Appendix L – Network Management Plan

September 2011

westernpower

Network Management Plan

1 July 2011 – 30 June 2017

August 2011

Prepared by:	Approved by:
Network Performance Branch	Western Power Board – September 2011 (Resolution 064/2011/BD)

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NETWORK VISION

An intelligent, connective and safe network that delivers sustainable shareholder and customer value, is compliant with statutory obligations, and enables the delivery of energy solutions that are customer oriented, environmentally responsible and socially acceptable.

1 Executive Summary

Western Power holds electricity transmission (ETL2) and electricity distribution (EDL1) licences, granted by the Economic Regulation Authority (ERA) of Western Australia. These licences provide Western Power with the rights to construct and operate transmission and distributions systems in accordance with the conditions of the licences. One particular requirement of these licences is for Western Power to provide an *asset management system* for its assets. The asset management system includes the measures that Western Power takes for proper maintenance, expansion or reduction of the transmission and distribution system.

The Network Management Plan (NMP) details Western Power's approach to sustainable[1] management of the network in-service assets and is a key document in Western Power's Asset Management System, as illustrated in Figure 1.1.

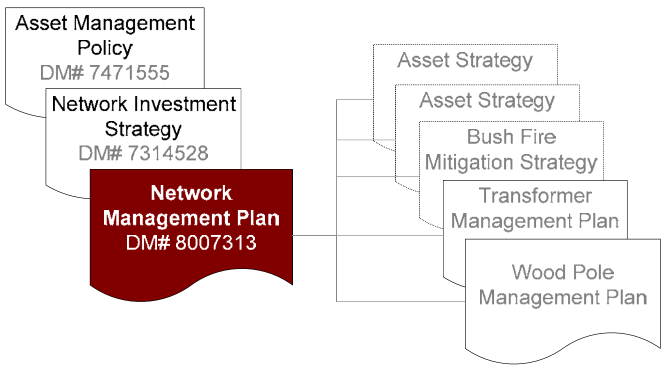

Figure 1.1 : Network Management Plan in the Asset Management System document hierarchy

The NMP *does not* cover:

- Strategies to address load growth or additional generation and its impact on power system
- Non-network assets like office buildings, depots and warehouse, fleet management, business systems etc

These are discussed in other business documents.

[1] Sustainability means achieving or retaining an optimum compromise between performance, costs and risks over the asset's life cycle, whilst avoiding the long-term impacts to the organisation from short-term decisions (definition extract from PAS 55-1:2008).

1.1 Investment context

Western Power is a Western Australian State Government owned statutory corporation. It is a combined transmission and distribution network service provider and owns and operates the network.

There are many external stakeholders who have significant influence over, or interest in, the network investment decisions made by Western Power and the outcomes these deliver. The key stakeholders include the State Government (shareholder, funder and policy maker), customers, market participants, communities and regulators.

Western Power is required to make investments in its network within the context of the *often competing* needs and expectations of the various stakeholders, balancing return on investment, cost, performance and risk.

Ensuring commercially sound, well justified and transparent network investments is crucial to Western Power for a number of reasons, including:

1. Delivering sustainable shareholder and customer value;

2. Achieving satisfactory determinations from the ERA on *Access Arrangement* revisions (pricing and revenue outcomes and appropriate returns on past investments) and compliance with licence conditions;

3. Gaining access to adequate funding from the shareholder to support investments;

4. Achieving corporate strategic objectives;

5. Supporting and enabling the decision-making of external stakeholders; and

6. Achieving a reputation as a competent, credible, customer focused, commercially sound and environmentally and socially responsible service provider.

Figure 1.2 depicts some of the links and relationships between key external stakeholders, Western Power and the investments it makes in the network.

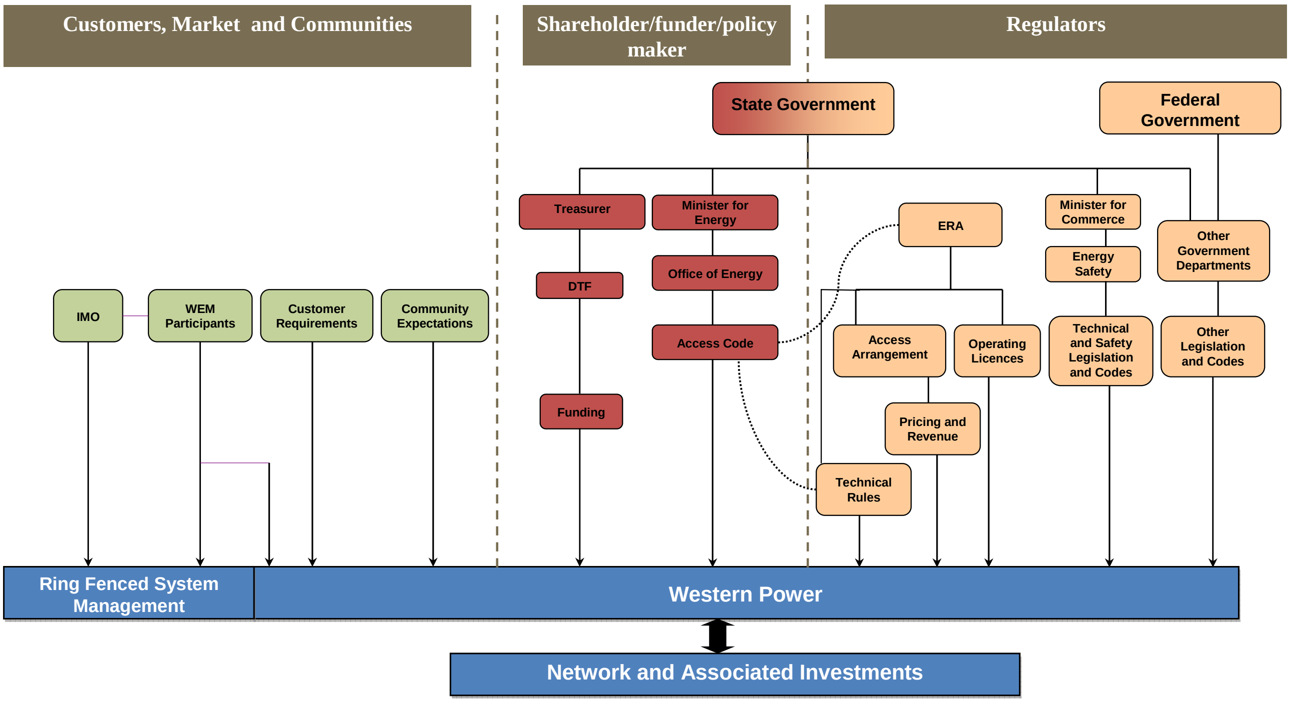

Figure 1.2: Relationships between key external stakeholders and network investment decisions

1.2 About The Network

Western Power's network transports electricity from generators to customers via its transmission and distribution networks. Figure 1.3 shows how Western Power transports electricity.

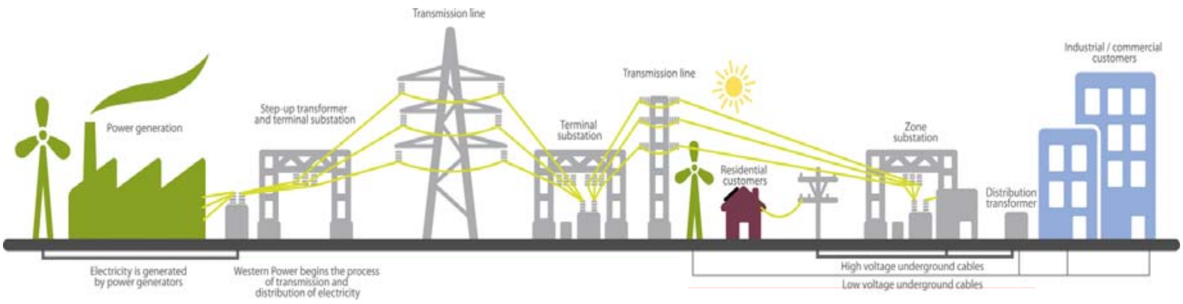

Figure 1.3: How Western Power transports electricity (green is transmission and red is distribution)

The transmission and distribution networks cover a very large geographical area of Western Australia, extending from Kalbarri in the north, to Albany in the south and to Kalgoorlie in the east. The total area serviced by the network is 257,800 km^2 and the total perimeter is 3,761 km.

Transmission and distribution of power is undertaken using a network of overhead lines and underground cables. Western Power's network is made up of approximately 96,000 km of power lines and it is one of the largest isolated networks in the world - powering more than 965,000 homes and businesses and 230,375 streetlights.

1.3 The Transmission and Distribution network

The *transmission network* transports electricity from large generators to transmission terminal stations and to zone substations. It consists of more than 100,000 defined assets and has a value of over $5 billion[2].

The *distribution network* is used to transport electricity from the zone substations to individual customers. The voltages used range from 240 V to 33 kV. The distribution assets consist of more than 2,000,000 defined assets and have a value of over $8 billion.

The transmission and distribution networks include substation, overhead lines, underground cable, secondary systems (protection, control and data acquisition) and land assets, streetlights and metering assets.

1.4 Development of the network

Western Power's network has developed over time in response to the increase in power demand from the growth in the State's population, increase in industrial activity and as new power generators are connected to the network. The network has grown to the point of successfully supplying a system peak load of 4,028 MW during the summer of 2010. The network has been developed to varying standards and design objectives. The current network continues to reflect this diversity. Changes to industry standards in recent years and the conversion of industry guidelines to Australian Standards presents challenges in managing the assets in a consistent manner to achieve the objectives for the network.

1.5 Impact of past investment profile

Figure 1.4 shows a conceptual view of the network investment profiles in the past and the response required in the future[3].

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[2] The values are approximate based on a forecast depreciated value at 30 June 2012 of $2.7 billion (transmission) and $4.0 billion (distribution) and an average expired life of 50 per cent or more.
[3] This figure is an approximation of the investment profile.

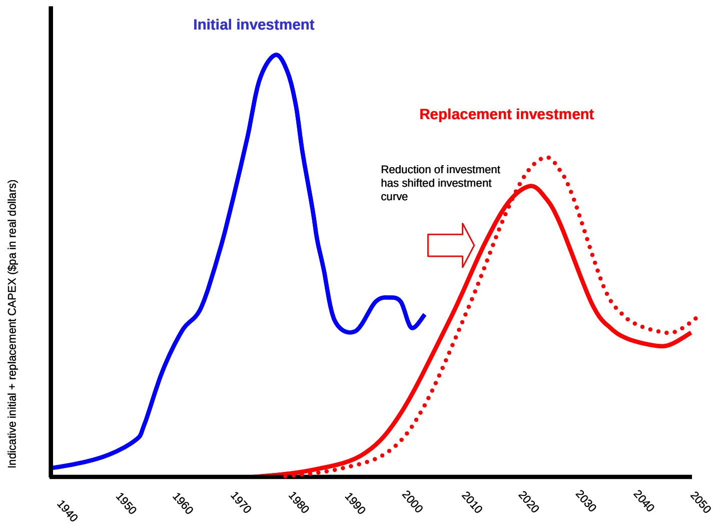

Figure 1.4 : Network investment curves

The shape of the blue curve (Figure 1.4) is illustrative of the investment profile that has occurred since the 1930's. Investment was substantial when the network was being initially constructed - throughout the 1960's, 70's and early 80's. A significant proportion of the original network is reaching the end of its useful life. For example, 30% of the wood poles on the network are over 40 years old.

However, as with many utilities around Australia, an appropriate replacement investment profile was not sustained over the years due to:

- Competition for resources – priority for major investment oriented toward funding major power stations; and
- Investment not consistent with achieving the lowest total cost of ownership over the life of the assets, primarily because of a focus on increasing asset utilization.

