Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 7-6

20-year Strategic Asset Management Plan - Electricity (ELE PL 0019)

Public

30 April 2015

Page intentionally blank

Jemena Electricity Networks (Vic) Ltd

20 Year Strategic Asset Management Plan - Electricity

ELE PL 0019

Public

21 April 2015

An appropriate citation for this paper is:

20 Year Strategic Asset Management Plan - Electricity
Our Ref: ELE PL 0019

Authorisation

Name	Job Title	Date	Signature
Reviewed by:			
Sean Ward	General Manager, Asset Investment and Major Projects	21/04/2015	
Approved by:			
Alf Rapisarda	Executive General Manager, Asset Management	21/04/2015	

History

Rev No	Date	Description of changes	Author	
1	08/02/15	Final draft - expenditure to be finalised	Kieran Coughlan	
			Contributors:	Graeme Wirges
			Aditya Upadhye	James Harding
			Alexus Van Der Weyden	Jason Pollock
			Ana Dijanosic	Jonathan Chan
			Anton Murashev	Kopeeswaran Vaikundan
			Ashley Lloyd	Peter Wong
			Benjy Lee	Robert McMillan
			Dalibor Balicevic	Steven Spence

Owning Functional Area

Business Function Owner:	Asset Investment and Major Projects

Review Details

Review Period:	Last Review Date + 1 year, Full revision date + 2 years
NEXT Review Due:	09/02/2016

TABLE OF CONTENTS

List of tables

List of figures

EXECUTIVE SUMMARY

The 20-year Strategic Asset Management Plan represents Jemena's long term approach to the provision of electricity network services to customers in the north western suburbs of Melbourne.

This document establishes the linkages between the Jemena business plan, our asset management strategy, objectives and our five-year asset management plan. This integrated governance of our asset management ensures that we plan and manage our long-lived network assets prudently and efficiently, and in line with the service levels our customers' value. It also ensures we are well placed to respond to and facilitate the changes that are currently occurring in our energy market and over the next 20 years.

So that we can achieve our vision, purpose and strategic objectives, the 20 year-strategic asset management plan considers:

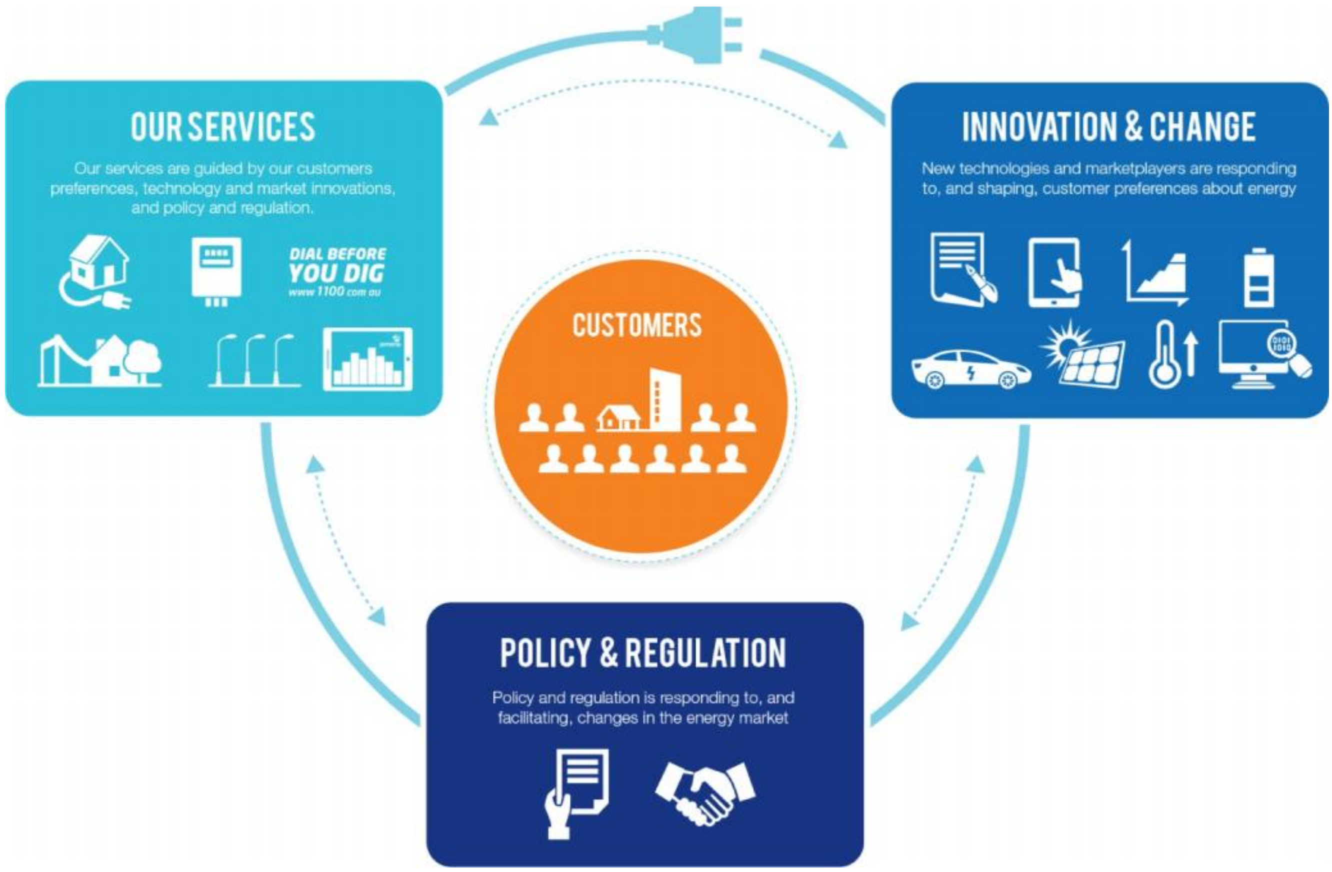
- the future environment (assesses the changes that are currently occurring, the impacts on our services to customers, and our plans relating to that change);
- strategic asset management drivers (including stakeholder expectations, health, safety and the environment, growth, demand and customer connections, asset integrity, regulatory compliance and technology);
- service levels;
- asset class strategic plans;
- technology plans;
- network capacity and development;
- customer initiated connections;
- network maintenance and operations;
- approaches to pricing; and
- capital and operational expenditure scenarios

OUR CHANGING ENERGY MARKET

Our electricity market is changing – driven by interrelated changes in customers' attitudes and use of our network, technological and market innovations, and policy and regulatory developments.

Together, these trends are driving changes in the roles and responsibilities of energy market players, as well as changes in the way our customers use our network – necessitating changes in the services we provide and the way we plan and manage our long-lived network assets, as per Figure 0–1.
Electricity distribution networks like ours will still play a critical role in transporting electricity to and between homes and businesses. For example, we will continue to provide a reliable energy platform to our customer that facilitates innovation in new technologies and customer choice in their energy supply.

Figure 0–1: Our service, innovation and change, policy and regulation



ENSURING OUR SERVICE LEVELS REFLECT CUSTOMERS' PRIORITIES AND LONG TERM INTERESTS

Like any business, we need to strike a balance between the safety of our services, the service levels we provide and the prices we must charge to recover the costs of these safety and service levels. We want to ensure the decisions we make reflect our customers' priorities and long-term interests.

As part of developing this document, we engaged extensively with our customers and the community to better understand their priorities and preferences for this regulatory period and beyond—including what they want and value in their electricity supply, and what role our customers want us to play in meeting their energy needs.

We modelled five scenarios based on the interaction between capital and operational expenditure, levels of service, and average cost per customer over the next 20 years. This modelling criterion is depicted in Figure 0–2. Customer feedback through various forums has guided our decision making on forecast expenditure.

Figure 0–2: Safety, service levels, costs and prices

Through our engagement process, our customers indicated:

- growing interest in taking greater control over how they source and use energy;
- strong support for our focus on safety and a preference for maintaining the current balance between safety, service levels and prices, and a preference to maintain current levels of reliability over the long term[1]; and
- want us to explore new ways of more efficiently delivering our services (supply side initiatives) and ways of enabling them to use our services more efficiently (demand side initiatives)

Based on these findings, we are planning to maintain our current service levels in areas indicated by our customers, and leveraging and responding to new technology and exploring new ways of more efficiently delivering our services and support efficient usage decisions by our customers into the future so that we can minimise our costs over the life of our network assets.

[1] The vast majority of customers in our deliberative forum supported our proposal to maintain our current service ' and responsiveness.

ENSURING OUR COSTS ARE PRUDENT AND EFFICIENT

NETWORK CAPACITY AND DEMAND AND CONNECTIONS

Meeting and managing anticipated maximum demand with acceptable levels of security and reliability of supply is the primary driver for network capacity and demand expenditure and operating expenditure on demand management activities. Our analysis has established three main findings for changing demand profile on our network:

- The network-wide maximum demand growth rate is forecast to slow over the next 20 years, to an average of 1.4% per annum, compared to the long-term average of 2.7%. This is largely due to energy efficiency improvements and action reducing peak demand growth, and rooftop photovoltaic (PV) connections offsetting summer demand growth;
- Some areas of the network are experiencing significant maximum demand growth and require network augmentation. These are driven by urban development in the northern part of our network and new high-rise residential developments in established areas throughout the network; and
- Some areas within our electricity network will experience a decline in maximum demand over the next 20 years, due to large commercial business closures and the continued impact of rooftop PV connections and energy efficiency technology and action.

Major customer-initiated works during the 2016-2020 period are expected to result in a higher than average expenditure. This is due to major development works at the Melbourne International Airport, as well as some other off-trend customer-initiated connections.

The total number of new network connections is expected to continue to grow by approximately 4,500 per year over the next 20 years.

ASSET CLASS STRATEGIC PLANS

The relevant asset classes considered in this document are poles, pole top structures, zone substation transformers, switchgear and other zone substation property and equipment, overhead conductors, meters and metering infrastructure, fleet, property, tools and equipment, and public lighting.

Our analysis has established the following findings:

- Our network is ageing (a proxy for condition) and we are still going through the initial phase of a replacement cycle for many assets, requiring us to increase replacement expenditure to maintain service levels over the next period. This replacement cycle is likely to continue to increase over the next 10-15 years. Our forecast asset replacement volumes will ensure that we maintain existing levels of service;
- Our practical approach to maintenance is based around strategies that implicitly account for the appropriate balance of capital and operating expenditure through the consideration of total lifecycle management costs;
- Compounding the ageing issue, there are a number of areas where safety has deteriorated more than expected during the current period, requiring us to increase replacements in these areas to arrest this degradation and address concerns raised by ESV; and
- The property expenditure proposed for 2016-2020 primarily relates to the development of a new office/field depot at Broadmeadows, hence the forecast reduction in expenditure in subsequent periods.

TECHNOLOGY PLANS

Our focus is on providing energy services that are safe, affordable and responsive to our customers' preferences. This involves exploring new ways of more efficiently delivering our services – both traditional and innovative supply side investment in 'poles and wires' as well as new demand side or 'non-network' investment to minimise or defer the need for costly investment. Both forms of investments seek to minimise the cost of supplying customers while maintaining or improving customer options and service levels.

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. We have been developing and applying smart network compatible technologies to the distribution network over many years. Our long term focus for smart networks is to continue to embrace new and innovative technologies which present net benefits to customers. We also plans to leverage the infrastructure provided by the Advanced Metering Infrastructure (**AMI**) program to further develop a smart network and ensure continued efficiency in service delivery to customers.

A smart network will ensure efficient service provision and empower customers who want flexibility in using power efficiently. Adoption of smart network concepts will help us to maintain a market leading position and to provide a platform for innovation to meet changing customer needs.

Our focus is on the following aspects for our 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 & 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– 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;
- Ensure that peer-peer technology can be facilitated through our network; and
- 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

Also, to meet our demand management objectives, we are starting to diversify our network management by introducing the following projects – many of which leverage the benefits of our investments in AMI[2] – and using the findings from these to ensure that we provide dynamic solutions in the long term interests of customers:

[2] The efficiencies we plan to develop in terms of how we use meters to manage the network to the benefit of our customers involve enhanced outage management, LV grid modernisation, customer supply impedance monitoring, and demand response and distributed generation initiatives.

- **Efficient connection of micro-embedded generators** - maximising the capacity of Low Voltage networks for efficient connection of inverter based micro-embedded generators;
- **Direct Load Control Trial (DLC)** - test the effect of DLC as a means to managing peak demand and develop DLC dispatch algorithms that optimise load reduction amongst participating customers;
- **Managing peak demand through customer engagement** - empowering customers to make informed decisions through education, incentives and analytics;
- **Technology and economic assessment of residential energy storage -** Assess technical and economic viability of residential battery storage paired with PV systems and identify key barriers for wide scale uptake;
- **Distributed grid energy storage** - storage solutions to mitigate network capacity constraints and maintain quality of electricity supply; and
- **Demand response field trial – phase two** - field test desktop models developed in Phase 1 and understand practical issues with operation of demand response.

We are focused on further realising the benefits of the introduction of AMI for customers. Our plans reflect this focus, and we will:

- provide information to consumers to allow them to actively manage their energy consumption and for communicating pricing/control information; and
- offer price-reflective tariffs to customers to incentivise behaviours that lead to efficient usage change and better attribution of our cost recovery to those customers who's usage behaviour drives our incremental costs

ENSURING THE REGULATORY FRAMEWORK ENCOURAGES EFFICIENT INVESTMENT IN OUR ENERGY MARKET

Our investments are generally funded through borrowings from capital markets and paid back over the long term. The regulatory framework is designed to ensure we have access to the funds we need to spend on our assets and recover these funds over time (deferred cost recovery), so both current and future customers who benefit from the assets contribute to their costs. However, the changes in our energy market create new risks. The widespread installation of solar PV and other distributed generation has changed the way customers use our network. We expect further changes in the way our network is used, as new technologies (e.g. battery storage, electric vehicles and smart grids) and new market players emerge and develop and new energy policies drive investments in new areas. It is difficult to predict the pace of technological development, and to forecast how, where and when our customers will chose to use these new technologies. These uncertainties create risks that we may not be able to fully recover the efficient costs of investing in our long-lived network assets, dampening the incentives we have to invest in long term lowest cost assets to meet the service levels our customers' value.

As we increasingly compete against a range of other technologies and energy market players, the regulatory framework will need to be capable of adapting to these changing circumstances if we are to manage these changes in a way that continues to promote customers' long-term interests. For example, it is critical that the regulatory framework:

- manages the risks of deferred cost recovery given the uncertainty about future use of our network, to provide us with incentives to continue to invest in long term lowest cost solutions; and
- encourages us to compete in these emerging markets, to drive innovation and make use of our knowledge and capabilities, including our economies of scale and scope

PRICING AND TARIFF STRUCTURES THAT ENCOURAGE INFORMED ENERGY DECISION-MAKING

Our network prices for residential and business customers have not evolved to provide signals for informed energy decision making. To some extent, the structure of our network pricing has not kept up with the diversity in how people use the network.

Currently, a large portion of our revenue is recovered through consumption charges on a cent-per-kilowatt-hour basis, however actual energy use is a relatively minor cost driver and thus not entirely cost reflective.

We propose to update our network tariff structures to encourage more informed customer decision making and put downward pressure on our costs and average prices over the long term by:

- introducing a new 'maximum demand charge' for all residential and small business customers to more clearly signal the higher costs of using our network during periods of peak demand, and thus encourage these customers to reduce or shift consumption during periods of peak demand; and
- changing the existing demand charges for all large business customers to improve their cost-reflectivity

We will continue to have a fixed standing charge and variable consumption charges, and on average these charges will be lowered so we do not recover more revenue from customers.

To complement the proposed tariff changes and facilitate more informed decision making, we will publish information on our website and continue to engage with customers to help them understand how they can respond to the new maximum demand charge and take control of their electricity bills. We will also encourage our customers to make use of our electricity portal which provides customers with easy-to access information on their electricity usage. This tool, together with our smart meters, will enable our customers to see how much electricity they are using and when they are using it, to set savings targets and track their progress, and to use their usage information to compare retail market offers.

1. INTRODUCTION

1.1 DOCUMENT PURPOSE

The 20-year Strategic Asset Management Plan provides the strategic actions and associated capital and operational expenditure forecast for the asset classes in order to achieve regulatory and business performance targets for the next 20 years.

It documents our approach to the provision of electricity network services and establishes the linkages with and between our business plan, asset management strategy and objectives, and asset management plan.

Over the next 20 years, with increasing innovation in the energy sector and greater customer interaction and choice, the electricity distribution network's operating environment is changing.

1.2 SCOPE

This 20 Year Strategic Asset Management Plan covers the Jemena distribution electricity network in Victoria and considers:

- the forecast augmentation, refurbishment and replacement required for the asset classes to ensure that we efficiently deliver the needs of customers through the next 20 years;
- how we continue to meet our strategic objectives; and
- the changing environment and how it may impact on the provision of our services

Importantly, it examines the drivers of our network costs over the long term and scenarios of the service levels and cost outcomes of these scenarios.

So that we can achieve our vision, purpose and strategic objectives (as outlined below), the 20 year-strategic asset management plan considers:

- the future environment (assesses the changes that are currently occurring, the impacts on our services to customers, and our plans relating to that change);
- strategic asset management drivers (including stakeholder expectations, health, safety and the environment, growth, demand and customer connections, asset integrity, regulatory compliance, and technology);
- service levels;
- asset class strategic plans- identifying the key drivers for expenditure in the short, medium and long term;
- technology plans- identifying the steps that we as a business are taking to ensure that we ensure efficiency in the delivery of our services to customers, whilst also realising and delivering benefits to customers from advancements in the capability of the network;
- network capacity and development- identifying the forecast growth on the network over the next 20 years in recognition of the changing environment;
- customer initiated connections – identifying the trend in customer connections anticipated over the next 20 years;

- approaches to pricing- identifying changes in our approach to pricing over the next 20 years; and
- capital and operational expenditure scenarios

1.3 OUR VISION AND PURPOSE

Our 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 is:

We deliver energy to our customers

Our Vision is:

Figure 1–1: Vision

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

1.4 STRATEGIC OBJECTIVES

Jemena's vision is to be recognised as a world class owner and manager of energy delivery assets and plans to realise this vision through developing a corporate culture that achieves the following specific objectives for the electricity network:

- 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 the 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

1.5 STRATEGY, KEY OBJECTIVES AND MEASURES

Our strategy that links the vision, strategy and key success measures is detailed in the figure below. 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.

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.

Figure 1–2: Strategic themes

We will measure success with five key success measures and objectives:

Figure 1–3: Key objectives and measures

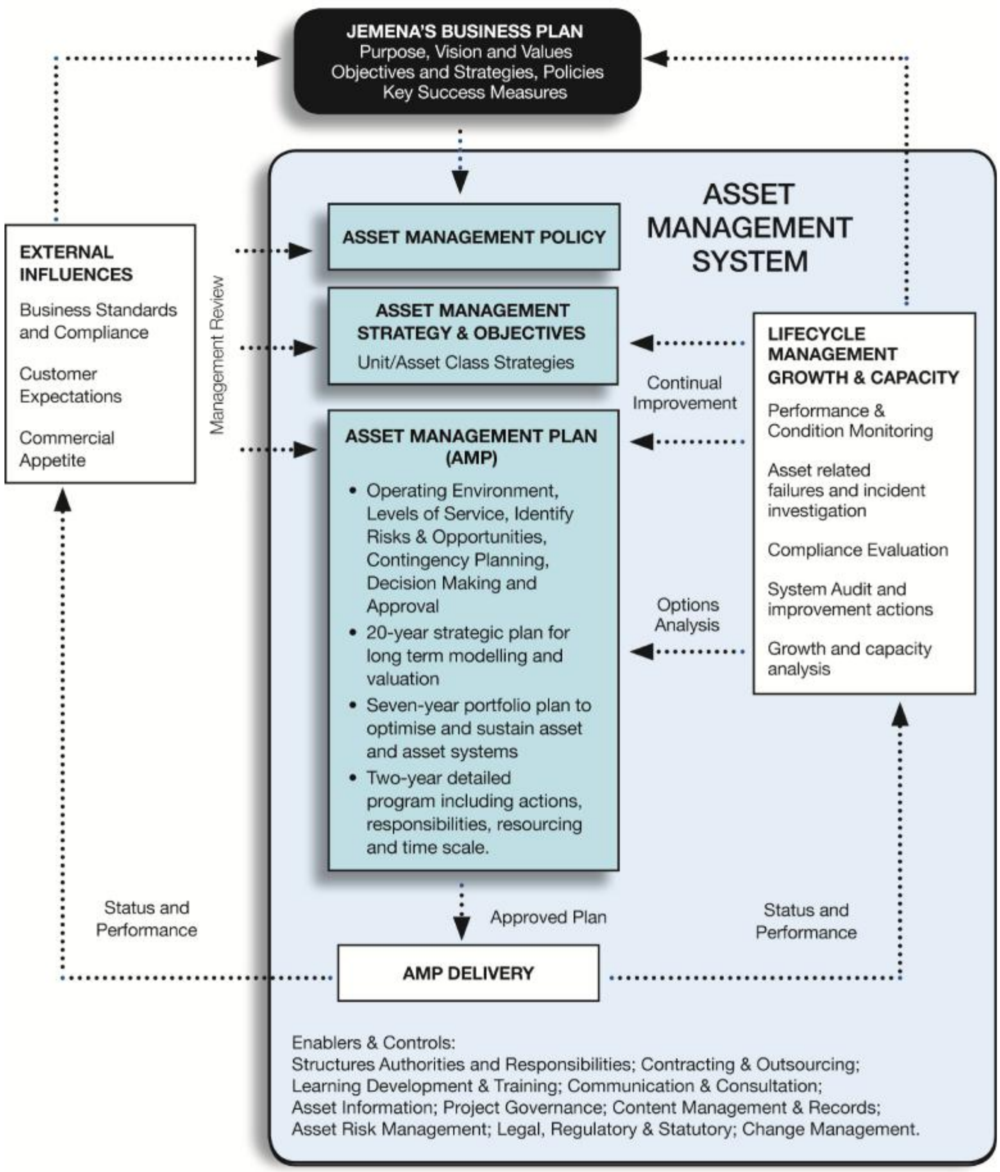
The objectives and strategy for managing our assets are discussed in more detail in document JEN PL 0012 - Asset Management Strategy and Objectives.

1.6 ASSET MANAGEMENT APPROACH

Our Asset Management framework provides guidance when establishing work programs focussed on maintaining safety, performance and efficiency. It also brings together the external influences, asset management drivers, business values and asset management to the benefit of all stakeholders.

We ensure best practice asset management when managing our network and are certified to PAS 55[3]. Our focus is on continually improving the way we make investment and operational decisions, to the benefit of our customers. This 20-year strategic plan forms part of our Asset Management Plans, as shown in Figure 1–4.

Figure 1–4: Jemena Asset Management Framework



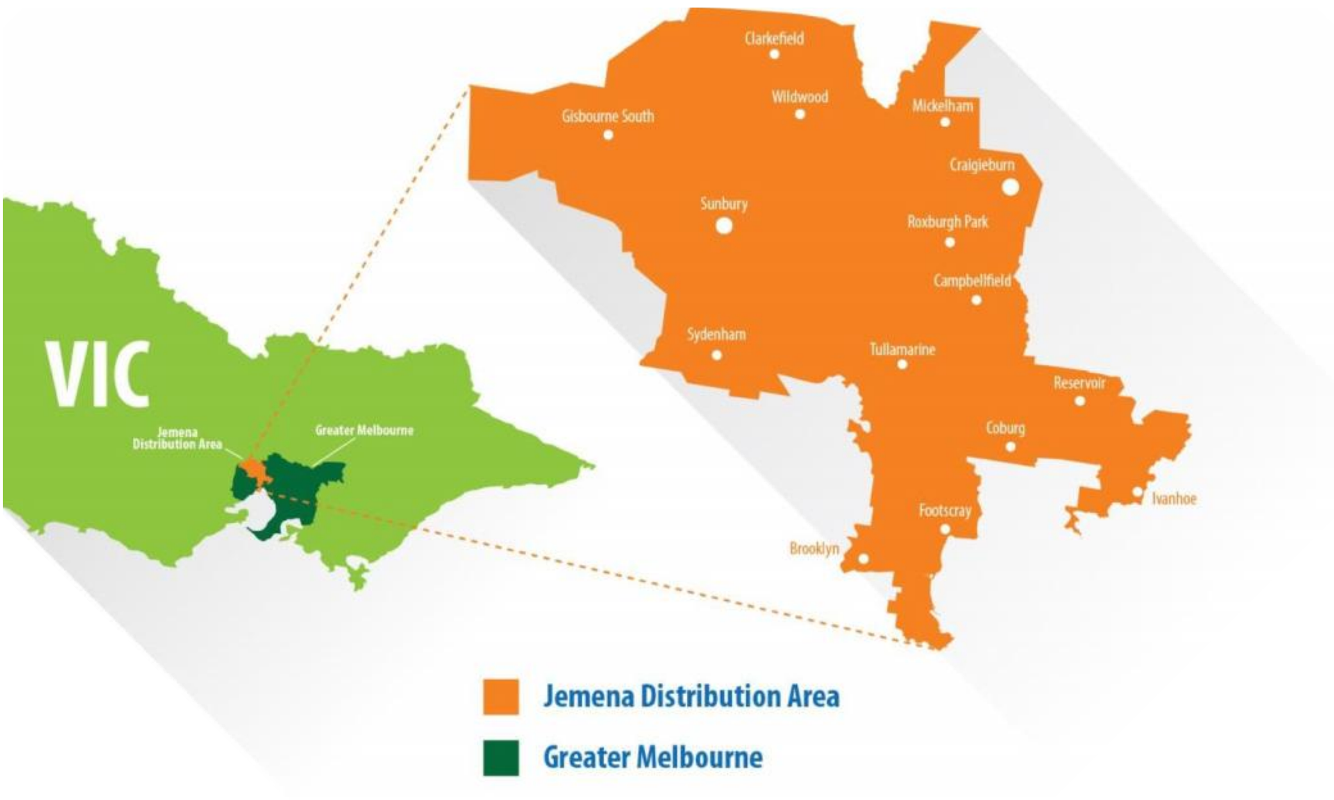
[3] PAS 55 is an internationally recognised asset management standard that identifies the optimum approach for the management of assets. We were independently accredited to this standard in June 2014 (the third business to be successfully accredited in Australia).

2. DESCRIPTION OF NETWORK

2.1.1 NETWORK OVERVIEW

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

Figure 2–1: Jemena Electricity Network



2.1.2 NETWORK SUMMARY

Table 2-1 provides a summary of the network statistics.

Table 2-1 – Network Summary

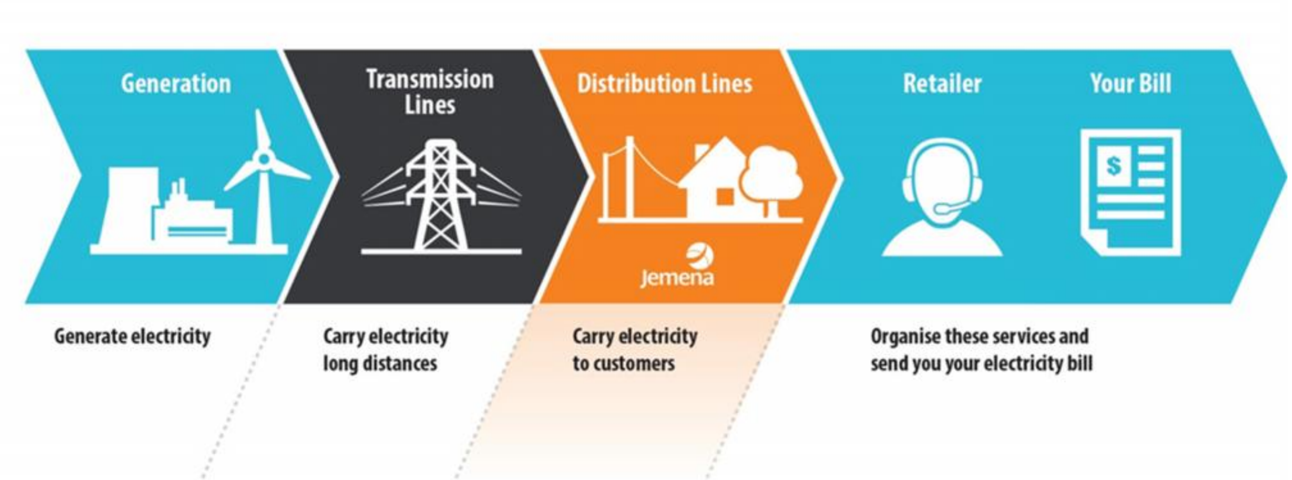
Description	Details
Area (sq. km)	950
Line length (km)	6,159 (4440 overhead, 1719 underground)
Sub-transmission lines (66 and 22kV)	46
Feeders	220
Poles	97,813
Customers	318,294
Transmission connection points	7
Number of Zone substations	25
Zone substation capacity (MVA)	1,770
Number of Distribution substations	5,962
Energy Served (supplied) (GWh)	4,330
Maximum Demand (MW)	989

2.1.3 OUR SERVICES

We provide distribution network services to electricity consumers, electricity retailers, the electricity market operator, and other distribution businesses and third parties seeking access to our infrastructure. We also provide 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 and data management; and
- Dial Before You Dig (**DBYD**).

Figure 2–2: Our Services



Electricity delivery

We provide 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 a 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

We provide non-standard control services to local councils, Vic Roads, 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

Our customer connection services involve connecting new premises, or upgrading existing connections, 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 services.

Inter-distribution (Inter-DB) business settlement

We provide inter-DB settlement services to distribution businesses (**DB**) 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 our metering installations are supplied by another DB network.

Meter provision and data management

We provide meter services for AEMO and electricity retailers, involving electricity meter installation and maintenance. We 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

We provide 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.

2.1.4 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).

3. FUTURE ENVIRONMENT

3.1 ENERGY POLICY, REGULATION AND PRICING

3.1.1 POLICY

Given the essential nature of the services we provide to our customers, electricity distribution is subject to a high degree of safety, technical, economic and other regulation. Additionally, both State and Federal Government policies can have a significant impact on our business, services and customers.

Public interest in government energy policy has grown over the past decade, much of which followed significant increases in retail electricity and gas prices over the past five years. Additionally, strengthening community expectations for government action on climate change have seen climate policy become a key focus of mainstream politics, and increasingly intertwined with energy policy.

Policy decisions can have a long-term impact on our regulatory frameworks. As policy makers provide high-level direction to regulatory framework development, these frameworks can also change in response to community concerns or political pressures. For example, electricity price increases that started from around 2010 caused significant public and media interest in regulatory issues, eventually leading to the Better Regulation program of regulatory framework reforms.

In the future, the public desire to realise and leverage the benefits of AMI technology in Victoria may also lead to policy decisions that influence regulatory frameworks (for example, in areas such as network tariff reform), with the potential to have longer-term impacts on the way people use our services and our network investments.

Government environmental policy is a key enabler of mass-market take-up of new technologies, which significantly impact the way our customers use and generate electricity. For example, policies encouraging the large-scale adoption of rooftop solar photovoltaic (**PV**) systems have accelerated this technology's development and added to downward pressure on manufacturing costs as it matured. These policies have included schemes providing subsidies for the purchase of PV systems, such as the Small-scale Renewable Energy Scheme (**SRES**) and mandatory premium feed-in tariffs. These policies and subsidies have begun to be wound back.

Policy interventions

The Federal Government appears likely to place an emphasis on exploring the impact of policies, such as feed-in tariffs, including whether they are causing undesirable price distortions[4]. It is possible that future schemes, such as feed-in tariffs or up-front subsidies, will be introduced to encourage the greater adoption of new or larger micro-embedded generators, such as micro gas-fired (including co-generation and tri-generation) and micro wind generation. These schemes may significantly increase the attractiveness of embedded generation to our customers.

Emissions reduction scheme

Other emissions reduction schemes can potentially impact demand for grid-sourced electricity. For example, the SRES provides subsidies for solar and electric heat pump water heating systems but not gas. The scheme therefore disincentives the take-up of gas water heaters, which in some cases is an alternative technology to electricity. In the future, careful consideration of such schemes is required to ensure equitable solutions for all customers.

