern or type. Sample sizes are determined in accordance with Standard AS/NZS 1284.13 for testing by variables. Pass and fail levels are in accordance with the Standard. Each meter in a sample is tested for accuracy and register operation.

In the event that a sample of meters are deemed to have failed further analysis of the population is conducted to determine if sub populations can be identified and whether meter replacement programs can focus on only the defective population.

The populations of new meter patterns or types are sampled and tested for compliance during the first one to three years of being placed in service to determine the compliance period for that meter population. This is kept in accordance with Table 4 of AS/NZS 1284.13.

HV and LV CT Connected Meter Testing

Jemena tests all HV and LV CT connected meters as per Schedule 7.2 and 7.3 of the National Electricity Rules. These installations are associated with large energy consumption and therefore should not be sample tested.

JEN owned wholesale boundary Type 2 and 3 HV meters and Type 4 to 6 LV CT meters are tested in accordance with the requirements of this section. HV meters are located within JEN owned and operated zone substations.

These meters are tested using a full range accuracy test at least once every five years. In addition, burden tests are undertaken at these installations whenever the meters are tested or when changes are made to the installations.

The maximum allowable level of testing uncertainty for meters is as per Table S7.3.1 of Chapter 7 of the NER. All reference / calibrated test equipment are tested to ensure full tractability to Australian National Measurements Standards through verifying authorities or directly referenced to the National Measurement Laboratory.

LV CT Sample Testing

The Schedule 7.3 of the National Electricity Rules requires the CTs to be tested every 10 years or as per an alternative testing period and method acceptable by AEMO. AEMO in conjunction with the industry has developed a guideline known as ‘Alternative Testing Minimum Requirements: Low Voltage Current Transformer Metering Installations’.

These Requirements are established to facilitate clause S7.3.1(c)(2) of the Rules and outline the obligations, technical requirements, measurement process and performance requirements that are to be performed, administered and maintained by a responsible person.

JEN has developed a sampling testing plan for current transformers in accordance with the above requirements.

HV CT & VT Testing

The aim is to test all HV CTs and VTs as per Schedule 7.2 and 7.3 of the National Electricity Rules. High voltage installations are classified as high risk due to the large energy consumption involved.

The Rules require all HV Instrument Transformers to be tested every 10 years. Consequently, JEN’s asset management strategy commits the testing of HV CTs and VTs as per the requirements of the Rules. These requirements are stated within JEN’s asset management strategy approved by AEMO.

9.30.3 Asset Failure Risk

The failure of the metering assets is either the catastrophic failure of the metering installation or where the accuracy requirements are not in accordance to the NER. Normally, discovery of the metering installation failures are achieved by the following methods:

- Sample testing of metering installations in accordance to Metrology Procedure and the approved Asset Management Plan by AEMO; and
- Failure detection by customer complaints and active monitoring of AMI meter status information.

Where the large family failure of the meters is found, Jemena liaises with AEMO to ensure the proposed replacement program can be accepted by AEMO.

Over the life cycle of the metering assets, JEN expects the risk profile of the system to change. Consequently, there will be a need to update the risk assessment periodically to keep the risk evaluation, controls and / or mitigations current.

The risk categories JEN associates with asset failures are:

- Development – Residual Design Risks;
- Operations and Maintenance Risks; and
- Installation Risk.

9.30.4 Integrity Issues

Despite Jemena's efforts to replace all legacy meters with AMI meters, due to customer refusals, Jemena has over 7,000 legacy meters remaining on its network. These meters are electromechanical devices that utilise magnetic bearings and consequently deliver long operational lives. They were accumulation type meters. The failure mode for these meters relates to the weakening of the breaking magnets over time, which results in the meters running faster as they get older and consequently they reach a stage when they exceed the error limits allowed in the applicable regulatory metrology requirements.

The new AMI meters use semiconductor-based digital processor technology, which do not have the same operational history and there have been examples of premature failure of these devices. Increased complexity, network connectivity and cross-integration with backend systems impose further risks on the integrity of the metering system and collected data security.