The red curve (Figure 1.4) is illustrative of the predicted investment now required to achieve desired service outcomes *and* to achieve the lowest total cost of ownership.

1.6 Challenges for Western Power's network

Large number of assets at or approaching the end of their useful service life, deteriorating asset condition, non-compliance to current standards – Apart from the challenges owing to the diversity in asset designs (and their varied adequacy in the context of the latest standards), large volumes of assets are approaching or exceed their expected design lives. The relatively high level of expenditure required to treat the high and increasing volume of assets in poor condition and under performing assets, is a growing challenge.

Increasing expectations of customers – over time, electricity customers have come to depend on a supply of electricity as an essential service. Customers' expectations for a reliable supply of appropriate power quality have risen. Some assets are no longer adequate (either due to outdated designs or condition) to sustainably meet the current expectations and requirements.

Increasing safety and environment risk exposure – more than 50% of the network consists of bare conductors supported by poles and towers that cause electrical and other hazards. There is also an increasing underground cable network in the metropolitan area creating new risks associated with buried assets. The network therefore carries an inherent public safety and environmental impact risk. Rising community expectations for a safe network that has minimal impact on the environment combined with more prescriptive legislative requirements, requires closer management to reduce the likelihood of incidents.

Rising peak demand – with the rising peak energy demand, more pressure is put on assets, potentially stressing them to the extent that they suffer accelerated ageing and/or fail prematurely, causing an increase in defects, a reduction in reliability and security, and an increase in operating expenditure.

1.7 Western Power's response to the challenge

Considerable resources are required to address the challenges discussed above. This requires a long term strategic approach. Western Power must balance a portfolio of risks and benefits, cognisant of the affordability impact of proposed investment on customers and government. Western Power operates at the point of tension – there are a number of vectors that must be considered in constantly managing trade-offs.

Figure 1.5: Tensions balanced within the NMP

This NMP presents Western Power's long term asset management strategy whilst balancing the impact of the tensions mentioned above in the short and medium term.

1.8 The Network Management Plan objectives

The NMP provides comprehensive information on the network management strategies to meet network objectives, associated works plans, budgets and the approach to deliver these works plans. The primary output of the NMP is an optimised rolling five year capital and operating investment program for management of the network assets. This version of the NMP covers the six year period (July 2011 to June 2017) and it spans two access arrangements: one year (2011/12) of Access Arrangement 2 (AA2) and five years (2012-17) of Access Arrangement 3 (AA3).

The NMP is supported by a suite of asset management processes and IT systems that underpin Western Power's approach to network management.

The NMP is coordinated with other key strategies to optimise the asset management investment decisions. The NMP is part of the annual planning cycle that allows integration of the growth and non-growth investment sectors.

The NMP is set in an environment of continuous improvement from which it is continuously refined through:

- Constant feedback through performance monitors;
- Benchmarking and asset management strategies adopted by other utilities (ITOMS, ENA etc); and
- Feedback from third party asset management system reviews.

The structure and content of the NMP is:

- Aligned with international good practice through PAS 55-1:2008 (Publicly Available Specification); and
- Benchmarked against the Asset Management System Effectiveness Framework as per the Audit Guidelines: Electricity, Gas and Water Licenses published by the ERA.

1.9 Focus for the AA3 (2012-17) investment period and beyond

Investment during the AA3 period is based upon the following three desired service outcomes:

1. *Safety* – addressing the highest priority public safety risks, recognising that all public safety risks will not be immediately resolved;

2. *Growth and security* – addressing the need to expand the networks capacity to meet growth and connect new customers, and the network's sub-optimal resilience to widespread outages; and

3. *Service and compliance* – maintaining current service standards, only improving service where it is valued by the customer and efficient to do so, in compliance with statutory regulations.

The focus for the expenditure in the NMP is to meet the desired *safety, service and compliance* outcomes.

1.10 Scenario and Risk Planning

The proposed NMP expenditure balances the challenges associated with delivering the network objectives against *safety* and *service and compliance* risks.

Various investment scenarios have been assessed, with the most appropriate scenario chosen to progressively address:

- Public safety risks, with expenditure prioritized to the highest risks (noting that in some asset categories, reaching a sustainable position will require many years); and
- Areas of technical non-compliance, including with the NQRS Code (service and compliance).

This scenario is designed to achieve the risk outcomes illustrated in Figure 1.6 shows that the NMP investment will maintain the risk profile during the AA3 period and place the network on a pathway to improvement in successive Access Arrangement periods[4].

[4] The risk reduction will be achieved provided adequate funding levels are approved.

Period	Safety	Service and Compliance
AA3	HIGH	MODERATE
AA4	HIGH	MODERATE
AA5	MODERATE	MODERATE

Figure 1.6 : Long-term network risk profile

1.11 Operations and Maintenance Expenditure

Transmission and distribution assets have differing impacts on safety and service and compliance outcomes. These differences are taken into account to select the most appropriate asset management approach for a particular asset class. The broad approaches are:

- *Non-run to failure* (N-RTF) – these assets are typically large assets, high cost, long lead times and practical to monitor; for example, power transformers and switchgear, and are addressed by preventative maintenance
- *Run to failure* (RTF) - these assets are kept in operation until failure; for example, cables, pole mounted distribution transformers, distribution surge arrestors and associated distribution switchgear and are addressed by corre*ctive maintenance.*

The majority of the forecast expenditure in this plan is for the recurrent operating and maintenance activities that Western Power currently undertakes to provide its services and meet its service standard obligations. The remaining share is driven by non-recurring activities.

Recurrent network costs comprises:

- *Preventative maintenance* - to maintain expected asset life through proactive inspection and treatment of identified conditions

- *Corrective maintenance* - to rectify unsafe conditions due to extreme weather events, ageing assets and other reactive events
- *Network operations* - to provide communication within the South West Interconnected Network, allow access to the network for maintenance and capital works and maintain reliability through network monitoring and network switching operations
- *Customer service and billing*[5] - to maintain service to customers through Western Power's call centre, billing services, and repair and maintenance of meters

The network operating expenditure forecasts have been developed based on actual 2010/11 costs and detailed maintenance policies that exist to support operational activities. They constitute a relevant cost base against which forecasts of these non-capital costs are determined.

1.12 Capital expenditure

Western Power's strategy for both its' transmission and distribution networks is to maintain network performance within acceptable risk levels as articulated. This is achieved by balancing a mix of proactive and reactive asset strategies using capital and operating solutions

The asset management process considers the type of asset and the associated risks and consequences of failures. The investment trigger is based on an assessment of the criticality of network assets in conjunction with the condition assessment. This analysis informs the forecasts of future asset replacement requirements, which are documented by asset class in Chapter 7 of this document. This is consistent with good industry practice.

1.13 Summary of key Asset Management Strategies

Life Cycle Management Plans (LCMP's) have been developed for each asset class. They describe the strategies to achieve network performance and cost efficiency objectives, and specify where inspection, condition assessment (opex expenditure) and replacement (capex expenditure) requirements occur. A summary of the strategies is presented in Table 1.1 and Table 1.2.

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[5] Customer Services and billing is not included in the NMP

Table 1.1: Summary of asset management strategies addressing safety issues

Asset	Population	Key Issue And Response
Distribution and transmission overhead structures	751,552 distribution structures 45,026 transmission structures	*Issue*: the deteriorating condition of wood poles; the volume of wood poles condemned exceeds the current replacement rate creating a back log of condemned wood poles on the network. This represents a public safety and environmental risk associated with the consequences of a falling wood pole. *Response*: replace or reinforce an average 34,000 poles per year during the AA3 period and for a further 15 years as part of the Wood Pole Management Plan to achieve a sustainable replacement rate of 16,000 poles per year.
Distribution and transmission overhead conductors	69,710 km distribution conductors 7,738 km transmission conductors	*Issue*: the safety of the general public and environment is at risk from the potential of asset initiated fires due to the deterioration of distribution conductors, particularly in *extreme* and *high* fire risk areas. *Response*: reduce the likelihood of an event in extreme and high fire risk areas by replacing 1,550 km of deteriorated conductor; reduces the risk from *high* to *moderate* by the end of 2016/17 as part of a 15 to 20 year program of proactive conductor replacement. *Issue*: 30 fires have been caused by conductor clashing over the last five years and the annual event trend is increasing. *Response*: reduce the likelihood of conductor clashing by continuing the existing program and remedying 8,904 HV and 16,142 LV bays. This will reduce the risk from *high* to *medium* by the end of 2016/17. The program will be complete by the end of 2021/22.
Distribution HV overhead conductors	32,500 EDOF's	*Issue*: 9,385 drop-out fuses (EDOF's) installed in *low* and *moderate* fire risk areas have been identified as being susceptible to a type defect that prevents the drop-out mechanism from operating correctly. The risk of extended customer outages due to the EDOF malfunction is assessed as *high*. *Response*: pro-active replacement of all identified defective EDOF's during AA3 will reduce the risk from *high* to *moderate* at the end of AA3.
Distribution HV overhead conductors	11,656 pole top switch disconnectors (PTSD)	*Issue*: public and employee safety is at risk due to some 1,500 PTSDs being unserviceable potentially having earthing system breakdown. *Response*: inspect PTSDs as part of the pole bundling

		inspection program. Prioritise repair and replacement within the preventative condition program and address any PTSD with earthing related issues immediately reducing the risk profile from *high* to *moderate*.
Distribution meters & services	410,000 Overhead service connections	*Issue*: older OH services *twisties* pose an electric shock hazard. *Response*: 100,000 services have already been replaced. The remainder will be replaced by 2015/16 reducing the risk profile from *high* to a *moderate* level at the end of AA3. *Issue*: poor work practices have been identified as a potential new source of electric shocks. *Response*: one off inspection of all new OH service connections to begin in January 2013 providing an updated picture of high risk services.
Transmission substations	24 terminal 125 zone	*Issue*: public and staff safety issues related to the unauthorised entry into transmission substation sites resulting in damage to perimeter fencing, theft of property and vandalism. *Response*: regular inspection of existing fences, signage and locking at all sites. Increase levels of security patrols, progressively upgrade or replace security fences at the most vulnerable sites. Prioritise replacement/upgrade four fences per year and maintaining the current *high* risk level until 2016/17, but place the 15 to 20 year program on a pathway to achieving a *moderate* risk level by the end of AA4.

Table 1.2: Summary of asset management strategies addressing service and compliance issues

Asset	Population	Key Issue And Response
Distribution and transmission underground cables	52 km transmission 6,082 km distribution	*Issue*: there is an increase in the rate of leaking oil filled transmission cables; this raises issues of service availability and environmental damage. *Response*: a corrective maintenance program will target the prompt repair of leaking cables. Condition assessment of each cable section will quantify and prioritise the future replacement program of the most deteriorated oil filled cable infrastructure.

Asset	Population	Key Issue And Response
Distribution HV ground mounted switchgear	12,101 disconnectors 7,648 fuse-switch 5,098 Ring Main Units (RMU) 4 Circuit Breakers (CB)	*Issue*: compliance and safety issues associated with the *in-service* failure of ground mounted switchgear due to corrosion, oil and gas leaks and failed insulation. *Response*: reinstatement of the managed asset approach to this asset class, which will proactively replace 40 *bad* condition units which will be identified through routine substation inspection. It is expected that a further 16 units per year will require reactive replacement in line with existing failure rates within this asset family. *Issue*: safety issue associated with the Hazemeyer type switchgear unit. *Response*: these will be replaced as part of the proactive replacement approach during the AA3 period.
Distribution HV overhead	1,703 recloser 917 sectionaliser 11,676 disconnector	*Issue*: hydraulic controlled reclosers impede bushfire mitigation as they cannot be automated resulting in the safety of the general public and environment being put at risk from asset initiated fires. *Response*: replace all 3-phase hydraulic reclosers by the end of the AA3 period and 50% of the single phase reclosers in extreme, high and medium bushfire risk areas. Replace the balance of the single phase units by the end of June 2022. *Issue*: poor performance of obsolete and mechanical sectionalisers impacts system reliability resulting in longer duration of outages and affecting a greater number of customers. *Response*: replace all obsolete and mechanical units by the end of the AA3 period improving the overall performance of sectionalisers to maintain reliability performance.
Distribution transformers	10,600 transformers (>300kVA)	*Issue*: there is an environmental contamination risk due to the failure in service of oil-filled transformer. *Response*: inspection and proactive replacement prior to failure. *Issue*: overloading and degradation (corrosion & oil leaks) *Response*: replace approximately 100 transformers per year.
Distribution street lighting	Over 220,000 street lights and associated switch wires	*Issue*: the deterioration of overhead streetlight switch wires has the potential of falling to the ground and creating an electrical hazard. *Response*: replace all switch wires by the end of 2016/17.