[4] For example in Queensland, where approximately 20 per cent of Energex's customers had a PV system installed as of 2013, the cost of premium feed-in tariffs currently accounts for six per cent of a typical household's electricity bill.

Energy efficiency policies

Energy efficiency policies are another pillar of climate policy that impacts the energy sector. These policies may involve establishing minimum energy efficiency standards for buildings and consumer goods or providing households and businesses with equipment that reduces energy consumption. These policies also generally have the effect of reducing electricity demand intensity (reducing aggregate demand but generally not peak demand), while greater efficiencies have been facilitated by improved and cheaper technological developments (such as energy efficient lighting).

Energy efficiency policies that can be designed to achieve environmental goals as well as lower electricity bills appear to be more attractive to some governments than policies that only target carbon abatement. Despite the fact that some jurisdictional schemes are currently being wound down (such as the Victorian Energy Efficiency Target), energy efficiency remains a key policy focus. For example, the Federal Government's recent Energy Green Paper suggests that a National Productivity Plan to improve energy productivity may be implemented. On balance, energy efficiency standards and initiatives are likely to be continuously strengthened over the next 20 years as technology evolves and community desire for carbon abatement increases.

Carbon abatement policies

Over the longer term, carbon abatement policies are likely to continue being an important subject for policy makers. Australia's stated goal is to reduce its greenhouse gas emissions by at least five per cent below 2000 levels by 2020 and 80 per cent by 2050. In mid-2014, the Federal Government repealed Australia's carbon pricing mechanism and moved to implement an emissions reduction fund, which will form Australia's primary carbon abatement policy for at least the next three years.

It is unclear whether the current carbon abatement policy settings will enable Australia to meet its stated emissions targets, and the current Parliament's opposition and minor parties favour alternative abatement policies such as the introduction of an emissions trading scheme. It appears somewhat likely that Australia will move towards a market-based technology-neutral scheme over the longer term, and continued delay in implementing longer-term large-scale emissions reduction policies increases the likelihood that carbon abatement policy will focus on small-scale electricity generation (potentially encouraging the take-up of micro embedded generation).

Natural gas pricing policy impacts

Government policy that affects the supply (and therefore price) of natural gas can impact the way customers use our electricity services over the longer term. Recent structural changes in the East Australian gas market, coupled with state government restrictions on onshore unconventional gas development in Victoria and New South Wales, have supported a significant wholesale gas price increases. Persistently high wholesale gas prices have the potential to impact the adoption of micro embedded gas-fired generators (including co- and tri-generation).

New technologies

Over the next 20 years, government policy is likely to continue to play a key role in driving the adoption of new technologies that impact the way customers use our services. Governments in Australia have not set targets for the take-up of electric vehicles, which currently comprise a very small proportion of new vehicle sales. In Victoria, a government-supported electric vehicle trial has been operating since 2010.

Encouraging the take-up of electric vehicles; international policy examples.

A number of countries have implemented policies to encourage the deployment of electric vehicles, primarily motivated by environmental goals and reduced reliance on imported energy (oil). Policy measures include up-front subsidies for the purchase price of electric vehicles, tax incentives, reductions in or exemptions from vehicle registration and road congestion charge costs and other non-financial ownership incentives. Some countries (such as Germany and Ireland) have placed a greater emphasis on providing funding for further electric vehicle-related research and development.

The mass-market deployment of distributed battery storage systems may also significantly change our assets and services. While this technology is generally still not economic for most customers, policies to encourage its adoption as it naturally approaches economic viability may significantly change the way our customers source electricity from the grid.

In the future, policy may also be developed to realise the potential benefits that distributed energy storage and electric vehicles (functioning as distributed energy storage) can provide to electricity distribution systems. This may potentially involve feed-in tariffs to encourage battery system and electric vehicle owners to provide support to the distribution network.

3.1.2 REGULATION

Changes in economic regulation

Like other electricity distribution network businesses in the National Electricity Market, Jemena is regulated by the AER. The AER applies the regulatory framework specified in the National Electricity Rules (**NER**), and these rules are administered and reviewed by the Australian Energy Market Commission (**AEMC**). Federal and State energy ministers, through the Council of Australian Governments (**COAG**) Energy Council, administer and review the National Electricity Law (**NEL**), and the broader governance framework of independent economic regulation.

In 2012, changes were made to the NER in relation to how network revenues are determined and adjusted over time, and to enhance the ability of customers to meaningfully participate in this decision making process. Following recommendations from the COAG Energy Council, further changes were made to the regulatory framework in 2014 including changes to how network revenues are recovered from customers through network prices, including the guidance provided to network businesses in balancing cost, efficiency and customer considerations and the timeframe for annual changes in network prices.

Some of the specific changes to the regulatory framework aimed at increasing customer participation include the new RIT-D process, which requires network businesses to consult with community stakeholders throughout the capital planning process, and the AER’s customer engagement guidelines, which require network businesses to proactively engage with customers and explain how they have sought to address any relevant concerns identified as a result of the engagement process.

Other changes to the regulatory framework in recent years include:

Advanced Metering and the roll-out of advanced metering infrastructure and the imminent introduction of metering contestability. The provision of metering services is due to become contestable from 1 January 2017; however this milestone is still uncertain. This plan does not forecast beyond the forecast regulatory period for meter installation; and

Benchmarking and a shift towards applying benchmarking techniques to compare the relative efficiency of network businesses

The AER's approach to benchmarking has been influenced by the approach adopted by Ofgem in the UK. While the effectiveness of benchmarking as a regulatory tool in the Australian context is yet to be seen, its adoption has already had a significant impact on our business. In recent years, our plans have altered to completely overhaul our reporting capabilities to capture and monitor very detailed expenditure and volume information, as required by the AER.

Innovation in technology

Given the long-term investment decisions we (and all electricity distribution networks) are required to make, it is important that regulatory impacts resulting from economic, customer and technology changes are anticipated and that the regulatory framework accounts for these changes.

As the rate of technological innovation and market change increases, it will become more challenging for the regulatory framework to keep pace. If change takes place too slowly, there is a risk that our investors will lose the confidence to support our long-term investment decisions. Some of the future changes the regulatory framework will need to address include:

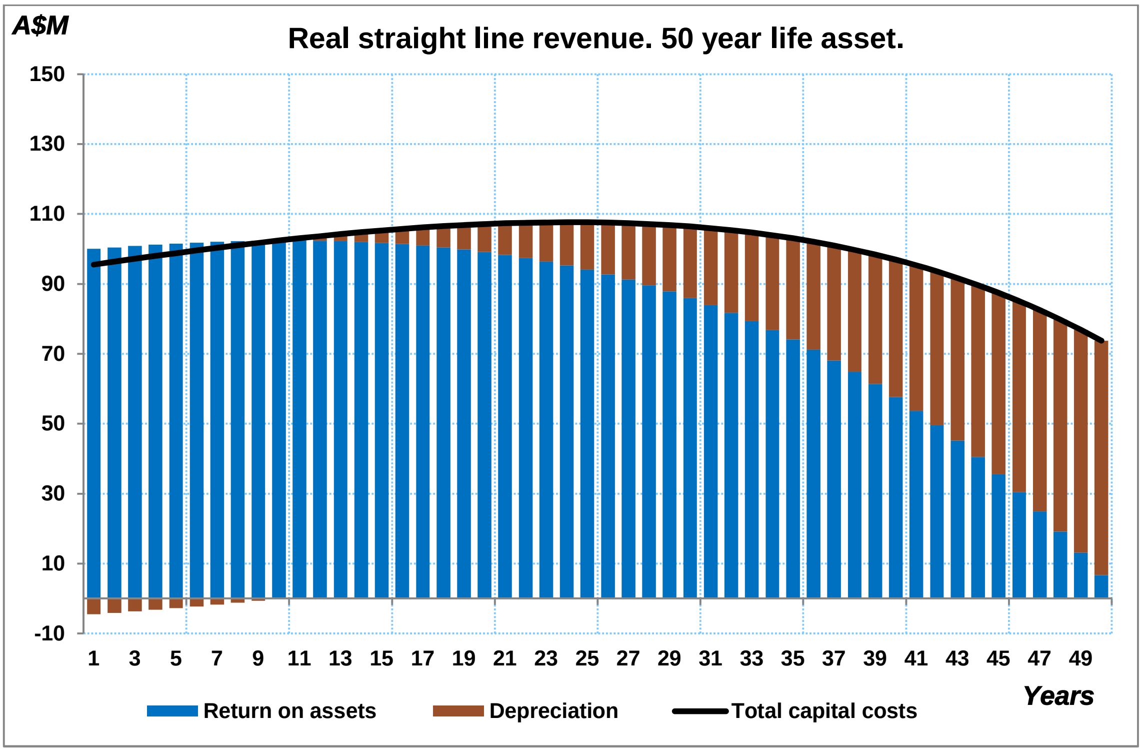
- the increasing network connection of distributed generators (for example, the widespread installation of solar PV), and also developments in new technologies such as electric vehicles
- increasing consumer energy-use options as a result of more decentralised networks, and
- an increased choice of fuel substitution (renewable energy and storage options with batteries)

Regulatory framework

Our investments are generally funded through borrowings from capital markets and paid back over the long term. The regulatory framework is designed to ensure we have access to the funds we need to spend on our assets and recover these funds over time. This 'deferred cost recovery' through the depreciation or 'return of capital' component of the building blocks ensures that both current and future customers who benefit from the assets contribute to their costs.

Prior to committing funds our investors value certainty about recovering their significant up-front investment in our network. Historically, with little alternative energy sources and expectations of a growing market, our investors could assume that there was a reasonable opportunity to recover their investment over its economic life, even though in many cases the depreciation component was negative in the initial ears as per Figure 3–1. This provided them with incentives to invest their funds and allowed us to efficiently and prudently invest in long term low cost asset solutions.

Figure 3–1: Traditional approaches to depreciation involve significant deferral of the recovery of capital investment



Source: Jemena

However, the changes in our energy market create new risks for our investors. The widespread installation of solar PV and other distributed generation has changed the way customers use our network. We expect further changes in the way our network is used, as new technologies (e.g., battery storage, electric vehicles and smart grids) and new market players emerge and develop with new energy policies driving investments in new areas. It is difficult to predict the pace of technological development, and to forecast how, where and when our customers will chose to use these new technologies. These uncertainties create risks that:

- our investors may not be able to fully recover the efficient costs of investing in our long-lived network assets, dampening their incentives to invest their funds in our business; and
- we may not be able to invest in lowest cost (typically long lived capital solutions) to meet the service levels our customers value

As we increasingly compete against a range of other technologies and energy market players, the regulatory framework will need to be capable of adapting to these changing circumstances if we are to manage these changes in a way that continues to promote customers' long-term interests. For example, it is critical that the regulatory framework manages the risks of deferred cost recovery given the uncertainty about future use of our network. Under the NER the AER currently has the 'tools' to manage this risk through approval of the deprecation profile which set out the rates at which the investments in our assets are recovered. Using these tools in a 'fit for purpose' manner is critical to ensuring:

- our investors are provided with incentives to invest their funds in our business; and
- we are provided with incentives to efficiently and prudently invest in long term low cost asset solutions to provide the services our customers value

3.2 CLIMATE CHANGE

The meaning of 'climate change' is a clear, sustained change (over several decades or longer) in the components of climate, such as temperature, precipitation, atmospheric pressure, or winds[5]. The potential for our network to be impacted by climate change is significant. Our role is to ensure that our investment decisions are based on understanding the risks and impacts of climate change for the services that we provide to our customers.

According to government forecasts for climate change impacts in Victoria[6], the average annual number of days above 35 degrees Celsius is likely to increase from 9 days currently experienced in Melbourne to up to 26 days by 2070 without global action to reduce emissions.

Correlated to those forecasts, our network area is likely to experience increased bushfire risk due to higher temperatures and drier conditions.

3.2.1 Impacts to services

Climate change is an important issue that is likely to impact the services that we provide. We will continue to assess the impacts of climate change when making investment decisions and recognise that the risks that are likely to prevail over the next 20 years will include:

- warmer, drier summers raising possible issues with earthing, bushfires and increasing vegetation management;
- warmer, drier summers reducing asset capacities;
- changes in the timing of peak demand;
- increasing wind storms;
- a possible increase in lightning faults; and
- increasing use of air conditioning

Electricity asset capacity is constrained by ambient temperature, and increasing temperatures will require us to assess the risks associated with our existing designs.

5 Reference: Australian Parliament

6 Reference: http://www.climatechange.gov.au/climate-change/climate-science/climate-change-impacts/victoria

4. STRATEGIC ASSET MANAGEMENT DRIVERS

A series of strategic asset management drivers have been identified for the Jemena electricity network. Along with the drivers' specific to a particular asset class, these drivers are used as the basis for the development of the strategies adopted for the management of the various asset classes forming the electricity distribution network. These drivers are balanced so as to optimise the outcomes from the strategies.

These drivers include:

- health, safety and environment;
- stakeholder expectations;
- growth, demand and customer connections;
- supply reliability and quality;
- regulatory compliance (including technical, safety and the environment); and
- technology

A brief discussion of Risk Management within Jemena is also discussed within this chapter.

Comined these strategic asset management drivers help us to balance the individual asset class drivers with an overall network view, so we can optimise the outcomes from the strategies. This is important because the decisions we make today will affect asset condition, cost and performance over the life of the assets, and thereby affect our ability to provide the safety, service level and cost/price outcomes that our customers expect us to deliver. The following sections provide a summary of these drivers.

Figure 4–1: Safety, service levels, costs and prices

4.1 HEALTH, SAFETY AND ENVIRONMENT

Safety is a number one priority for Jemena. Jemena's policy directives include the following:

- Manage our assets without compromising our employees', contractors' and the public's safety, as per the Jemena Health and Safety Policy;
- Apply the Jemena risk management approach to asset management activities; and
- Facilitate continual improvement in the safety and performance of the assets, through the establishment, maintenance and governance of effective asset and safety management systems.

This includes, but is not limited to:

- providing a safe and environmentally sound network and workplace, and managing health and safety so as to eliminate workplace accidents, injuries and illnesses;
- proactively providing a safe environment for employees, contractors, and the public that meet or exceed our corporate standards and the requirements of relevant state and federal legislation;
- maintaining effective disaster recovery business continuity processes supported by approved plans that meet or exceed good industry practice;
- completing regular safety audits and providing appropriate training to staff;
- managing key network risks through the successful application of management controls and frameworks in conjunction with risk management systems to maintain the current risk profile; and
- ensuring that bushfire mitigation remains an integral element of the risk management program. The purpose is to minimise the risk of fires caused by electricity assets and to ensure compliance with legislative and regulatory requirements

All asset lifecycle activities are designed to ensure compliance to health and safety standards and legislation, as well as our own internal controls. We are committed to ensuring asset and public safety. Outcomes from reviews such as Electric Line Clearance Plan, ESMS and Bushfire Mitigation Plans are inputs to the strategies for each asset class.

Appendix A, Appendix B, and Appendix C provide the Jemena Asset Management, Environment, and Health and Safety Policies, which provide the governing principles by which we manage and operate the network.

We are committed to ensuring that all operations meet or exceed corporate safety standards and the requirements of relevant state and federal legislation, as well as meeting employee, customer and community expectations for the management of health and safety.

Throughout our customer engagement, customers strongly supported our focus on safety with almost universal agreement that safety should be the number one priority (96% agree strongly/somewhat). This was regarded as important not just for the community but for our own employees.

4.2 STAKEHOLDER EXPECTATIONS

Stakeholders are defined as our customers, network users, the industry regulators, government departments, and the broader community. We must consider and balance the competing interests and preferences of stakeholders including:

- 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;
- technical and economic regulators;
- local governments, who are customers of our public lighting services; and
- energy retailers, who collect revenue from small customers on our behalf

The community expects environmental responsibility; a safe and reliable level of service; a responsive service; public amenity; equitable levels of service available to all consumers; and affordable pricing.

Understanding our customers' long-term preferences is critical to us in providing the services that our customers expect. We must also balance this with the interests of other stakeholders, including our regulators (the Australian Energy Regulator, Energy Safe Victoria), and Federal and State Governments. Community expectations drive both our shorter term planning and our longer term planning. In the case of the development of this document, our community has had opportunities to engage with us about long-term preferences. This is part of our efforts to better understand our customers' preferences and ensure that we provide services that are in their long-term interests. Additional detail relating to the results of our customer engagement can be found in Appendix E Customer Preferences.

4.3 GROWTH, DEMAND AND CUSTOMER CONNECTIONS

Growth, demand, and customer connections can be driven by the the following:

- **Customer demand and energy forecasts -** Meeting anticipated maximum demand with acceptable levels of security and reliability of supply is a capacity and demand driver. This may require increases in capacity of the integrated assets;
- **New customer connections, numbers and growth** – we are obliged to connect new customers to the network, ranging from individual properties and urban residential developments through to new large commercial and industrial customers;
- **New and additional supply points (underground and overhead), increased supply, upgrading of low voltage mains, minor low voltage extensions and the installation of low voltage substations;**
- **New or upgraded public lighting including both major and minor road schemes, single major and minor lights, watchman lights, and sustainable lights;**
- **Capital works carried out for customers** (including authorities) where the actual costs are externally financed and for which the prime purpose is to satisfy a requirement other than new or increased supply. This includes customer or developer requests for minor pole relocations together with distribution network rectification work due to third party damage; and
- **Embedded generation and demand-side management initiative**-this becomes relevant when existing and new installations influence demand levels and technical characteristics across the network in a dynamic and complex manner; and
- **Maintaining supply and asset utilisation** - pre-defined, 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. Solutions to these may be either demand management (as a solution to reduce energy at risk), or traditional network augmentation.

The implications of these customer and demand drivers for our 20 year asset planning and management are set out in Chapter 1.

4.4 ASSET INTEGRITY

Asset integrity covers the provision of the required service standards expected of the particular asset class. Aspects of asset integrity include:

- **Service standards** - prescribed service levels are mandated through license conditions and regulations. Increasing fault levels, voltage issues, reactive power issues and degaradation in power quality may drive network augmentation.
- **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 that must be managed based on the safety and reliability risks involved.
- **Service target performance incentive scheme (STPIS)** - provides a mechanism for the AER to financially reward (or penalise) service performance. Annual targets are based on the previous year's performance (the regulated period).
- **Maintaining asset integrity through a combination of asset performance, risk and operational safety** - a network failure, due to a loss of asset integrity can cause personal injury or loss of life, property and environmental damages and loss of supply. Our asset management needs to comply with corporate and legislative requirements. This is linked closely to, and overlaps with the health, safety and environment driver.

4.5 REGULATORY COMPLIANCE

Aspects of compliance that are asset management drivers 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.**

We will continue to ensure safe and efficient operations in the future by complying with corporate and legislative requirements, as well as implementing prudent and industry best practice measures so as to meet customers' long term interests.

4.6 TECHNOLOGY

Changes in technology and network capability can be a driver for changes in how we manage the network. These drivers, and the context for Jemena is discussed in detail in Chapter 6 and Chapter 8. Technology drives include, but are not limited to:

- **Demand side technology**
  - Demand management technologies and innovation (storage, AMI, distributed generation, customer side innovation); 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 new AMI technology to better empower customers to more efficiently use electricity and also incentivise behavioural usage change to reduce traditional ‘poles and wires’ expenditure and focus more on smart technology use.
- **Supply side technology**
  - Network monitoring and control; and
  - Information technology-based systems for network operations, engineering and capital works, customer management, retailer management, billing, and corporate services.

In addition to these, changes in technology may drive change in how we manage the asset to ensure efficiency in the provision of our services and ensuring that our expenditure is in the long term interests of customers.

4.7 RISK MANAGEMENT

All of the preceding drivers are assessed through a structured risk management program that is essential to minimise reasonably foreseeable disruption to operations, harm to people and damage to the environment and property, and all our risk management activity is governed by the Jemena Risk Management Policy and Framework. This framework is designed to enable us to identify, evaluate and appropriately manage credible risks to low as reasonably practicable and minimise the costs of doing so.

Our long-term asset management decisions will be prudent from the perspective of both customers and investors, and will reflect the way the regulatory framework supports and provides certainty to our investors in terms of recovering their capital investments.

Certainty is primarily provided by the AER’s regulatory framework, which provides reasonable opportunities to recover network investments as well as ensuring efficient long-term investment decisions. This has become even more important as alternative energy sources have become commercialised and increasingly affordable and accessible.

5. SERVICE LEVELS

5.1 LEVEL OF SERVICE ATTRIBUTES

Stakeholder feedback has been used as the basis for level of service attributes in scenario modelling that we undertake. The relationship between the attributes tested and the indicators is as follows:

1. **Safety**[7]
   - Loss of integrity of assets, personal injury or loss of life, property and environment damages, loss of supply.
2. **Visual Amenity**
   - Vegetation management, more attractive substation design, bundling of insulation of overhead lines, and undergrounding.
3. **Responsiveness**
   - The time it takes to respond to supply interruptions, the time to reconnect customers, the time required to connect new customers, and the time to respond to emergency events.
4. **Reliability and Quality**
   - The frequency of unplanned service interruption, and the quality of the services provided.
5. **Affordability**
   - Ensuring the most efficient delivery of services to customers.

We measure our performance on an ongoing basis to ensure we consider and meet the resulting targets set by the Regulators (AER and ESV), the market operator (AEMO[8]), and our own targets based on our customers' stated preferences. There are also regulatory incentives for performance improvements and penalties when performance declines through the AER (e.g. STPIS).

While our short term service level targets are set by the regulatory regime, we also have engaged customers to understand their long term preferences with respect to service levels given the cost consequences of these and the fact that our assets have a very long service and cost recovery life.

Chapter 10 discusses the impacts of various capital and operational expenditure scenarios on these indices and our customers' feedback on these.

5.2 SAFETY

The total number of reportable incidents to ESV is a measure used for tracking safety reporting. This measure provides a lag indicator on the effectiveness of the risk management systems and processes. Overall safety performance is driven in the long term by the application of rigorous design standards, controlled project management and construction processes, and prudent investment in asset replacement expenditure.

7 JEN sees the safety of its employees, customers, and the community as a non-negotiable top priority.

8 AEMO annually undertakes surveys to determine the value of customer reliability (VCR). We use this in evaluating network augmentation projects and reliability, quality maintained projects.

In the shorter term safety can be adversely impacted by reduction in replacement, operations and maintenance expenditure and resourcing.

5.3 RELIABILITY AND QUALITY

5.3.1 RELIABILITY

The JEN reliability performance is measured on a continuous basis, and targets are set based on our historical performance (through the AER). Known as service standard factors (or s-factors), these indicators determine the percentage of allowable revenue increase or decrease that applies to each regulatory year up to the value of revenue at risk (5%).

The measures involve two indices that directly relate to reliability:

- Momentary Average Interruption Frequency Index (MAIFI)[9]; and
- System Average Interruption Frequency Index (SAIFI)[10].

Our performance has been consistent over the past 10 years, reflecting our maintenance of reliability, but also the achievement of improvements and cost effectiveness, having regard to our customers' willingness to pay for reliability under the STPIS incentive scheme. SAIFI and MAIFI performance levels over the last ten year period can be found in the ELE PL 0004 - Asset Management Plan.

Reliability is an integral part of our service, and our target achievements reflect our focus on providing this. Maintenance of our current service levels beyond the next planning period has been identified as a key customer preference.

5.3.2 QUALITY

Quality of supply issues involve the accuracy of the supply voltage, the shape of the voltage waveform (as measured by harmonic distortion), and momentary changes in supply voltage that include sags, swells transients and flicker. Our customers have indicated a preference for us to maintain existing levels of service (see Chapter 10). Presently, our focus is on ensuring that power quality on our network does not adversely impact equipment performance or asset life expectancies.

To meet customer preferences with respect to power quality, we monitor and manage:

- power quality performance, to identify existing problem areas or worsening trends by using information from the power quality monitors;
- customer supply voltages, to ensure they comply with mandated regulatory quality of supply limits;
- over-voltage events and the number of customers receiving them;
- high voltage injections;
- voltage variations;
- complaints (technical quality of supply and numbers); and

[9] MAIFI is the total number of momentary interruption events (less than one minute) that a customer experiences in a year, on average.

[10] SAIFI is the number of occasions, on average, each customer experiences an outage in excess of one minute in a year.

- distribution losses

Table 5–1 lists power quality performance statistics for the period 2010 to 2014.

Table 5–1: Power quality performance

Year	Voltage variations-steady state feeders	Voltage variations-steady state ZSS	Voltage variations – 1 minute	Voltage variations-10 seconds
2010	2897	396	0	48
2011	1091	143	27	1377*
2012	3428	214	46	1395*
2013	3392	72	38	850*
2014	1622	148	39	760*

(1) Voltage variations denoted by * includes all voltage variations that have minimum voltage below 0.9 of set point voltage

Power quality has remained within the ranges outlines in the NER in recent years. That said, power quality is likely to become increasingly important to electricity customers, particularly in the manufacturing sector, and there are several quality-of-supply impacts we need to account for in planning and managing our network that we expect will continue for the next 20 years. As we see growth in distributed generation, increased power quality issues will require active network management. Additional contributory factors will include:

- the increased sensitivity of customer electrical equipment;
- reduced equipment life and performance;
- increased penetration of non-linear loads;
- increased penetration of air-conditioning; and
- non-linear and intermittent loads

5.4 RESPONSIVENESS

To measure our responsiveness to network incidents/failures, we review our performance on an ongoing basis.

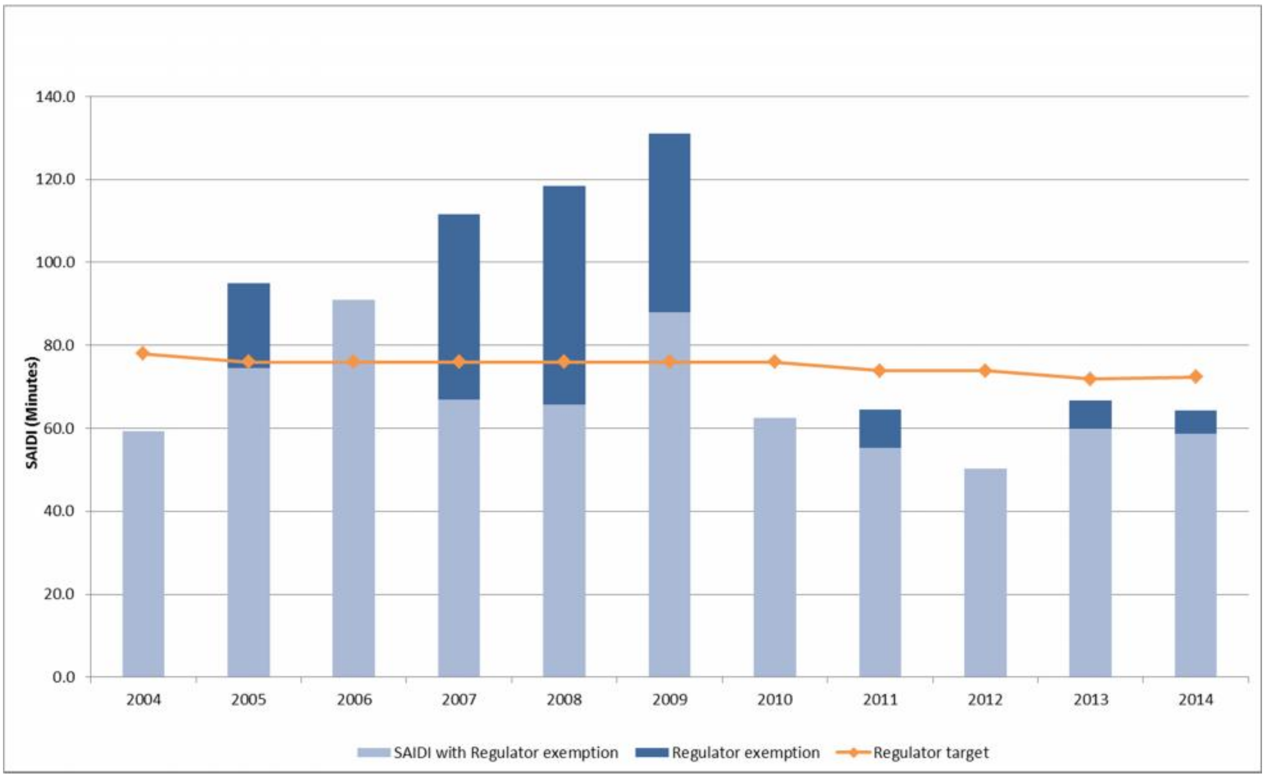
Targets are based on our historical performance and are set by the AER. Known as service standard factors (or s-factors), these indicators determine the percentage of allowable revenue increase or decrease that applies to each regulatory year up to the value of revenue at risk (5%).

The measures involve two indices that directly relate to responsiveness:

- System Average Interruption Duration Index (SAIDI)[11]; and
- Customer Average Interruption Duration Index (CAIDI)[12].

Figure 5–1 shows the actual SAIDI (in minutes) as compared to the annual reliability targets for the period 2004 to 2014.

Figure 5–1: System Average Interruption Duration Index (excluding planned)



Responsiveness to customers is also measured through timely performance of customer works, and our responsiveness to customer communications.

We place customers central to our decision making and planning, and monitor a range of customer service indicators to ensure that we track and improve service performance, and meet the guaranteed service levels as

[11] SAIDI is the total minutes, on average that a customer is without electricity in a year.

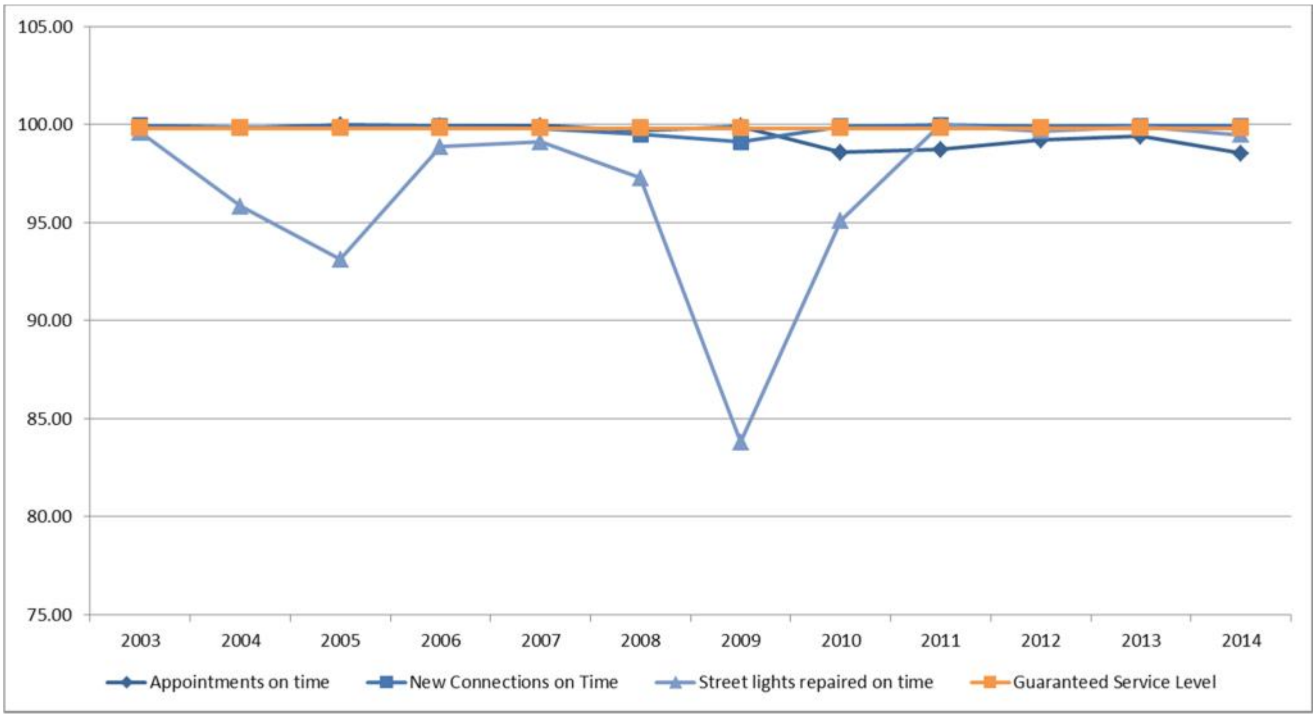
[12] CAIDI is the average time taken for supply to be restored when an outage greater than one minute has occurred.

specified in the Electricity Distribution Code and the Public Lighting Code. Our focus for customer service includes:

- meeting customers' appointments on time;
- making supply connections within agreed periods;
- fixing public lights to agreed time periods;
- reducing the number of distribution complaints; and
- ensuring timeliness in responding to calls

Table 5–2 shows our performance in terms of appointments, new connections and repairs as compared to our service level guarantees for the period 2003 to 2014.