9.30.5 Emerging Issues

Since most of the JEN metering assets are now AMI meters, which are heavily integrated with IT infrastructure and communication technologies, new types of issues and risks are now considered by JEN. These include:

- Changing landscape of cyber security threat levels and its impact on network connected systems;
- Metering contestability's impact on business continuity and resilience;
- Access management to meter data (open access) and associated consumer privacy; and
- Continuously evolving regulations and standards.

9.30.6 Key Management Strategies (Reactive Plan, Maintenance Plan, Replacement Plan)

The Asset Class Strategy (ACS) and Asset Management Plan has been developed to provide a systematic approach to the planning of programs which are intended to ensure that the condition and performance of metering infrastructure and assets are being efficiently maintained to satisfy regulatory compliance obligations and JEN stakeholders' requirements. These include:

- Maintenance of existing assets;
- Development of new assets; and
- Providing an effective and efficient metering service to JEN's customers.

The ACS also covers the maintenance and replacement requirements which are intended to maintain the operating capability of the system over the long term.

Procurement

All new meters shall be purchased with pattern approval in accordance with the requirements of the National Standards Commission via the 'National Measurements Act' as referenced in the 'Electricity Customers Metering Code' and the 'National Electricity Rules' (NER). Copies of approvals and associated type tests shall be provided with the first of any new meter population delivered and maintained in accordance with the NER.

All instrument transformers purchased are to be in accordance with relevant Australian Standards.

Replacement

The asset replacement program allows for the replacement of obsolete or otherwise inappropriate meters and associated equipment. Equipment that is identified as not complying with the NER is brought up to necessary standard as required.

Asset replacement or re-calibration of Type 2, 3 and 4 instrument transformer connected metering installations shall be carried out on an individual basis based on the results of the test and inspection programs.

Meter Replacement – Planned

This asset replacement program is established to replace meters for customers with annual consumption of energy of less than 160MWh, which are no longer compliant in terms of accuracy or functionality. Sample testing of these meters is undertaken based on AS1284.13. This Standard sets out the pass-fail requirements and sample sizes for individual meter families. The meter population has been divided into meter families based on manufacturer, type and year of manufacture. Non-compliant meter families are scheduled for replacement in accordance with this program.

Meter Replacement – Unplanned

This asset replacement program is established to allow faulty meters to be replaced as reported by the customer or discovered through AMI back-end systems on an ad hoc basis.

The approach taken for meter replacement is dependent upon meter type. Type 2, 3 and 4 meters (CT and VT connected meters) are replaced on an individual basis based on the results of the inspection and testing programs. For Type 2-6 metering installations, should the replacement of the faulty metering installations not be achieved within the required time, as prescribed under the NER, an exemption is applied as per AEMO's exemption procedure.

The performance of each meter or instrument transformer is assessed and replacement or re-calibration is programmed according to the test results and the age and condition of the meter.

9.30.7 Asset Disposal

All meters and associated equipment are assessed and reused where appropriate. Metering equipment that is not capable of being reused is recycled and/or disposed of as per the approved asset replacement program.

10 List of Abbreviations

AAC	All Aluminium Conductor
ABC	Aerial Bundled Conductor
ACR	Automatic Circuit Recloser
ACSR	Aluminium Conductor Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARMC	Audit and Risk Management Committee
ALARP	As Low As Reasonably Practicable
AMA	Asset Management Agreement
AMC	Asset Management Committee
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plan
AO	Asset Owner
AS/NZS	Australian Standard/New Zealand Standard
AVR	Automatic Voltage Regulators
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CBRM	Condition Based Risk Management
CC	Covered Conductors
CCA	Copper Chrome Arsenate
CCT	Circuit
CFC	Construction Forecasting Council
CFL	Compact Fluorescent Lamps
CIS	Customer Information System
CMEN	Common Multiple Earthed Neutral
CoC	Coordination Centre
COWP	Capital and Operating Work Plan
CRA	Charles River Associates
CRO	Caution Re Operating
DAPR	Distribution Annual Planning Report
DB	Distribution Business
DBYD	Dial Before You Dig
DC	Direct Current
DCF	Discounted Cash Flow
DDF	Dielectric Dissipation Factor
DFA	Delegations of Financial Authority
DINIS	Distribution Network Information System