Asset	Population	Key Issue And Response
Distribution meters and services	972,885 meters	*Issue*: there is a large ageing volume of mechanical and electronic meters which are non-compliant (due to reading inaccuracy). *Response*: replace all identified inaccurate meters during AA3 period. Also incorporate the replacement of ageing and inaccurate meters (some 280,000) into the *smart meters* installation program during 2011/12 to 2016/17 period improving efficiencies of the installation program.
Transmission power transformers	339 units in service	*Issue*: reliability of service and compliance issues *associated* with 24 transmission transformers identified in *bad* condition based on condition assessment. *Response*: replace 16 *bad* condition transformers on a like-for-like basis (10) or as part of network growth (six) (increased customer demand) where more cost *effective* to maintain the risk profile at *moderate*. Undertake dry-out process for those transformers with high moisture content that will not be replaced in AA3.
Transmission circuit breakers	1,407 indoor circuit breakers (enclosed in 121 switchboards)	*Issue*: an increasing likelihood of the 16 *bad condition indoor* pitch filled switchboards failing in service, resulting in potential fire events, loss of supply and long repair times. *Response*: reduce the risk likelihood of an in-service failure by replacing eight pitch filled switchboards during the AA3 period to maintain the current risk profile of high. The remaining eight boards will be replaced in AA4 at which time the risk profile should be reduced to *moderat*e.
	1,147 outdoor circuit breakers	*Issue*: service and asset unreliability risk due to lack of available spares and manufacturers support associated with three different types of outdoor circuit breakers. This prevents repair to drive mechanisms, insulation replacement and gas containment, which represents a risk to service and the environment. *Response*: phased replacement of 162 outdoor circuit breakers affected by this issue by the end of the AA3 period in alignment with other asset replacement works. *Issue*: condition assessment has indicated that there is another 38 outdoor circuit breakers in *bad* condition, which represents a risk to network service. *Response*: phased replacement of the identified circuit breakers, aligned with other asset replacement works on site during the AA3 period.
Transmission disconnectors and earth switches	10,123 assets	*Issue*: 15% of the existing disconnector population has been assessed as being in a *bad* condition. This has the potential of causing loss of service and a safety incident if a disconnector fails during operation.

Asset	Population	Key Issue And Response
		Response: replace 560 of the *bad condition* units by the end of AA3 aligned to other asset replacement works on the site. This will remove over half of those units in bad condition maintaining the risk to *moderate*. The remaining units will be addressed by the end of AA4.
Transmission instrument transformers	4,599 Current Transformers (CT) 1,177 Voltage transformers (VT) 284 CVTs 45 combined units	*Issue*: service risk associated with over 10% of the entire CT and VT population assessed as being in a bad condition. This is due to a combination of leaking oil and breakdown of insulation. *Response*: replace 540 CTs and 120 VTs by the end of the AA3 period. This will result in 75% of the known bad condition units being removed from the network by 2016/17 maintaining the risk profile at its current level. The remainder will be addressed in the AA4 period.
Transmission reactive plant	341 capacitor 834 reactors 3 SVC	*Issue*: the reliability of supply in the Eastern Goldfields area is emerging as high risk with SVCs at West Kalgoorlie and Merredin Terminal substation being assessed in *bad* condition. *Response*: planned replacement of the West Kalgoorlie SVC in AA3 with installation beginning at the start of AA4. Replacement of the SVC at Merredin Terminal is planned to follow and be complete during AA5. During this period, maintenance will be tailored to address an issues to minimise network disruption and maintain supply services to end users.
Transmission surge arrestors	263 gap type 1,847 metal oxide	*Issue*: gap type surge arresters suffer from rapid deterioration. Approximately 5% of surge arresters have failed their high voltage test resulting in a bad condition assessment. *Response*: replace 42 surge arresters per annum (gap type) during the AA3 period.
Secondary system services **Protection relays**	29,859 relays	*Issue*: poor performance of General Electric (GE) Type T60, F60 and L90 protection relays, and unstable frame leakage protection schemes have caused unplanned service interruptions. *Response*: replace associated relays and protection schemes and 10 frame leakage protection schemes during AA3.
Secondary system services **DC systems**	516 battery banks 550 chargers 57 parallel boards	*Issue*: the risk of soft tissue injury and electrolyte splashing on personnel due to restricted working conditions inside battery cabinets. *Response*: upgrade 77 DC systems and battery stands at identified sites during the AA3 period reducing the risk

Asset	Population	Key Issue And Response
		profile from moderate to low.
Secondary system services **Communication sites & structures**	726 sites 191 radio structures	*Issue*: availability and reliability of the communication system is at risk due to deterioration of communication shelters resulting from environmental effects such as corrosion. *Response*: maintain current level of availability and reliability by replacing 21 communication shelters between 2012 and 2017. *Issue*: 15 communication towers do not comply with new and more stringent revision of the Australian Standard (AS/NZS1170.2) imposed on mast and towers. *Response*: upgrade the 15 communication towers between 2012 and 2015 to comply with the Australian Standard.

1.14 Integration of Growth and Non-Growth Work Plans

Figure 1.7 illustrates the approach to developing the Network Management Plan.

The Network Management Plan is developed by considering (among other things) the growth driven plans outlined in Network Development Plan (augmentation of the network) and the Customer Driven Plan (which involves customer connection works).

This approach is integrated into the overall business planning processes through alignment with the Annual Planning Cycle.

The Annual Planning Cycle includes consideration for a number of optimisation points throughout the planning cycle to ensure a consistent and transparent process for effective optimisation and prioritisation of network investments.

Optimisation is a state of continually making and improving on sensible, prudent investment choices. The aim is to deliver maximum benefit for the investment made throughout the life of the project/program lifecycle. This is achieved by having a committed, collaborative approach to effective communication, clarity of processes and of the desired future state of the network.

'Optimisation' occurs slightly differently at each phase:

- Initiation - Needs/Drivers
- Scoping - Costs vs. Benefits
- Planning – Solutions

The optimization process includes frequent cross-checking for opportunities to reduce overall cost by combining the asset-driven and customer-driven investments. For example, if meeting customer requirements requires the replacement of a power line, maintenance will be modified (even halted) to reduce wasted expenditure.

Once the Network Management Plan is developed and externally driven plans are taken into account, supporting business cases are developed, the sponsor's statement of intent is ratified and, a deliverability assessment can be made leading to the development of the production plan.

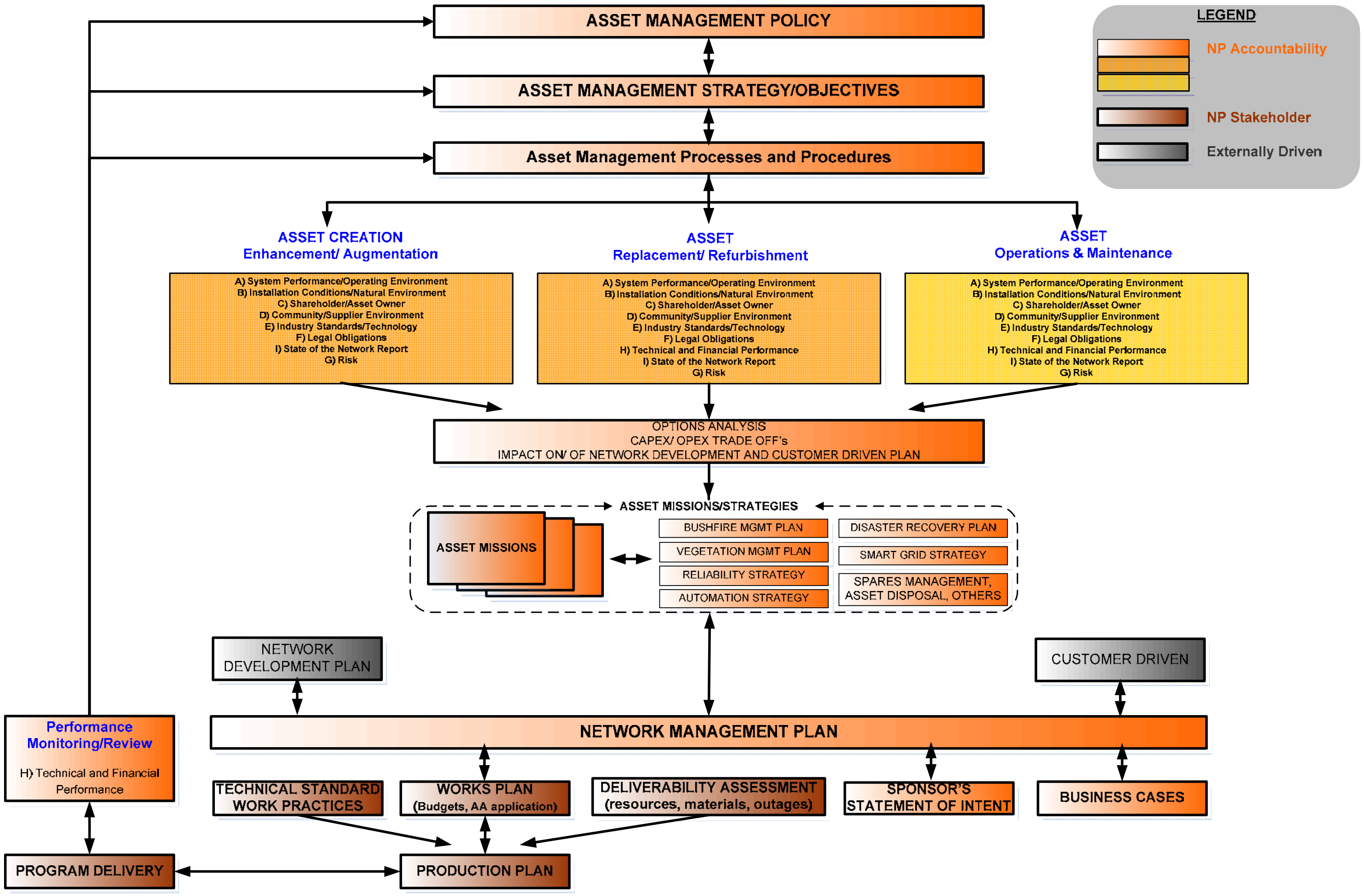


Figure 1.7: Network Performance – Asset Management Process

1.15 Chapter disposition

The contents of the NMP are as follows:

- Chapter 1 (Executive Summary) outlines the messages contained in the body of the NMP;
- Chapter 2 (Introduction) provides all elements of the network assets within the NMP;
- Chapter 3 (About the Network) provides an overview of the transmission and distribution network;
- Chapter 4 (Network Management Framework) provides an overview of various network management practices and systems applied by Western Power for responsible and prudent asset management;
- Chapter 5 (Network Objectives, Drivers and Outcomes) outlines the objectives of network management, outlines the processes and information systems used to monitor the performance and how the information on performance is integrated within decision making;
- Chapter 6 (System Planning and Development (Growth)) provides a high-level overview of the plans to respond to demand growth;
- Chapter 7 (Life Cycle Management Plan (Non-Growth)) outlines the issues and challenges at the individual asset level; it also discusses the plans to manage and operate the network at agreed levels of service while optimising lifecycle costs;
- Chapter 8 (Integration of the Works Plans – Growth and Non-Growth) discusses the integration of the works across various asset classes and across growth and non-growth;
- Chapter 9 (Delivery Strategy) sets the delivery strategy which includes in sourcing / outsourcing strategies, contracting and procurement model, unit prices trend and the outlook over Access Arrangement 3;
- Chapter 10 (Financial Summary - Consolidated Works Plan) contains the financial requirements resulting from all the information presented in previous chapters; and
- Chapter 11 (Network Management Plan Maintenance and Improvement) outlines the plans for maintaining the network and outlines the improvements to asset management systems.