Figure 5–2: Customer guaranteed service level performance



Chapter 10 discusses the impacts of various capital and operational expenditure scenarios on this measure to ensure an approach which is in the long term interests of customers is selected.

Reliability is an integral part of our service, and our target achievements reflect our focus on providing this. Maintenance of our current service levels beyond the next planning period has been identified as a key customer preference.

Customers' experience of responsiveness is a function of asset condition, capacity loading, and our retention of a sufficiently resourced emergency response labour force. Our 20 year strategic asset management plan reflects our continued maintenance of our responsiveness levels that customers have told us they value. This inherently involves a level of capex and opex trade-off that balances service performance outcomes with total expenditure outcomes.

6. NETWORK CAPACITY AND DEMAND, AND CONNECTIONS

This section provides information about network capacity and demand, and connections, a summary of the 20 year plans, and a forecast and analysis of both volume and expenditure for the next 20 years.

Meeting and managing anticipated maximum demand with acceptable levels of security and reliability of supply is the primary driver for network capacity and demand expenditure and operating expenditure on demand management activities. Other factors include:

- electricity demand and energy growth;
- fault level management and mitigation;
- power quality maintenance and mitigation;
- voltage issues; and
- reactive power issues

A full list of the network development strategies that are developed are provided in Appendix F - Key Document References.

6.1 NETWORK CAPACITY AND DEMAND

Network capacity and demand requirements

The requirements and considerations that underpin network capacity and demand decisions include:

- the value of customer reliability (VCR);
- network outage rates and durations; and
- network augmentation costs

We undertake network augmentation to cover any load shortfall that cannot be economically met by other means. Our augmentation investment decisions aim to maximise the present value of net economic benefits to all electricity producers, consumers and transporters in the National Electricity Market (NEM). To achieve this objective, we apply an economic planning methodology that considers the likelihood and severity of critical network outages. This methodology:

- combines the expected supply delivery impacts, which could be due to network outages or in some cases just high demand conditions, with VCR, which is the value consumers place on supply reliability; and
- compares the combined outcome with the augmentation costs required to reduce the likelihood and/or impact of supply interruptions

To ensure net economic benefit maximisation, we only undertake augmentation projects where the benefits to customers outweigh the costs of the proposed network augmentation. Since there will not always be an economically feasible solution to mitigate an identified supply risk, this planning methodology carries an inherent risk of not being able to fully supply demand.

Typical network augmentation works to meet increasing demand on our network can include:

- re-conductoring overhead power lines with higher capacity conductors;
- establishing new sub-transmission lines and re-arranging existing sub-transmission loops;
- establishing new high-voltage distribution feeders and re-arranging and transferring load between existing feeders;
- adding transformers to existing zone substations;
- establishing new zone substations;
- installing distribution transformers;
- installing new capacitors or reactors; and
- installing voltage regulators

We also consider non-network solutions (such as demand management and embedded generation) to ensure supply costs, quality and reliability standards match our customers' preferences.

In supplying the forecast maximum demand, we aim to maximise utilisation of our existing assets before considering network augmentation. The publication of our Distribution Annual Planning Report (**DAPR**) informs stakeholders of our planned projects and provides them with an opportunity to review planned projects, network constraints and propose potential alternative solutions.

6.1.1 NETWORK DEMAND ANALYSIS

The main findings from our network demand analysis include the following:

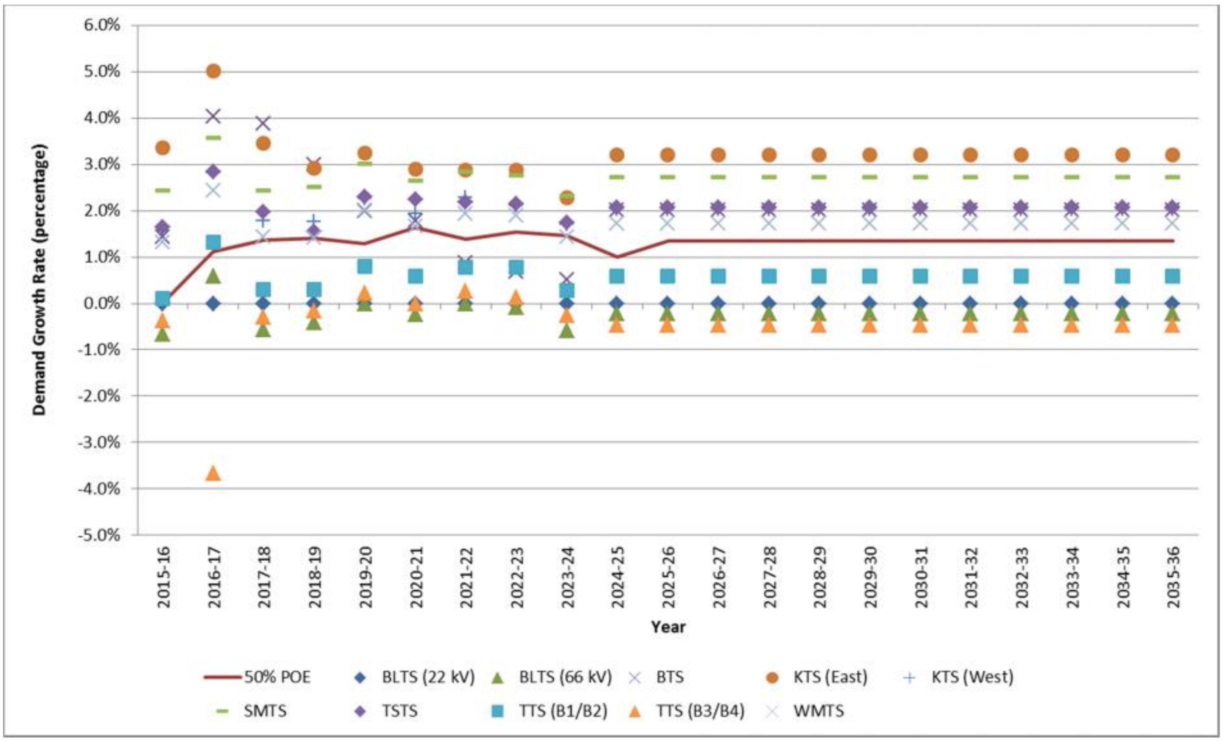
- The network-wide maximum demand growth rate is forecast to slow over the next 20 years, to an average of 1.4%[13] per annum, compared to the long-term average of 2.7%. This is largely due to energy efficiency technology and action reducing peak demand growth, and rooftop photovoltaic (**PV**) connections offsetting summer demand growth. In the short to medium term, this is also influenced by the significant expansion of Melbourne Airport. This is expected to be driven by a return to trend GDP growth[14], as well as a stabilisation of electricity prices over the period.
- Despite the slowing maximum demand growth rate, there are still pockets of significant maximum demand growth that require network augmentation. These pockets are driven by urban sprawl in the northern part of our network and new high-rise residential developments in established areas throughout the network.
- Some areas within our electricity network will experience a decline in maximum demand over the next 20 years, due to large commercial business closures and the continued impact of rooftop PV connections and energy efficiency technology.

Over the past eleven years, peak demand has grown by an annual average of 2.7% (see Section 5.4 Network Connections for information about augmentation growth at low voltage). Network augmentation expenditure is primarily driven by peak demand growth, as opposed to annual energy growth, including localised peak demand growth that does not necessarily coincide with the network-wide peak.

[13] 50% Probability of exceedance

[14] Annual growth in GDP according to the historical trend

Figure 6–1: Forecast Demand Annual Growth and non-coincidental demand



Source: ACIL Allen Consulting. Jemena Electricity Demand Forecasts Report - 20 November 2014.

As per the figure above, despite low aggregated network-level maximum demand, augmentation expenditure is still required due to localised network constraints (as identified by the demand growth at the various terminal stations (SMTS, TSTS, TTS, BLTS, BTS, KTS (East), KTS (West), WMTS)[15]. AEMO has forecast[16] increased residential and commercial consumption in Victoria, driven by strong population and income growth (the highest of the NEM regions).

Our network is experiencing significant demand growth in the north, due to urban sprawl toward the edge of the urban growth zone. As a result of this urban sprawl and the rezoning of areas to increase urban growth zones, over the next six years we expect to see strong maximum demand growth in areas currently supplied by the zone substations at Somerton (forecast to grow at an average of 5.0% per annum), Sydenham (3.1%), Sunbury (2.6%), and Coolaroo (2.0%).

In addition to growth in the urban growth zones, we are also experiencing significant growth in established pockets of the network. This growth is predominately due to the development of high rise residential and office buildings, and the expansion of community facilities and services, such as around Essendon Airport and Melbourne International Airport. As a result, over the next six years we are forecasting high growth in maximum demand for areas currently supplied by the zone substations at Footscray East (forecast to grow at 5.6% per annum), Fairfield (4.0%), Airport West (3.7%), and Coburg South (2.8%) zone substations.

15 SMTS- South Morang, TSTS- Templestowe ,TTS- Thomastown, BLTS -Brooklyn, BTS- Brunswick, KTS (East)- Keilor East, KTS (West)-Keilor West, WMTS – West Melbourne

16 Reference: National Electricity Forecasting Report June 2014

This increase is moderated by increased forecasts for rooftop PV penetration and energy efficiency offsets. Victoria's growth in rooftop PV uptake is the second highest in the NEM[17]. This distributed generation growth has been caused by a reduction in rooftop PV system costs while financial incentives have remained the same.

Augmentation expenditure is expected to be higher than average in the 2016-2020 period due to off-trend projects that are required to maintain safety and reliability, which include the following:

- Installation of rapid earth fault current limiters (**REFCL**) at our more rural sites. These devices will limit fault current, thereby reducing the chance of fire ignition resulting from network faults.
- Conversion of our Preston and East Preston high voltage supply areas from 6.6 kilovolt to 22 kilovolt. Replacement works are required due to the condition of the assets, and higher voltage equipment is more cost effective because 6.6 kilovolt equipment is no longer commonly used, and the higher voltage will reduce network losses and provide additional capacity, which is required to manage the heavily loaded network surrounding these areas.

The long term augmentation capital expenditure requirement can be predicted by applying a long-run marginal cost to future maximum demand growth forecasts, adjusted for a unit rate increase. The net augmentation capital expenditure required may be lower if other, more economically viable, non-network solutions are available[18].

Fault level management and mitigation

Network fault levels are gradually increasing due to increases in customer load requirements and corresponding increases in network interconnection and generation, particularly distributed generation connections that add new current sources close to load dominated areas. As a result, fault level mitigation measures are required to ensure fault levels remain within network design capabilities to safely withstand and quickly switch and isolate faulted sections. As a result, active management of network fault levels is required.

Fault level management and mitigation options include:

- installing higher rated circuit breakers and other network equipment, to ensure network assets are capable of withstanding and isolating faults with increased fault currents;
- installing current limiting equipment to reduce prospective fault levels; and
- network splitting and rearrangement to reduce prospective fault levels

Fault levels have a significant impact on the likelihood of a bushfire being ignited by an electrical fault. Reducing fault levels can help to mitigate this risk, and we are proposing additional augmentation expenditure in our 2016-2020 forecast for the installation of REFCL at some of our more rural sites.

Based on innovation and change, we expect the cost associated with fault level management and mitigation to become significant over the next 5 to 10 years as low cost options are becoming increasingly scarce.

Power quality maintenance and mitigation

Residential loads have changed over the last 10 years. In addition to more traditional loads, modern loads now typically include sophisticated power electronic devices that can cause a range of power quality issues. Additionally, the number of embedded generation proponents connecting to our network has increased, which

[17] Reference: Energy Green Paper 28/09/14

[18] Non-network solutions have not been undertaken on our network yet. We have assumed a historical trend in Capex, and future forecasts will be updated to reflect the learnings from our proposed trials during the 2016-20 regulatory period.

will lead to long-term expenditure increases for power quality/safety measures, depending on supply security, reliability and quality standards.

Three power monitoring systems continuously monitor voltage supply at the zone substation 6.6 kilovolt, 11 kilovolt and 22 kilovolt buses, and at strategic 240/415 volt buses at the end of various feeder lines. These systems record:

- steady state voltage levels;
- short-duration voltage disturbances, including sags, swells and transients;
- voltage harmonics; and
- voltage imbalances

The information recorded by these devices enables us to identify power quality issues and rectify them. With the penetration of non-linear residential load expected to increase with the proliferation of power electronics devices, augmentation expenditure to maintain power quality within specified limits is expected to increase.

Reactive power control and voltage issues

Due to the relatively small size of our electricity network, voltage and reactive power issues are generally not particularly limiting. However, given the forecast growth to the north of our network, and its relative remoteness from the bulk of our network and network supply points, regulating voltages to a suitable level will require additional work in the near future.

During the 2016-2020 period, we are proposing to install voltage regulators to maintain suitable voltage levels on two Sunbury feeder lines. New capacitor bank installations are planned at four zone substations (Braybrook, Coburg South, Heidelberg and North Heidelberg) within the same period. These new installations will help to maintain suitable reactive power levels, while also providing some thermal capacity benefits by slightly off-loading the zone substation transformers.

As areas develop throughout the urban growth zone, additional works (potentially including installing voltage regulation plant, network strengthening or even establishing new zone substations) may be required to manage long-term voltage levels. The establishment of new zone substations will require assessing the need for additional reactive support and in-line with past trends is expected to include the installation of some reactive support plant.

Network property

With increasing network demand, particularly in the more remote areas to the north of our network, new zone substations will be required to supply future demand. This will require the purchase of appropriately zoned and located sites. Based on forecast demand growth (and where growth is located), we expect to purchase an average of two new zone substation sites during each five-year planning period.

We recently purchased land for the zone substation proposed for Craigieburn in 2019.

The Sunbury zone substation site, which is currently leased, is slated for purchase in 2017 due to developments planned during the 2016-2020 period. The purchase will ensure any further investment at the site will be fully utilised for the life of the assets, without the risk of uncontrollable leasing costs.

6.1.2 NETWORK DEMAND FORECASTS

Table 5–2 lists the key economic measures and values that form inputs for network augmentation decisions.

Table 6–1: Key information - Augmentation

Measure	Growth Value
Economic growth/decline	2.75% per annum growth
Max peak demand growth/decline	1.4% per annum growth

(1) Source: ACIL Allen Consulting. Electricity Demand Forecasts Report. 20 November 2014.

6.2 CONNECTIONS

This section provides information about customer connections. Connections, which involve customer initiated network projects, represented an average of 37% of our annual capital expenditure over the last 5 years. Forming a significant component of our ongoing capital expenditure, the number of CIC projects initiated in any given year is largely outside our direct control. In the past, connections have formed a significant proportion of our total network capital expenditure.

6.2.1 NETWORK CONNECTIONS ANALYSIS

The main findings from the network connections forecasts include the following:

- Major customer initiated works during the 2016-2020 period are expected to result in a higher than average expenditure for that period. This is due to major development works at Melbourne International Airport, as well as some other off-trend customer-initiated connections.
- The total number of new network connections is expected to continue to grow by approximately four thousand per year over the next 20 years.

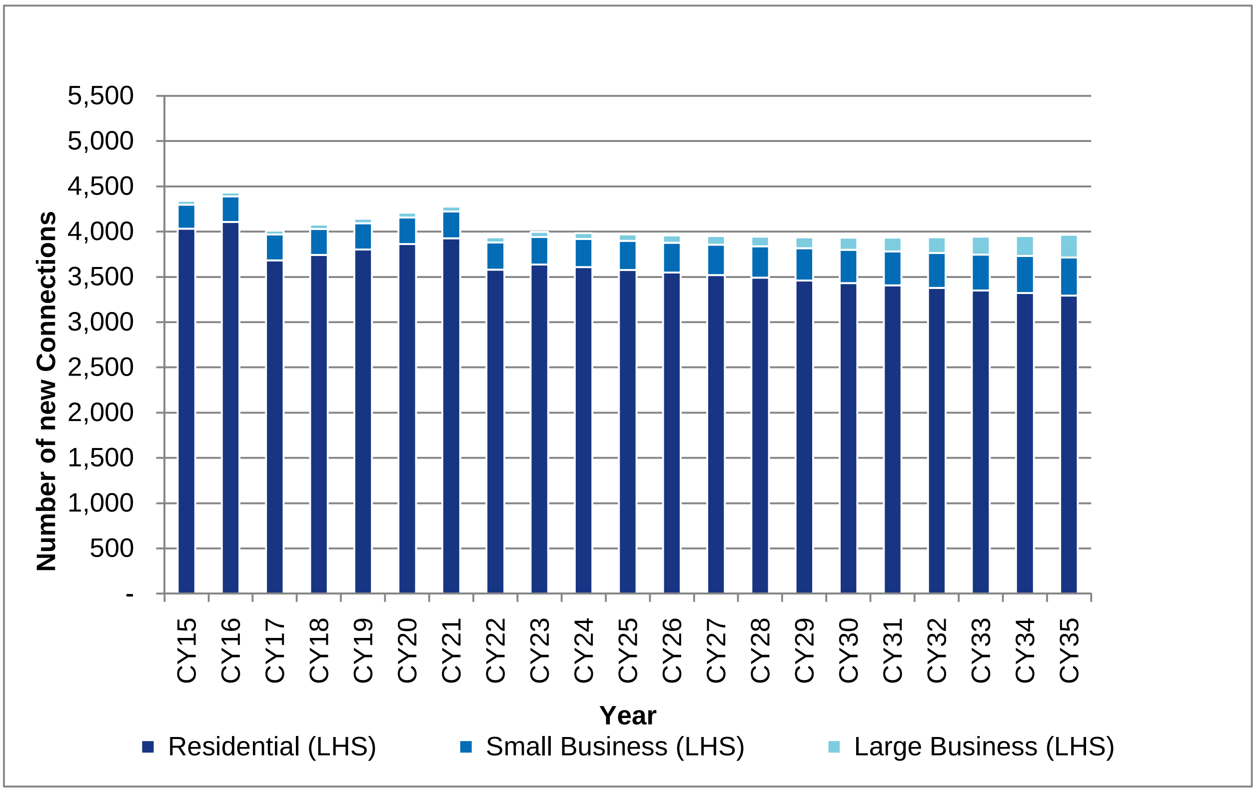
Network connections have, on average, formed a significant proportion of our total network capital expenditure. In response, we ensure that we:

- provide connections efficiently;
- optimise connection costs;
- recover the customer contribution;
- employ construction benchmarking; and
- determine and set appropriate tariffs

6.2.2 NETWORK CONNECTIONS FORECASTS

The figure below shows the forecast for customer connections volumes.

Figure 6–2: Connections volumes 2015-2035



7. ASSET CLASS STRATEGIC PLANS

This section provides information about asset class strategic plans based on the outputs of individual asset class strategies. We consider our strategic asset management drivers—set out in Chapter 4 in the development of our asset class strategies.

The Asset Management Strategy and Objectives[19] provides strategic direction for the development of the asset class strategies, and the asset class strategies provide an assessment of the asset performance, risks, issues and condition. Together, these documents help inform our short, long and medium term plans and forecasts.

The strategies for each asset class are based on the best practice approach to the management of assets including:

- asset acquisition/creation
- asset utilisation
- asset maintenance, and
- asset renewal/disposal

This approach ensures that we:

- establish the objectives and strategies required to achieve the balanced and efficient creation, utilisation, maintenance, and replacement of each network asset; and
- take an integrated approach to lifecycle management that assesses the impact of each element of the lifecycle on capital and operational expenditure to be considered

For more information about asset replacement strategies see JEN PL 0012. Growth, demand and customer connection drivers are not considered in this section, and are dealt with in Chapter 6.

7.1 ASSET CLASS STRATEGIES

This section provides information about our asset classes and asset forecast analysis. The asset lifecycle strategy for each asset class is included below.

Table 7-1: Asset lifecycle strategy for each asset class

#	Asset	Age Based	Failure Rate Based	Condition Assessment Based
1	Poles		✓	✓(1)
2	Pole Tops		✓	✓ (1)
3	Conductors & Connectors	✓	✓	✓
4	Overhead Line Switchgear		✓	✓(1)
5	Automatic Circuit Reclosers (ACR)		✓	✓(1)

[19] JEN PL 0012 – Asset Management Strategy and Objectives

#	Asset	Age Based	Failure Rate Based	Condition Assessment Based
6	Public Lighting	✓	✓	
7	HV Outdoor Fuses	✓	✓	✓
8	Surge Arrestors	✓	✓	✓
9	Pole Type Transformers		✓	✓ (1)
10	Non Pole Type Distribution Substations		✓	✓ (1)
11	Earthing Systems			✓
12	Underground Distribution Systems	✓	✓	
13	LV Services	✓	✓	
14	Substation Grounds			✓
15	ZSS Capacitors			✓
16	ZSS Circuit Breakers			✓ (1)
17	ZSS Instrument Transformers			✓
18	ZSS Disconnectors & Buses			✓ (1)
19	ZSS Transformers			✓ (1)
20	ZSS DC Supply Systems	✓	✓	✓
21	ZSS Protection	✓	✓	✓
22	ZSS Control	✓	✓	✓
23	Metering		✓	
24	Power Quality Monitoring Systems	✓	✓	✓
25	Communication Systems	✓	✓	✓

(1) Condition based risk model as discussed in Appendix H.

7.2 POLES

7.2.1 DESCRIPTION

We own almost 100,000 poles including public lighting poles. These include wood poles, concrete, steel, undersized wood poles, staked wood poles, and steel towers. Steel poles are typically used for public lighting. In the development of CBRM[20], poles were identified within three categories (including Public Lighting):

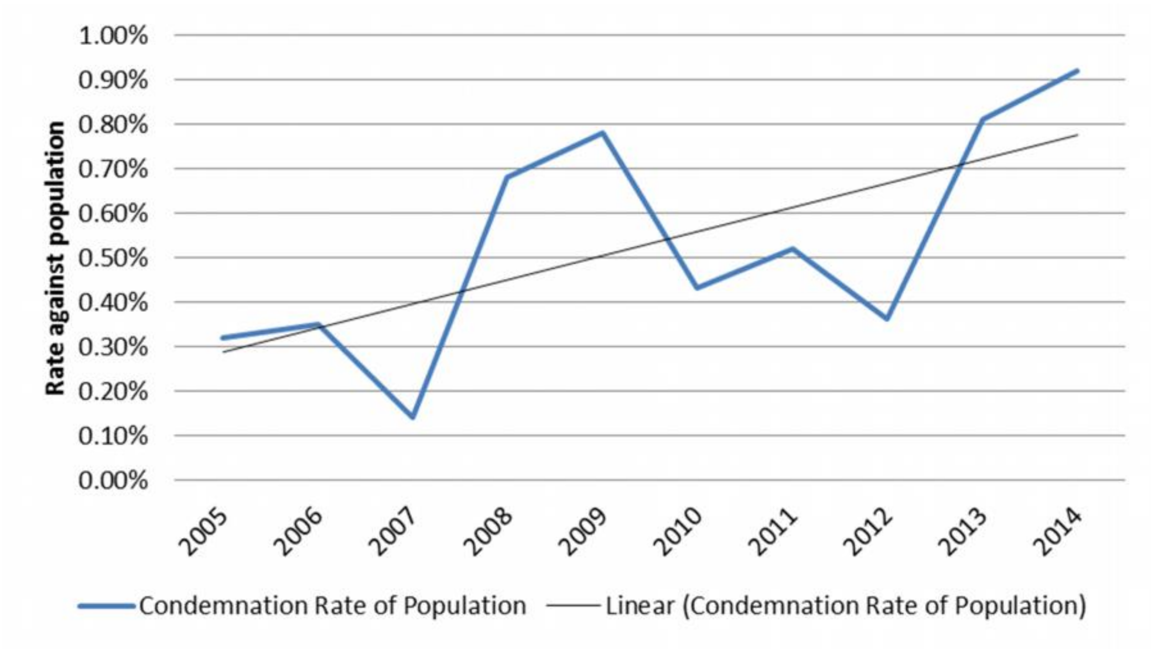
- Poles LV;
- Poles HV; and
- Poles ST

[20] CBRM is a proprietary model that uses an asset's information to generate to provide a quantitative risk evaluation across the asset population.

7.2.2 ASSET CONDITION

From 2005 – 2014 the condemnation rate of poles on the network has increased significantly. This is shown in Figure 7–1 below.

Figure 7–1: 2005-2014 Pole Condemnation Rates (of total population)



7.2.3 ASSET STRATEGY

We employ a condition based approach to the replacement and refurbishment of Poles, but use a combination of age and condition to forecast volume of replacements required. Poles that are deemed unserviceable are either staked (reinforced) or replaced. The condition of the pole is the primary driver for staking or replacement. The decision to either stake or replace a pole is based on condition using defined criteria outlined in the JEN Asset Inspection Manual. Poles that have previously been staked and have further deteriorated so that it is no longer safe for the pole to remain in service are also replaced. JEN requires that unserviceable poles are actioned within 12 weeks of identification.

Full details of capital and operational requirements are discussed in the Poles Asset Class Strategy (JEN PL 0024), the Asset Management Plan (ELE PL 0004) and Asset Inspection Manual.

7.2.4 ASSET CLASS SPECIFIC DRIVERS

Table 7–2 provides the asset class specific drivers for poles

Table 7–2: Asset Class Specific Drivers: Poles

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Significant numbers of undersized poles due to previous network ownership. Until 2011, undersized poles were allowed to remain in service provided there was sufficient sound wood and no external decay.	Failure of three undersized LV poles in wind storm in 2008 indicated replacement/staking required 10-20 years sooner than previously identified.

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Wood poles suffer ground line fungal timber rot.	Primary failure mode for wood pole leading to loss of supply, fire start etc.
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Ground line corrosion of steel poles is increasing, despite recent increase in replacement.	Many of these poles are used as public lighting poles in estates, the security of the cable access cover is a high priority to prevent access to the public. Increasing replacement required over the next five years.
Asset Integrity	Supply reliability risks associated with concrete poles installed due to historic use of the same insulation system as wood poles when initially rolled out despite the conductive nature of concrete poles.	Poor supply reliability (mostly resolved).
Regulatory compliance	Inspection of private overhead electric lines on a regulated 37 month interval mandated by ESV since 2010.	Increase in inspection activity.
Technological Developments	Improvements in preservation of hardwood through manufacturing (CCA), helping to extend asset lives.	Marginal extension in asset lives.

7.2.5 CAPITAL REQUIREMENTS

Poles have relatively low forecast failures when compared to the other CBRM assessed assets. However, as the consequence of failure is high in most instances (e.g. bushfire risk and public safety) and poles are a high volume asset on the network, it forms a significant component of our asset replacement program. This is to ensure that we maintain the network risk and safety levels.

Currently, where circumstances permit the replacement of unserviceable poles is deferred by pole refurbishment (utilising steel stakes). Copper Chrome Arsenate (**CCA**) treated hardwood poles are now almost exclusively used for all new/replacement works.

The table below provides the CBRM forecast replacement volumes for poles over the next four planning periods, based on the condition of the assets.

Table 7–3: Forecast Replacement Volumes: Poles

Asset Type	2016-2020	2021-2025	2026-2030	2031-2035
Poles	4918	8337	8337	8337

Notes:

(1) These volumes are based on CBRM 21 Year Forecasts (assumes flat line replacement across 2021-2035).

(2) These volumes are based on reinforcement/replacement of existing poles.

(3) Other drivers (augmentation, connections, compliance etc.) will cause these numbers to be different in total poles installed. This is not accounted for in the CBRM model.

(4) Excludes public lighting pole replacement (ACS/Negotiated).

7.2.6 OPERATIONAL REQUIREMENTS

Poles are inspected on a three-year cycle in hazardous bushfire risk areas, and a four year cycle in low bushfire risk areas. The criterion applied is defined in the Asset Inspection Manual.

To prevent ground line fungal rot of wood poles, localised wood preservative treatments can extend the service life of the poles significantly. We have an ongoing preventative maintenance program; however as indicated above, current trends indicate an increase in pole condemnation rates per number inspected. The age profile of poles also indicates that the rate of condemnation will rise significantly in subsequent periods.

7.3 POLE TOP STRUCTURES

7.3.1 DESCRIPTION

Pole top structures include crossarms and insulators (sub transmission, high voltage, and low voltage). 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 sub transmission poles. Current construction standards require the exclusive use of steel crossarms on high voltage and sub transmission poles. Wooden crossarms continue to be used exclusively on the low voltage network to facilitate safe work practices.

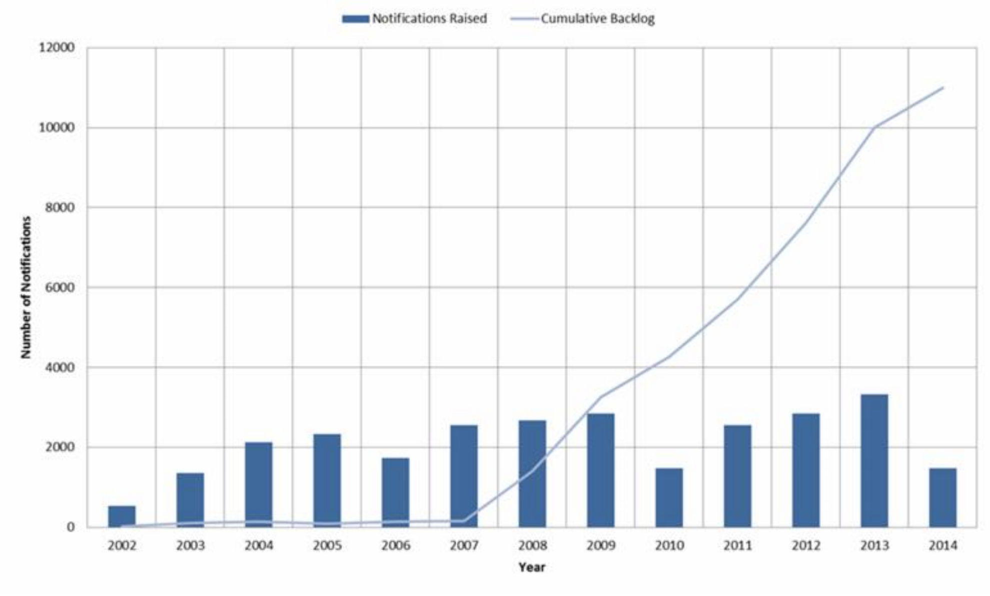
7.3.2 ASSET STRATEGY

We employ a condition based approach to the replacement and refurbishment of Pole Top Structures, but use a combination of condition and age to forecast replacement. Full details of the asset strategy and condition can be found in ELE PL 0004 Asset Management Plan, and the Asset Class Strategy JEN PL 0025- Pole Top Structures.

7.3.3 ASSET CONDITION

The trend in asset inspection results for pole top structures is indicating an increase in the rate at which pole tops are being classified as unserviceable and requiring replacement. Figure 7–2 shows the profile of cross arm condemnations against replacements each year since 2003. For 2014, this information only represents the notifications up until October 2014.

Figure 7–2: Backlog of notifications for cross arms



Source: JEN Pole Statistics Model – October 2014

It should be noted that while pole top notification rates are increasing, the number of pole tops being replaced is relatively consistent. To maintain network reliability, this program of work will need to increase over the next period, and beyond.