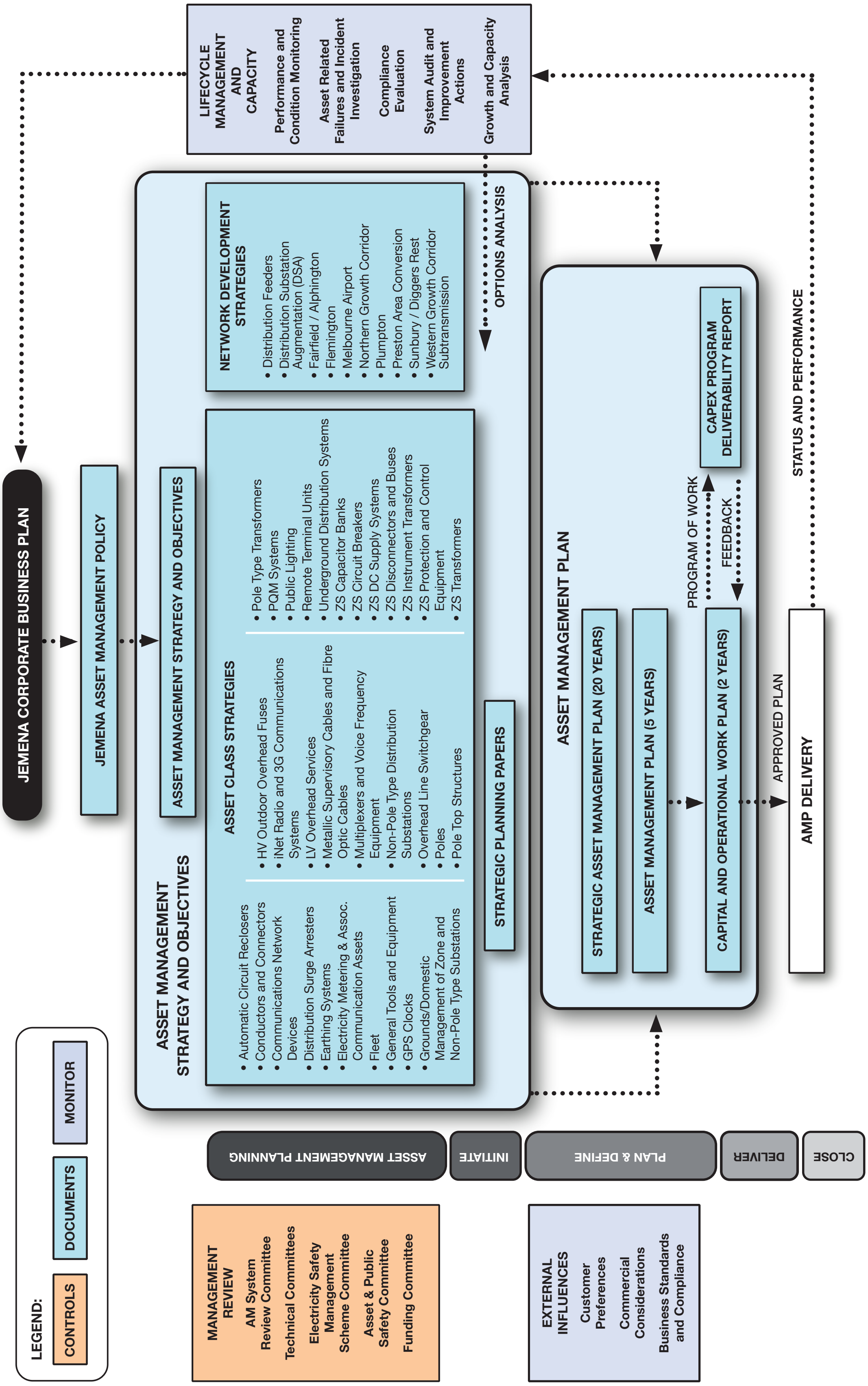
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DP	Degree of Polymerisation
DSE	Department of Sustainability and Environment, Victoria
DUOS	Distribution Use Of System
EBS	Enterprise Business Services
ECMS	Electronic Content Management System
EDMS	Electronic Document Management System
EDO	Expulsion Drop Out
EDPR	Electricity Distribution Price Determination
EE@R	Expected Energy at Risk
EMF	Electric and Magnetic Fields
ENA	Energy Networks Association
EPA	Environment Protection Authority
ESELC	Electricity Safety (Electric Line Clearance) Regulations
ESMP	Electricity Safety Management Plans
ESMS	Electricity Safety Management Schemes
ESV	Energy Safe Victoria
EWOV	Energy and Water Ombudsman Victoria
EWP	Elevated Work Platform
FMECA	Failure Mode Effects and Criticality Analysis
GHGE	Green House Gas Emissions
GIS	Geographical Information System
GSL	Guaranteed Service Level
GWh	Gigawatt hour
HBRA	Hazardous Bushfire Risk Area
HPS	High Pressure Sodium
HSEQ	Health, Safety, Environment and Quality
HV	High Voltage
ISO	International Organization for Standardization
IS	Information Services
JEN	Jemena Electricity Networks (Vic) Ltd
kA	kilo Amps
kV	kilo Volts
LAPP	Lead Acid Pasted Plate
LBRA	Low Bushfire Risk Area
LCMP	Life Cycle Management Plan
LCTA	Least Cost, Technically Acceptable
LNSP	Local Network Service Provider
LTNPQS	Long Term National Power Quality Survey

LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MEC	Major Electricity Company
MM	Materials Management
MV	Mercury Vapour
MVA	Mega Volt Ampere
MW	Mega Watt
NMI	National Meter Identifier
NEM	National Electricity Market
NER	National Electricity Rules
NGERS	National Greenhouse and Energy Reporting System
NIEIR	National Institute of Economics and Industry Research
OFAF	Oil Forced/Air Forced
OLTC	On Load Tap Changer
ONAF	Oil Natural/Air Forced
ONAN	Oil Natural/Air Natural
OPEX	Operating Expenditure
PAS	Publicly Available Specification
PCB	Polychlorinated Biphenyl
PM	Plant Maintenance
PM Order	Plant Maintenance Order
POEL	Private Overhead Electric Lines
POW	Program of Work
PQ	Power Quality
PSSE	Power System Simulator for Engineering
PSTN	Public Switched Telephone Network
RCM	Reliability Centred Maintenance
REALM	Risk Evaluation and Loss Method
RIT-D	Regulatory Investment Test – Distribution
RMC	Risk Management Committee
RTU	Remote Telemetry Units
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Works Management System
SCADA	Supervisory, Control and Data Acquisition
SECV	State Electricity Commission of Victoria
SF_6	Sulphur Hexafluoride
SGSPAA	State Grid Singapore Power Australian Assets Pty Ltd
SIM	Substation Inspection Manual
SNMP	Simple Network Management Protocol

STPIS	Service Target Performance Incentive Scheme
SUPS	Substation Utilisation and Profiling
SWER	Single Wire Earth Return
TEV	Transient Earth Voltages
URD	Underground Residential Development
VCR	Value of Customer Reliability
VEDN	Victorian Electricity Distribution Networks
VESI	Victorian Electricity Supply Industry
XLPE	Cross-linked Polyethylene
ZS	Zone Substation

11 Appendices

Appendix A – Document Map – From Planning to Delivery



Appendix B – Summary of Strategy

Key Documents

Regulation

Electricity Safety Act 1998 Version No. 061, January 2012

Electricity Industry Act 2000, Version No.060, March 2011

Electricity Distribution Code, Version No.6, January 2011

Electricity Safety (Electric Line Clearance) Regulations 2010, Version No.001, June 2010

Electricity Safety (Installations) Regulations 2009 Version No. 004, August 2011

Electricity Safety (Management) Regulations 2009 Version No. 001, December 2009

Electricity Safety (Bushfire Mitigation) Regulations 2003 Version No.003, October 2010