2 Introduction

2.1 Background

Western Power manages the electricity transmission and distribution network in the south west area of Western Australia. This network transports energy from generators to customers and comprises a large number of physical assets such as towers, poles, conductors and transformers.

The purpose of this Network Management Plan is to describe how the network assets are managed and to present Western Power's network asset programmes of works for a 5-year rolling period. This is the first plan in this format. It covers the 6-years from 2011/12 to 2016/17 to provide alignment of the plan with the next Access Arrangement period. The plan replaces the former Transmission Asset Management Plan and the Distribution Asset Management Plan.

The network asset programmes presented in this NMP are based on meeting known business objectives derived from Western Power's understanding of customer and stakeholder requirements, knowledge of the existing and projected network assets, the measured and expected condition of these assets, and the required and expected asset performance requirements.

There are a number of obligations and performance targets relating to the use, maintenance and operation of the network. This plan also describes the environment in which the network is operated and the asset management systems and processes used to meet the business' obligations and targets.

2.2 Document hierarchy

The NMP is a key document in the asset management system. The plan is co-ordinated with the Network Investment Strategy and the Transmission Network Development Plan to ensure asset management investment is optimised. It is implemented through the Approved Works Program. Figure 2.1 illustrates the overall asset management document framework and where the NMP sits in this document hierarchy.

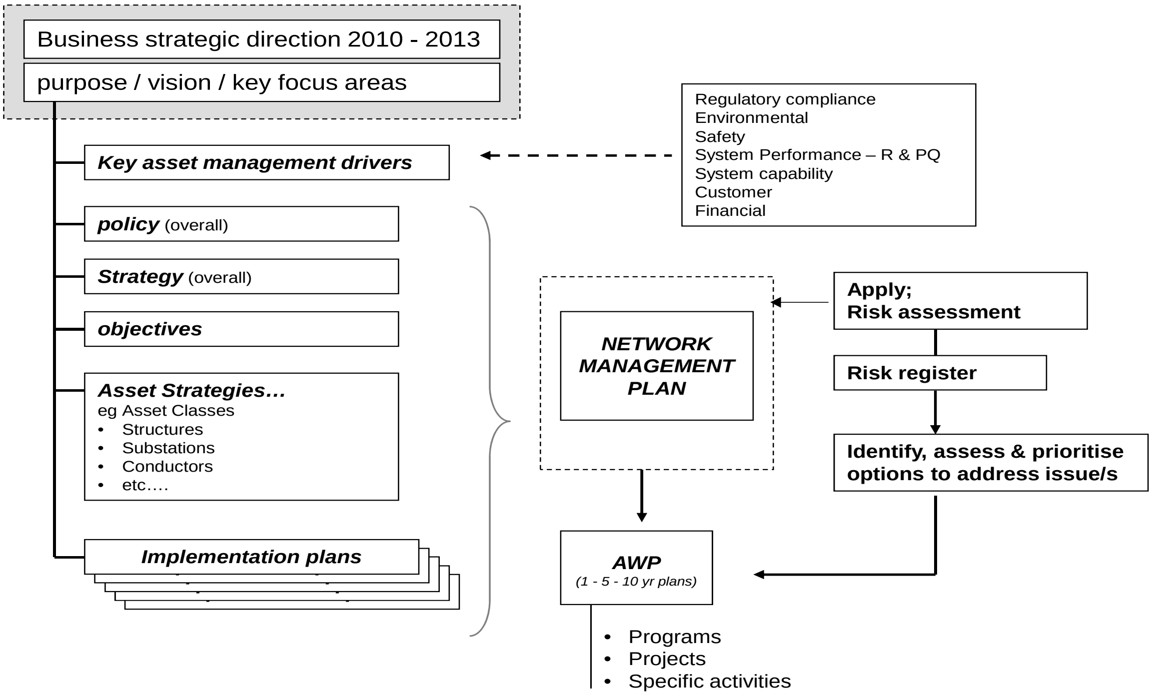


Figure 2.1: Overall asset management document framework

2.3 Infrastructure assets included in the plan

The asset categories that are within the scope of the NMP include:

- network primary infrastructure assets (such as overhead lines, underground cables, switchgear and transformers);
- network secondary assets such as batteries and protection equipment;
- network related Information and Communication Technology (ICT) assets (e.g. metering, protection, SCADA and communication equipment);
- network related land, easement and building assets (such as substation sites or buildings);
- investments in alternatives to traditional network solutions (such as network control services, distributed energy resources and energy management solutions) and associated ICT investments; and
- network and non-network related research and development/innovation.

The asset categories that are outside the scope of the NMP include:

- plant, vehicles and tools;
- human resources;
- land, buildings and associated fixtures not related to the network (such as depots, offices and warehouses);
- system operation and management activities and ICT to support operation of the Wholesale Electricity Market;
- ICT not directly related to network or non-network investments (such as corporate IT systems); and

- investments to support work not related to services covered by an Access Arrangement.

2.4 Western Power's role and key objective

The network is owned by the Western Australian State Government and managed by Western Power as a Government Trading Enterprise (GTE). The GTE operates in a commercial environment, and the managing director of Western Power reports to an independent Board of Directors.

A key business objective is to serve the people and industry of Western Australia by planning prudent investment in the network to meet their current and future needs, consistent with Western Power's 2020 Vision and Strategic Direction 2010 – 2013, Transform the Core. The primary drivers of investments in the network within the period of this plan are safety, growth and security of supply, and service performance. Service performance is primarily related to maintaining reliability of supply and the environment. Key factors include condition and performance of assets and the associated risk of plant failures.

To meet this key business objective and to respond to the drivers for investment, this plan aims to achieve the following:

- safety of employees, customers and the public;
- optimised asset performance;
- optimised asset lifecycle costs;
- timely replacement of assets; and
- environmental compliance.

2.5 Shareholders and stakeholders

The sole shareholder in Western Power is the Western Australian State Government. However, there are many external stakeholders who have significant influence over or interest in the network investment decisions made by Western Power and the outcomes these deliver. These stakeholders include various departments of the State Government (shareholder, funder and policy maker), customers, market participants, communities and regulators (technical and economic).

Western Power is required to make investments in its network within the context of the 'often competing' needs and expectations of the various stakeholders, balancing return on investment, cost, performance and risk.

Ensuring commercially sound, well-justified and transparent network management is important to Western Power for a number of reasons, including:

- delivering sustainable shareholder and customer value;
- achieving satisfactory determinations on Access Arrangement revisions (pricing and revenue outcomes and appropriate returns on past investments), and compliance with license conditions;
- gaining access to adequate funding from the shareholder to support investments;

- achieving corporate strategic objectives;
- supporting and enabling the decision-making of external stakeholders; and
- achieving a reputation as a competent, credible, customer focused, commercially sound and environmentally and socially responsible service provider.

The regulations that apply to Western Power support this approach to network management through tests that require Western Power to demonstrate the prudency and efficiency of proposed investments. The New Facilities Investment and Regulatory Tests as required under the Access Code focus on capital expenditures.

2.6 Key Elements of the Plan

The key elements of the NMP are set out in separate sections as described below.

- Description of the network: Chapter 3 provides an overview of the network, including its history, a description of its current state, and challenges that Western Power can expect in the future.
- Network management framework: Chapter 4 provides an overview of the approach to network management, and the asset management policy, practices and systems applied by Western Power. These support responsible and prudent asset management. It also describes the legal and regulatory environment that applies to Western Power.
- Objectives, investment drivers and outcomes: Chapter 5 provides a summary of the objectives of network management that are fully set out in the Network Investment Strategy. It also outlines the drivers to add to or modify the network and shows how these objectives and investment drivers lead to the outcomes expected of the network.
- System planning and development (growth): Chapter 6 provides details of growth forecasts, which affect the management and utilisation of assets. It also provides details of the customer drivers that influence capital expenditures. Details of customer connections such as the methodology for forecasting customer connections, forecasts of numbers of new connection and an overview of the Connection Policies are also included in this chapter.
- Life cycle management plans (non-growth): Chapter 7 sets out the key issues and challenges facing the network and what is planned in order to manage and operate the network at the agreed levels of service (as defined earlier in the plan) while optimising lifecycle costs. Network strategies are detailed for each asset class. Thus this chapter details individual network management strategies and provides a consolidated management strategy at the network level.
- Integration of the works plans – growth and non-growth: Chapter 8 discusses the integration of the works across various asset classes and across growth and non-growth works. The interrelationship of the strategies is also discussed in this chapter for example the impact of growth capex and opex.

- Delivery Strategy: Chapter 9 discusses the strategy to deliver the plan.
- Financial Summary: Chapter 10 contains the financial requirements associated with implementing the plan.
- Network management plan monitoring and improvement: Chapter 11 outlines the measures used to assess the performance of the NMP, the improvement program through which improvements are made to asset management processes, and the procedures used to monitor and review the effectiveness of the asset management system.

2.7 Periodic Review of the Plan

The NMP is an internal document.

Custodianship of the NMP document resides with the Network Performance Branch within the Networks Division. The plan will be formally reviewed and updated at least annually. However, more frequent revisions may occur if appropriate.

3 About the Network

This section provides an overview of the Western Power network, including its history and future challenges that can be expected.

3.1 Overview

Western Power transports electricity from generators to customers via its transmission and distribution networks. Figure 3.1shows how Western Power transports electricity.

As shown in Figure 3.2, the transmission and distribution networks cover a very large geographical area of Western Australia extending from Kalbarri in the north, to Albany in the south and to Kalgoorlie in the east. The total area serviced by the network is 257,800 km^2 and the total perimeter is 3,761 km.

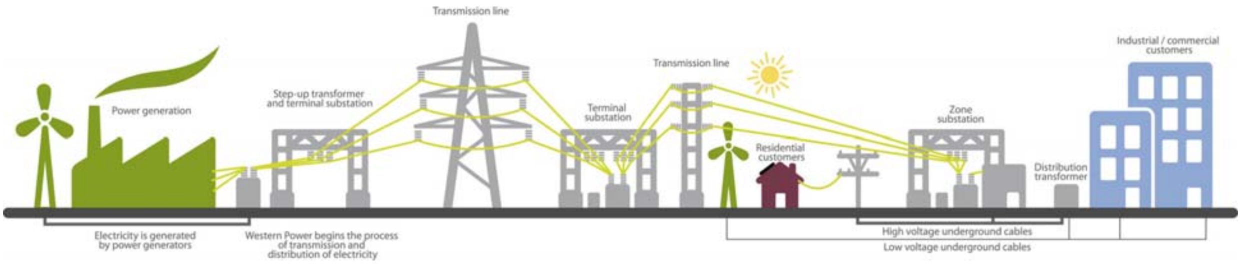


Figure 3.1: How Western Power transports electricity

Figure 3.2: Western Power's South West Interconnected System (SWIS)

3.2 The Transmission Network

The transmission network transports electricity from generators to transmission terminal stations and onward to zone substations. Transmission network assets fall into four broad categories:

- Primary line and cable assets – These assets include poles, towers, conductors and cables with voltages ranging from 6.6 kV to 330 kV;
- Primary substation assets – These assets include 6.6 kV to 330 kV equipment, such as transformers, circuit breakers and capacitor banks, which allow the management of power flows from the generators to the zone substations;
- Secondary assets – These assets generally comprise low voltage equipment concerned with the protection and control of the primary assets. Communications and SCADA equipment also fall into this category; and
- Land assets – These assets include the substation site and any easements required for transmission lines or underground cables.