7.3.4 ASSET CLASS SPECIFIC DRIVERS

The table below provides the asset class specific drivers for Pole Top Structures

Table 7–4: Asset Class Specific Drivers: Pole Top Structures

Driver	Risk/Opportunity Description	Consequence
Extension of life of poles	Extension of the life of wood poles (through reinstatement and preservation treatment) has led to increased rate of pole top structure replacements.	Increased replacement of pole top structures due to pole maintenance and refurbishment programs.
Asset Integrity, Health, Safety and the Environment, Regulatory compliance	Wooden cross arm failure due to deterioration in wood due to weather, fungal attack and occasionally termite attack.	Failure leading to loss of supply, voltage injections, pole top fires, and ground fire starts.
Asset Integrity, Health, Safety and the Environment, Regulatory Compliance	Pole/Cross arm arcing due to combined effect of environmental condition (weather and particle build up on insulators) and wooden pole tops.	Ignition of the pole or pole top structure.
Asset Integrity	Bird/Animal strikes to pole top structures, particularly where an earth is at the top of the pole as in the case of concrete poles.	Supply reliability issues.

7.3.5 CAPITAL REQUIREMENTS

With the exception of targeted pole top fire mitigation programs to address identified high risk locations, no bulk replacement programs are in place.

Since 1980, all ST and HV crossarm installed on the network are steel (to reduce replacement cycle).

Table 7–5: Forecast Replacement Volumes: Crossarms and Insulators

Asset Type: Poles Type Structures	2016-2020	2021-2025	2026-2030	2031-2035
Crossarm and Insulators LV	29394	20763	20763	20763
Crossarm and Insulators HV and ST	10308	7775	7775	7775

Notes:

(1) These volumes are based on CBRM 21 Year Forecasts (assumes flat line replacement across 2021-2035)

(2) Other drivers (augmentation, connections, compliance etc.) will cause the total numbers to be different, and are not accounted for in the CBRM model.

7.3.6 OPERATIONAL REQUIREMENTS

Pole top structures are inspected on a three-year cycle in hazardous bushfire risk areas, and a four year cycle in low bushfire risk areas. The criterion to assess pole top structure is defined in the Asset Inspection Manual. There are no effective preventative maintenance programs that extend pole top structure life.

7.4 ZONE SUBSTATION TRANSFORMERS, SWITCHGEAR AND OTHER

7.4.1 DESCRIPTION

Zone substation transformers

There are 69 zone substation transformers on the network. These have a forecast engineering life of 50 years. Zone substation transformers are critical to ensure that we maintain network reliability and safety. On average, a zone substation has three transformers supplying over 10,000 customers.

Fifteen of the zone substation transformer were installed over a five year period from 1963-1968, so many of these are likely to require a higher level of replacement over the next 10 years, with decreasing numbers between 2026 and 2035.

Zone substation switchgear

Zone substation switchgear includes Circuit breakers and Disconnects/Isolators. This asset group also includes instrument transformers, but the it has been assumed that the replacement volumes for this asset type will remain consistent with 2016-2020 forecast levels from 2021-2035.

Zone substation other

This includes substation grounds, control buildings, earth grids, minor property works, and capacitor banks. For the purpose of the 20 year plans, this has been assumed to be maintained at 2016-2020 forecasts in the long term.

Other assets, such as high voltage fuses, surge diverters and fault indicators are assumed to be maintained at existing replacement levels for the 20-year forecasts.

7.4.2 ASSET CONDITION

Detailed condition information relating to zone substation transformers, switchgear and others can be found in the Asset Management Plan (ELE PL 0004), and also in the following asset class strategies:

Zone substation transformers

JEN PL 0042- Zone substation Transformers

Zone substation switchgear

JEN PL 0039 Zone Substation Circuit Breakers

JEN PL 0041 Zone Substation Disconnectors & Buses

JEN PL 0043 Zone Substation Instrument Transformers

Zone substation other

JEN PL 0038 Zone Substation Capacitors

JEN PL 0037 Grounds/Domestic Management of Zone & Non-Pole Type Substations

7.4.3 ASSET STRATEGY

The asset class strategies above provide the detailed asset strategies relating to each of the asset classes identified in this section. A combination of condition monitoring, preventative, and corrective maintenance approach is adopted for zone substation equipment. The high cost associated with these asset classes warrants this approach. Replacement strategies are specific to the asset classes.

7.4.4 ASSET CLASS SPECIFIC DRIVERS

The following provides a high level summary of the asset class specific drivers for zone substation transformers.

Table 7–6: Asset Class Specific Drivers: Zone Substation Transformers

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment, Regulatory compliance	66kV bushing on ZS Transformers (known manufacturer defect in Victorian electricity networks).	Failure of bushing leading to customer supply issue.
Asset Integrity	Long lead time for repair/replacement of zone substation transformers.	Risk to customer supply (approx. 10,000 customers impacted).
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Irreversible ageing of zone substation transformers due to moisture content in the insulation.	Increasing likelihood of failure of the asset leading to customers off supply, and increased risk to public, employee and contractor safety.
Asset Integrity	Overloading of zone substation transformers.	Reduce asset life of transformers causing earlier replacement.
Regulatory compliance, Health, Safety and Environment	Reducing core clamping pressure in Zone substation transformer.	Increasing levels of noise.

Driver	Risk/Opportunity Description	Consequence
Regulatory compliance, Health, Safety and Environment	Non-compliance of older stations with noise regulations (particularly during peak load conditions).	Increasing levels of noise.
Regulatory compliance, Health, Safety and Environment	Typical ZS transformers contain 18,000 litres of oil and historically not all of these tranformers have been bunded.	In the event of oil leaks, risk of non-compliance with environmental requirements.
Technological Developments	Improved preventative moisture in insulation methodologies extending the life of the insulation.	Improved asset maintenance (Trojan equipment).

The following provides high level summary of some of the asset class specific drivers for zone substation switchgear.

Table 7–7: Asset Class Specific Drivers: Zone Substation Switchgear

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment	Circuit breakers experiencing tripping defects (slow operation, maloperation etc.).	Failure to fulfil critical network functions, that could cause significant numbers of customers off supply (i.e. Zone substation protection tripping) Failure to insulate properly causing safety risks. Failure to interrupt fault currents.
Asset Integrity	Increased operational duty of some circuit breakers.	Will cause mechanical failure of the primary contact drive systems and lead to reduced asset life (particularly caused in the case of Zone substation Capacitor bank CB installations that are operated on a daily basis).
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Leaking insulating compound on some CB bushings.	Will cause failure if unattended, leading to interruption of supply to customers.
Asset Integrity	Some CB types have been identified as suffering age related deterioration of the insulating systems (related to synthetic resin bonded paper bushings).	Failure may lead to customer supply interruption.
Asset Integrity, Health, Safety and Environment	Increasing fault levels at zone substations needs to be monitored to ensure that the interruption capability of the CBs is adequate.	Inadequate CBs causing supply, fault current interruption, safety and other risks.
Asset Integrity, Health, Safety and Environment	Disconnectors not closing/opening circuit properly	Failure to appropriately isolate plant within stations. Risk to employee safety.
Asset Integrity, Health, Safety and Environment	High resistance connections in some families of older bus systems.	Failure to appropriately isolate plant within stations. Risk to employee safety.
Asset Integrity, Health, Safety and Environment	Issue with latching mechanism in some disconnects, that also have a history of failure.	Will cause it to open during heavy loads/while carrying fault current. Risk to employee safety.

7.4.5 CAPITAL REQUIREMENTS

The capital requirements for the following assets are identified through a combination of condition assessment, and the use of the CBRM model, including the drivers described above. This ensures that all of the indicators for the asset (condition, age, failure rate) are considered in the forecast replacement.

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.

Table 7–8 shows the forecast replacement volume required to maintain the current levels of performance for zone substation transformers, circuit breakers and disconnects/isolators.

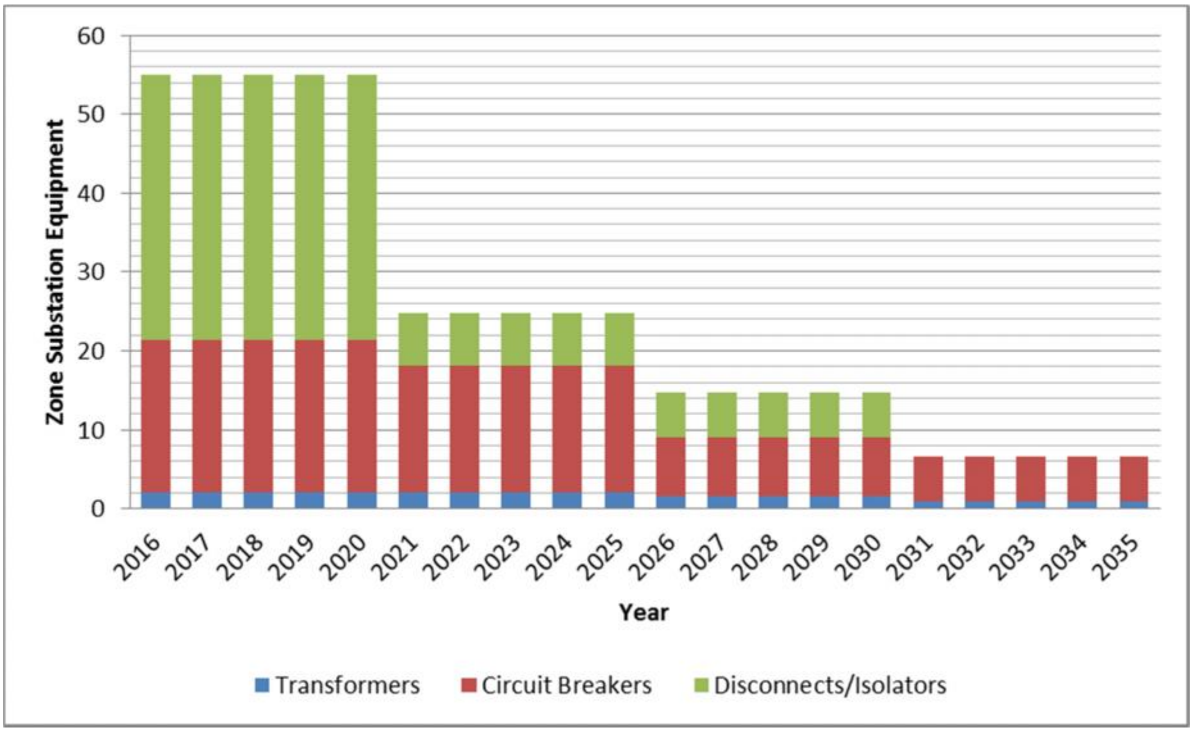
Table 7–8: Forecast Replacement Volumes: Zone Substation Transformers, CBs and Disconnects/Isolators

Zone Substation	2016-2020	2021-2025	2026-2030	2031-2035
Transformers	10	10	8	5
Circuit Breakers	97	81	37	28
Disconnects/Isolators	168	33	29	-

(1) Based on individual asset condition assessment with combined assessment of CBRM as at December 2014.

Figure 7–3 indicates the replacement volumes identified for zone substation equipment over the next 20 years.

Figure 7–3: Forecast Replacement Volumes: Zone Substation Equipment



7.4.6 OPERATIONAL REQUIREMENTS

We undertake a significant program of maintenance on our zone substation transformers, so as to extend the life and defer asset replacement where economical. The principal condition monitoring tools applied to power transformers include annual oil sampling and testing that includes dissolved gas analysis, furan analysis, particle count and moisture measurement. Also tests for dielectric response measurement (age assessment), thermal imaging, dielectric dissipation factor tests for high voltage bushings, monitoring of the on-load tap changer operation counters, monitoring of temperature alarms and load and general monthly inspections. Management of the moisture content in the insulation extends the life of the transformer. Two "On-line oil dry out units" have been purchased to treat zone substation transformers that have high moisture content.

The maintenance strategies for circuit breakers are preventative and corrective and are based on a combination of elapsed time and 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. The monitoring of high duty cycle zone substation circuit breakers has been modified due to increased likelihood of failure.

Maintenance of disconnects/isolator involves close inspection, checking of connections, cleaning of insulators, earth switches, surge arrestors and wall bushings. These are inspected on a monthly operational basis and also through the annual substation engineering audits. Infra-red thermographic surveys are also completed annually as part of HV plan surveys.

7.5 DISTRIBUTION SWITCHGEAR AND TRANSFORMERS

7.5.1 DESCRIPTION

Distribution Switchgear covers a range of asset types primarily associated with high voltage installations on the distribution network, including gas insulated switchgear, disconnectors (isolators), automatic circuit reclosers (ACRs), ring main units, and air break switchgear.

Distribution transformers include pole transformers and non-pole transformers. Pole type transformer replacement is undertaken as a result of substation capacity upgrade, remediation relocation, or transformer damage/failure. Together with the distribution switchgear, and protection equipment, non-pole transformers are a major component of non-pole distribution substations.

7.5.2 ASSET CONDITION

Detailed condition information relating to distribution transformers and switchgear can be found in the Asset Management Plan - ELE PL 0004, and also in the following asset class strategies:

JEN PL 0028 Automatic Circuit Reclosers

JEN PL 0030 HV Outdoor Fuses

JEN PL 0032 Pole Type Transformers

JEN PL 0033 Non Pole Type Distribution Substations

7.5.3 ASSET STRATEGY

The asset class strategies above provide the detailed asset strategies relating to each of the asset classes identified in this section.

7.5.4 ASSET CLASS SPECIFIC DRIVERS

The following provides a high level summary of some of the asset class specific drivers for distribution switchgear and transformers.

Table 7–9: Asset Class Specific Drivers: Distribution Switchgear and Transformers

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment	Air break switches fitted with arc chutes are prone to misalignment, corrosion, stiffness and breakage of components. 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/deterioration.	Reduced operational flexibility will result in customer interruptions during planned and unplanned work activities. Failed switchgear if operated can cause an electrical flashover which poses a risk to those in close proximity.
Asset Integrity	Disconnectors (isolators) may have loose mounting bolts, burnt button contact, hot connections and tracking of the insulators	Customer supply reliability will be impacted in the event of failure of a disconnect.
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Faulty or defective ACRs.	Loss of customer supply and/or the release of SF_6.
Asset Integrity, Health, Safety and Environment	Failure of pole type transformers (low probability).	Significant impacts to supply reliability and safety.
Asset Integrity	Integrity of gas pressure gauge on gas insulated ring main unit switchgear.	Impact to customer supply reliability in the event of loss.

7.5.5 CAPITAL REQUIREMENTS

The need to replace air break switches is identified when the switches are operated or via inspection. Any switch that is inoperable, or that requires extensive maintenance will be assessed for operational requirements and possible replacement with a gas insulated switch.

There is no plan for ACR refurbishment. Seven ACRs are forecast to be replaced in the next period.

Table 7–10: Forecast Replacement Volumes: Distribution Switchgear

Asset Type: Distribution Switchgear	2016-2020	2021-2025	2026-2030	2031-2035
Gas Switches	77	47	46	46
Isolators	112	62	62	62
ACR	7	3	3	3
Ring Main Units	25	14	14	14

Asset Type: Distribution Switchgear	2016-2020	2021-2025	2026-2030	2031-2035
Air Break Switches	282	183	183	183
Pole Transformers	167	452	452	451
Non Pole Transformers	48	115	115	115

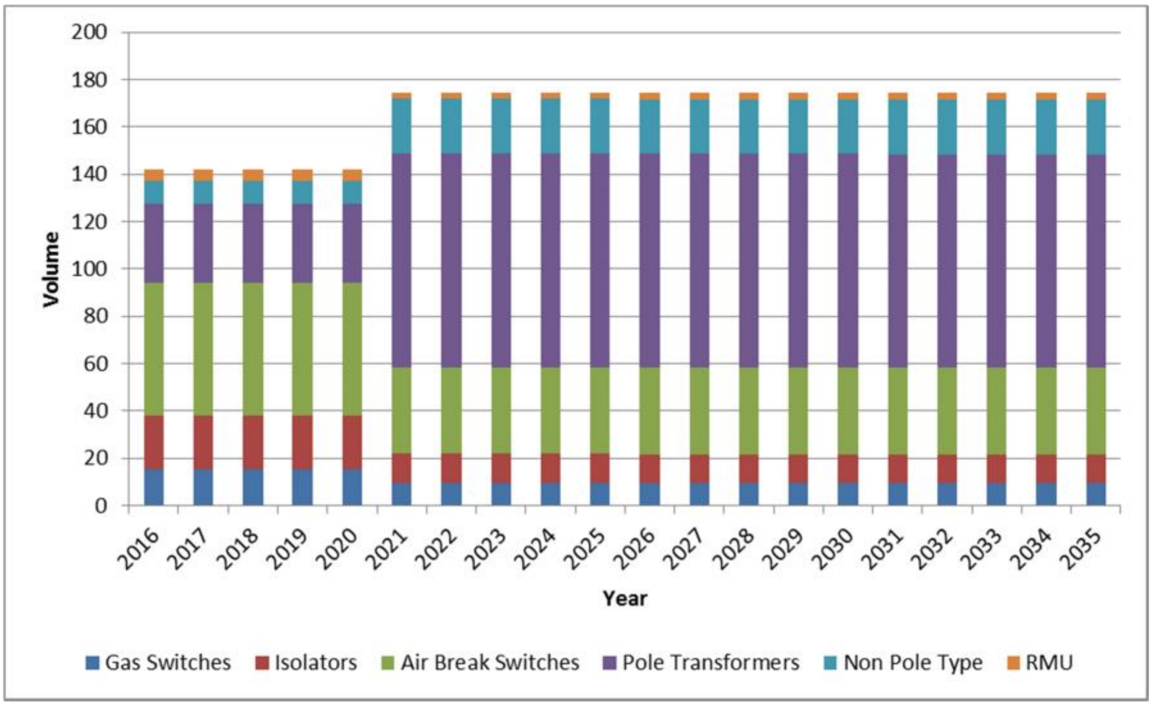
Notes:

(1) These volumes are based on CBRM 21 Year Forecasts (assumes flat line replacement across 2021-2035).

(2) The replacement volumes only indicate type of asset requiring replacement, not the solution for the replacement. (eg. Air break switches have not been installed on the network since 1995).

(3) Other drivers (augmentation, connections, compliance etc.) may cause these numbers to be different, and is not accounted for in the model.

Figure 7–4: Forecast Replacement Volumes: Distribution Transformers and Switchgear



As can be seen from the forecasts, an increase in the replacement is expected between 2021 and 2035. An increase in replacement volumes for distribution transformers is likely over the next 20 years. This increase is likely to be in parallel with the original installation volumes of the assets (refer to asset class strategies).

CBRM is consistent with this assessment and suggests that we will require an increase in our replacement volume for these assets after the next planning period.

7.5.6 OPERATIONAL REQUIREMENTS

The maintenance requirement for switches is determined from the results of scheduled inspections. Remote controlled gas switches are inspected every five years in conjunction with battery maintenance, while manually operated gas switches are inspected as part of the asset inspection program. A targeted inspection program for air break switches will commence in 2016 in addition to the asset inspection program.

Any switch that fails the inspection criteria is deemed defective (or inoperable) and is categorised as Caution Re Opening (**CRO**). In addition visual inspections, all switches and disconnectors are included in the regular thermal survey of overhead lines, where some may identified for repair or replacement.

ACRs are monitored in conjunction with the asset inspection program that is on a four year cycle in the low bushfire risk area, and a three year cycle in the hazardous bushfire risk area.

Pole type transformers are inspected as per the line inspection program, three-years in hazardous bushfire risk areas and four-years in low bushfire risk areas.

Non pole type distribution substations (which include non-pole transformers) are inspected as per the Asset Inspection Manual, with an earth resistance test (Non-CMEN) every 10 years. The inspection requirements for are set out in the Enclosed Substation Inspection Manual and include as a minimum the following: visual inspection of SF6 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, and security checks.

7.6 UNDERGROUND CABLE SYSTEMS

7.6.1 DESCRIPTION

We have in excess of 1,700 kilometres of underground cable in service on the network. These include old oil filled cable, paper insulated cable and more recently crossed linked polyethylene (XPLE) insulated cable.

In addition, we have low voltage pillars and low voltage pits.

Typically, underground cable systems are employed on a run-to-failure basis and are repaired when a fault is identified via fault locating techniques.

Faults may be caused by a number of factors:

- water ingress into the cable;
- breakdown of cable insulation (and associated partial discharge); and
- Third party intervention.

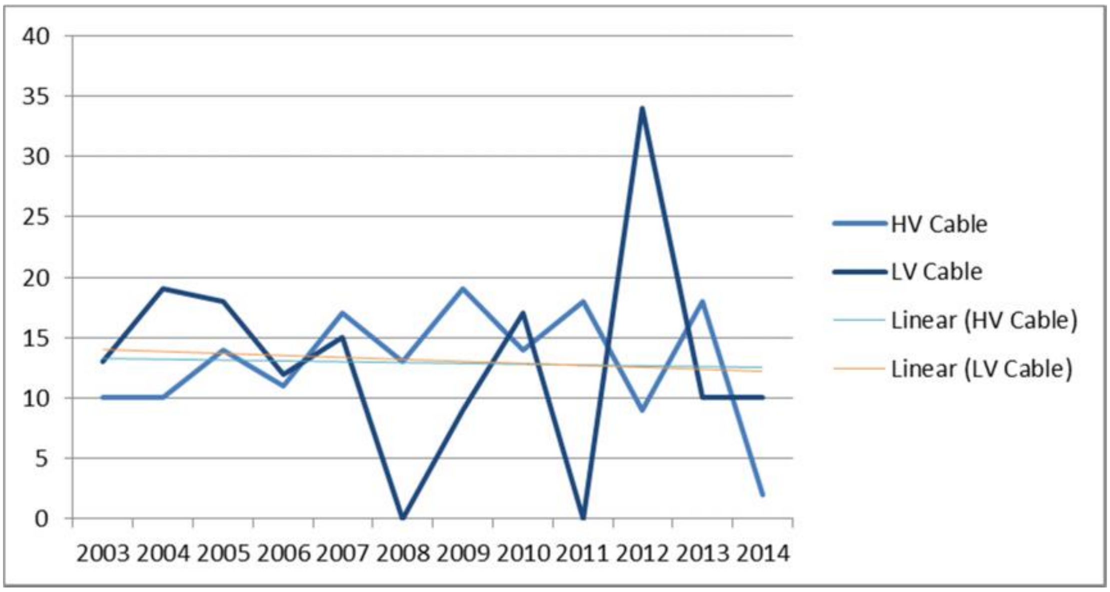
7.6.2 ASSET CONDITION

The following tables and figure provide an indication of the faults for HV and LV cables. More detail can be found within the asset class strategy, JEN PL 00035 Underground Distribution Systems and ELE PL 0004 Asset Management Plan.

Table 7–11: Historical Underground Cable Faults: HV and LV

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
HV Cable	10	10	14	11	17	13	19	14	18	9	18
LV Cable	13	19	18	12	15	0	9	17	0	34	10

Figure 7–5: Graphical representation of HV and LV Cable Faults



There have been elevated failure rates of 22kV XLPE cables, which were installed in the 1990s, mainly attributed to cable joint failures. This will be closely monitored over the next planning period to ensure network reliability is maintained.

7.6.3 ASSET STRATEGY

To date, a reactive replacement/repair strategy has been employed for HV and LV cables, with proactive maintenance of LV pillars and pits. An operational expenditure step change relating to cable condition monitoring is proposed for 2016-2020.

7.6.4 ASSET CLASS SPECIFIC DRIVERS

The following provides a high level summary of the asset class specific drivers for underground cable systems.

Table 7–12: Asset Class Specific Drivers: Underground cable systems

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment	Known trifurcating metal clad insulation risk.	Failures pose high risk to public safety.
Asset Integrity	Third party damage.	Asset failure leading to customer reliability, and also risk to safety.
Asset Integrity	Known issues with early XLPE manufactured cables (water treeing of the insulation due to steam curing, instead of gas curing during manufacture).	Customer supply interruption.
Technology	Improved condition monitoring techniques.	Customer supply interruption managed more effectively.

7.6.5 CAPITAL REQUIREMENTS

Currently, there is a program to phase out high voltage metal box outdoor cable terminations (trifurcating boxes), which are prone to failure and pose a high risk to public safety. This program will be completed over 3 of the next 4 planning periods, and involves identifying and replacing all older-style cable terminations with XLPE terminations.

Also, a significant risk is held for the approximate 7.3 km of 66 kV oil-filled cables. Only limited spares are available for this cable type, which may cause significant increases in outage durations in the event of a failure. This will need to be addressed over the next 20 years.

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.

Approximately 3.5 km of HV and 1.0 km of LV underground cables are forecast to be replaced in the 2016-2020 period. This is forecast to remain consistent over subsequent planning periods.

Table 7–13: Replacement Forecast Volumes: Underground Cable Systems

Asset Type	2016-2020	2021-2025	2026-2030	2031-2035
HV Underground Cable (km)	3.5	3.5	3.5	3.5
LV Underground Cable (km)	1.0	1.0	1.0	1.0
Terminations	193	193	193	193

7.6.6 OPERATIONAL REQUIREMENTS

Although there has been limited to no effective condition-monitoring system available for installed high voltage and low voltage cable systems, developments in partial discharge monitoring and testing are being investigated with a view to the implementation of a program to monitor and assess in-service cable condition 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.

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.

7.7 OVERHEAD CONDUCTORS

7.7.1 DESCRIPTION

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.

7.7.2 ASSET STRATEGY

The lifecycle replacement strategy adopted for overhead conductors is condition based replacement. Inspection of conductors and connectors is conducted as part of the overhead line inspection program.

7.7.3 ASSET CONDITION

For details of the asset condition for overhead conductors refer to JEN PL 0026- Connectors and Conductors.

Overhead conductors are of mixed age 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.

Table 7–14: Installation years: Conductors

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

7.7.4 ASSET CLASS SPECIFIC DRIVERS

The following table provides a high level summary of the asset class specific drivers for conductors.

Table 7–15: Asset Class Specific Drivers: Conductor

Driver	Risk/Opportunity Description	Consequence
Regulatory Compliance, Health, Safety and Environment, Asset Integrity	Deteriorated conductor and conductor connectors.	Failure of connectors/conductors. Damage, outages, claims and damage to customer’s equipment from HV injections. Increase risk of fire starts, particularly in HBRA. Public safety issues.

7.7.5 CAPITAL REQUIREMENTS

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 twenty years.

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 is spans of steel conductor exhibiting evidence of rust degradation. Programs are in place to identify and replace this conductor as its condition is identified.

7.7.6 OPERATIONAL REQUIREMENTS

Inspection of conductors and connectors is conducted as part of the overhead line inspection program, conditions of which are documented in JEN MA 0500 - Asset Inspection Manual. Thermal surveys and corona discharge tests are conducted to identify high impedance connections.

Notifications are raised for the rectification of defects or replacement of assets as identified. The condition of sub transmission and distribution conductors and connectors is monitored through thermographic surveys on a predefined basis, every one, two or three years.

On a routine five year cycle, steel conductor in the hazardous bushfire risk area (HBRA) is visually assessed for extent of corrosion. Also, high quality aerial photographic techniques are utilised to provide accuracy, consistency and confidence in the assessment. This technique has been implemented successfully for steel conductor.

Recognising the risk of ignition in the event of conductor/conductor connector failure in HBRA areas we have implemented several programs in the HBRA to minimise the likelihood of connector or conductor failure. The programs include:

- Steel Conductor Assessment Program (**SCAP**) which also targets replacement in the priority of the assessed condition (this is a direct input to the CAPEX program). This program is in addition to the routine asset inspection program;
- Replacement of unacceptable surge diverters;
- Installation of bird and animal proofing;
- Installation of vibration dampers and armour rods where required;
- Replacement of unreliable non-tension connectors;
- Install LV spreaders where required;
- Replace wood crossarms with steel crossarms, which includes insulators and new ties;
- Removal of open wire LV mains in the HBRA;
- Routine asset inspection – 3 year cycle;
- Dedicated hazard tree management program; and
- Auto-reclose suppression for feeders in the HBRA on Total Fire Ban (**TFB**) days

7.8 OVERHEAD SERVICES

7.8.1 DESCRIPTION

The low voltage overhead service is defined as the service that connects the pole (our asset) to the point of supply (customer’s asset).

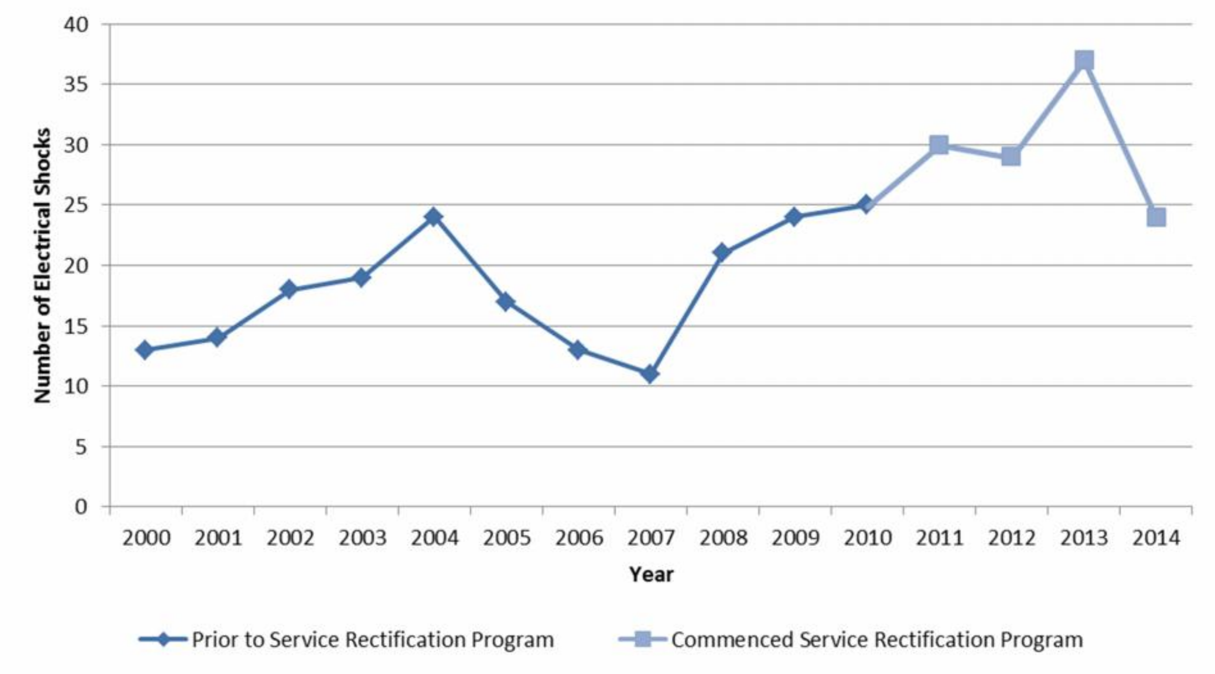
7.8.2 ASSET STRATEGY

A preventative maintenance regime is employed for overhead services. For more details of the strategy for this asset class, refer to JEN PL 0036 Overhead Services.

7.8.3 ASSET CONDITION

We apply a condition-based replacement strategy for these assets. As can be seen from the figure below, we have seen an increase in the failure rate of neutral services since 2008. There is a health and safety risk to staff and the general public caused by minor electrical shocks. Faulty services are also unknown until we are notified by the customer.

Figure 7–6: Number of service related network shocks



Source: Jemena - Neutral Service Testing and Electric Shocks Report June 2014

7.8.4 ASSET CLASS SPECIFIC DRIVERS

The following table provides a high level summary of the asset class specific drivers for overhead services.

Table 7–16: Asset Class Specific Drivers: Overhead Services

Driver	Risk/Opportunity Description	Consequence
Regulatory compliance	Testing of service neutral every ten years	Compliance.
Regulatory compliance	Current regulations set new requirements and largely provide no “grandfather provisions” for services erected in accordance with superseded regulations. As a result there are a large number of services that are not in strict compliance with current regulations	Not strictly compliant. Low services can be struck by vehicles causing asset damage, leading to asset damage etc.

Driver	Risk/Opportunity Description	Consequence
Asset integrity. Health, Safety and Environment	Damage/failure of services or neutral connection, due to: • Third party damage; • Corrosion; and • Water ingress etc.	Asset failure with risks of electrical shocks, safety issues, and supply interruption. Fire starts.

7.8.5 CAPITAL REQUIREMENTS

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 2016-2020.

Services are upgraded to current standards in conjunction with other work such as network augmentation, pole replacement, re-conductoring, and asset relocation.