Public Lighting Code (ESC), April 2005

Policy and Procedures

JEN MA 0006	Distribution Construction Manual
JEN MA 0002	Electricity Service Lines Inspection and Maintenance Manual, March 2008
JAA MA 0050	Group Risk Management Manual
JEN MA 0500	Jemena Electricity Networks Asset Inspection Manual, July 2012
JEN PR 0107	Jemena Electricity Networks Customer Capital Forecasting Procedure, May 2013
JEN MA 0695	Jemena Electricity Networks Enclosed Distribution Substation Inspection Manual, August 2012
JEN GU 0006	Jemena Electricity Networks Operational Reliability Committee Charter, June 2009
JEN MA 0010	Jemena Planning Manual, March 2013
JEN RIS 0001	JEN Risk Management Policy
JEN MA 0005	Overhead Line Design Manual, March 2013
JEM PO 0600	Scrap Materials Policy
JEN ST 0610	Zone Substation Primary Design Standard, April 2014
JEN ST 0600	Zone Substation Secondary Design Standard, February 2012

Papers and Plans

ELE PL 0021	Adopting Fault Current Limiter Technology to Reduce the Risk of Bushfire Ignition Strategic Planning Paper
ELE PL 0032	AMI Benefits Realisation – Outage Management Strategic Planning Paper
ELE PL 0034	AMI Benefits Realisation – Supply Monitoring Strategic Planning Paper
ELE PL 0003	Bushfire Mitigation Strategic Plan 2016-2020
ELE PL 0005	Capital and Operational Work Plan 2016-2020
	Demand Forecasts – Expert Consultant Report
ELE PL 0033	Demand Management Innovation Allowance – Program and Proposals Strategic Planning Paper
ELE PL 0017	Distribution Substation Augmentation Strategic Planning Paper
ELE PL 0016	Electric Line Clearance Engineering Solutions Strategic Planning Paper
ELE PL 0002	Electric Line Clearance Strategic Plan 2016-2020
	Emergency Management Reference Manual, December 2013

ELE PL 0020	Environmental, Safety and Legal (ES&L) Programs Strategic Planning Paper
JEM ST 0051	Fleet Management Strategy
JEN ST 0105	General Tools and Equipment Management Strategy
ELE PL 0052	HV Installation Replacement Program – Enclosed Switches Strategic Planning Paper
ELE PL 0053	HV Installation Replacement Program – Overhead Switches Strategic Planning Paper
ELE PL 0018	HV Installation Replacement Program – Transformer Platform Height Rectification Strategic Planning Paper
	JEN EDPR16 Delivery Plan
	Jemena Electricity Networks Distribution Annual Planning Report, 2014
ELE PL 0051	JEN IT Asset Management Plan 2016-2020
JEN PR 0900	Jemena Electricity Networks Safety Management Scheme – Synopsis
JEN PR 0507	Load Demand Forecast Procedure
ELE PL 0014	LV Mains Removal in the HBRA Strategic Planning Paper
ELE PR 0012	Network Asset Useful Lives Procedure
JEN PR 0007	Network Augmentation Planning Criteria Procedure
ELE PL 0010	Non-Preferred Service Replacement Strategic Planning Paper
ELE PL 0011	Pole Replacement and Reinforcement Strategic Planning Paper
ELE PL 0015	Pole Top Fire Mitigation Strategic Planning Paper
ELE PL 0012	Pole Top Structure Replacement Strategic Planning Paper
ELE PL 0023	Power Factor Improvement Strategic Planning Paper
ELE PL 0022	Power Quality Strategic Planning Paper
ELE PL 0013	Public Lighting Switch Wire Removal Strategic Planning Paper

Asset Class Strategies (Lifecycle Management Plans)

JEN PL 0028	Automatic Circuit Reclosers Asset Class Strategy
JEN PL 0009	Communications Network Devices Asset Class Strategy
JEN PL 0026	Conductors and Connectors Asset Class Strategy
JEN PL 0031	Distribution Surge Arresters Asset Class Strategy
JEN PL 0034	Earthing Systems Asset Class Strategy
JEN PL 0045	Electricity Metering and Associated Communication Assets Asset Class Strategy
JEN PL 0010	GPS Clocks Asset Class Strategy
JEN PL 0037	Grounds/Domestic Management of Zone and Non-Pole Type Substations Asset Class Strategy
JEN PL 0030	HV Outdoor Overhead Fuses Asset Class Strategy
JEN PL 0005	iNet Radio and 3G Communication Systems Asset Class Strategy
JEN PL 0036	LV Overhead Services Asset Class Strategy
JEN PL 0004	Metallic Supervisory Cables and Fibre Optic Cables Asset Class Strategy
JEN PL 0006	Multiplexers & Voice Frequency Equipment Asset Class Strategy
JEN PL 0033	Non-Pole Type Distribution Substations Asset Class Strategy
JEN PL 0027	Overhead Line Switchgear Asset Class Strategy
JEN PL 0025	Pole Top Structures Asset Class Strategy