The transmission network consists of more than 100,000 defined assets and has a value of over $5 billion.

3.3 The Distribution Network

The distribution network is used to transmit power from the zone substations to individual customers. The voltages used range from 240 V up to 33 kV. The assets are classed into five general groups:

- Poles;
- Transformers;
- Overhead Switchgear;
- Ground-mounted Switchgear; and
- Conductors (overhead lines and underground cables).

The distribution network consists of more than 2,000,000 defined assets and has a value of over $8 billion.

3.4 History of the Network

Electricity supply in Western Australia started off as localised isolated distribution networks in townships. Throughout the 20th century these networks were slowly connected by what was to become an integrated transmission network. The transmission network expanded through the energisation of key backbone circuits. In comparison, the distribution network expanded and upgraded continually as the demand increased from a combination of population growth, evolution of home electrical appliances, as well as commercial and industrial development.

The first electricity supply commenced in 1891 with the connection of an electric light in the Old Legislative Assembly Chambers. For the next couple of decades, localised networks were constructed in towns such as Kalgoorlie, Claremont, Northam, Midland, Subiaco and Fremantle.

The early development of network integration was initiated in 1913 after the reorganisation of several independent power operations in the Perth metropolitan area. Over the next 12 years the integrated network which distributed power at 6.6kV reached as far south as Rockingham.

The next phase of development followed the end of the Second World War which saw rapid increases in electricity demand driven by strong economic growth. This resulted in the formation of the State Electricity Commission which was created to develop and manage a south west power scheme that came into being over the proceeding decades by two factors.

The first factor was the construction of the large scale transmission lines connecting Perth to other major towns which were previously islanded networks managed by the respective shires. This started with the Greenbushes and Balingup distribution networks in 1947 and continued through to 1983 when Lake King was connected.

The second factor was the expansion and maturity of the existing distribution networks through the Contributory Extension Scheme (CES). The CES was developed to provide an economic framework to connected remote customers (such as farmers) to the integrated network by way of sharing the cost between customers and suppliers. The CES ran until 1991 and saw the network extend to a geographic area that exists today.

In comparison to the gradual growth and maturity of the distribution network, the growth of the transmission network was in incremental steps from the energisation of circuits of higher voltages.

The 1950’s and the next two decades saw the energisation and growth of a small 132kV network. However, by the end of the 70’s, load demand had surpassed 1,000MW, which resulted in the first 330kV transmission lines and associated terminals being introduced into the network.

The 330kV lines allowed the transfer of power from regional generation in the south to the central metropolitan areas, where the majority of the load was located.

This task was made simpler since load centres throughout the network were, for the most part, fed radially from the major terminal sites at Kwinana, Western Terminal, East Perth, Northern Terminal, Cannington Terminal, Southern Terminal and South Fremantle. This allowed for highly controllable load flows across the transmission system from generation sources to load centres.

The 330kV lines that were constructed during this period form the backbone of the transmission network that still exists today. Approximately 574 km of 330kV line were constructed, opening up large areas of the network across the state.

The most recent significant milestone in the growth of the transmission network was the connection of the network to the goldfields region in the 80’s. This was done by the construction of a 665 km 220kV transmission line between Muja and Kalgoorlie. This line enabled the connection to the network of the Eastern Goldfields and various towns and mining customers between Muja and Kalgoorlie.

As Western Australia’s development continued into the new millennium, an increasing number of load centres began appearing across the network away from the traditional metropolitan area load centre.

An increasing number of substations and lines were required to support this growth. The most cost effective and prudent strategy at the time was to proliferate the 132kV network.

3.5 State of the current network

3.5.1 Operational issues

The cumulative effect of the above development is that the network, in its current form, is highly meshed between the 330kV and 132kV networks, with a heavy reliance on the 132kV transmission lines to transfer power directly from generation in parallel to the 330kV bulk system. Recent system study results confirmed that approximately 700MW of power is running through 132kV network resulting in reduced utilisation of the 330kV system while the maximum capacity has been reached for the meshed 66kV and 132kV network arrangement.

Under normal operating conditions, the peak load on the 330kV lines is generally approaching 35% of line capacity with approximately 20% of network demand flowing through the meshed 132kV network. While the existing 330kV network is currently under utilised, the emerging consequences include:

- overloading of the meshed network under contingency conditions;
- need for increased reactive support required at 66kV and 132kV levels under contingency conditions; and
- increased 132kV line losses and high 132kV fault levels across major terminals and some zone substation.

There are also significant difficulties with controlling 132kV power flows to avoid post-contingent overloading of lines on the 132kV meshed network. This also creates system operability challenges, such as planning network outages for operational activities such as maintenance.

3.5.2 Improving reserve capacity

In addition to these technical issues, the network is reaching a definitive point in its life cycle. As the State emerges from its brief economic hiatus during the global financial crisis, rising peak energy demand is increasing pressure on a network that has endured unsustainably low levels of investment, particularly in areas that ensure electricity supply is safe and secure. Investment is required to improve the reserve capacity of the network so that security of customer's loads is not unnecessarily placed at risk.

3.5.3 Standards

The network has been developed over time by several asset owners to varying standards and design objectives. The current network continues to reflect this diversity. Changes to industry standards in recent years and the conversion of industry guidelines to Australian standards presents challenges in managing the assets in a consistent manner to achieve the current objectives for the network.

In particular, the change of ESAA publication CB1 to a mandatory standard has resulted in a lines development program to become compliant that continues.

3.5.4 Aged network

The network is relatively old, with a large volume of assets approaching or exceeding expected design lives. A corresponding increased replacement rate for such assets is included in this NMP. The need to increase the inspection of assets to more closely monitor their condition is necessary to help ensure the treatment is optimised.

3.5.5 Customer expectation for electricity services

Electricity is an essential commodity in the community. The reliability and power quality expectations are much higher than in the past. The technological advancements in some customer equipment require connection to a network that has more robust power quality. Energy demanding products such as air conditioners and second refrigerators put extra peak load demands on the network. And in recent times, the rapid adoption of the PV cells at a commercial, industrial and residential level provides new challenges to maintain required quality of supply on the network. This results in some assets installed in the past now being inadequate to meet the outcomes expected. Plans to remediate or manage these assets are considered in this NMP.

3.5.6 Safety and environment

Consistent with most electricity networks around the world, the Western Power network mostly consists of bare conductors supported by poles and towers. This approach provides a network that carries an inherent public safety and environmental impact risk. Rising community expectations for a safe network that has minimal impact on the environment, and more prescriptive legislative requirements, have resulted in closer management to reduce the likelihood of incidents.

3.6 Future challenges

Challenges that are likely to be faced by Western Power include:

- Increasing demand driven by increasing population (both in numbers and density), increasing usage per capita and additional industrial/commercial activity predominantly due to the mining sector;
- Increasing severe weather from climate change which has the potential to affect reliability and design requirements of the network;
- During the next ten years, significant amounts of plant will be approaching their Asset Nominal Life, indicating the amount of asset maintenance and replacement required across the network will increase. This will provide a challenge to Western Power in terms of resourcing and funding;
- Increased reliability expectations (driven by both customers and regulation); and
- Compliance with changing environmental, regulation and OH&S requirements.

4 Network Management Framework

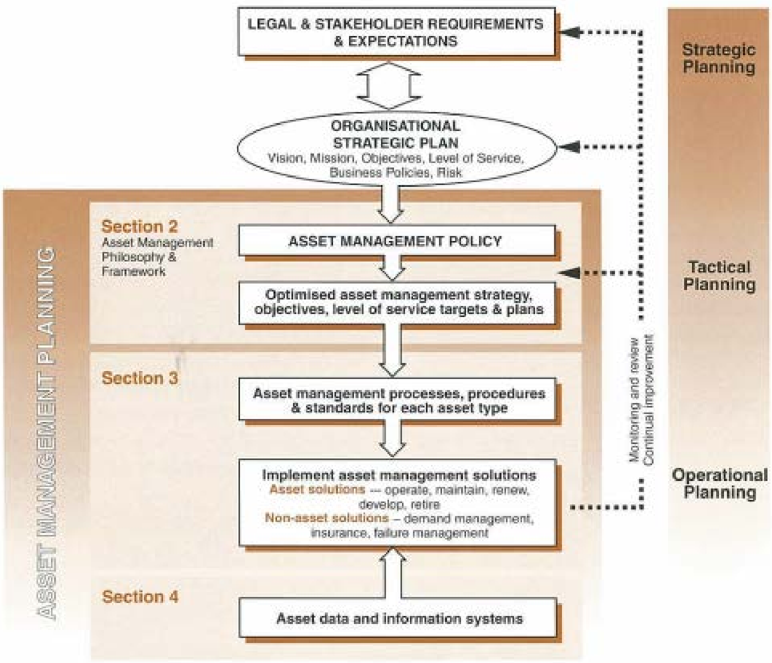
Western Power has established a network management framework that ensures it achieves the objectives set for the network and its responsibilities as an asset owner to achieve a return on capital invested and to manage its assets in a safe manner. The framework also incorporates elements that ensure that assets are managed in a sustainable manner, in accordance with applicable law, and to meet the current and changing needs of customers. The network management framework has been developed to be consistent with current standards for asset management systems.

This chapter sets out the standards for the network management framework that have been adopted, the legislative requirements that apply, the overall approach to asset management, and the supporting corporate elements, policy, methodology, tools, and information systems that have been established.

4.1 Asset management Standard

There are a number of nationally and internationally recognised asset management standards such as the International Infrastructure Management Manual (IIMM) from the Institute of Public Works Engineering Australia (IPWEA), and the Publicly Available Specification 55 (PAS 55) from the Institute of Asset Management (IAM).

Figure 4.1 shows the IIMM Asset Management Process Overview.



Source: International Infrastructure Management Manual, p. 1.6

Figure 4.1: IIMM Asset Management Process Overview

Since the revision of PAS 55 in 2008, the IAM has been promoting the development of a formal International Standard. Following a preliminary meeting in June 2010, a new International Standards Organisation (ISO)

Project Committee (ISO/PC 251) has been established to develop an international standard on asset management. While Western Power has not formally adopted a specific asset management standard it participates in committee MB-019 with a view to aligning its asset management practices with the developing international standard.

Figure 4.2 shows that there is a close alignment between the PAS 55 Asset Management Framework and the corresponding Western Power documentation and systems.