In addition to the dedicated service replacement program, replacement of an LV service will occur where:

- it is damaged or fails in service;
- the service fails an NST test, and repair is not viable;
- minimum clearances are not maintained, and the service is not suitable to be raised; and
- a service disconnect device is used for low services, the service will require replacement with ABC (XLPE)

In the next planning period, a neutral screen service replacement program has been identified due to increasing numbers of neutral shocks. There will be a steady increase in the service rectification program between 2016-2030, when it is expected to be completed. This will drive a significant increase in service replacements from 2020-2030.

Table 7–17: Forecast Replacement Volume: Overhead Services

Asset Type	2016-2020	2021-2025	2026-2030	2031-2035
Services	28,882	64,059	65,970	4,920

7.8.6 OPERATIONAL REQUIREMENTS

Electrical Safety Regulations require all overhead services to have a neutral to earth resistance of less than 1 ohm and must be verified at least once every 10 years. The 10 year Service Inspection & Testing Program involves a height measurement, safety, and mechanical integrity assessment and also a Neutral and Supply Tester Program. The regulatory obligation for the testing of service neutrals every 10 years will occur between 2016 and 2020. During the AMI roll out, a precise measurement of the service neutral resistance was undertaken which identified defective services that require replacement. As per the capital requirements section, many of the maintenance activities identify required replacement works.

7.9 PROTECTION AND CONTROL

Protection and control equipment (referred to as secondary equipment) is installed in zone substations and connected to instrument transformers (to sense current and voltage signals), switchgear, and plant equipment (for monitoring and control). It includes network control devices, DC systems and power quality meters. This equipment is designed and configured to detect the presence of network faults and other abnormal operating conditions and automatically isolate the fault by opening appropriate circuit breakers, or correct the abnormal operating condition by initiating some pre-defined control sequence.

Network communications infrastructure comprises a number of different technologies, protocols and functionalities (including equipment such as copper supervisory cable, fibre optic cable, and radio and public telecommunication services), which supports field secondary equipment engineering access, and protection and control schemes.

The main communications network components include network devices (for example, routers, Ethernet switches, and firewalls), multiplexers, radios and 3G modems, GPS clocks, and remote terminal units (**RTU**).

We have approximately 1,500 protection and control relays, which consist of around 250 different types of relay. The relays types fall into three categories, based upon their technology:

- 36% are electro-mechanical relays, which represent our oldest relays and technology;
- 18% are analogue electronic relays, which were installed in the 1970s and into the 90s; and
- 46% are microprocessor-based relays, which were installed in the 1990s.

A failure to isolate faults can cause severe damage to high voltage equipment and presents a significant safety hazard to both operational personnel and the public. Experience has shown that the failure of these assets may lead to the failure of primary plant (significantly more costly) and extended customer interruptions (potentially for several days). It is not cost effective to remove the possibility of any failures. But we typically aim to proactively replace our protection schemes, when they begin to exhibit unreliable behaviour and the costs and risks suggest it is no long prudent and efficient to continue their use. For this, we monitor the performance of relays types to see emerging trends in failures.

To identify which relays will need to be replaced, we have analysed the failure history of relays. We have identified three cohorts of relays that are exhibiting signs of significantly deteriorating performance. These cohorts are as follows:

- Our older electro-mechanical relays tend to lose magnetism resulting in significant timing errors and reducing the grading margin between protection schemes. This increases their likelihood of mal-operations and increases the costs to maintain them.
- Two of our early types of microprocessor relays (SPAJ and GE SR series) are showing an increasing trend in failures, related to failures of the power supply. These older units do not have any remote monitoring, and therefore, this failure can lie undetected until the relay is required to operate or it is discovered through our routine inspection and maintenance programs.

We identify replacements of relays at specific substations where other work is being carried out to gain efficiencies through the replacement of a group of relays at one location.

Across the network, there are legacy electromechanical relays (approximately 35% of the relay population). The replacement of these relays has been completed on a staged basis over a number of planning periods. These relays do not provide any real-time monitoring, so failures remain undetected until a fault occurs. This poses a risk of a significant loss of supply, damage to more valuable assets, and risks impacting public safety.

Specific programs as part of the next planning period include replacing relays that are faulty (faulty power supply modules, and input/output modules) and therefore are no longer fit for purpose. A number of these faulty relay types have resulted in extended customer impacts.

We also are committed to using IEC 61850 technology to enhance substation automation and ensure greater network management efficiency. A number of relay replacement projects planned over the next 20 years will provide an opportunity for IEC 61850 implementation. The introduction of the IEC 61850[21] standard for the design of electrical substation automation defines a protocol for interoperability between network control devices from different manufacturers, and introduces models of primary and secondary distribution substation and communication equipment.

An increase in protection and control replacement costs is forecast in the next planning period to meet specific issues and risks relating to protection relays, with a reduction in expenditure thereafter. Where possible, communication projects are aligned with protection and control projects, gaining efficiencies and synergies as a result.

7.10 SCADA AND RTS

Network real-time systems (**RTS**) are installed at data centres and zone substations to provide network remote control, monitoring, and management capability. Characterised as having specific requirements for high availability, security and system access, these systems include:

- SCADA
- Distribution Management Systems (**DMS**)
- Outage Management Systems (**OMS**)
- Outage Historian and Business Intelligence (**OUBI**) System
- Historical Data Management System (**HDMS**), and
- Infrastructure Monitoring Systems (**IMS**).

There are a number of key SCADA and RTS management and maintenance strategy drivers over the next 20 years, including:

- anticipated changes in consumer technology and electricity consumption patterns; and
- the cost-efficient maintenance of reliability and quality of supply

As the use of ‘smart‘ remote-controllable appliances on distribution networks and within substations increases, so does the need for RTS to provide better processing and leveraging of data in support of cost-effective network operation (including remote LV network management).

New capabilities and features to maintain existing levels of asset performance and reliability of supply, while also facilitating adaption to the expected changes in consumer technology and electricity consumption patterns, are expected to require fully automated support for the real-time analysis of asset logs, asset condition data, and the cross correlation of data and integration with other network management systems (such as meter management, demand management and power quality management systems).

[21] IEC (International Electrotechnical Commission) 61850 – Power Utility Automation

RTS will also need to support a broader range of technology and new appliances for directional/unit protection, embedded generation, smart fault indicators, voltage/current sensors, temperature probes, conductor strain gauges, condition-based switching and asset maintenance automation.

The expenditure associated with SCADA and RTS is captured by the IT AMP.

7.11 METERING & METERING INFRASTRUCTURE

This section discusses both the alternative and standard control services associated with Metering within Jemena. Metering and metering infrastructure assets predominantly comprise Advanced Metering Infrastructure (AMI) meters, but also include retained non-AMI meters (legacy meters), the AMI communications infrastructure and associated AMI network management systems.

Metering services provided by Victorian distribution network service providers (DNSP) in prior planning period were specifically excluded from the distribution price review process and instead recovered via the alternative AMI Cost Recovery Order in Council (CROIC) framework. In the next planning period it will be part of the regulatory price submission.

Some of the activities requiring metering and metering infrastructure expenditure include:

- installing meters for new customer connections;
- installing meters for alterations to customer connections;
- replacing end-of-life and defective meters;
- remotely reconfiguring meters for alterations to customer service;
- augmenting the AMI communication network (for example, installing access point and/or relay communications equipment to service new customers);
- replacing, maintaining and relocating AMI communication network equipment;
- upgrading systems software and hardware to maintain performance, supportability and metering services compliance;
- introducing new meter types and variants into our meter base as new, efficient technologies become commercially available; and
- upgrading metering and metering systems to support regulatory framework changes

For the next planning period, we will still apply a bottom-up forecasting methodology that demonstrates (by activity) that the volumes and unit costs underpinning our forecast metering capital expenditure are efficient and within the scope of what a prudent and efficient business should incur.

Revised rules, procedures and protocols for the Metering Contestability framework are proposed for introduction in 2016, with transitional arrangements specific to Victoria. While the details remain fluid and subject to industry consultation, it is apparent that regulated DNSP metering business activities will be phased out in favour of contestable metering businesses under a market-driven scenario. As a result, we assume that:

- regulated metering activities will diminish over time with jurisdictional controls providing reasonable protection up to 2020 and likely to be in the form of AMI exit fees to ensure DNSP cost recovery

- metering growth will require Jemena to develop or engage a separate contestable ring-fenced business for ongoing metering services outside the existing AMI meters in service that will be unregulated (not subject to the price review), and
- metering can only be reasonably forecast to 2020 and subsequent periods will be biased towards contestable meter service provision, with network services derived from metering provided as an OPEX service, either by our own contestable metering provider, by third party providers, or a combination of both.

7.11.1.1 Metering Infrastructure Analysis

The main findings from metering infrastructure analysis include the following:

- Metering infrastructure has been largely renewed in previous periods and little to no end-of-life replacements are due before 2020; and
- Metering contestability creates significant uncertainty in preparing a long-range forecast beyond 2020 (and therefore has not been included in this document).

SCADA and network control infrastructure

Advanced metering assets are expected to remain in service for 15 years. With greater than 98% of our customer base having had a new meter installed between 2009 and 2014, this suggests a program of replacement will need to be considered from 2024 onwards. We are taking a condition, age and failure-based approach to the replacement of these assets, and using a bottom-up cost build to forecast metering capital expenditure.

The volume forecasts underpinning our metering capital expenditure plan are based on historical trends, customer number forecasts, and compliance obligations relating to metering contestability arrangements and meter specification requirements. As with other capex methodologies, and using the same approach as our other network assets, we apply unit costs to forecast metering capex (which may be subject to a greater degree of forecasting error than other capex forecasts due to the uncertainty associated with metering contestability arrangements in Victoria and some cases of persistent metering installation refusal by customers).

Communication asset scheduled maintenance

Communication assets require scheduled maintenance at different times:

- Access point and relay batteries are replaced every 5 years.
- Access point 3G modems are replaced when the mobile service becomes obsolete, approximately every 7 years.
- Network Management Software (NMS) upgrades are required at least every 2-3 years to maintain vendor support.
  - Upgrades are covered by licensing, but a capex allowance is included for system changes and testing to accommodate compatibility issues and ensure the integrity of the upgrade before deployment.
- Network communications may degrade over time due to environment changes (buildings, foliage, etc) and network growth. Augmentation occurs when performance or capacity issues are detected.
- Metering assets require maintenance, sample testing and inspection in accordance with the AEMO approved Metering Asset Management Plan.

Victorian AMI functional specifications include network services and capabilities over and above national market metrology obligation requirements. Consequently, the metering end-to-end solution has embedded metering and network functions, which require allocation and distribution between the future state of Alternative Control Services (ACS) metering and Standard Control Services (SCS).

7.12 FLEET, PROPERTY, TOOLS AND EQUIPMENT

This capital expenditure addresses service delivery needs that are not directly related to the development and augmentation of our electricity network. It includes our vehicle fleet, property, tools and equipment. Fleet expenditure makes provision for both heavy vehicles required for the construction and operation of the distribution network, as well as other standard vehicles.

Property expenditure provides for non-network property management relating to carrying out our business effectively.

Tools and equipment expenditure provides for specialist equipment necessary to construct, maintain, monitor, repair and test our assets.

7.12.1 FLEET, PROPERTY, TOOLS AND EQUIPMENT ANALYSIS

Fleet

Our fleet management strategy provides guidance for the re-build or replacement of vehicles, which ranges from replacement at 5-yearly intervals for passenger vehicles, to a rebuild of large, elevated platform vehicles (EPV) after 10 years of service.

The fleet forecast is based on replacement criteria documented in our Fleet Management Strategy for each class of vehicle utilised on the electricity network. The vehicle classes range from small to medium passenger vehicles to large, elevated work platforms (EWPs). EWPs have statutory maintenance obligations as prescribed in Australian Standard AS1418.10. This standard also mandates a rebuild of the EWP's tower after 10 years of service.

The replacement criteria for vehicle classes other than EWPs are based on the safe operation of vehicles whilst maintaining an optimal asset lifespan. Historical data indicates that if vehicles are run for too long without replacement, operating costs escalate as more funds need to be spent on maintenance and vehicle overhauls, such as vehicle transmission rebuilds.

Tools and equipment

Tools and equipment have a linear expenditure profile. The equipment ranges from hand tools valued at several hundred dollars to protection diagnostic equipment and underground cable test equipment.

Condition monitoring of safety equipment, such as line worker harnesses, is carried out on regular intervals, while many other classes of tools and equipment are replaced upon failure. Historical data is used as a basis to indicate the typical lifespan of a particular type of tool or equipment.

Property

The property expenditure proposed for 2016-2020 primarily relates to the development of a new office/field depot, at Broadmeadows hence the reduction in expenditure in subsequent periods.

7.13 ASSET REPLACEMENT ANALYSIS

Broadly across the network, there are a number of emerging issues that will impact the forecast asset replacement program over the next 20 years:

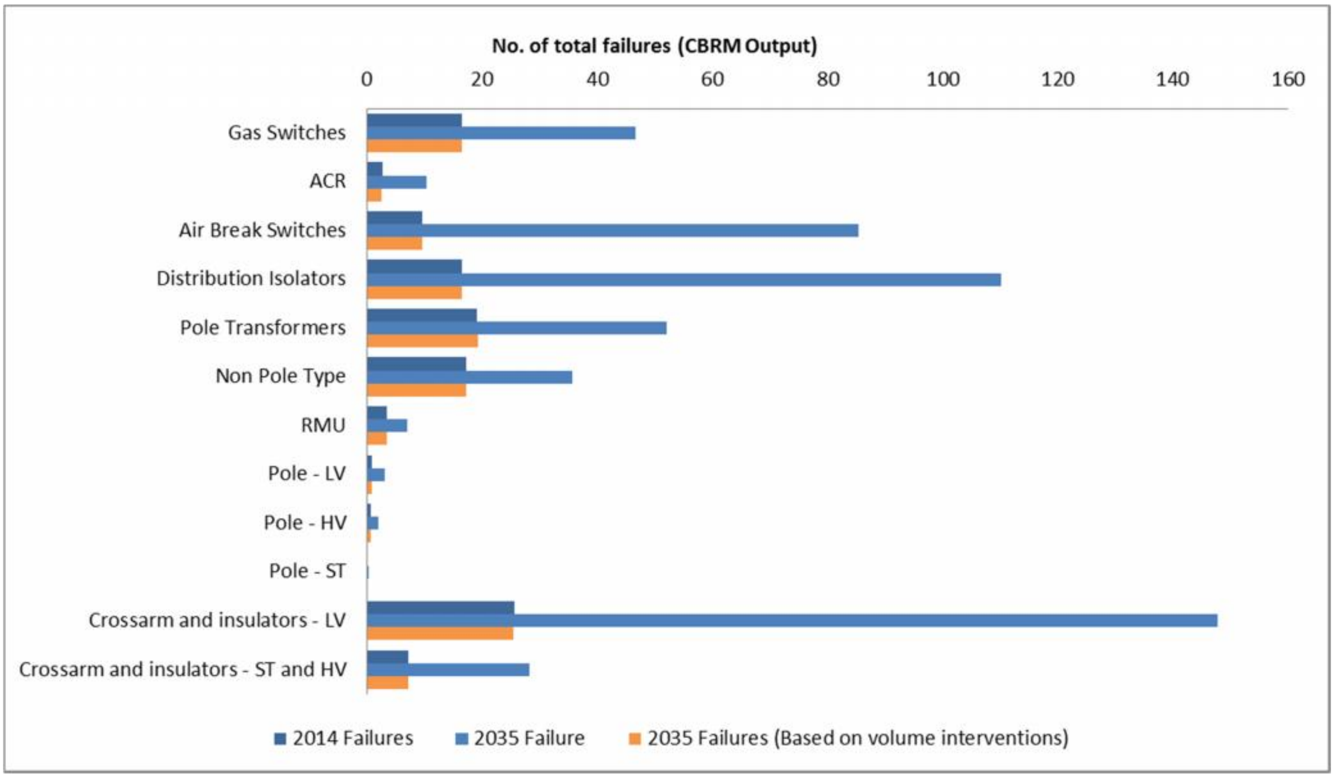
- Our network is ageing and we are still going through the initial phase of a replacement cycle for many assets, requiring us to increase replacement expenditure to ensure reliability, security and safety do not degrade over the next period; and
- Compounding the ageing issue, there are a number of areas where safety has deteriorated more than expected during the current period, requiring us to increase replacements in these areas to arrest this degradation and address the concerns raised by ESV.

Detailed programs identified for the next five year planning period are provided in the ELE PL 0004 - Asset Management Plan.

7.13.1 ASSET CLASSES

Figure 7–7 shows the CBRM prediction of failures from 2014 through to 2035. For 2035, the figure shows the number of failures if no replacement occurs, and also the number of failures assuming the volume of interventions recommended by the model.

Figure 7–7: CBRM Failures for Assets



Notes:

(1) Pole top structures (regulatory category) include sub-transmission, high voltage and low voltage cross arms and insulators.

(1) Distribution Switchgear (regulatory category) includes air break switches, gas switches, ring main units, and isolators.

(2) ZSS Switchgear and ZSS Transformers are excluded from this graph.

(3) This figure assumes that we complete the volume of interventions required to maintain the quantum of risk on the network.

(4) Based on 2014 levels and forecast for 21 Years (2015-2035).

The asset failures predicted by the model increase over time. As can be seen from the 2014 Failures, and the 2035 Failures (Based on interventions), our forecast volume of replacements maintains the existing levels of reliability, security and safety (as these are all linked to the number of failures).

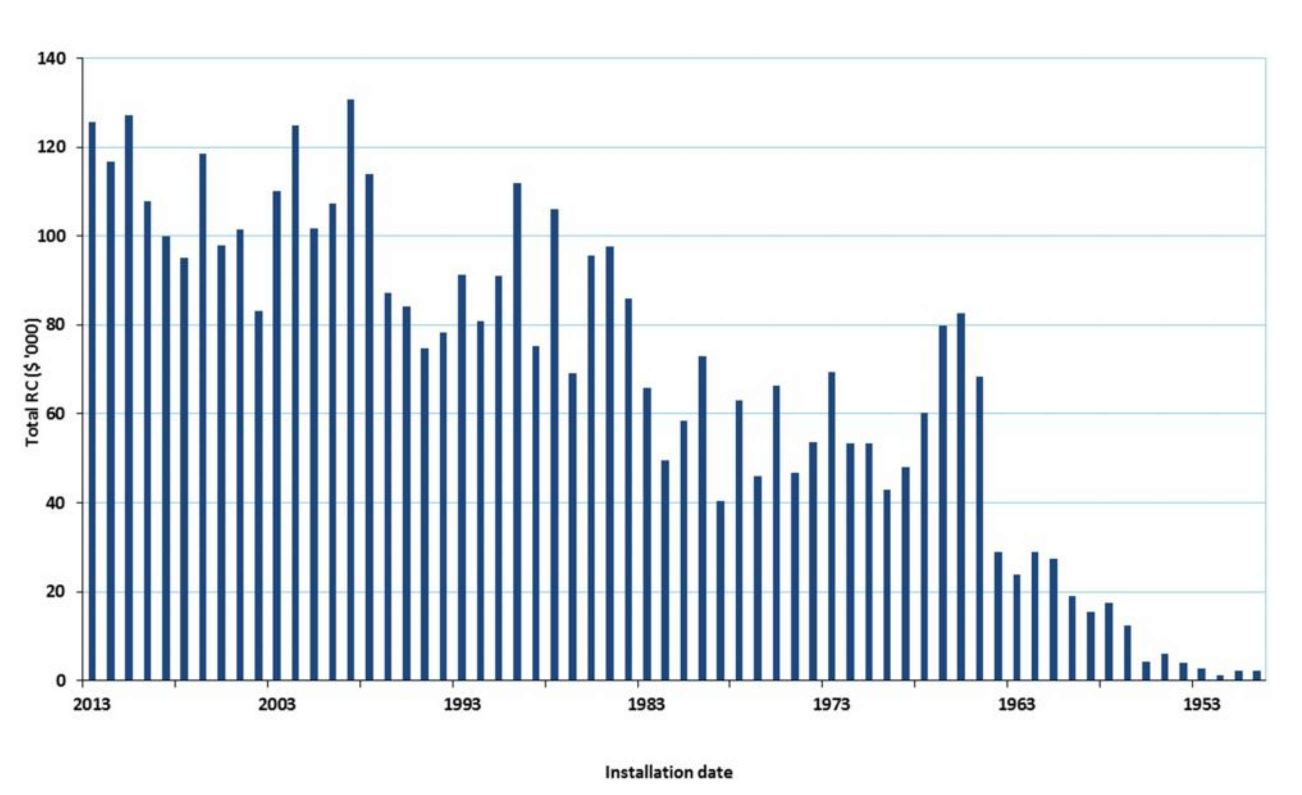
7.13.2 AGE INDICATORS

Our replacement forecast is not aimed at arresting the ageing of our network but used to understand trends. We expect our asset replacement expenditure and volumes, and the aggregated age of our network assets to increase over the next 20 years for two reasons:

- Most of the network was developed after 1960 and a significant proportion of our asset population has never been replaced. The figure below provides a profile of the forecast asset age across a number of asset categories based on our forecast expenditure.
- Improved asset management techniques and information enables us to extend the lives of assets through optimised maintenance, operation and replacement, and improved condition monitoring. In addition to this we also have several programs in place to ensure that we mitigate risks, and maintain the performance of the network where known issues need to be addressed.

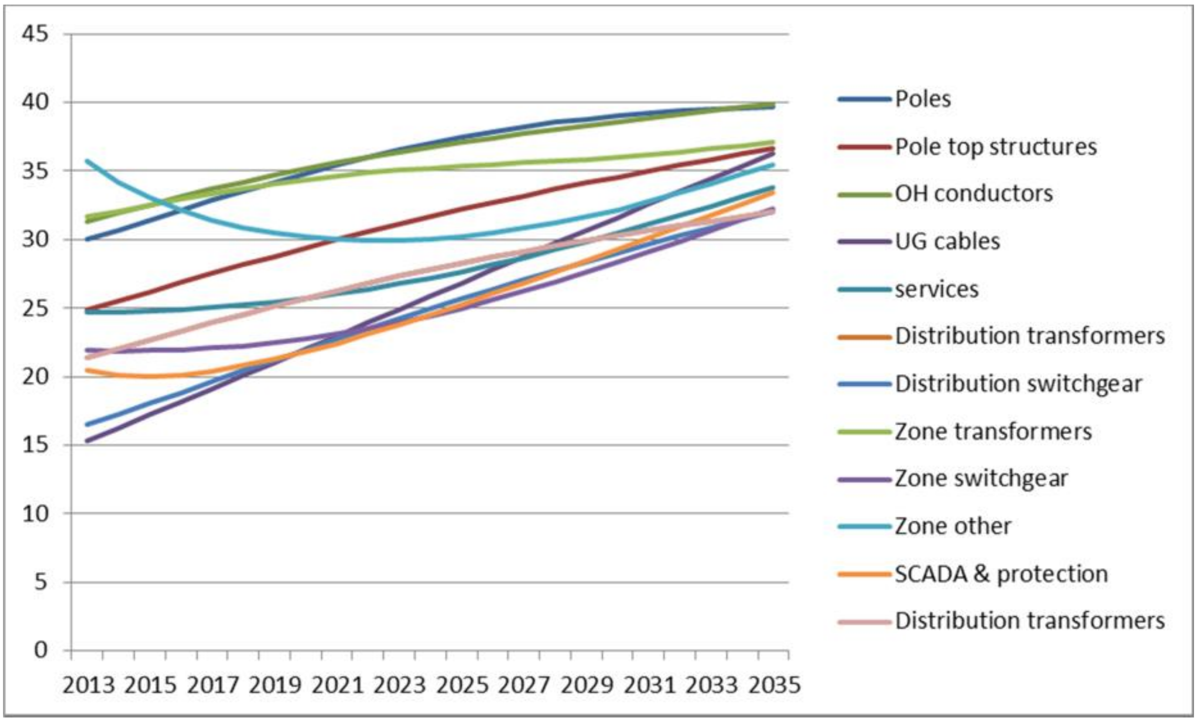
The figure below shows the age profile of our network. This age profile has been developed from the replacement model templates within our category analysis RIN, submitted to the AER. This profile reflects the undepreciated replacement cost of the network.

Figure 7–8: Total replacement cost of the assets versus installation date



Our analysis using the AER's replacement model suggests the average life of our network assets is dependent on the asset type. As per the original installation dates, this places us at the early stages of a replacement cycle. It would be expected that the ageing of our network may cause increasing levels of replacement over the next 20 years. The figure below provides our forecast weighted average of assets for the asset categories discussed in Section 5 of this document.

Figure 7–9: Forecast Weighted Average Age of Assets, Age (Years) vs. Year



We expect some smoothing of this profile as assets reach end of life, and some reduction in the weighted average age through the need to replace due to network augmentation and technical compliance.

7.13.3 REGULATORY COMPLIANCE

We undertake several programs to ensure that we mitigate bushfire risk and ensure network safety

Much of our network is above ground and so a major failure of an asset (for example, a pole failing and falling to the ground) can injure the public or start fires. Safety issues relating to our replacement programs form part of our ESMS which is overseen by ESV. We mitigate this bushfire risk by ensuring that we optimise the management of poles and pole top structures (cross arms and insulators) through:

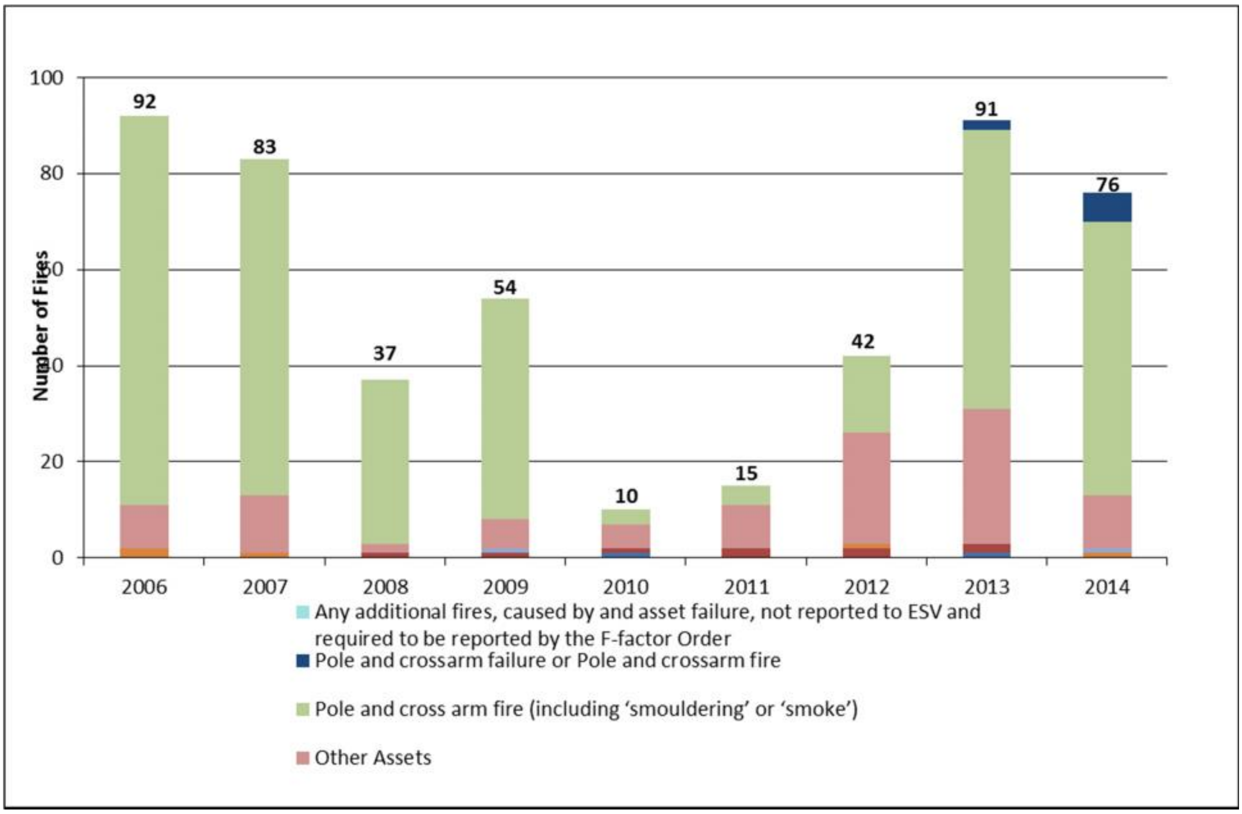
- standard condition-based replacement; and
- safety-driven replacement of poles and pole top structures (for example, bushfire mitigation relating to f-factor).

Our programs have been developed to minimise the fire risk associated with the network assets to as low as reasonably practicable. From 2003-2013, pole and crossarm fires accounted for 9% of network incidents[22]. Pole fire events can be large scale events that occur in a short period of time, that stretch resources, and in some cases require the commencement of emergency management structures.

Over the past five years we have seen an increasing frequency of severe weather events. This coupled with our inspection regime (every 3 years in hazardous bushfire risk areas and every 4 years in low bushfire risk areas) has identified an increasing number of poles and pole tops requiring replacement to maintain the same levels of safety. We are seeing an increasing trend in service failures.

The figure below shows the number of fire starts by type of asset in the network from 2006-2014.

Figure 7–10: Fire Starts by type 2006-2014



In addition to our plans to complete the removal of all timber high-voltage cross arms from the hazardous bushfire risk areas by the end of 2015, we also acted on the recommendation of the Victorian Bushfire Royal Commission (**VBRC**) to remove Single Wire Earth Return (**SWER**) from Victorian distribution networks. A logical progression from this is the proposal to progressively remove all 42 km of bare low voltage mains conductors from the hazardous bushfire risk area in the next period.

22 JEN 2003-2013 Incident Analysis Report

8. TECHNOLOGY

This chapter considers developments in the context of our electricity network, and our plans relating to these developments with specific reference to:

- Distributed Generation;
- Energy Storage;
- AMI;
- Demand Management; and
- IT

Over the next 20 years, we expect continued growth in distributed generation, energy storage, energy management systems, energy efficiency, demand management, and information all of which will instigate changes in how we provide our services. As a direct result, we will need to continue to adapt so that we can respond to our customers' preferences in how we provide energy services.

8.1 TECHNOLOGY ENVIRONMENT

8.1.1 DISTRIBUTED GENERATION

We classify distributed generation into three broad categories:

- micro-embedded generation less than 30 kilowatts 3-phase and 10 kilowatts single-phase;
- mid-scale embedded generation less than 5 megawatts; and
- large embedded generators greater than 5 megawatts

For inverter-based generators that are less than a certain size threshold (10 kilowatts for single-phase systems and less than 30 kilowatts for 3-phase systems) we currently have a standardised connection process. Most residential-scale rooftop PV generators can connect to our network by meeting the installation, inverter and grid protection requirements of AS4777 (grid connection of energy systems via inverters).

For generators applications larger than the inverter-based generator size thresholds (or that are not inverter based), we assess on a case-by-case basis and follow the applicable National Electricity Rules (and other applicable jurisdictional instruments). We have streamlined this connection process to consider the proponent's commercial and project delivery considerations and our obligation to maintain a safe, secure and reliable distribution network.[23]

Distributed generation developments

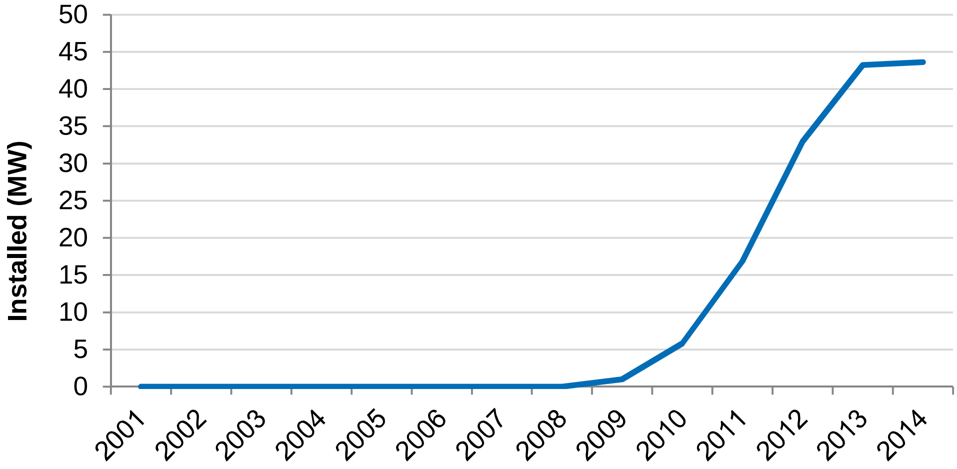
We have seen significant distributed generation growth on our network over the past five years in terms of both numbers and total capacity. To date, distributed embedded generation within our network has predominantly been micro-embedded generators, such as rooftop PV systems. From 2010 to 2012, government subsidies and the mandatory renewable energy certificate scheme promoted the uptake of rooftop PV. Changes in energy

[23] http://jemena.com.au/what-we-do/assets/jemena-electricity-network/embedded-generation.aspx

technology and policies have also resulted in a large number of customers subsidising rooftop PV and the sale of any surplus energy rooftop PV generates.