JEN PL 0032	Pole Type Transformers Asset Class Strategy
JEN PL 0024	Poles Asset Class Strategy
JEN PL 0022	PQM Systems Asset Class Strategy
JEN PL 0029	Public Lighting Asset Class Strategy
JEN PL 0007	Remote Terminal Units Asset Class Strategy
JEN PL 0035	Underground Distribution Systems Asset Class Strategy
JEN PL 0038	Zone Substation Capacitor Banks Asset Class Strategy
JEN PL 0039	Zone Substation Circuit Breakers Asset Class Strategy
JEN PL 0023	Zone Substation DC Supply Systems Asset Class Strategy
JEN PL 0041	Zone Substation Disconnectors and Buses Asset Class Strategy
JEN PL 0043	Zone Substation Instrument Transformers Asset Class Strategy
JEN PL 0021	Zone Substation Protection & Control Equipment Asset Class Strategy
JEN PL 0042	Zone Substation Transformers Asset Class Strategy

Network Development Strategies

ELE PL 0006	Distribution Feeders Network Development Strategy
ELE PL 0017	Distribution Substation (DSA) Network Development Strategy
ELE PL 0026	Fairfield/Alphington Network Development Strategy
ELE PL 0027	Flemington Network Development Strategy
ELE PL 0028	Melbourne Airport Network Development Strategy
ELE PL 0025	Northern Growth Corridor Network Development Strategy
ELE PL 0031	Plumpton Network Development Strategy
ELE PL 0029	Preston Area Conversion Network Development Strategy
ELE PL 0030	Sunbury/Diggers Rest Network Development Strategy
ELE PL 0036	Western Growth Corridor Subtransmission Network Development Strategy

Appendix C – AMP Development Process

ASSET MANAGEMENT PLAN DEVELOPMENT PROCESS

INPUTS	PROCESS	OUTPUT	ACCOUNTABILITY
Business Plan; Company Policies; Vision and Values	1. Develop Asset Management Policy	Asset Management Policy	EGM NAPS
Asset Management Policy; Business Plan; Asset Performance and Risk	2. Develop Asset Management Strategy and Objectives	Asset Management Strategy and Objectives	GM, Electricity Asset Management
Asset Management Strategy and Objectives; Asset Performance and Risk	3. Develop Asset Strategies / Regional Strategies	Regional Development and Strategic Planning Papers	GM, Electricity Asset Management
Asset Management Strategy and Objectives; Asset Class Strategies; Regional Development and Strategic Planning Papers	4. Review Project/Program Justifications	Projects and Programs	GM, Electricity Asset Management
Project Risk Assessments; Capital Expenditure Allowance	5. Prioritise Projects	Prioritised Projects List	JEN Asset Management and Electricity Operations
Budget Proposal	7. Budget Endorsement	Endorsed Capital Budget	JEN LT
Endorsed Capital Budget; Prioritised Projects List	8. Identify Project Dates and Programs	Seasonalised Works Program	Works Delivery and Asset Management
Endorsed Capital Budget	9. Integrate Capital Budget into JEN Budget	Budget Pack	Finance & JEN Asset Management
Proposed JEN Asset Management Plan	10. DFA Approval	Approved JEN Asset Management Plan	Managing Director & Funding Committee
JEN Asset Management Plan	11. Commencement of Plan		