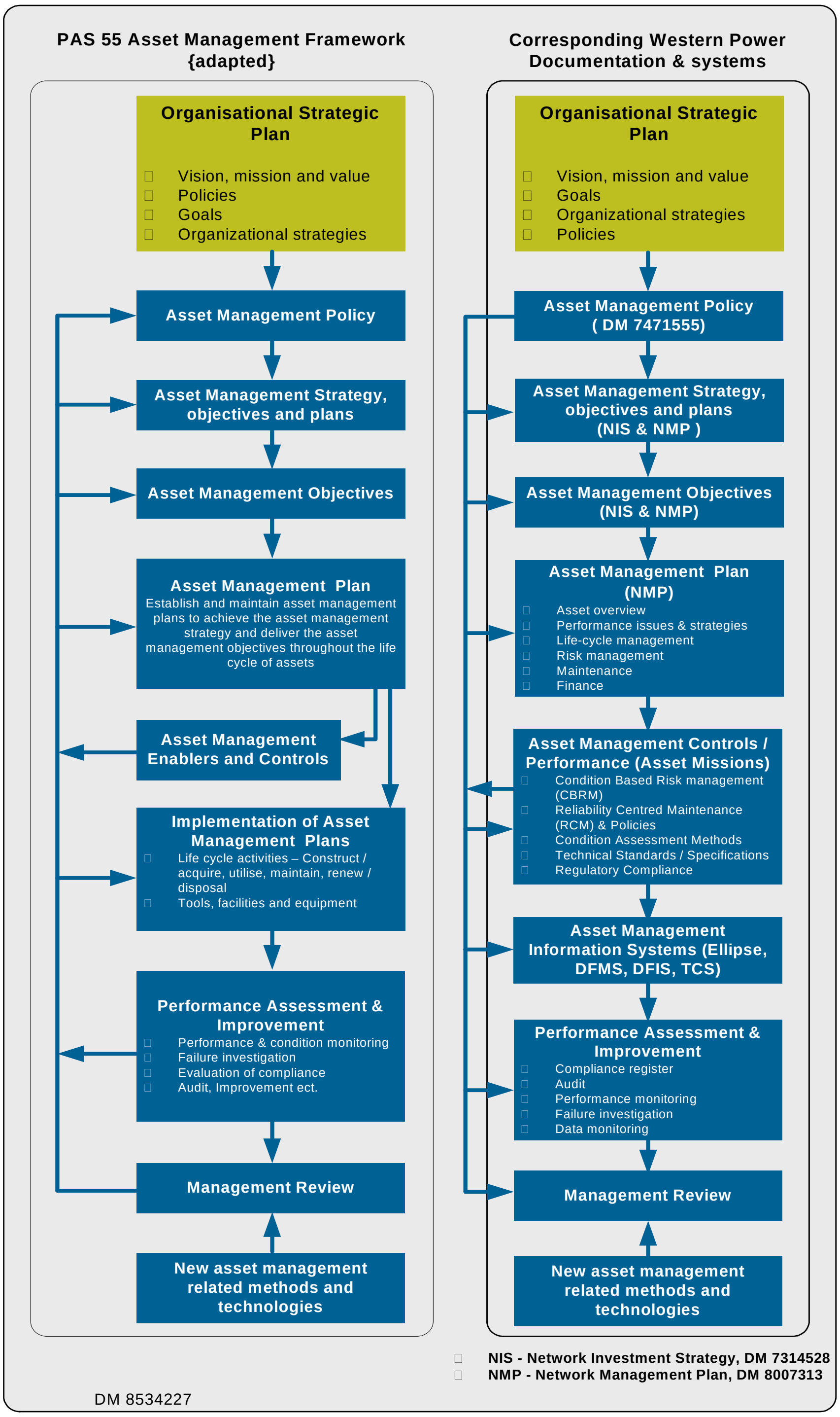


Figure 4.2: Alignment with PAS 55

4.2 Overall Approach to Network Management

Western Power aims to operate the network so it can continually provide the required function and meet its specified performance requirements in a sustainable manner. To achieve that outcome, assets must be carefully managed throughout their lives, by applying targeted strategies, from procurement, operation and maintenance through to decommissioning and disposal.

The premise underlying the NMP is that the network primary assets (lines, cables, stations etc.) are required forever so as to continue to deliver energy from generators to customers. This premise is being reviewed as the instance of distributed/local generation increases and as smart grid technology offers the potential to operate the network differently. For this plan, however, decisions are made to invest in new assets, or to maintain, replace and refurbish assets in accordance with the network investment drivers. This means that the characteristics such as cost versus asset life and the management practices such as inspection/ maintenance routines of an individual asset or group of assets should be optimised to reduce the life cycle cost.

A key to lifecycle management is to identify the triggers that lead to the adoption of a particular asset strategy. Triggers such as poor asset condition lead to a process where options are evaluated and a strategy is adopted to manage the assets over the remainder of their life.

Western Power has adopted a whole of life cycle approach to asset management. The key elements of the approach are shown in Figure 4.3 below. These are described below together with examples of supporting documents:

- Plan, Acquire - Standards & policy documents, Technical / equipment specifications (e.g. poles, crossarms, insulators etc);
- Create, Design, Construct - Distribution Design manual, Distribution Construction standards (e.g. long bay solutions document), Work practices manual;
- Operate, maintain - Inspection procedures, Condition assessment / management procedures (e.g. identify defects / issues, prioritise and manage), Work practices manual, Specific asset / key issues operational documents (e.g. long bay solutions document), Network Operations Centre procedures/plans (e.g. identifying, recording defects, contingency plans);
- Monitor, review, feedback, incidents - Defects register / recording systems, Incident recording / management procedure, Incident investigation procedure, Specific asset assessment / investigations / studies, Periodic reporting / assessment, Auditing / reviewing; and
- Act, augment, replace, dispose - Programs of work, Specific projects, Management of defects process, Works scheduling procedures, Close out / completion process

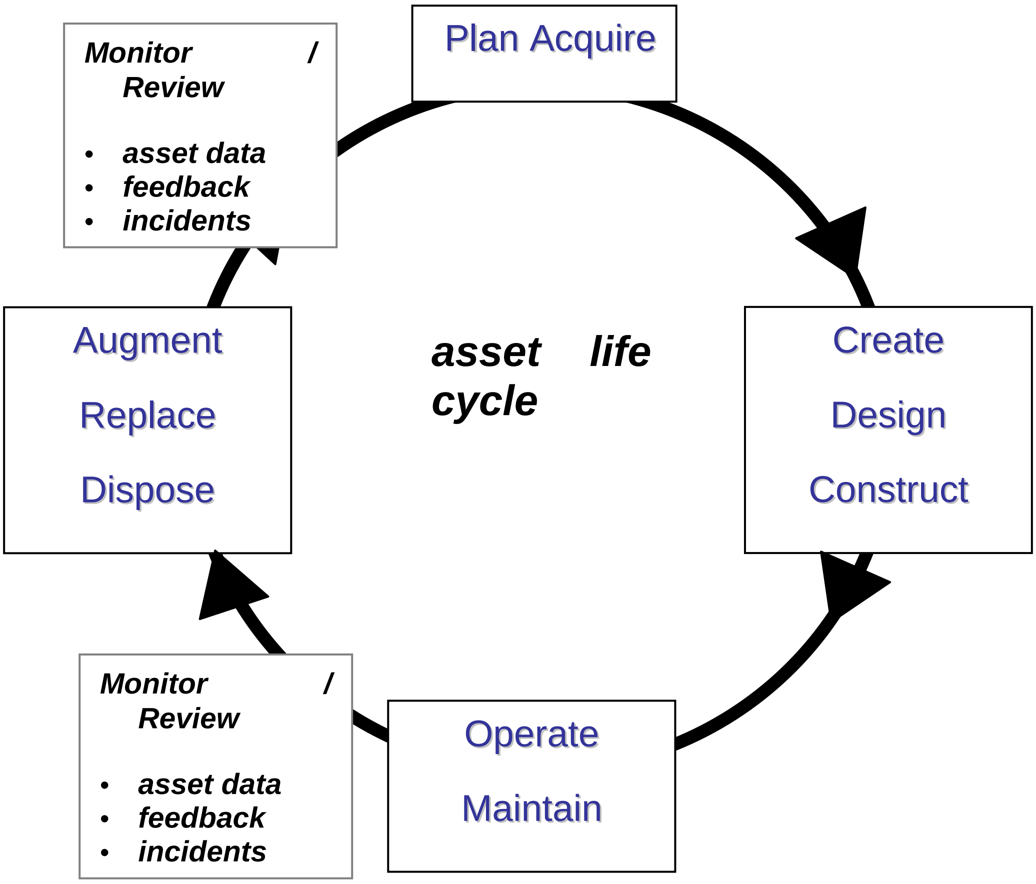


Figure 4.3: Asset life cycle

The Network Management Framework and plan is subject to periodic review at intervals not exceeding 24 months by the Economic Regulation Authority (ERA), who has issued a guideline for such reviews. The review is conducted by an independent third party. This NMP has been structured to be consistent with the ERA guideline, and the improving outcomes of the review process demonstrate Western Power's commitment to continuous improvement of its asset management system.

Western Power also manages its network assets in accordance with "Good Electricity Industry Practice" as defined in the Access Code. That is "The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments."

Consistent with the above whole of life cycle approach, the transmission and distribution networks are managed within a broad external framework of legislation, codes and standards, and within an internal framework of policy, strategy, and plans. This Network Management Framework consists of a set of interrelated documents, systems and processes that together provide the essential information that enables the business' network management practices.

Figure 4.4 below provides an overview of the key elements (pink) of the network management framework.

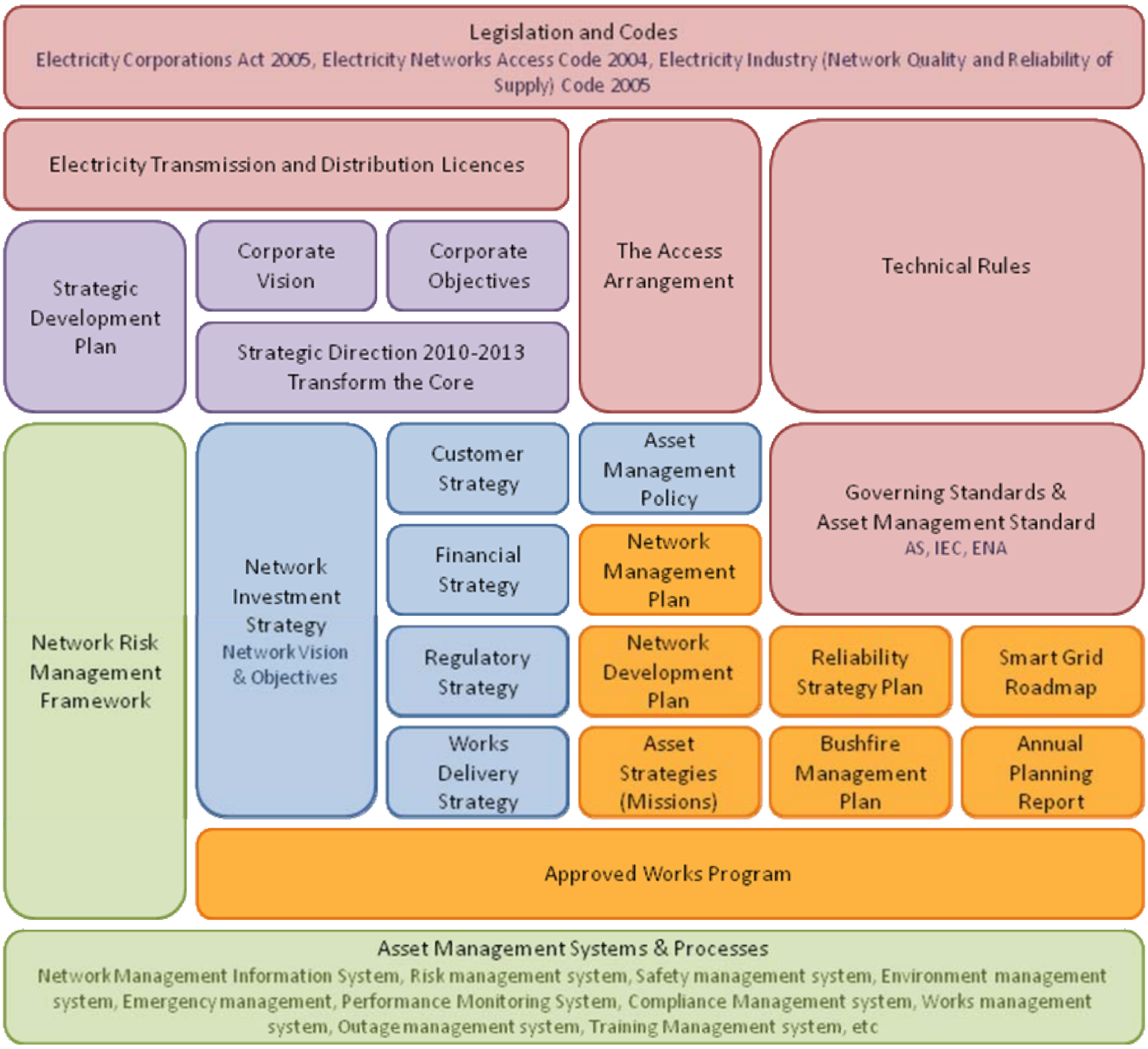


Figure 4.4: Network Management Framework Overview

4.3 Legislation and Codes

Western Power's network management framework sits within a broader external framework of legislation and codes. The main regulations and codes are the Electricity Industry Act 2004, the Electricity Corporations Act 2005, the Electricity Networks Access Code 2004, and the Electricity Industry (Network Quality and Reliability of Supply) Code 2005.