The figure below shows the growth of installed rooftop PV in megawatts within our network over the period 2001 to 2014.

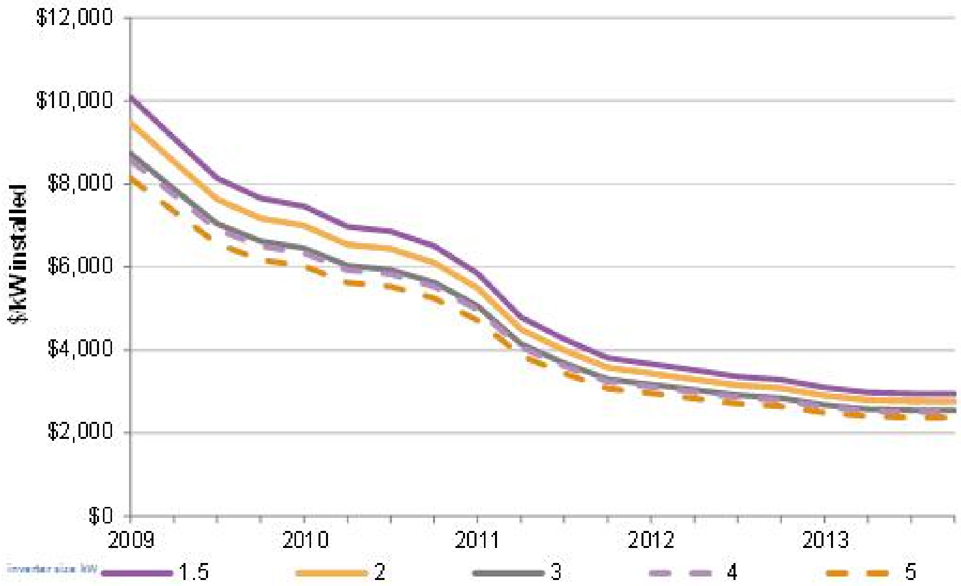
Figure 8–1: Total installed rooftop PV (MW)



Source: Jemena Installed PV data October 2014

The rapid adoption of rooftop PV has resulted from reducing technology costs, changes in government policy, and regulatory incentives. From 2009 to 2014, we have seen the cost of installing rooftop PV systems (in dollars per kilowatt) decline (as shown in the figure below).

Figure 8–2: Cost of rooftop PV installation ($) on the JEN from 2009-2013



Source: Acil Allen October 2014 Demand Forecasting Report on behalf of Jemena

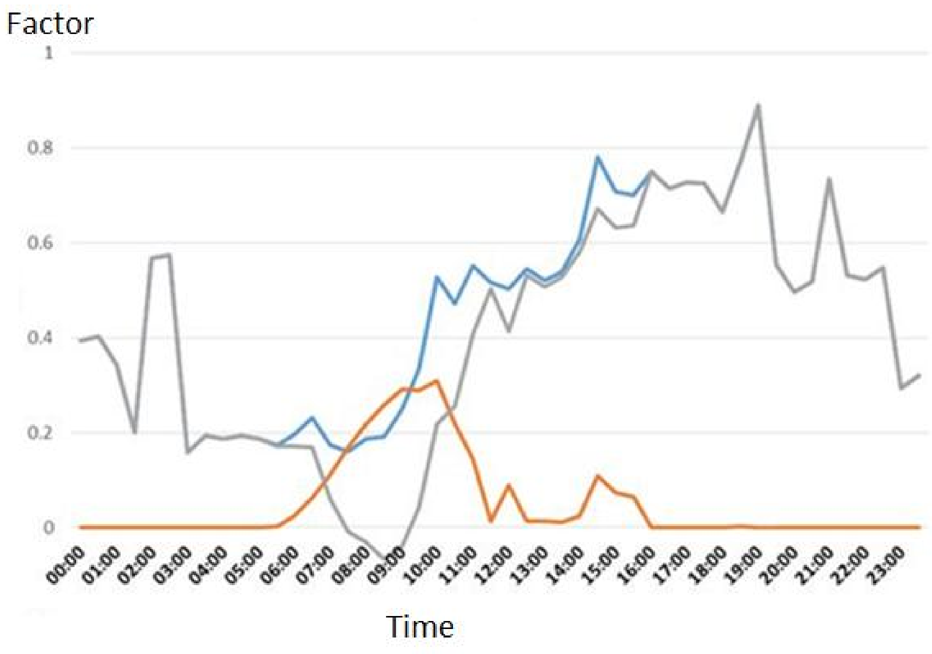
Our network is largely a suburban network with a limited wind resource and limited available land for the construction and operation of utility-scale wind farms. As such, we have not seen much activity relating to the connection of wind farms, large or small.

On the other hand, we are increasingly connecting more numbers of combined heat and power (**CHP** or co-generation) plants or combined cooling, heat and power (**CCHP** or tri-generation) plants, which are generally mid- to large-scale embedded generators. This type of technology is typically deployed by large industrial or commercial customers (e.g. airports, hospitals, community swimming pools, large building complexes), and helping reduce demand.

Distributed generation over the next 20 years

With the increasing penetration of distributed generation in electricity grids, the traditional 'top-down' one-way flow structure of electricity supply is changing to a more multi-directional flow. In the coming years, more and more customers will become producers of electricity, either lowering demand or supplying excess generation to the grid, including the possibility of 'peer-to-peer' energy transfer. In this evolving market, generation is dispersed across our network rather than being centralised and controllable. Distribution networks like ours, which were designed for unidirectional flow, will see the emergence of new constraints with respect to quality of electricity supply, voltage regulation and stability. The figure below shows an example of demand at a single customer's residence with a rooftop PV installation.

Figure 8–3: An example of the impact of solar PV on resident demand, Power (kW) vs. time of day



During the time of peak generation (orange trace), the customer is a net exporter (grey trace) of electricity. However, during the evening peak, generation is minimal and the load (blue trace) remains closely matched to the net transfer of energy. When aggregated at a high-voltage feeder level or upstream to the zone substation level, such localised and de-centralised generation creates a series of challenges for distribution system operation:

- The net export of rooftop PV generation to the grid causes local voltage rise; and
- The quality of electricity supply is degraded when there is high penetration of intermittent rooftop PV generation (for example, the output is impacted by weather conditions).

Balancing new sources of supply (such as intermittent rooftop PV and small-scale wind and gas-fired CHP systems) with more intelligent usage (such as energy consumption monitoring and control) will make demand pooling and storage increasingly important[24].

We will continue to monitor the key trends in distributed generation technology markets as they have particular relevance to our business model and obligations towards our customers. There are several areas of uncertainty are likely to influence our long-term plans:

Micro-embedded generation technology such as rooftop PV

- Whether the current trends in uptake of solar PV continue when the capital and production subsidies are completely removed.
- Whether the cost of technology will plateau over time and customers seek value through efficiency gains.

Mid-scale and large embedded generation

- Whether the technical barriers on the distribution network (for example, fault current limitations) will create an upper limit for embedded generator connections to distribution networks.
- What influence energy market prices will have on the economics of these generators.
- What the influence of regulatory and market reform may have.

Interplay of technologies

- Whether the growth profile and development of other non-network technologies such as energy storage and demand response will impact the uptake of distributed generation within our network.
- Whether non-network technologies compete with or enable the growth of distributed generation.

The type of technology preferred by customers may change over time, and today's rooftop PV generation may be replaced by more efficient and less expensive technology. However, we expect customers will continue seeking more control and flexibility over their electricity supply needs, including the possibility of a peer-peer market place for energy use in the long term.

Distributed generation growth predictions include the following and have influenced our demand forecasts:

- Micro-embedded generation (less than 30 kilowatts 3-phase or 10 kilowatts single-phase) is expected to experience growth similar to the growth observed since 2009.
  - Rooftop PV generation is expected to maintain steady growth over the next five years. This growth will primarily be on account of efficiency gains and reduction in cost of technology (PV panels and inverter systems).
  - Other types of micro-embedded generation technologies can be expected to spur growth in this sector in the 5-year (or more) time horizon.
- Mid-scale embedded generation.
  - Mass production of CHP units is starting to occur.

24 Nillesen, Paul, Pollitt, Michael, and Witteler, Eva, New Utility Business Model, Distributed generation and its implications for the utility industry, First edition- February 2014

- A stable increase in uptake over the period 2016 to 2035 is anticipated for CHP and CCHP generation of less than 5 MW.

- Large-scale embedded generation (greater than 5 megawatts).
  - This is expected to experience continued growth. The size, location and technical feasibility of such large generators will be decided on a case-by-case basis. However, we expect that regulatory and market reform will maintain favourable economic conditions for projects to become feasible.

Impact on services

There are physical limitations to how much distributed generation can be fed back into the network without upgrading infrastructure. The growth in distributed generation poses challenges in terms of predictable power flows and power quality issues. This will become even more pointed as energy flows and quality of supply issues grow more complex, given distributed generation impacts include voltage and power flow limitations, as well as voltage control and automation. We will need to actively monitor and develop solutions to:

- improve the ability of low voltage networks to accommodate increased penetration of dispersed micro-embedded generation;
- improve the ability of medium-voltage and high-voltage networks to accommodate large distributed generation both at a local level and an aggregate level with consideration to network fault levels;
- limit the impact of intermittent generation on network load characteristics, voltage profile and quality of electricity supply; and
- facilitating the coordination of inter-play of distributed generation with other energy demand-side management solutions such as energy storage

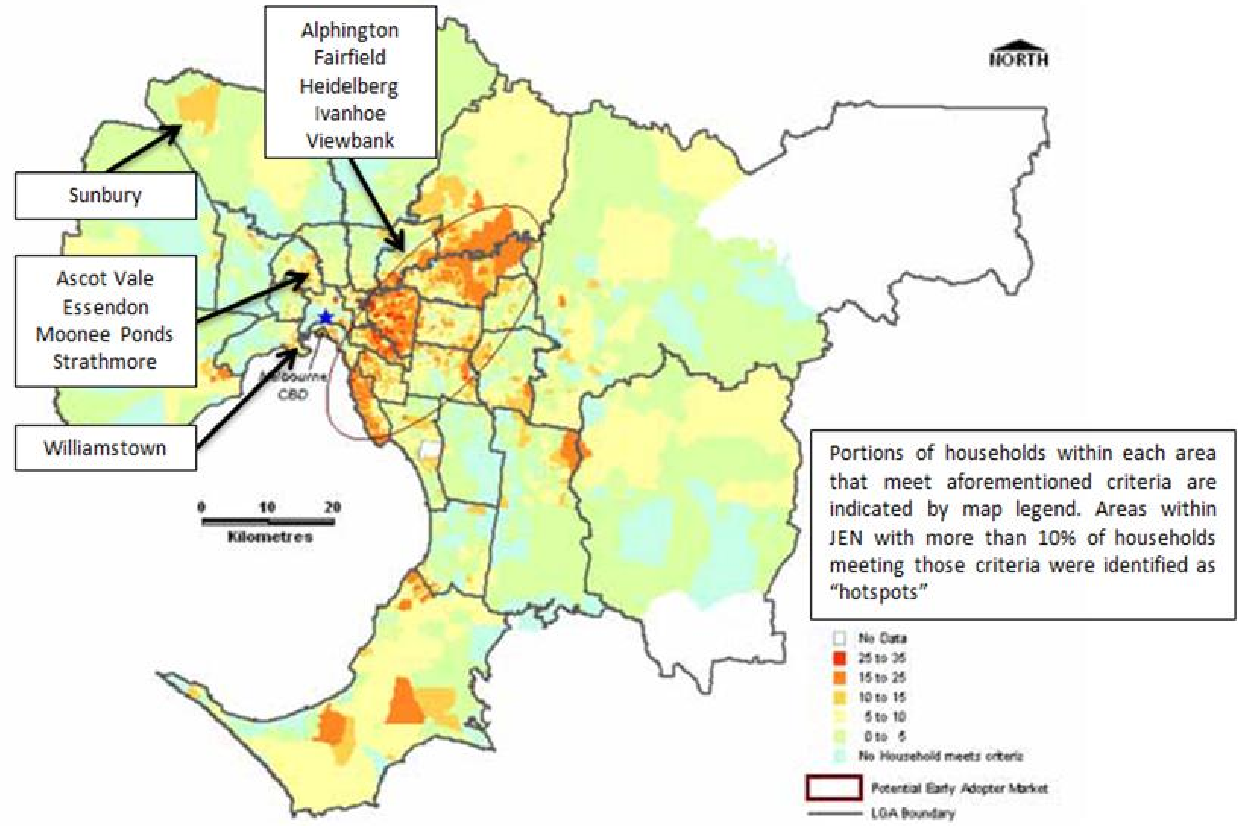
8.1.2 ELECTRIC VEHICLES

Electric vehicle developments

There are currently relatively few electric vehicles (**EVs**) in Australia and only a limited variety in terms of vehicle models. The main barriers to EV uptake are vehicle range, the relatively high purchase price of EVs and a lack of a widespread public charging network.

A study on potential EV adopters was conducted by in 2010 for the Victorian EV trial[25] identified areas in the Metropolitan Melbourne area where there was a concentration of residential households that met the following criteria:

Figure 8–4: Household meeting early EV adopter criteria



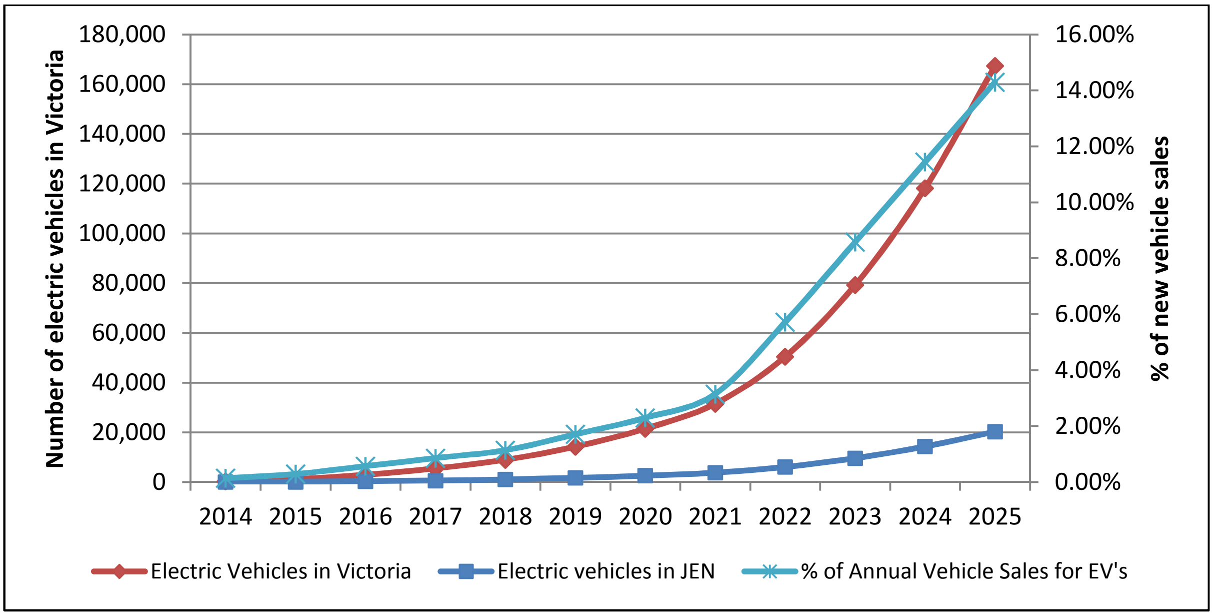
Source: Rorke, J. (2010)

Electric vehicles over the next 20 years

Projections from a demand forecast report prepared by the National Institute for Economic and Industry Research (NIEIR) for Jemena in July 2014 are reflective of the initial stages of EV adoption that Australia is experiencing and are presented in Figure 8–5, predicting an uptake of about 20,000 EV's in the area covered by the JEN by 2025, assuming that 12% of Victoria's population draws power from JEN.

[25] Rorke J. (2010) "Potential Early Adopters of Electric Vehicles in Victoria", report for the Victorian Electric Vehicle Trial

Figure 8–5: EV Uptake Projections for Victoria and JEN



Source: National Institute of Economic and Industry Research (NIEIR) (2014) "Maximum demand forecasts for Jemena Electricity Networks terminal stations to 2025", report for Jemena

Impact on services

We currently only has capacity for about 5,200 to 16,600 EV charging during peak periods in the areas identified hotspots in Figure 8–4. If EV adoption were to be focused on one area of the network, the JEN could experience peak demand issues that would need to be addressed.

Residential EV charging could trigger network challenges even at low levels of uptake, due to a combination of several factors:

1. The expected standardisation of faster charging rates, which can be equated to EV charging drawing the same amount of power as 2 to 5 air conditioners operating simultaneously.
2. The charging behaviour of private EV owners in the absence of load-shifting mechanisms, which may exacerbate peak demand during the early evening on weekdays.
3. The initial stages of EV adoption, which is likely to occur in spatial clusters due to the demographics of early adopters and may create peak demand issues for areas of the distribution network that are already constrained.

8.1.3 ENERGY STORAGE

Energy storage solutions are emerging as a technology that will impact the way electricity networks are planned and operated. Energy storage allows users, be they distributors, generators or consumers, to store energy when appropriate for later consumption, the timing of which will depend on the application of the storage solution and in most cases will be in response to price signals.

Energy storage solutions generally comprise the storage technology (chemical battery, flywheel etc.), the storage management system, and the power conversion system (which acts as the grid interface). Energy storage solutions that are of relevance to us and our distribution network fall in the following categories:

- **Local Energy Storage** which can be deployed behind the meter within the premises of residential or medium/small business customers usually in conjunction with local embedded generation. The objective of such customers is to minimize electricity bills by producing and storing energy during off peak hours and discharging the storage during peak hours
- **Grid Energy Storage** is deployed within the distribution system, either on the low voltage or high voltage network with the primary objective of mitigating capacity constraints or managing a local area reliability problem
- **Electric Vehicles** – development in electrical transportation provide opportunity to use vehicles as an energy storage technology.

Energy storage developments

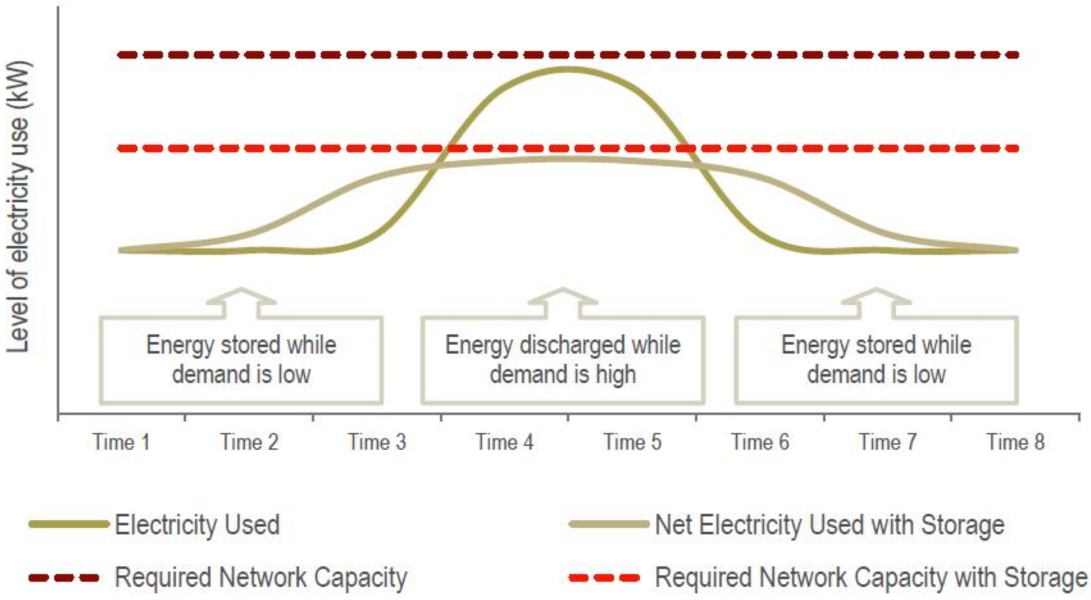
Over the past few years, there have been significant advances in energy storage technologies, for example chemical batteries (lithium-battery, flow battery) and mechanical flywheel technology. Technology costs are decreasing rapidly and there is increased uptake globally of storage solutions for specific applications. Many large consumers, generators and grid operators are evaluating storage solutions to identify how they can support their business objectives. However, we have not yet seen any significant development involving this technology within our network. Our trials and capability in this area are discussed later in this chapter.

Energy storage over the next 20 years

The use and application of energy storage will be influenced by electricity prices, energy policy, and technological developments and pricing.

Energy storage technologies have the potential to moderate the impact of peak demand by enabling our customers to store energy during low demand periods, and discharging it (creating supply) during high demand periods, when network capacity is more constrained. Efficient storage may also have a mutually beneficial impact on the uptake of distributed generation by allowing energy to be stored at the time of generation and discharged when needed. In capacity-constrained parts of the network, a grid storage solution offers a scalable alternative that can be sized to meet the magnitude of the constraint. Provided the costs can be justified, energy storage can be used as a mechanism to shift demand from peak to off peak (see the figure below).

Figure 8–6: Peak shifting using Grid Energy Storage



Source: 'Energy Storage in Australia' – Marchment Hill Consulting

The dual purpose of electric vehicles for transport and as electricity storage and supply could make plug-in electric vehicles an attractive storage technology.

Impact on services

While many of the energy storage and electric vehicle technologies have not reached maturity and their wide-scale commercial viability is currently limited, this technology has the potential to change the way the network is planned, maintained and operated.

Limitations in the capacity (power and energy) of energy storage devices may result in suboptimal dispatch if the devices are not adequately sized for the load. Outages occurring within the grid or peaking prices in the market may also require storage to be sourced for ancillary network services or market responses. As a result, the optimal dispatch of distributed storage for network or market requirements will require its aggregation into larger 'blocks' for scheduling by a central dispatching system (which already occurs with generation and demand-side management). Additionally, Power Conversion Systems (**PCS**) may play an important role in managing distribution network voltage regulation and supply quality.

The impact of electric vehicles will depend on whether their charging will be controlled by the network or by the customer. Also, the impact on services will be related to the tariff incentives. Charging infrastructure providers and retailers may shape the charging profile of vehicles and use them as a form of scheduled, aggregated load.

While uptake rates are an important planning consideration for adapting to this emerging load, the clustering and timing of electric vehicle charging is more important because it will directly impact the performance and utilisation of the network in specific locations. Other considerations include the following:

- Recharge times - as without any incentive to charge during off-peak times, the demand during existing peak periods may increase, triggering the requirement for substantial network augmentation.

- Customers- are generally willing to actively explore new technologies, however, moderate oil prices may limit more widespread uptake, as customers will generally engage when it is convenient to do so without too much disruption to current lifestyles.
- Impact on electricity distribution networks - will be determined by the uptake rate, charging and discharging profile, and the availability to access the stored energy as required.
- Independent operator controlled and monitored charging stations - will require contracts to provide aggregated demand management to support the network.

8.1.4 ADVANCED METERING INFRASTRUCTURE [COMMERCIAL-IN-CONFIDENCE]

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between us and our customers.

Advanced Metering Infrastructure Developments

In 2014, we successfully completed the deployment of smart meters to 98% of our residential and business customers (< 160 megawatt-hour per year). This has changed the way we are delivering services to and engaging with our customers, and planning and operating the network.

The following services are now provisioned remotely, improving the efficiency of service delivery:

- Re-energisation/de-energisation (for example, when customers move house);
- Meter re-configuration (for example, when customers switch to a solar tariff);
- Special meter read; and
- Remote meter reading.

To empower our customers to take greater control of their electricity bills and household consumption we have created tools that provide access to their energy data. “Energy Outlook”, one of the very first smart meter enabled web portals in Australia, allows customers to:

- view their interval energy data graphically on a daily, weekly, seasonal or annual basis;
- compare their consumption against the average for the area;
- extract the data to a spreadsheet;
- compare retail tariffs using historical data; and
- connect Home Area Network (HAN) devices, such as an in-home display (IHD), to their AMI meter

Advanced metering infrastructure over the next 20 years

While we are still in the early stages of realising benefits from AMI, there are many features that have the potential to provide additional customer benefits. These features include:

- real-time reports to the Outage Management System of supply outage and restoration, enabling faster fault detection and restoration;
- customer supply quality monitoring, enabling pro-active detection and rectification of degraded services;
- direct or indirect load control to support demand-side responses;

- improved low voltage asset utilisation through the identification and optimisation of phase loading and load projection;
- detection of customer fraud (for example, meter tamper and supply bypass);
- emergency load limiting (Emergency Supply Capacity Control) to maintain network integrity when discretionary load limiting fails; and
- customer enabled load limiting

Data will also play a key role in the use of AMI over the next 20 years, but how it is used will largely depend on metering contestability[26]. Metering contestability will impact the type and cost of AMI data available to the network. It is expected that interval data and supply status information will be available at no cost, but access to supply status and other information from third party meter suppliers will require the development of new business-to-business interfaces. Other information may incur a charge, potentially affecting the cost benefit of AMI data for network use.

These considerations also cover the use of the AMI communication network.

Following the implementation of customer supply profiling, AMI will also support the following functions:

- Conservation Voltage Reduction (**CVR**);
- Low Voltage Dynamic Reconfiguration;
- Low Voltage Automated Volt-VAr Control; and
- Real-time low voltage load monitoring (for example, 10-minute aggregated customer load on the same substation).

Distribution voltage conservation/regulation

Voltage conservation is a technique for improving network efficiency by optimising feeder line voltages. The widespread adoption of this technology was previously limited due to the high cost of monitoring device installation across the network.

Distribution automation (DA) and network monitoring

To date, a major challenge for utilities to fully implement distribution automation functions is the lack of a global communication network across the low voltage network. Using distribution automation (IEC 61850[27]/DNP3) in conjunction with AMI will provide new opportunities for power grid modernisation that include:

- transformer monitoring;
- distribution feeder automation;
- fault isolation and restoration; and
- electric vehicle integration

26 Contestability is due to be introduced after December 2016.

27 IEC 61850 is a suite of standards widely used for electrical substation automation. DNP3 (Distributed Network Protocol) is a set of communications protocols used between components in process automation systems.

Gas and water metering

In the future, the AMI communication network may also be considered for gas and water metering.

Impacts on services

AMI provides enhanced energy usage visibility and more information relating to power quality, helping us to plan and operate the network in different ways. AMI can be utilised to realise more service benefits for customers in the following ways:

- Enhanced outage management in terms of:
  - quicker fault response times; and
  - determining whether a fault is customer/network related
- Customer supply measurement including impedance measurement;
- Improved load balancing, which may lead to better utilisation; and
- Demand management.

8.1.5 DEMAND MANAGEMENT

Demand management projects or programs are measures undertaken to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation.

Demand response is a particular type of demand management initiative that involves contracted load reduction either controlled by customers or by the network through direct load control. When deployed for mitigating capacity constraints within the network, demand response can be effective in achieving peak load reduction. Customers can be contracted to voluntarily reduce their demand on specific direction from the network and in return these contracted participants are eligible for capacity and performance payments.

Demand response can include targeted incentives, technologies and customer education programs directed towards reducing or changing patterns of energy use.

Demand management developments

The growth in peak demand continues to exceed the growth of average demand, leading to an inefficient use of the power system given that generation, transmission and network assets remain underutilised for most of the time. Throughout the National Electricity Market (**NEM**), the residential sector and air conditioner usage on hot days contribute the most to peak demand (as much as 35% to 45% on days of extreme heat or after a succession of hot days[28]).

In recent years, electricity consumption in the NEM has changed and the expected growth in both average and peak demand has not eventuated. This can be attributed to forecast revisions from some major electricity consumers, increased rooftop PV generation, and reduced residential consumption due to higher electricity prices.

---

28 These figures have been derived from the highest 100 half hour periods of energy use in each region in the National Electricity Market for the period 1999 to 2011. Australian Government, Productivity Commission, Electricity Commission Regulatory Frameworks, Draft Report, Volume 2, pp 308, October 2012.

Demand response is one of the more mature demand management solutions that is effective in meeting the objective of peak demand reduction. It has been trialled and implemented in many parts of the world, including Australia. However, the form of demand response and the commercial and cost recovery aspects of these programmes rely on the particular regulatory and market mechanisms in place.

We are already seeing evidence of both customer and distributor controlled demand response initiatives:

Customer controlled demand response programmes typically involve an aggregation component. We can either manage the aggregation function internally or outsource it to external agencies that can assist in customer acquisition, contracting, technology deployment, performance testing and settlements. We would have control over operations and dispatch and have the ability to call a demand response event when the network conditions require a reduction in load, either during times of high network load or during outage conditions.

Distributor controlled demand response programmes have a larger technology component and rely on the deployment of advanced metering and communications infrastructure. The customers participating in the programme also need to have loads, such as air conditioners or refrigerators, which can communicate with the smart meter and are enabled for direct load control.

In the current environment, foundations for an effective and vibrant demand response marketplace are beginning to emerge. In our view, the key drivers include the following:

- There are strong signals from a policy and regulatory perspective that are incentivizing the uptake of demand-side participation and demand response.
- The overall objective of the AEMC's Power of Choice review[29] is to ensure that the community's demand for electricity services is met by the lowest cost combination of demand and supply-side options. One of three key reforms recommended by this review is to 'task AEMO with developing a rule change proposal to establish a new demand response mechanism that allows consumers, or third parties acting on consumers' behalf, to directly participate in the wholesale market and to receive the spot price for the change in demand'.
- Customers, especially larger commercial and industrial customers, are keen to manage their electricity consumption and willing to be flexible with their processes if it results in financial savings or possible revenue for their businesses. For example, an industrial customer when called upon as part of a demand response programme can readjust its afternoon/evening shift to avoid the peak of the day and earn extra revenue.

Also energy efficiency is practical approach to demand management. Businesses can benefit from improving energy efficiency, through better energy information and management. At a residential level, energy efficiency can be achieved through either capital expenditure or more informed energy use (for example, through using energy management systems). Improved energy efficiency allows our customers to better manage their energy costs by using less energy, or to improve their amenity while using the same amount of energy.

We expect energy efficiency trends to be inherent in our network's base demand and to continue to have an impact over the next 20 years. We also expect customers to become more aware, through information from the market and in-home displays/smart devices about the potential for savings in the long term from reducing energy consumption.

[29] AEMC (Australian Energy Market Commission) Power of choice review – giving consumers options in the way they use electricity, Final Report, 30 November 2012

Demand Management over the next 20 years

Demand management represents a major change for the energy market, requiring market reform to facilitate it. It also has the potential to create new platforms for customer participation, and to introduce new market participants and demand response innovation.

Other changes we anticipate include:

- information technology, which will be essential to delivering effective demand response, requiring development in communications, monitoring, measurement, and analysis, and
- residential consumption (already the principal contributor to network peak demand), which is trending towards high-rise, high density housing that is even more reliant on mechanical heating and cooling

Impacts on services

On the network side, a smart grid platform linking distributed generation sources (including a variety of conventional and renewable energy generation) across the grid, in the midst of distributed embedded networks (micro grids) and distributed system operators, will not be possible without implementing a suite of demand-management systems and services. The types of intelligent business enabling applications and systems required to manage these changes and maintain network stability include:

- power generation management;
- dynamic load flow monitoring;
- energy market monitoring tools and applications; and
- advanced distribution automation applications and outage and communication network management systems

Installation of efficient lighting (including street lights), efficient appliances and equipment, and the adoption of energy efficiency practices are reducing energy use on our network while saving our customers money. Technologies including variable speed drives, load control, and waste energy capture and reuse (such as co/tri-generation) are offering opportunities for energy efficiency for industrial customers, while efficient motors and compressors have the potential to significantly reduce energy consumption[30].