KEY: Input/Output Document; Process; Responsible Party; Data

Appendix D – Substation Names

Sub	Indoor/ Outdoor	Street	Postcode	Suburb	Melway
Zone Substations					
AW	O	Moore Road (opp. house No. 71)	3042	Airport West	15 - K5
BD	O	Cnr Maffra Street & Barrys Road	3048	Coolaroo	7 - C3
BMS	B	Lot 602, 2-22 Maygar Boulevard	3047	Broadmeadows	7 – C9
BY	B	Cnr Bosquet Street & Mitchell Street	3012	Maidstone	27 - H11
CN	O	Newslands Road (north of Norfolk Court)	3058	Coburg North	18 - A6
COO	B	Zakwell Court (absolute northern end of court)	3048	Coolaroo	180 - A9
CS	I	Cnr Victoria Street and Hudson Street	3058	Coburg	17 -G12
EP	B	Cnr Swanston Street and Quinn Street	3072	Preston	31 - C1
ES	B	Cnr Buckley Street and Price Street	3040	Essendon	28 - B4
FE	B	Somerville Road (west of Hyde Street)	3013	Yarraville	42 - C8
FF	B	Cnr. Station Street and McGregor Street	3078	Fairfield	30 - K8
FT	I	Cnr Smith Street and Rankins Road	3031	Kensington	2A - A3
FW	B	Sanderson Street (east of Gent Street)	3013	Yarraville	41 - G8
HB	B	Yarra Street (west of Dora Street)	3084	Heidelberg	32 - B5
NH	I	Cnr McNamara Street & Ruthven Street	3085	Macleod West	20 - A9
NS	B	Cnr Moreland Road and Jhonson Street	3044	Pascoe Vale South	38 - K3
NT	I	Douglas Parade (north of Hobson Street)	3015	Newport	56 - B4
P	B	Cnr Murray Road and St Georges Road	3072	Preston	18 - F11
PV	B	Cnr Northumberland Road, and Arnold Court	3044	Pascoe Vale	17 - A7
SA*	B	Cnr Sunshine Avenue and Stenson Road	3021	St Albans	14 - F12
SBY	O	Horne Street (opposite Mitchells Lane)	3429	Sunbury	382 - C6
SHM	B	Victoria Road	3037	Sydenham	3 - A7
SSS	O	O'Herns Road	3062	Somerton	180 - F6
ST	I	Cnr Hume Highway & Pattulos Lane	3062	Somerton	180 - D4
TH	B	Somerville Road (opposite McDonald Road)	3012	Tottenham	41 - B6
TMA	B	72 Keilor Park Drive	3043	Tullamarine	15 - A5
TT*	B	High Street (adjacent to TTS)	3074	Thomastown	8 - H10
WT*	B	Frensham Road (north east of Todman Street)	3087	Watsonia	20 - E4
YVE	B	5 Globe Street	3013	Yarraville	42 - B10

Sub	Indoor/ Outdoor	Street	Postcode	Suburb	Melway
HV Customer Substation with Jemena Assets installed					
MAT	B	Cnr South Centre Road and Link Road	3045	Melbourne Airport	5-C11
VCO	B	Visy Board Factory	3048	Coolaroo	180-B10
NEI	O	Sheehan Road (north of Dougharty Road)	3081	Test Facility Heidelberg West	19 - F10
Terminal Substations (AusNet Services)					
BTS		Cnr King Street and Alister Street	3057	Brunswick South	30-B9
BLTS		Kyle Road (north of Clematis Avenue)	3012	Brooklyn	41 - D11
KTS		Dodds Road	3033	Keilor	15 - A11
TSTS		The Parkway	3106	Templestowe	34 - D2
TTS		Cnr Mahoneys Road and High Street	3074	Thomastown	8-H11
WMTS		Lloyd Street	3003	West Melbourne	43-A4
SMTS		Williamsons Road	3752	South Morang	183-C10

Definitions	
I	Indoor
O	Outdoor
B	Indoor Distribution Bus
*	Not Jemena Electricity Networks owned

Appendix E – Jemena Asset Management Policy

OUR POLICY

Jemena

Jemena Asset Management Policy

Jemena is committed to being recognised as a world class owner and manager of energy delivery assets.