The Electricity Industry Act 2004 amongst other things sets out the licensing arrangements. The electricity transmission and distribution licences [6], [7] form an essential part of the network management framework. In particular, under section 14.2 of the Electricity Industry Act 2004, it is a requirement of these licences that Western Power provides an Asset Management System which sets out measures for the proper maintenance of electricity supply assets used in the operation of, and, where relevant, the construction of, any generating works, transmission system or distribution system.

It is also requirement of the electricity transmission and distribution licences that Western Power has an extension and expansion policy which sets out arrangements for the geographic and capacity expansion of the system as well as the connection of customers to the system.

The Electricity Corporations Act 2005 is the overarching statute that institutes the business itself, as well as establishing the fundamental focus and objectives of the business' asset management practices. Amongst other matters this Act sets the area within which the corporation operates, defines its powers to undertake works, sets out Ministerial approval requirements, as well as the requirements for economic regulation. Of particular importance to asset management are the exemptions from planning laws, rights to interrupt or restrict supply, requirement to act on commercial principles, as well as the requirements for a strategic development plan and a statement of corporate intent.

The Electricity Networks Access Code 2004 establishes detailed requirements for management of the Western Power Network. Amongst other matters the code sets out such general principles as the code objective which is to promote economically efficient investment in operation of the network in order to promote upstream and downstream market competition. The code also establishes matters such as the requirement to undertake work, funding arrangements, network access arrangements, as well as price control principles and objectives. Of particular significance to network management practise are the codes requirements relating to the basis of cost calculation and the establishment of the capital base. The code also sets out the new facilities investment test and the regulatory test and its objectives, as well as the investment adjustment mechanism. In addition, the code establishes the requirements for the service standards and technical rules.

The Electricity Industry (Network Quality and Reliability of Supply) Code 2005 sets out the service standard to be provided by the network and its operation in terms of supply quality and reliability. Amongst other matters this code sets the required quality standards for voltage and harmonics, reliability, and interruptions. The code also specifies penalties for failure to meet the required service standards, as well as requirements for complaints management, monitoring, record keeping and performance reporting.

Other codes and regulations: In addition to the above legislation there are other codes and regulations which are more general in application but impact

6 Electricity Transmission Licence Electricity Networks Corporation (t/a Western Power)ETL2, Version 5, 13 January 2011

7 Electricity Distribution Licence Electricity Networks Corporation (t/a Western Power) EDL1, Version 5, 13 January 2011.

on Western Power's network management practices. These include the Electricity (Supply Standards and System Safety) Regulations 2001, the Electricity Industry Metering Code 2005 (WA), the Environmental Protection Act 1986 (WA), the Environmental Protection (Noise) Regulations 1997 (WA) and the Occupational Safety and Health Act 1984.

The Access Arrangement describes the terms and conditions for obtaining access to the Western Power Network, as well as establishing the applicable service standards and rates to be paid for those services. In addition, the access arrangement determines the allowable annual revenues based on approved capital and operating expenditure forecasts. Key elements of the access arrangement that impact on network management include the:

- Queuing policy;
- Transfer and relocation policy;
- Contributions policy;
- Standard Access Contract;
- Distribution headwork methodology;
- Weighted average cost of capital establishment; and
- Definition of trigger events.

While the access arrangement does not define the network management practices of the business, it sets important objectives and constraints on these practices and also drives investment through the access arrangement obligations.

The Technical Rules detail the specific technical requirements and planning criteria that are to apply to the transmission and distribution systems within the Western Power Network. In addition, the Technical Rules place a specific obligation on Western Power to manage, maintain and operate the network so as to minimise the number and impact of interruptions or service level reductions. Hence the Technical Rules provide the core set of essential criteria that Western Power must apply across all aspects of the business' network management practices.

Governing Standards - There are a broad range of governing standards that are either specifically or generally applicable to the management of Western Power's transmission and distribution networks. In particular Australian Standards (AS), standards issued by the International Electrotechnical Commission (IEC), as well as guidelines issued by the Electricity Networks Association (ENA) have direct application. Compliance with relevant standards and guidelines is a part of meeting good industry practice, although some are mandated through legislation. Like the Technical Rules, governing standards provide a core set of essential criteria that may be applicable across all aspects of the business' network management practices.

4.4 Corporate elements

The corporate elements of the network management framework are:

The corporate vision describes the desired future state for the overall business and directs the whole-of-business response to challenges and opportunities. Allied to this vision is the Strategic Direction 2010-2013, Transform the Core, which articulates the business strategy to drive excellence across the core operations to simplify and improve the responsiveness and commerciality of the business. Consequently, the Corporate Vision and the Transform the Core strategy provide a broad business context to network management in terms of direction and management practices.

The strategic development plan (SDP) and Statement of Corporate Intent (SCI) are submitted annually by the Western Power Board to the Minister for approval in accordance with the Electricity Corporations Act 2005. The SDP sets out the business objectives, strategies, financial objectives and operational targets for Western Power over a five year period, as well as the proposed works program and associated capital and operating expenditure. The SCI articulates Western Power's accountability requirements as agreed with the Minister for Energy. It provides an annual, high level overview of Western Power's objectives, major activities and performance targets for the financial year. These documents represent the agreement between Western Power and the Minister in terms of financial and non-financial expectations and requirements for the coming financial year (SCI) and five-year expectations (SDP) and are effectively Western Power's 'Macro' budget. Consequently, the SDP and SCI set important criteria for the business' network management practices and are also critical outcomes of these practices.

The Risk Management Framework provides an overarching risk management framework for the business as a whole. Network risks form a critical subset of the broader business risks that arise through Western Power's ownership of the transmission and distribution networks and the provision of covered services, including the application of statutory obligations. Risks arise from issues such as load growth, varying asset condition, environmental influences, operational circumstances as well as changing legislative or performance obligations.

- Western Power has initiated a project to enhance the risk management framework through the addition of a specific Network Risk Management Framework (NRMF). The NRMF will implement Western Power's Risk Management Policy in the management of network risks. Network risks will be identified, analysed, evaluated, and treated in accordance with the NRMF.
- At the strategic level, network risk is pervasive in the consideration of network objectives, definition of network risk tolerance, and the identification of network investment drivers. At the functional level, network risk is also considered when selecting and justifying solution options and as part of optimisation and prioritisation of network investments. Consequently, when completed, the NRMF will form a critical element within the Network Management Framework.

These corporate elements provide context for the detailed management of network assets. By setting out objectives and requirements, policy and strategy, as well as guidance, key information and specific plans, the network management framework supports and enables processes from assessing network performance and options analysis to address identified needs, to investment, maintenance and operational decisions. In doing so the framework also supports and enables stakeholder engagement, governance practices, regulatory oversight, and transparency of management activities.

4.5 Asset Management Policy

The Asset Management Policy informs stakeholders of the integral role that asset management has within the business, and sets out the principles that Western Power applies in order to achieve the effective and efficient management and operation of the Western Power Network. In particular the policy establishes the following key principles:

- Compliance with all applicable legislation, statutory and regulatory requirements;
- Meeting and where appropriate, exceeding the asset management requirements of the ERA;
- Ensuring the asset management system integrates with and complements the company's safety and health, environmental, quality, human resources, procurement, crisis management and risk management systems;
- Identifying, assessing and managing the network assets to ensure continued safe and reliable performance throughout their whole life-cycle;
- Ensuring that the asset management system prioritises works accurately based on comprehensive risk management in accordance with the Corporate Risk Management Framework,
- Communicating openly and transparently with stakeholders on asset management matters; and
- Continually improving asset management performance.

These key principles set up a tension, competing for resources and priority. Western Power has established an approach that gives priority to Safety, Growth and Affordability of services over Reliability, Accessibility and Resourcability, as demonstrated in Figure 4.5. An ongoing challenge is determining tradeoffs the business must make for each of its investment decisions.

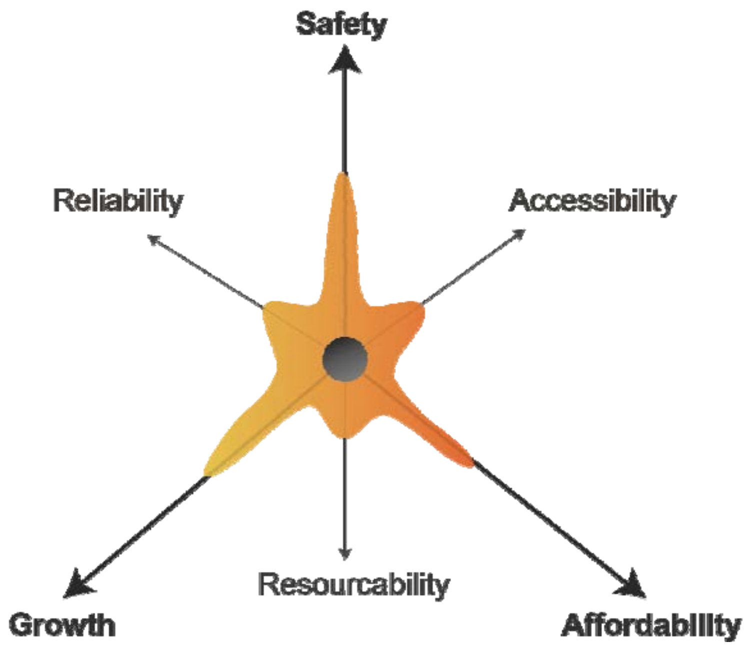


Figure 4.5: The policy of prioritising investment decisions

Through the application of these key principles the Asset Management Policy promotes systematic and coordinated activities and practices that enable Western Power to manage prudent investment in the network assets and their performance. These activities and practices are then realised through the Asset Management System (AMS), which provides a structured process for fulfilling due diligence requirements and achieving continuous improvement in asset management performance.

The Asset Management Policy also ensures that Western Power's asset management practices are consistent with the business' 2020 Vision and Strategic Direction 2010 – 2013, Transform the Core.

As this policy governs the business' asset management practices, the Managing Director and Executive Management are accountable to the Board of Directors for the policy's development and implementation.

4.6 Asset Management Methodology

The costs associated with each phase of an assets life change depending on the asset type, and the age and condition of the asset class. This is shown diagrammatically for a typical range of assets in Figure 4.6. Infant mortality (failure well before expected life) results in early capital expenditure. Assets that have not reached their expected life incur a greater proportion of maintenance expenditure and asset populations that are reaching the end of life incur a greater proportion of replacement expenditure. Most asset classes are managed through routine inspection with identified defects categorised by severity. The severity classification has defined timescales for defect rectification to maintain the expected life of the assets and meet the safety and reliability outcomes required.