8.1.6 INFORMATION TECHNOLOGY

Information technology developments

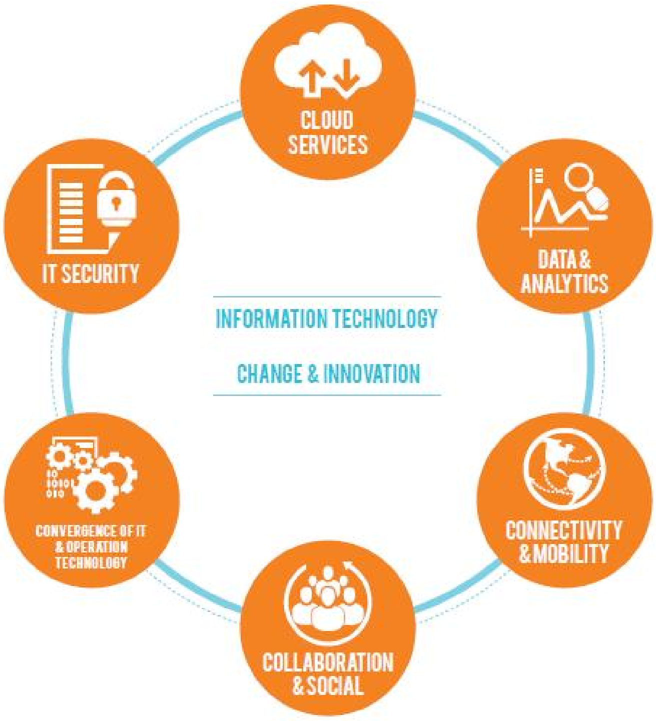
With the advent of mobile devices, increasing bandwidths and connectivity, and the introduction of AMI, customers will have increasing control of how they manage the information they need to inform their use of energy including connectivity and mobility, collaboration and societal, data and security of information.

Information Technology over the next 20 years

Technological developments have increased the available information about our assets and their condition. We expect that this will become even more integrated by 2035, with the advent of more automated assets that monitor their own condition, enabling us to make more informed investment decisions.

[30] Reference: The IEA estimates industrial energy savings potential as around 20 per cent in the five most energy intensive industries if they applied the best available technologies.

Figure 8-7: Change and innovation in Information Technology



The table below provides a summary of our forecast changes over the short, medium and long term.

Table 8–1: Forecast IT Changes

Driver	Impact
Connectivity and mobility	Convergence of enterprise and field services
	Improved communications and access to data
	Increase in mobile applications
Collaboration & Societal	Increased frequency and speed of customer and employee engagement
	Increasing levels of employee collaboration across distributed mobile workforce
	Growth in customer engagement
Convergence of Information Technology and Operations Technology	Digital technology will drive business process and technology convergence
	Increasing use of common IT standards, security models and lifecycle management
	We will see a common IT/OT governance model and approach to managing risks
Data	Significantly greater volumes of data
	Information-rich performance and event based insight
	Increasing use of geospatial data

Security	Network design (equipment data etc.)
	Increasing adoption and use of open technologies
	Increased cyber security risks
	Proliferation of internet enabled technologies
Cloud Services	Advantages of scalability depending on business needs
	Seeing a shift in capital expenditure to operational expenditure

Impacts on services

Developments in data and analytics (power quality, voltage profiles, power factor, etc.), predictive programs (maintenance programs, demand management and network tariffs), connectivity and mobility, the convergence of IT and operational technology, cloud services, IT security, and operational data (active voltage regulation, network performance indicators, and ratings) will drive investment in information technology over the next 20 years.

Information about assets and customer attributes with regard to electricity usage will be analysed with software systems that provide pertinent information. This analysis will help us to understand the impact of new technologies, but will also enable us to better understand existing technologies and any related impacts on our power quality. This can provide insights into the management of the network and help us to improve its management.

8.2 OUR TECHNOLOGY PLANS

We have the following technology related plans, to ensure that we continue to provide innovative services to customers.[31]

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. We have been developing and applying smart network compatible technologies to the distribution network over many years. Our long term focus for smart networks is to continue to embrace new and innovative technologies which present net benefits to customers. We also plans to leverage the infrastructure provided by the AMI (**Advanced Metering Infrastructure**) program to further develop a smart network and ensure continued efficiency in service delivery to customers.

A smart network will ensure efficient service provision and empower customers who want flexibility in using power efficiently. Adoption of smart network concepts will help us to maintain a market leading position and to provide a platform for innovation to meet changing customer needs.

Our focus is on the following aspects for our 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 & operation of the Jemena electricity network;

[31] A key finding of our customer engagement was that customers expected Jemena to look at innovative ways of reducing peak demand.

- 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– 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.

8.2.1 DISTRIBUTED GENERATION, ENERGY STORAGE AND DEMAND RESPONSE

To address the changing environment for distributed generation, we will continue to:

- implement balanced capacity planning and asset management (primary and secondary plant) methodologies that consider the impact of distributed generation;
- evaluate distributed generation as a non-network alternative, while performing cost benefit analysis of augmentation options;
- develop technology trials to facilitate connection of embedded generation, which include:
  - integrate information management systems for distributed generation;
  - support non-network solution providers to provide solutions in advance of projects becoming committed through the publication of our Distribution Annual Planning Report (**DAPR**) and demand-side engagement documents; and
  - actively engage with our customers and distributed generation solution providers via our demand-side engagement register to understand their socio-economic drivers for installing distributed generation

In the coming planning period, we are proposing to position ourselves for change by obtaining in-depth technical knowledge about how these technologies will impact our network and our customers and how we may be able to leverage them for our customers' benefit and to reduce costs.

8.2.2 DEMAND MANAGEMENT AND EMBEDDED GENERATION TRIALS

To set ourselves up with sufficient experience and capability so that over the next 20 years we can prudently optimise our network management methods across both supply side and demand side measures, and existing and new technologies, we are proposing to undertake trial projects under the AER's Demand Management and Embedded Generation Connection Incentive Scheme (DMEGIS) in the next regulatory period:

- **Efficient connection of micro-embedded generators** - maximising the capacity of Low Voltage networks for efficient connection of inverter based micro-embedded generators;
- **Direct Load Control Trial (DLC)** - test the effect of DLC as a means to managing peak demand and develop DLC dispatch algorithms that optimise load reduction amongst participating customers;

- **Managing peak demand through customer engagement** - empowering customers to make informed decisions through education, incentives and analytics;
- **Technology and economic assessment of residential energy storage -** Assess technical and economic viability of residential battery storage paired with PV systems and identify key barriers for wide scale uptake;
- **Distributed grid energy storage** - storage solutions to mitigate network capacity constraints and maintain quality of electricity supply; and
- **Demand response field trial – phase two** - field test desktop models developed in Phase 1 and understand practical issues with operation of demand response.

Demand response and other demand-side participation programmes need community participation to be successful, and we have undertaken[32] to ensure our customers are well informed and encouraged to participate. The introduction of demand response programmes to consumers involves not just technology but also detailed planning assessments, customer education and engagement, and development of innovative tariffs and pricing mechanisms. We will leverage the outcomes of our trial program to evaluate and then operationalise demand response solutions as a means to manage peak demand in a cost effective manner.

We have already initiated a Demand Response Field Trial (**DRFT**) project to develop our understanding of the benefits, costs, pricing / commercial arrangements and operational structures of targeted demand response programmes. Phase 1 of the trial includes model development and desktop analysis and is close to completion. Phase 2 is trialling the technology, customer acquisition and contracting processes and operational dispatch methodologies in a constrained area of the network.

The knowledge gained from this trial will help in:

- building demand management expertise within our organisation to ensure the demand management methodologies that can be introduced meet customer and stakeholder expectations;
- reinforcing the lessons derived from the demand response trials with targeted projects and information campaigns; and
- engaging with third party demand aggregators (through our annual planning review process) about specific opportunities for non-network solutions to alleviate emerging network constraints

8.2.3 ADVANCED METERING INFRASTRUCTURE [COMMERCIAL-IN-CONFIDENCE]

Our plans are to ensure that we leverage the capability of the meter to ensure customers will benefit from the investments made in AMI through initiatives to:

- provide options and flexibility to customers in managing their energy needs, which includes providing information to consumers to allow them to actively manage their energy consumption, and for communicating pricing/control information;
- detect degraded supply conditions and make corrections or repairs as appropriate to avoid unplanned outages and hazardous situations;
- ensure efficient provision of customer services;
- offer price-reflective tariffs to customers to incentivise behaviours that lead to usage change; and
- deliver a technology platform whereby smart meters can wirelessly interact with in-home displays, energy management systems or smart appliances

[32] An example is our free web portal for consumers in our jurisdiction (https://electricityoutlook.jemena.com.au/).

Enhanced outage management

By connecting the outage management system (**OMS**) with AMI we can receive both high and low voltage outage data in near real time, enabling quicker fault response times.

AMI enables call centre operators to communicate with a meter and determine if the fault is with the supply or the customer, reducing wasted truck visits, customer charges, and the time for a customer to engage an electrician. This will help identify single customer outages, although in the short term this feature is not expected to be used (due to system and process constraints relating to false identification and access issues).

LV Grid Modernisation

We are planning to enhance the AMI system's measurement capability to include supply measurement assessment (voltage, current, power and power factor). This will enable periodic measurements to be taken, providing the data to:

- detect customer connection phase; and
- voltage and load balance issues

Customer phase detection and common connection phase identification (by using analytic software to compare voltage profile and customer load information from meters on the same substation) will enable us to take a proactive approach to:

- load balancing across phases and consequently reliability (fuse overload), capacity, and voltage levels (where neutral currents are excessive), given transformer imbalances account for approximately 45% of all power quality issues; and
- substation load management through the aggregation of interval energy and power profile measurements from meters

Voltage profiling also enables load disassociation (for example, voltage profile analysis to determine energy use per appliance), with the data able to be provided as a service to retailers, third parties, or directly to customers so they can evaluate opportunities to reduce consumption. To facilitate voltage assessment:

- meters will be upgraded to include the extra measurement functions;
- the AMI Network Management System (**NMS**) will be upgraded to schedule and provide appropriate measurements; and
- a background meter function will be enabled to enable quicker complaint investigation. This will be available from the AMI NMS or via business reports

Measuring supply impedance through the meter can help detect neutral service degradation and scheduling repair work before failure occurs and a customer is subjected to an electric shock. It also has the potential to detect degraded distribution services when resistance measurements are compared for all connections on the same substation.

Our plans are to use this technology to ensure:

- better informed maintenance and replacement schedules through the adoption of an operate-to-near-failure strategy; and
- prioritised preventative maintenance, thereby mitigating asset risks

8.2.4 IT PLANS

The IT Plans are identified in the IT Asset Management Plan. Given that IT asset lifecycles are typically five years, we have not separately examined IT asset management in this 20 year strategy.

9. PRICING AND TARIFF STRUCTURES

Our network tariffs include the charges for our distribution and metering network services, as well as the charges we pay for transmission services.33 While we charge different customer groups (or tariff classes) different amounts for using our network, our charges for distribution network and metering services make up around 37% of a typical residential customer bill.[34]

Our network prices, particularly for residential and business customers — have not evolved to provide signals for informed energy decision making. To some extent, the structure of our network pricing has not kept up with the diversity in how people use the network.

We propose to update our network tariff structures to encourage more informed customer decision making about using the network that takes better account of the costs involved— which, in turn, will drive continued technological and market innovation to assist customers in managing energy use —and put downward pressure on network costs and average prices over the long term by:

- introducing a new 'maximum demand charge' for all residential and small business customers to more clearly signal the higher costs of using our network during periods of peak demand, and thus encourage these customers to reduce or shift consumption during periods of peak demand; and
- changing the existing demand charges for all large business customers to improve their cost-reflectivity

We will continue to have a fixed standing charge and variable usage charges, and on average these charges will be lowered so we do not recover more revenue from customers. Overall, our proposed network tariffs will result in lower average prices over the 2016 regulatory period. However, the impact on individual customers' bills will depend on how and when they use our network, and how they respond to the new price signals

9.1 RESPONDING TO A CHANGING ENERGY MARKET

Our network prices or 'tariffs' are made up of a number of charges, so that the total network cost incorporated into your electricity bill comprises several separate components. Typically, these include a fixed (or 'standing') charge that applies to each premise that we supply, and a variable charge that applies to the volume of electricity consumed.

Our customers have paid for electricity this way for many years. But our energy market has changed, and there is now more diversity in how our network is used. For example, our network no longer provides a one-way flow of electricity. With the widespread installation of solar PV units we increasingly provide a two-way flow of electricity between our customers.

As a result, our current charges don't send clear signals about the different costs of using our network in different ways—and mean some customers are paying more than the cost of their use of the network, while others are paying less.

We expect new technologies such as battery storage, electric vehicles and smart grids to become increasingly viable, and new market players to emerge to assist customers in managing their energy needs. It is difficult to

[33] Our proposed network tariffs are sometimes referred to as network use of system (**NUOS**) charges. These charges include the costs associated with both our distribution network (distribution use of system charges or '**DUOS**' charges), designated pricing proposal charges which include a portion of Ausnet Services' and AEMO costs for transporting electricity over its high voltage transmission network (transmission use of system charges or '**TUOS**' charges), costs associated with any NER allowed pass through events and jurisdictional scheme costs.

[34] Based on analysis by Oakley Greenwood for Jemena, December 2014.

predict the pace of technological development, and to forecast how, where and when our customers will chose to use these new technologies.

To help us address this issue in a way that promotes our customers long-term interests, we consulted extensively with our customers who agreed that our network charges need to be updated in a technology neutral way to respond to the changes in the energy market, to accommodate the future changes in how they may use our network and to use the benefits of the smart meters we have installed across our network to deliver better (as well as cheaper) services. Our customers also told us it made sense to transition to the updated charges as soon as practical.

9.2 OUR PLANS FOR PRICING

In this changing environment, we will need to ensure that the tariffs we charge reflect the costs of providing our network services as closely as possible.

The product we provide can be simply described as a service that:

- provides connection to a shared electricity network access point at a specified capacity; and
- allows a customer to consume electricity (provided by a retailer) at a rate that never exceeds the connection's capacity

For a range of reasons (including historical customer preferences, as well as policy and regulatory settings), our current price structure for most residential and small business customers does not fully reflect the nature of our service. For example, a large portion of our revenue is recovered through consumption charges on a cent-per-kilowatt-hour basis, however actual total energy use is a relatively minor cost driver. As a result, we will need to:

- remove minor cross-subsidies in our network pricing, which is important not only in terms of equity, but also to ensure customers make efficient long-term choices about whether to invest in distributed generation, reducing their reliance on the distribution network (often involving costly, long-term technology investments that are difficult to reverse); and
- ensure the most efficient use of the network to minimise our costs, leading to lower overall tariffs

We are constantly improving the way our pricing reflects our costs. However, due to the shared nature of services and costs, isolating cost components relating to individual customer classes[35] is difficult. Improvements in information systems and estimation techniques will improve our ability to make prices more cost reflective.

In the shorter term (from 2016-2020), we intend to:

- introduce a maximum demand component for residential customer pricing, charging a per-kilowatt price for the maximum demand recorded during a peak period (10 AM to 8 PM, Monday to Friday) over each month, encouraging residential customers to spread consumption during peak periods, and reduce the peak consumption in any given half-hour;
- introduce a demand component for small business pricing similar to our existing maximum demand pricing for large businesses, with the main difference being that billable maximum demand is the larger of a customer's maximum demand recorded over the last billing cycle (or the demand billed the cycle before last), encouraging small commercial customers to spread consumption during peak periods, and reduce the peak consumption in any given half-hour; and

[35] Referred to as 'tariff classes' in the NER.

- refine our maximum demand charge for large commercial customers by switching from a kilowatt-based charge to kilovolt ampere-based charge

Following engagement with our customers and stakeholders, we intend to introduce our new tariff components at 50 per cent of a cost reflective level for the relevant tariff class in 2018. We will aim to fully recover maximum demand-driven costs for the relevant customer class prior to the end of the next regulatory period (i.e. by 2025). This transition will also include reductions in our consumption and fixed charges to ensure that we recover no additional revenue. We also plan to investigate and trial other options for improving cost reflectivity, such as critical peak rebates or critical peak tariffs.

10. CAPITAL AND OPERATING EXPENDITURE FORECAST SCENARIOS

This section provides information about our capital expenditure analysis for the next 20 years.

In developing our capital expenditure forecasts, we undertake a process of modelling the risks and benefits of a number of scenarios. Asset management decisions made within this context are more likely to ensure safe, reliable and affordable network operations while minimising total lifecycle costs, avoiding price shocks and delivering customer's long term interests.

Modelling expenditure scenarios over extended time periods ensures that the long-term implications of different asset management decisions can be validated.

10.1 LEVEL OF SERVICE ATTRIBUTES

Stakeholder feedback has been used as the basis for the levels of service attributes in the scenario modelling. The relationship between the attributes tested and the indicators is as follows:

1. **Safety**[36]
    - Loss of integrity of assets, personal injury or loss of life, property and environment damages, loss of supply.
2. **Visual amenity**
    - Vegetation management, more attractive substation design, bundling of insulation of overhead lines, and undergrounding.
3. **Responsiveness**
    - The time it takes to respond to supply interruptions, the time to reconnect customers, the time required to connect new customers, and the time to respond to emergency events.
4. **Reliability and quality**
    - The frequency of unplanned service interruption, and the quality of the services provided.

As outlined in Chapter 1, one of our objectives is to deliver energy services that are safe, reliable, affordable and responsive to customers' preferences.

Each scenario was considered with respect to the service attributes, but also in respect of **affordability** (i.e. the cost of efficient delivery of services to customers), and also measure with respect to customer feedback.

While our short term service level targets are set by the regulatory regime, we have engaged customers to understand their long term preferences with respect to service levels given the cost consequences of these and the fact that our assets have a very long service and cost recovery life.

This chapter discusses the impacts of various capital and operational expenditure scenarios on these indices and our customers' feedback on these.

[36] JEN sees the safety of its employees, customers, and the community as our non-negotiable top priority.

10.2 SCENARIO ANALYSIS

For the purpose of scenario modelling[37], we assessed changes in operational and capital expenditure and the impacts on Jemena's average cost per customer over three time horizons:

1. Short term – within the next 5 years;
2. Medium term – between 5 and 15 years;
3. Long term – greater than 15 years.

The scenarios used to assess the approach are:

1. Maintain current service levels;
2. Reduce service levels for the longer term;
3. Short term reduction in service levels (return to current service levels over the medium & long term); and
4. Improve visual amenity.

[37] Key assumptions are: Demand and energy forecasts presented by external consultants. Incentive schemes are not included in the analysis. No ex-post review RAB adjustments are included. All percentages are relative to Scenario One.

10.2.1 SCENARIO ONE: MAINTAIN CURRENT SERVICE LEVELS

This scenario reflects the forecast expenditure required to maintain the network's current safety and operational performance levels for the next planning period with the aim to maintain our customers' preferred levels of service. The expenditure is characterised by:

CAPEX:

- Investment at optimal timing as per our technical, financial and economic analysis;
- Optimised delivery of programs through strategic procurement; and
- Apply best practice asset management techniques to retain efficiencies in delivering work.

OPEX:

- Sustainable, least cost service provision through efficient management of the network, including implementing efficiencies through IT projects and technology developments to drive long term improvements in dynamic efficiency; and
- Efficiency in procurement, and service delivery through optimised work program.

Table 10–1 lists the outcomes that characterise this scenario.

Table 10–1: Maintain Current Service Levels Scenario

Service Attribute/Objective	Outcome
Safety	• Maintain safety levels across the network. • Maintain risk levels associated with fire-starts, employee, contractor and public safety and other risk measures. • Meet compliance requirements, and meet expectations of the technical regulator (ESV).
Visual amenity	• Maintain design and operating standards that align to community expectations.
Responsiveness	• Maintain performance in emergency response events. • Individual customers receive largely the same level of responsiveness. • Meet guaranteed service levels.
Reliability	• Individual customers receive largely the same levels of reliability. • Maintain reliability in the shorter, medium and long term to ensure confidence for investment in the region, facilitating economic prosperity and broader societal benefits. • Meet existing guaranteed service levels.
Affordability	• Increase dynamic efficiency through the application of IT projects and technology development. • Achieve efficiency in procurement, and service delivery through optimised work program.

10.2.2 SCENARIO TWO: REDUCE CURRENT SERVICE LEVELS FOR THE LONGER TERM

This scenario assesses the effect of reducing capital expenditure relative to Scenario One in the long term to deliver reduced levels of service to customers. The resultant expenditure is characterised by:

CAPEX:

- Reduced from scenario one levels over the short term, however increasing in the medium term, and long term (despite the fact that service levels don't revert to present levels):
  - Replacement reduced over the short term, increasing in the medium term and long term;
  - Augmentation reduced over the short term, increasing in the medium term and long term;
  - Connections maintained; and
  - Non-network reduced over the short term, increasing in the medium term, and reverting to increased levels in the long term.

OPEX:

- Reduced to approximately in the short term through:
  - Removal of zone substation primary and secondary defect and equipment maintenance;
  - Reduced fault management;
  - Remove investigations of voltage complaints;
  - Remove thermal surveying of equipment; and
  - Reduced numbers of supply abolishment.
- Increased for maintenance catch-up in the medium and long term due to increasing numbers of faults, compliance voltage issues, reduced efficiency from non-network projects.

Table 10–2 lists the outcomes that characterise this scenario.

Table 10–2: Reduce current service levels for the longer term

Service Attribute/Objective	Outcome
Safety	• A significant reduction in safety levels across the network. • Increasingly high levels of risk associated with fire-starts, employee, contractor and public safety and other risk measures. • Increased risk of noise pollution and other environmental impacts. • Increased risk of major non-conformance with expectations of the ESMS in the short, medium and long term. • Increasing operational expenditure relating to safety management and due to one or more major/catastrophic events. • Suboptimal replacement of assets causes increased risk to the public, customers, employees and contractors. • Decreased expenditure in management of plant/vehicles, leading to increasing risks.
Visual amenity	• Reduce design and operating standards that would no longer align to community expectations.
Responsiveness	• Reduced performance in emergency response events. • Reduced responsiveness for all/some customers (longer waiting times for appointments). • Do not meet guaranteed service levels, causing financial penalties (modelling excludes STPIS which would also be impacted). • An increase in customer service and field response costs over the medium and long term due to increased volumes of asset failures. • An increase in volume of emergency response events with a corresponding reduction in performance. • Gradual increase in expenditure would be required to maintain lower performance.
Reliability	• Reduced reliability for all customers. • Do not meet guaranteed service levels, causing financial penalties. • Customer supply risk through excessive utilisation levels in some areas, with increasing numbers of customers off supply. • Reducing service levels (unplanned outage frequency and duration) causes performance penalties, and impacts customer satisfaction. (modelling excludes STPIS which would also be impacted). • Increasing condition and routine maintenance in the medium and long term due to suboptimal replacement of assets and associated increase in costs to maintain lower service levels. • Negative impact on delivery of the expectations of the technical regulator (ESV).
Affordability	• Increasing operational expenditure due to process inefficiencies as a result of not implementing IT projects that would otherwise introduce efficiencies. • Reduces the capability to facilitate innovation through IT projects. • Risk to certification to best practice asset management.

10.2.3 SCENARIO THREE: REDUCE CURRENT SERVICE LEVELS FOR THE SHORT TERM

This scenario assesses the effect of a significant short term reduction in total expenditure relative to scenario one to deliver reduced short term levels of service, and medium to long term increase in total expenditure relative to scenario one to deliver long term service levels consistent with scenario one. The expenditure is characterised by:

CAPEX:

- Significant reduction of capital expenditure relative to scenario one over the short term, followed by medium term increase in expenditure to recover to existing service levels by the end of the medium term.
  - Replacement reduced relative to scenario one in the short term, increasing in the medium term, and reverting to scenario one levels in the long term;
  - Augmentation reduced to relative to scenario one in the short term, increasing significantly in the medium term, and reducing to scenario one levels in the long term;
  - Connections maintained; and
  - Non-network reduced in the short term, increasing in the medium term, and reverting to scenario one levels in the long term.

OPEX:

- Reduced operational expenditure in the short term:
  - Removal of zone substation primary and secondary defect and equipment maintenance including remove thermal surveying of equipment;
  - Reduced fault management;
  - Remove investigations of voltage complaints; and
  - Reduced numbers of supply abolishment.
- Increased operational expenditure over the medium term:
  - To restore service levels for customers, restore maintenance of plant, respond to increases in voltage complaints, and to complete backlog of supply abolishment, and to account for inefficiency in undertaking works.
- Reducing to scenario one levels in the long term
  - Restored service levels and efficiencies.

Table 10–3 lists the outcomes that characterise this scenario.

Table 10–3: Reduce current service levels in the short term

Service Attribute/Objective	Outcome
Safety	• Significantly reduced safety levels across the network in the short term, reverting to scenario one safety levels in the medium term. • Increased risk of noise pollution and other environmental impacts in the short/medium term • Increasingly high risk levels associated with fire-starts, employee, contractor and public safety and other risk measures in the short term. • Increased risk of major non-conformance with expectations of the ESMS in the short and medium term • Decreased expenditure in management of plant/vehicles, leading to increasing risks in the short/medium term • Negative impact on delivery of the expectations of the technical regulator (ESV)
Visual amenity	• Reduce design and operating standards that would no longer align to community expectations.
Responsiveness	• Reduced performance in emergency response events in the short term (due to increasing volume of failures), but return to scenario one levels in the medium and long term. • Reduced responsiveness for all/some customers in the short term, but return to scenario one levels in the medium and long term. (also drop off in comparative performance relative to other distribution businesses) • Do not meet guaranteed service levels, causing financial penalties in the short and possibly medium term (modelling excludes STPIS which would also be impacted) • higher volume of failures, leads to longer outages and response times (inclusive of emergency response events)
Reliability	• Reduced reliability for customers in the short/medium term. (Immediate customer impacts as customers are off supply) • Do not meet guaranteed service levels, causing financial penalties in the short and possibly medium term (modelling excludes STPIS which would also be impacted)

Service Attribute/Objective	Outcome
Affordability	• Reduces the capability to facilitate innovation and leads to a “catch-up” phase in the medium term. • Resourcing impacts due to staff leaving in the short term and significant costs in increasing workforce numbers/outsourcing to deliver an increased program of work in the medium term (higher than a consistent level of work). There would also be a natural lag in reducing staff (due to lower workload), causing additional overheads for the business. • Sub-optimal network development timings (i.e. deferring projects and subsequently needing to deliver them in shorter timeframes to manage additional risks). • Increase in maintenance due to suboptimal replacement of some asset types. • Reducing service levels causes performance penalties in the short term and early part of the medium term. • Risk to certification to best practice asset management.

10.2.4 SCENARIO FOUR: INCREASE VISUAL AMENITY

This scenario reflects the forecast expenditure to maintain service levels as per scenario one, but also providing increased levels of visual amenity over the short, medium and long term. The expenditure is characterised by:

CAPEX:

- Increased augmentation and replacement expenditure relative to scenario one over the short, medium and long term to provide additional substation visual designs, bundling of insulation of overhead lines, and undergrounding of some parts of the network.
  - Investment at optimal timing as per our technical, financial and economic analysis;
  - Optimised delivery of programs through strategic procurement; and
  - Apply best practice asset management techniques to retain efficiencies in delivering work.

OPEX:

- Sustainable, least cost service provision through efficient management of the network, including implementing efficiencies through IT projects and technology developments to drive long term improvements in dynamic efficiency. Efficiency in procurement, and service delivery through optimised work program.
  - Increased operational expenditure to provide additional vegetation management relative to scenario one; and
  - Reduction in maintenance expenditure due to the introduction of underground cables.

Table 10–4 lists the outcomes that characterise this scenario.

Table 10–4: Increase Visual Amenity

Service Attribute/Objective	Outcome
Safety	• Maintain safety levels across the network. • Maintains risk levels associated with fire-starts, employee, contractor and public safety and other risk measures. • Meets compliance requirements.
Visual amenity	• Increase levels of visual amenity to customers.
Responsiveness	• Maintain performance in emergency response events. • Individual customers receive largely the same level of responsiveness. • Meet guaranteed service levels.
Reliability	• Individual customers receive different levels of reliability (i.e. dependent on the area of the network). • Maintains reliability in the shorter, medium and long term to ensure confidence for investment in the region, facilitating economic prosperity and broader societal benefits. • Meet existing guaranteed service levels.

Service Attribute/Objective	Outcome
Affordability	• Increased efficiency through the application of IT projects and technology development. • Efficiency in procurement, and service delivery through optimised work program.

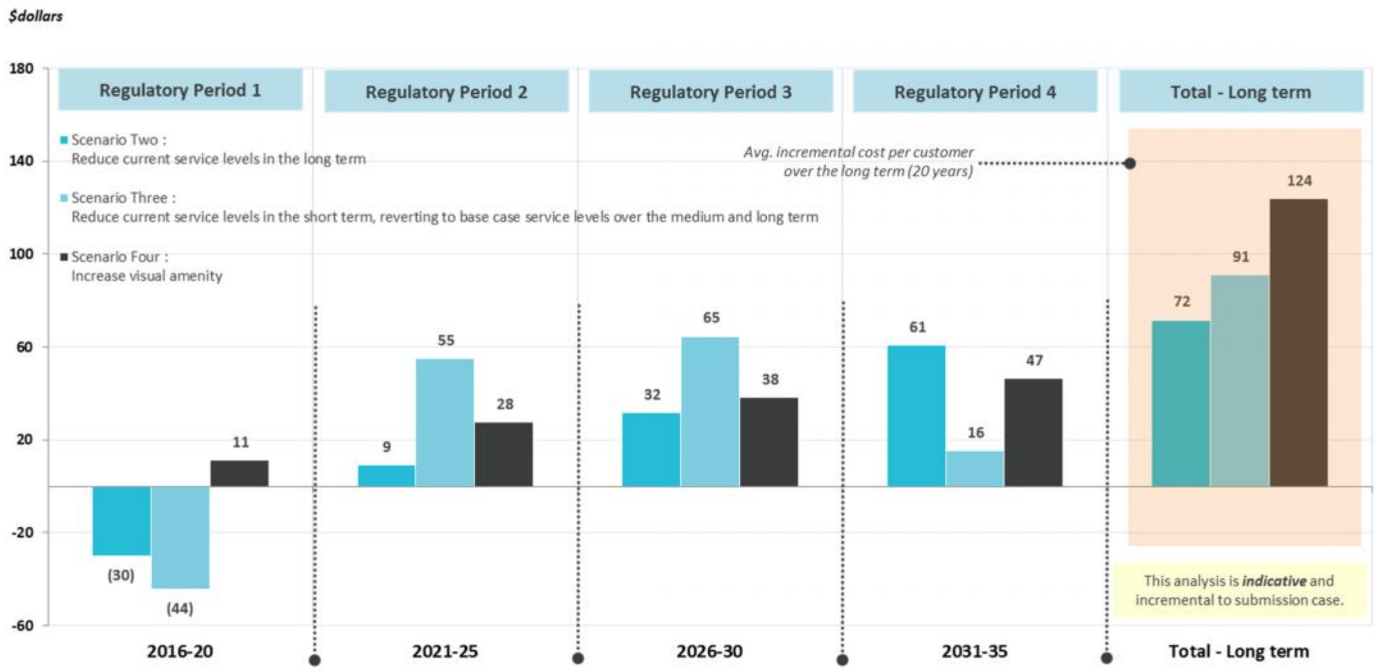
10.3 SUMMARY OF SERVICE SCENARIOS

A summary of the scenarios, in the context of the average cost per customer is presented in Figure 10–1 over the next planning period (2016-2020) and the following three planning periods – a total of 20 years.

The cost per customer is calculated using building block costs which is the approach specified in the electricity framework. These building block costs form the basis of the revenue approved by the AER.