To deliver on this commitment, it is the policy of Jemena to:

- Manage our assets without compromising our employees, contractors and public safety, as per the Jemena Health and Safety Policy
- Manage our assets in an environmentally sustainable manner in support of the Jemena Environmental Policy
- Comply with all relevant regulatory and legislative requirements
- Actively engage with customers and key stakeholders to understand and respond to their requirements to ensure outcomes are achieved that are in their long term interests
- Develop asset management plans that deliver the corporate objectives and business plan
- Facilitate continual improvement in the safety and performance of the assets, through the establishment, maintenance and governance of effective asset and safety management systems
- Make best practice asset management an accepted and important part of our "business as usual" approach, and measure it against an internationally recognised asset management framework
- Apply the Jemena risk management approach to asset management activities
- Develop and maintain asset information systems that support asset management decisions and activities throughout the asset lifecycle
- Establish a consistent, collaborative and integrated approach to the management of the lifecycle of the assets, to ensure that the optimum outcomes are delivered in an efficient way across Jemena
- Develop the skills and knowledge of our people to sustain and reinforce our asset management capabilities

Paul Adams
Managing Director
Jemena Limited
January 2014

Jemena produces detailed policies which support this policy statement.

Vital Service. Vital Planet.

Appendix F – Jemena Health & Safety Policy

OUR POLICY

Jemena

Health & Safety

At Jemena, we believe that the health and safety of our people and the community in which we operate is not only an organisational value, but also a key success factor in achieving our vision to be recognised as a world class owner and manager of energy delivery assets.

We are committed to:

- Providing a safe and healthy workplace where the risk of injury and illness is minimised;
- Having systems and processes that enhance the way our people work, thus maximising reliable performance;
- Complying with applicable statutory obligations, standards, codes of practice and other regulatory requirements relevant to our assets and our operations;
- Designing, operating and maintaining our assets in a way that protects or enhances community safety; and
- Creating a positive, trusting, caring and learning health and safety culture.

Wherever we operate, we strive to achieve this through:

- Setting, communicating and monitoring realistic and meaningful measures that are consistent with, and move us toward, our vision of world class;
- Establishing and maintaining health and safety management systems and processes, and asset specific safety management systems consistent with our business needs;
- Listening to and consulting with our people and other stakeholders to proactively identify hazards and manage the associated risk, safely;
- Providing training and education to our people in relation to health and safety leadership, hazards and their associated risk, our systems and process, culture and our journey to world class;
- Seeking feedback on our systems and risk control effectiveness for learning and continuous improvement;
- Continually improving the focus and effectiveness of our asset management approaches and practices;
- Maintaining a strong focus on employee health and wellbeing;
- The proactive participation in business, community and government programs to enhance our own and the community's health and safety;
- Providing adequate resources; and
- Continuing to mature and nurture our culture.

In Jemena, we believe that individual responsibility plays an important part in achieving a healthy and safe workplace and, for that reason, our people are empowered to take action that protects themselves, fellow employees, the public and other stakeholders.

Paul Adams
Managing Director
Jemena Limited
August 2013

Safety First. Hear, Listen and Think before we Act.

Vital Service. Vital Planet.

Appendix G – Jemena Environment Policy

OUR POLICY

Environment

Jemena

Jemena is committed to reducing its environmental footprint.

In delivering on this commitment it is the policy of Jemena to:

1. Comply with all relevant legal and other environmental requirements and provide employees and contractors with the necessary training and tools to maintain its assets in compliance to such requirements.
2. Conduct its business in a way that employees and contractors understand and ensure that they are accountable, for Jemena's environmental performance in their day to day activities.
3. Facilitate continual improvement in environmental performance by establishing and maintaining an appropriate Environmental Management System for all assets.
4. Identify and minimise risk by continually assessing, controlling and monitoring our environmental aspects and impacts.
5. Utilise its knowledge and expertise by supporting and pursuing strategies and projects that reduce our impact on the environment as well as providing customers with the necessary tools and information to understand and better manage their environmental impacts.
6. Identify, set and monitor realistic environmental performance measures and communicate them to all employees and stakeholders.
7. Actively engage with customers, government and other stakeholders to recognise and respond to all environmental concerns.

It is a requirement that all employees, contractors and visitors comply with the requirements of this policy and our Environmental Management standards at all times.

Paul Adams
Managing Director
Jemena Limited
January 2012

Vital Service. Vital Planet.

Jemena
bringing energy to life

Jemena Electricity Networks (Vic) Pty Ltd