Figure 10–1 provides the scenario representation in change in cost per customer relative to scenario one.

Figure 10–1: Incremental cost per customer $2015, $dollars relative to Scenario One



10.4 STAKEHOLDER FEEDBACK ON SERVICE LEVELS

Jemena has tested stakeholder preference based upon the scenarios, by engaging customers and community groups in a range of forums. To assist the forums, participants considered scenarios and made informed decisions about their preferences. Clear and simple information was presented by Jemena management of what is meant by service levels, the relationship between service levels, and the costs trade-off.

Customer feedback was that:

- 71% strongly agree/ 25% somewhat agree in maintaining safety as a number one priority for Jemena
- 68% thought that Jemena's current view on the balance between service and safety level, and the price customers pay is either very/completely acceptable
- 83% want similar reliability to now, with 85% viewing that the reliability levels proposed in scenario one are acceptable in the next period
- 55% identified that they were not at all willing to pay for increased levels of vegetation management to improve visual amenity across the network, and
- 83% identified that they were not at all willing to pay for undergrounding for improved visual amenity in their street.

A summary of feedback from customers is provided in Appendix E- Customer Preferences.

Table 10–5: Summary of scenarios and how each relates to stakeholder feedback

Criteria	Scenario One	Scenario Two	Scenario Three	Scenario Four
Safety	Meets	Does not meet	Does not meet	Meets
Visual amenity	Meets	Meets	Meets	Does not meet
Responsiveness	Meets	Does not meet	Does not meet	Meets
Reliability	Meets	Does not meet	Does not meet	Meets
Quality	Meets	Does not meet	Does not meet	Meets

10.5 RECOMMENDED STRATEGY

Jemena's proposed strategy is to adopt scenario one, which would result in Jemena continuing to deliver in the short, medium and long term the current acceptable services to customers and through a least cost provision of services and service levels that our customers have told us they value.

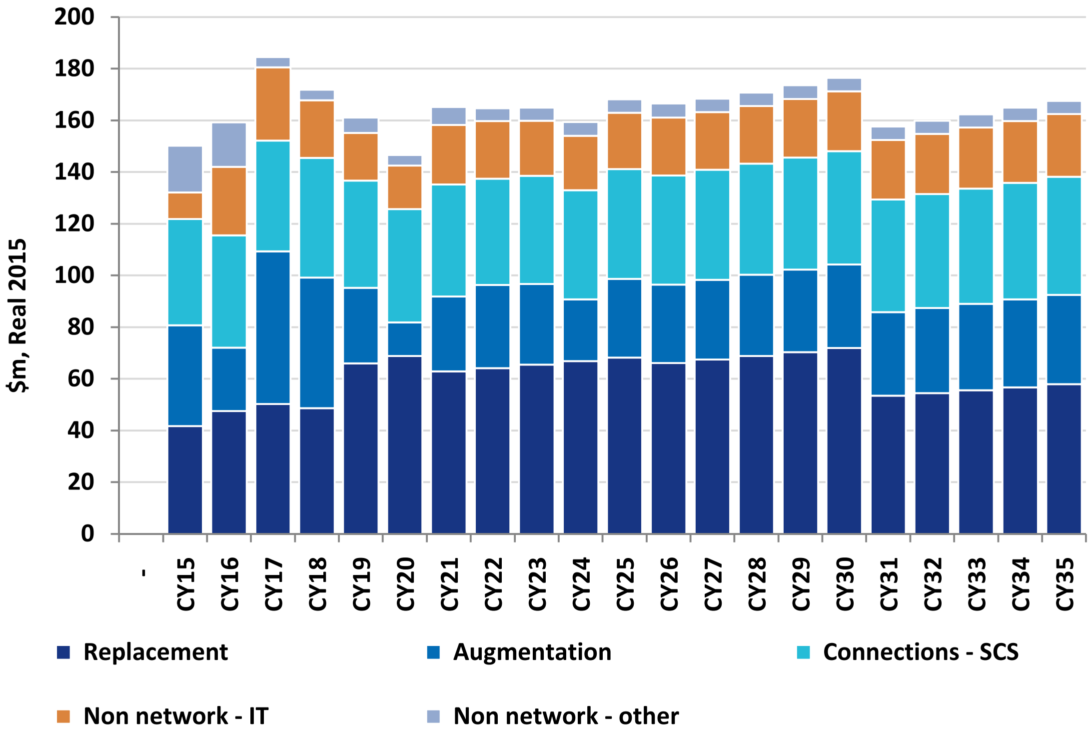
10.6 FORECAST EXPENDITURE

The following table provides a summary of long term expenditure forecasts for standard control services.

Table 10–6: Forecast network expenditure - SCS ($ million, $2015)

Category	2016-2020	2021-2025	2026-2030	2031-2035
Replacement	293	320	337	272
Augmentation	183	143	153	164
Connections	228	206	210	218
Non-network IT	102	107	110	116
Non-network Other	35	27	26	25

Figure 10–2: CAPEX SCS Forecast 2016-35 ($ million, 2015$)



11. APPENDICES

Page intentionally blank

Appendix A
Asset Management Policy

OUR POLICY

Jemena Asset Management Policy

Jemena

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 B
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.

Appendix C
Health and Safety Policy

OUR POLICY

Health & Safety

Jemena

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.

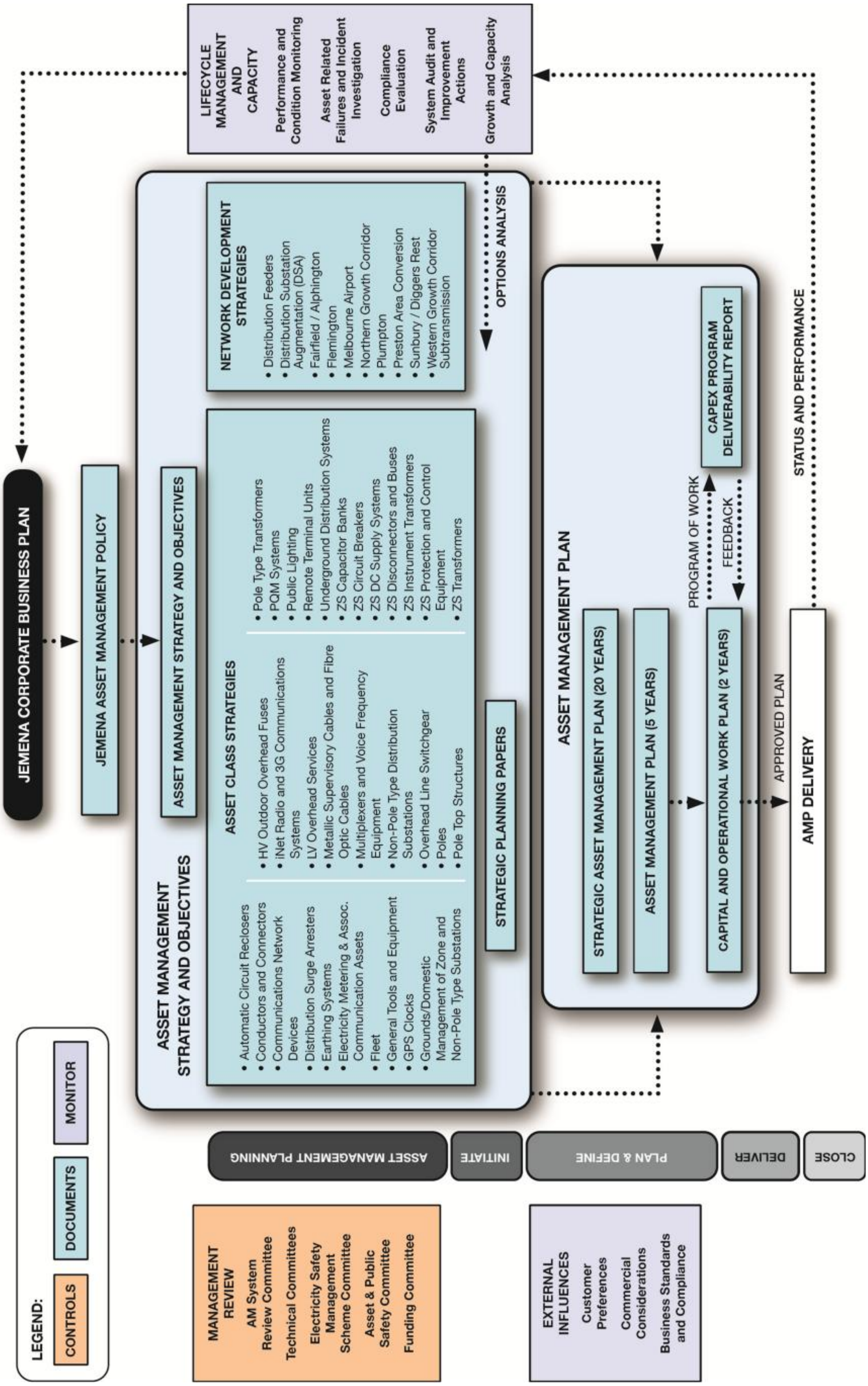
In Jemena, we believe that individual responsibility plays an important part in achieving a healthy and safe workplace and, for that reason, our people are empowered to take action that protects themselves, fellow employees, the public and other stakeholders.

Paul Adams
Managing Director
Jemena Limited
August 2013

Safety First. Hear, Listen and Think before we Act.

Vital Service. Vital Planet.

Appendix D
Document Map

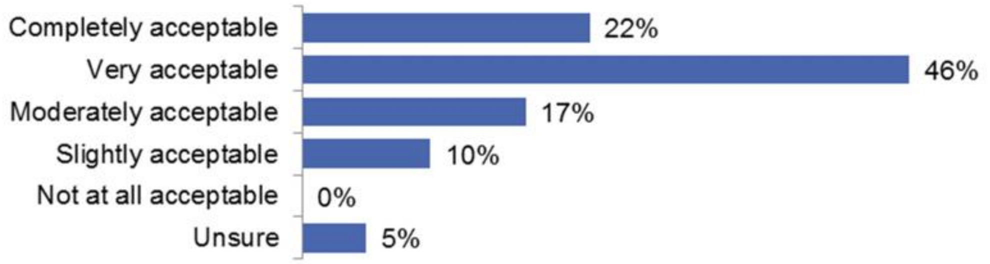

JEMENA CORPORATE BUSINESS PLAN
JEMENA ASSET MANAGEMENT POLICY
ASSET MANAGEMENT STRATEGY AND OBJECTIVES
LIFECYCLE MANAGEMENT AND CAPACITY
Performance and Condition Monitoring
Asset Related Failures and Incident Investigation
Compliance Evaluation
System Audit and Improvement Actions
Growth and Capacity Analysis
ASSET MANAGEMENT STRATEGY AND OBJECTIVES
ASSET CLASS STRATEGIES
• Automatic Circuit Reclosers
• Conductors and Connectors
• Communications Network Devices
• Distribution Surge Arresters
• Earthing Systems
• Electricity Metering & Assoc. Communication Assets
• Fleet
• General Tools and Equipment
• GPS Clocks
• Grounds/Domestic Management of Zone and Non-Pole Type Substations
• HV Outdoor Overhead Fuses
• iNet Radio and 3G Communications Systems
• LV Overhead Services
• Metallic Supervisory Cables and Fibre Optic Cables
• Multiplexers and Voice Frequency Equipment
• Non-Pole Type Distribution Substations
• Overhead Line Switchgear
• Poles
• Pole Top Structures
• Pole Type Transformers
• PQM Systems
• Public Lighting
• Remote Terminal Units
• Underground Distribution Systems
• ZS Capacitor Banks
• ZS Circuit Breakers
• ZS DC Supply Systems
• ZS Disconnectors and Buses
• ZS Instrument Transformers
• ZS Protection and Control Equipment
• ZS Transformers
NETWORK DEVELOPMENT STRATEGIES
• Distribution Feeders
• Distribution Substation Augmentation (DSA)
• Fairfield / Alphington
• Flemington
• Melbourne Airport
• Northern Growth Corridor
• Plumpton
• Preston Area Conversion
• Sunbury / Diggers Rest
• Western Growth Corridor
• Subtransmission
STRATEGIC PLANNING PAPERS
OPTIONS ANALYSIS
ASSET MANAGEMENT PLAN
STRATEGIC ASSET MANAGEMENT PLAN (20 YEARS)
ASSET MANAGEMENT PLAN (5 YEARS)
CAPITAL AND OPERATIONAL WORK PLAN (2 YEARS)
PROGRAM OF WORK
FEEDBACK
CAPEX PROGRAM DELIVERABILITY REPORT
APPROVED PLAN
AMP DELIVERY
STATUS AND PERFORMANCE
LEGEND:
CONTROLS
DOCUMENTS
MONITOR
ASSET MANAGEMENT PLANNING
INITIATE
PLAN & DEFINE
DELIVER
CLOSE
MANAGEMENT REVIEW
AM System Review Committee
Technical Committees
Electricity Safety Management Scheme Committee
Asset & Public Safety Committee
Funding Committee
EXTERNAL INFLUENCES
Customer Preferences
Commercial Considerations
Business Standards and Compliance

Appendix E
Customer Preferences

E1. BALANCING SAFETY, PRICE AND SERVICE LEVELS

Customers felt we had generally struck the right ‘balance’ between safety, price and service levels. Regarding the acceptability of our thinking behind our future plans, the broad response was that maintaining the current balance over the next five years was acceptable: a net of 85% thought it was at least moderately acceptable, with a substantial 68% seeing it as very or completely acceptable (shown in the figure below).

Figure 11–1: Acceptability of Proposed Balance between Service, Safety Levels and Price

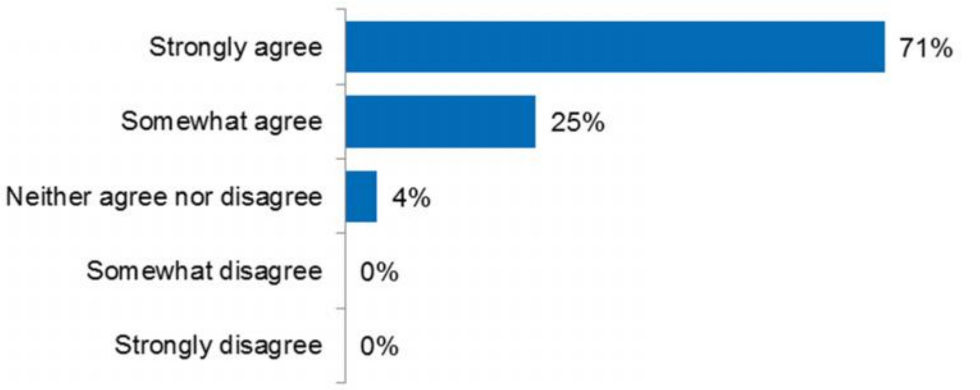


E2. SAFETY SHOULD BE OUR NUMBER ONE PRIORITY

Customers strongly supported our focus on safety with almost universal agreement that safety should be the number one priority (96% agree strongly/somewhat). This was regarded as important not just for the community but for our own employees.

“Safety is a non-negotiable and the most important priority.” (Residential customer)

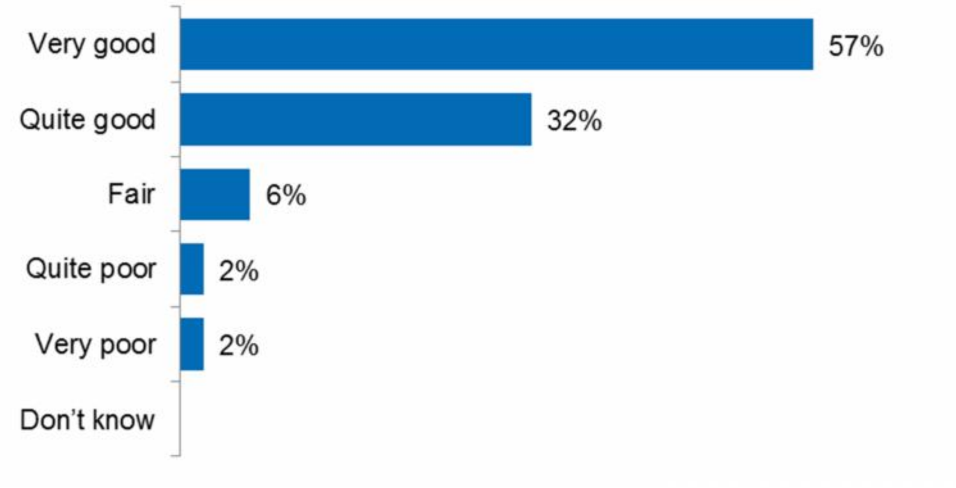
Figure 11–2: Safety is the number one priority: Agree/Disagree



E3. RELIABILITY

Customers generally considered their supply to be reliable, (see figure below), with 89% rating the reliability as very good (57%) or quite good (32%).

Figure 11–3: Current levels of reliability of electricity supply

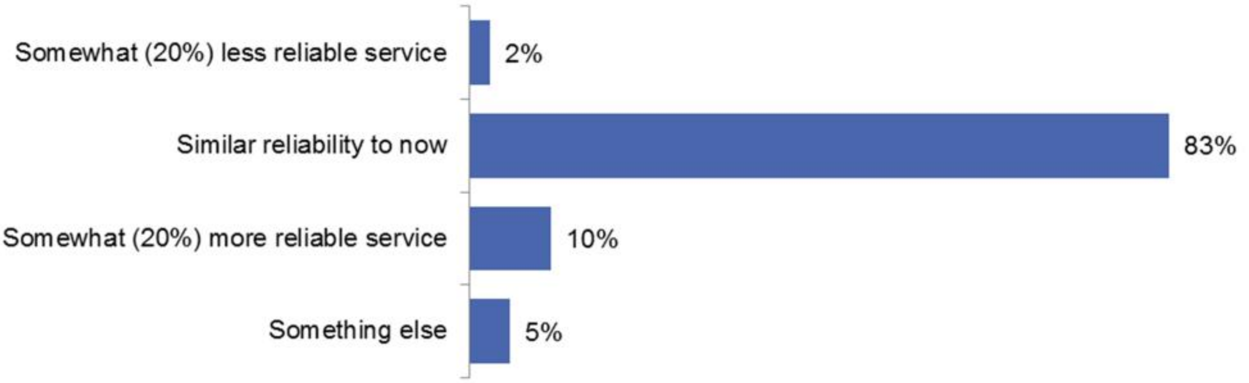


Considering that reliability of supply was regarded as a key priority for customers, several thought that we should continuously seek to improve reliability. However, although some customers thought that in principle we should strive for continuous improvement (higher service levels over time), the cost of improving reliability was 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)

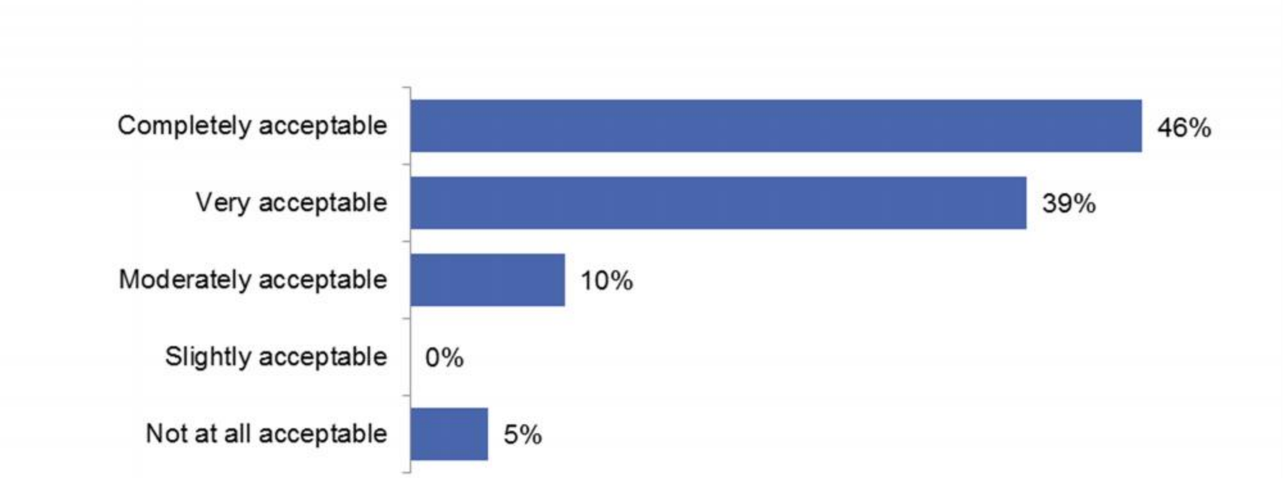
When asked to vote for their option preference in terms of downgrading, maintaining or improving reliability, the overwhelming majority (83%) preferred to maintain current levels of reliability (see figure below).

Figure 11–4: Long-term preference for reliability of supply option



When asked to rate the acceptability of our proposed approach of maintaining the current levels of reliability over the next five years, a strong majority (85%) considered this idea either completely or very acceptable, and a further 10% saw this as moderately acceptable, equating to a net of 95% rating this at least moderately acceptable (see figure below). This feedback on customers' preferences over the next five years is consistent with their preferred outcomes over the long-term (up to 20 years).

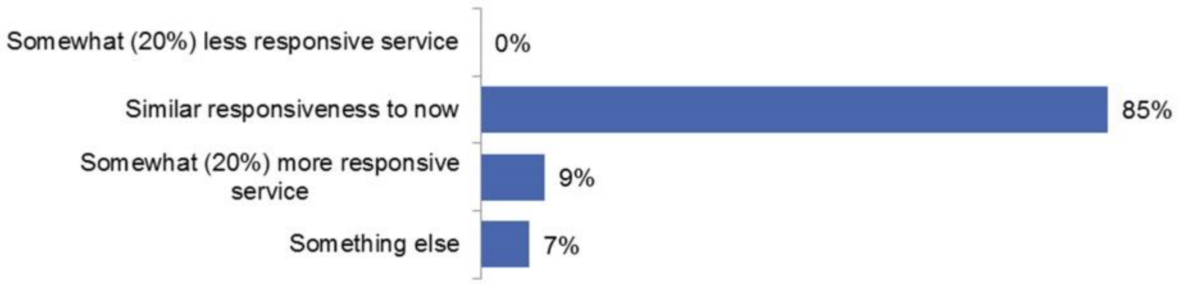
Figure 11–5: Long-term acceptability of maintaining current levels of reliability



E4. RESPONSIVENESS

Generally, there was strong support for maintaining current response service levels. The results were that no participants were willing to accept less responsiveness and the vast majority (85%) would like responsiveness levels to remain the same (see figure below).

Figure 11–6: Long term preference for responsiveness

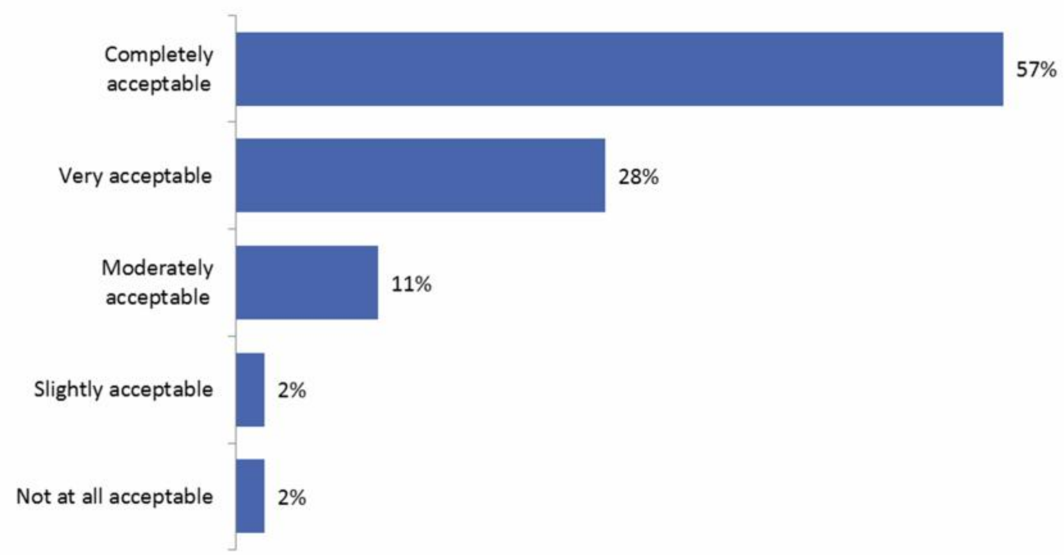


E5. CUSTOMER EMPOWERMENT

Customers generally support our forward thinking about new and innovative ways to reduce the need for future network investment. When given a choice between increasing investment in 'poles and wires' to cater for increased usage on peak demand days, or offering new incentives to consumers to decrease their usage at certain times to avoid the costs associated with building more poles and wires, most participants preferred behaviour change incentives (92%) over increased infrastructure (8%).

Customers also indicated an interest in future trials exploring ways to better utilise advanced metering infrastructure (AMI) technology for demand management. These include empowering customers with better appliance control and reducing peak demand by offering incentives to customers. There was strong support for us exploring trials with customers to help reduce peak usage and associated costs over the long-term (85% thought this was either completely acceptable or very acceptable) (see figure below).

Figure 11–7: Acceptability of Offering Various Trials to Customers to Help Reduce Peak Usage and Associated Costs?

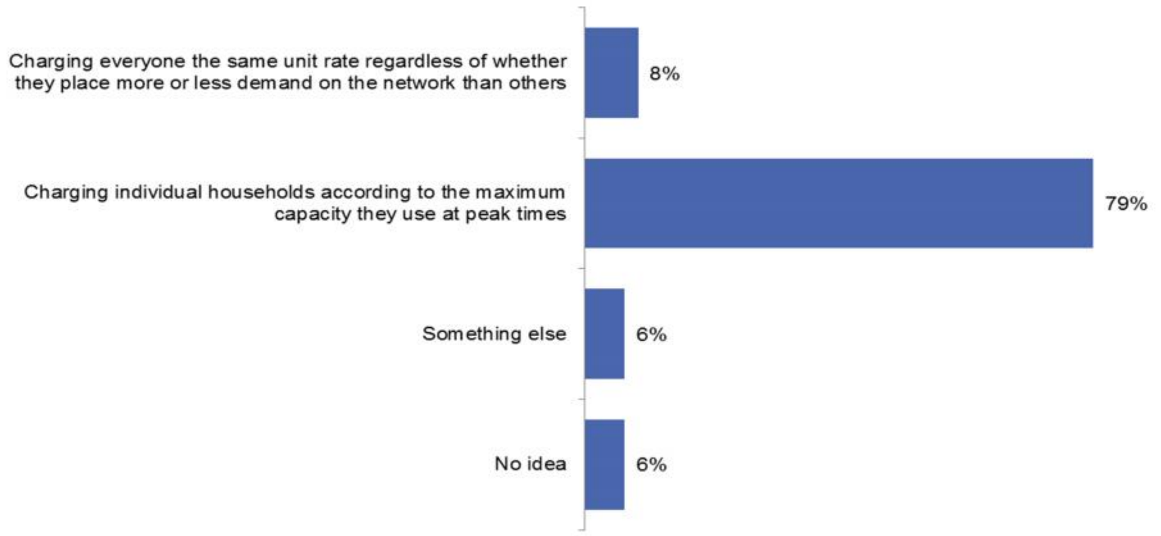


There is also support for pricing our services to encourage customers to make more informed (and efficient) decisions about how they use our services and allow us to more efficiently provide services to our customers. The majority of participants (90%) indicated that they understood why we want to move towards prices that better reflect the costs of delivering electricity to customers with different electricity needs. Customers felt positive about us thinking about ways to help people save money.

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

Most participants (79%) thought that charging individual households according to the maximum capacity they use at peak times of the day was fairer than charging everyone at the same unit rate regardless of whether they place more or less demand on the electricity network than other customers (see).

Figure 11–8: Perceived Fairest Option

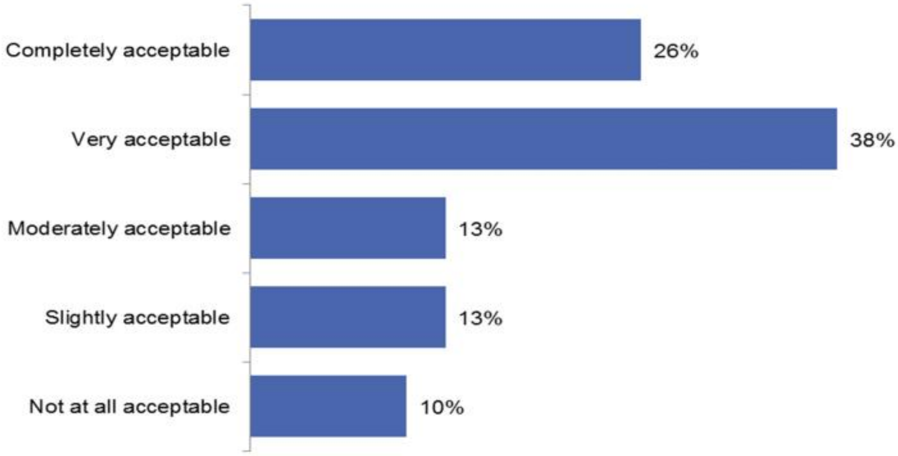


E6. VISUAL AMENITY

A large majority of customers saw our proposed approach of not prioritising expenditure on improving the visual amenity of our network as highly acceptable (see figure below). People did not place a high value on measures to improve the visual amenity and valued other service attributes more than this. The majority of participants thought maintaining our approach of continuing with our current practices for visual amenity was highly acceptable (net 64% completely/very acceptable) and that customers wanting improved visual amenity should be the ones paying for it (net 75%). When it came to their willingness to pay for visual amenity improvements, overall support for our approach was further emphasised. Most were not at all willing to pay for the one-off costs of 'Low Voltage Aerial Bundled Conductor (LV ABC) (83%) or undergrounding (80%). More than half (55%) felt the same way about more frequent tree pruning, and a substantial number (46%) also said this for more attractive substations.

"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)

Figure 11–9: Acceptability of Jemena's visual amenity proposal



Appendix F
Key Document References

Key Document References:

- JEN PL 0012 Asset Management Strategy and Objectives
- JEN PL 0028 Automatic Circuit Reclosers
- JEN PL 0026 Connector and Conductor
- JEN PL 0034 Earthing Inspection & Testing
- JEN PL 0010 GPS Clocks
- JEN PL 0037 Grounds/Domestic Management of Zone & Non-Pole Type Substations
- JEN PL 0030 HV Outdoor Fuses
- JEN PL 0036 LV Services & Terminations
- JEN PL 0008 Media Converters & Terminal servers
- JEN PL 0004 Metallic Supervisory Cables & Fibre Optic Cables
- JEN PL 0006 Multiplexers & Voice Frequency Equipment
- JEN PL 0009 Network Devices
- JEN PL 0033 Non Pole Type Distribution Substations
- JEN PL 0027 Overhead Line Switchgear
- JEN PL 0024 Pole Inspection and Replacement
- JEN PL 0025 Pole Top Structures
- JEN PL 0032 Pole Type Transformers
- JEN PL 0029 Public Lighting
- JEN PL 0007 Remote Terminal Units
- JEN PL 0031 Surge Arresters
- JEN PL 0035 Underground Distribution Systems
- JEN PL 0005 Unlicensed Spread-Spectrum Radio & 3G Modems
- JEN PL 0022 Zone Substation & End of Feeder Power Quality Meters
- JEN PL 0038 Zone Substation Capacitors
- JEN PL 0039 Zone Substation Circuit Breakers
- JEN PL 0023 Zone Substation DC Supply System Equipment
- JEN PL 0041 Zone Substation Disconnectors & Buses
- JEN PL 0043 Zone Substation Instrument Transformers
- JEN PL 0021 Zone Substation Protection & Control Equipment
- JEN PL 0042 Zone Substation Transformers
- ESMS Scheme Description – Jemena Electricity Networks (JEN GU 0900)
- Jemena Electricity Networks Safety Management Scheme – Synopsis (JEN PR 0900) Jemena Electricity
- Networks Emergency Management Reference Manual, December 2011
- Jemena Electricity Networks Electric Line Clearance Plan 2016-2020, December 2014
- Jemena Electricity Networks Bushfire Mitigation Plan 2016-20, December 2014

Jemena