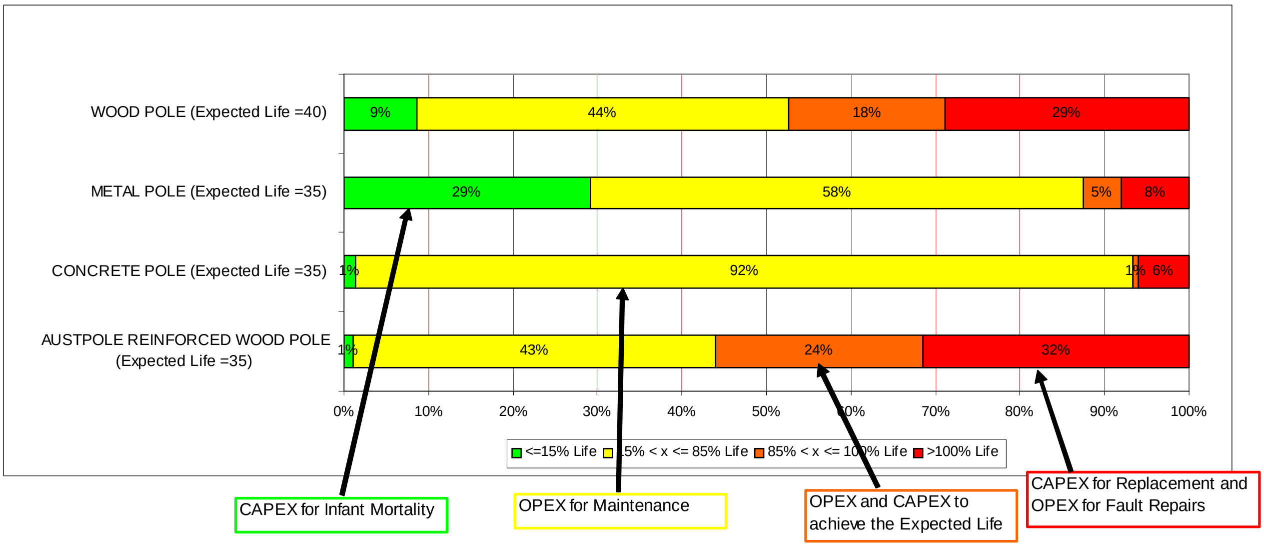


Figure 4.6: Expenditure over typical asset life

As assets age, their condition deteriorates and the expected failure rate increases, so eventually it is more economic to replace the asset than to continue maintaining the existing one. The economic factors include the cost of maintenance, the cost of replacement and the cost to customers of reduced service levels such as safety and network reliability. However, not all assets have the same impact on safety and network reliability, and accordingly to manage the network as efficiently as possible, assets are all allocated into the two broad categories of Non-Run To Failure and Run To Failure. Figure 4.7 shows that risk increases as the likelihood of failure increases and the consequence of failure increases. Potential strategies are RTF, time-based maintenance, condition monitoring, and time/life extension. The RTF and N-RTF strategies are further discussed in the following sections.

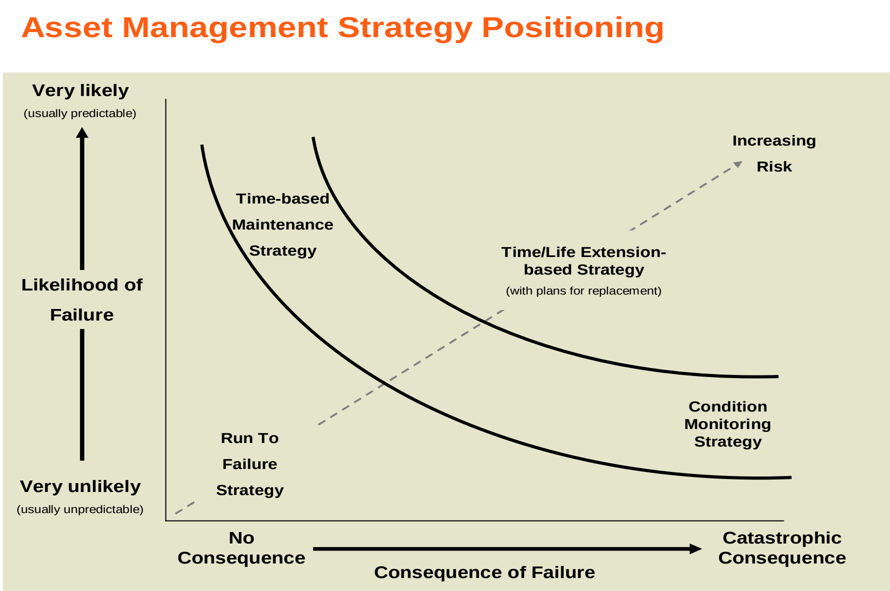


Figure 4.7: Potential strategies responding to likelihood of failure and consequence of failure

4.7 Non Run to Failure Assets

Assets that have been identified to have a significant impact on reliability, safety, the environment or economic aspects of the business are classed as N-RTF assets. These assets are subject to routine inspection and maintenance programs designed to keep the assets in an operating condition for extended periods of time, and are proactively replaced prior to failure to ensure the performance level of the network is maintained.

Life Cycle Management Plans have been developed for each of the N-RTF assets. LCMPs describe the asset strategies implemented to achieve network performance and cost efficiency objectives, and specify maintenance and replacement requirements of each asset class.

Weibull distribution curves are used to assess the probability of failure based on asset age. A web based simulation model by Davis Consulting Inc. is used to derive the failure frequency curves, using the four-parameter Weibull distribution to predict the time-to-failure probability distribution. Figure 4.8 shows the results for five asset types.

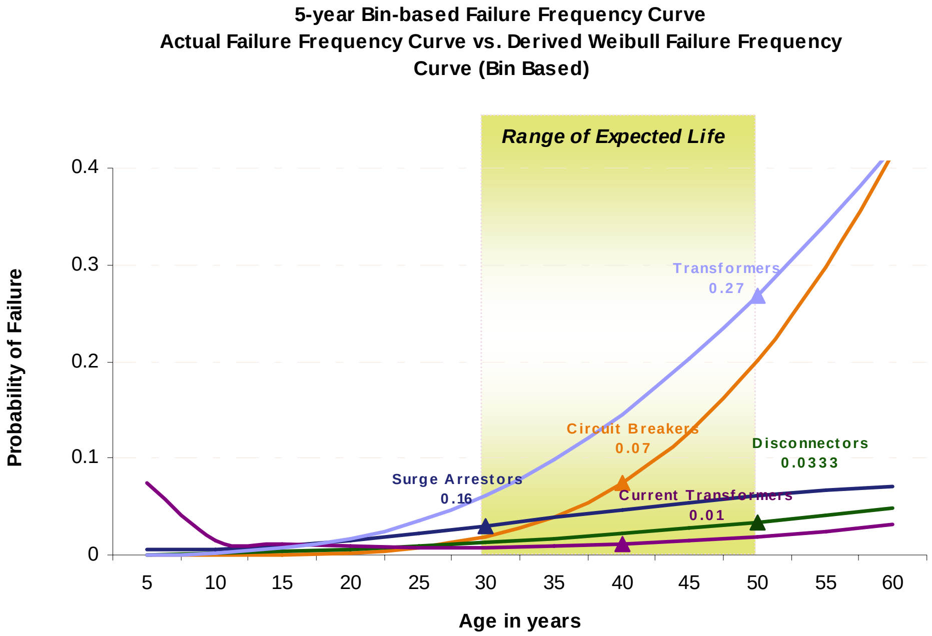


Figure 4.8: Time to failure probability distribution curve

This analysis, in conjunction with asset age profiles, informs the forecast of future asset replacement requirements. However, it is important to note that this is a predictive tool and actual replacement is undertaken based on a cost benefits analysis using actual asset condition as the driver.

The end of life and replacement criteria is different for each network asset. An appropriate combination of the following driving factors is considered during asset assessment:

- Safety and environment;
- Condition (defect history, testing results, type issues);
- Expected/nominal asset serviceable life [8];
- Regulatory compliance;
- Historical rate of failure for a specific asset group;
- Maintainability factors (obsolescence, availability of spares);
- Planning optimisation (criticality, voltage conversion);
- Delivery optimisation (completing projects in the same substation or on the same circuit concurrently to gain efficiencies); and
- Economic benefits (reduction in maintenance costs, benefits of network reliability).

4.8 Run to Failure Assets

RTF assets are those which have been assessed to have minimal impact on the overall network performance and as such, they undergo minimal maintenance or inspection and are allowed to operate until they fail or become unserviceable. These assets are allocated a “nominal life” which is based on industry standards and field experience of asset managers. The “nominal life” is defined as the duration over which the asset is expected to perform, without a significant increase in failures or maintenance costs, and is in line with industry standards. The “nominal life” is used to assist in forecasting expected replacement volumes of some RTF assets.

Life Cycle Management Plans are not developed for RTF assets. However, RTF assets are still subject to inspection programs which are generally orientated towards identifying safety hazards to ensure public safety. If a hazard is identified, then appropriate actions are taken to rectify it.

4.9 Asset management models and tools

Western Power has developed models and tools to assist it in making prudent decisions about its asset management. The key tools are described below.

Remaining life model: Western Power uses a “remaining life” approach as a basis to determine asset replacement. All assets are assigned an expected life based on the industry’s knowledge of similar assets. Employing the assets actual age, condition, defects, service location and performance, empirical formulae are applied to calculate the ‘Remaining Life’. The empirical formulae are described in Appendix A. Subsequently, the assets are further reviewed for replacement or refurbishment based on their performance, condition

8 While the expected life of an asset is known, in many cases the actual age of the asset is not known due to incomplete historical records. When data was initially established in electronic systems, 1970 was adopted as a default year for assets of unknown age. Generally assets allocated to the default year were installed prior to 1970. As a result, the age profile charts in the Lifecycle Management Plans are likely to understate the age of assets.

monitoring assessments and future needs of the network. The asset performance and monitoring process includes:

- Investigating asset incidents;
- Monitoring and analysing performance;
- Determining the condition of specific assets;
- Researching and assigning plant ratings; and
- Performing power system measurements.

The above information is reviewed and taken account in the asset strategies to ensure suitable asset management actions are taken.

Davies Consulting Inc.'s Asset Life Cycle Analysis™ model (ALCA™) is a web-based decision support model that allows utilities to forecast capital requirements for aging system assets and evaluate the effect of the aging assets on system reliability. A strategy module allows the user to create and compare different maintenance and replacement strategies for these assets. ALCA performs the following four core functions:

- Provides an interface through which the user uploads inventory information, associates assets with failure curves or time-to-fail probability distributions, and inputs reliability impacts of asset failures;
- Provides an interface for users to set strategies for their assets and combine such strategies into scenarios to forecast via discrete-event simulation;
- Combines user inputs in a stochastic analysis to predict future failures, maintenance/replacement costs, and reliability; and
- Allows users to change model inputs and conduct what-if analyses by creating, saving, running, and comparing scenarios.

4.10 Asset Management supporting strategies, Processes and Systems

The Network Management Framework includes a range of supporting strategies, asset strategies or asset missions, key planning elements and the Approved Works Program. Each of these supporting strategies, processes, and systems are discussed below.

Key supporting strategies - There are five key strategies that collectively support and give effect to Western Power's corporate vision, and are central to the Network Management Framework. These strategies are the Customer Strategy, the Financial Strategy, the Regulatory Strategy, the Works Delivery Strategy, and Network Investment Strategy.

- **The Network Investment Strategy** (NIS) – articulates the long term network vision, the associated objectives and the nature of the investments that need to be made to achieve these outcomes. It also sets out the guiding principles for network investment decision making, based on both traditional and emerging non-traditional (non-network) solutions.

    - For external stakeholders the NIS provides a communication platform to encourage dialogue on investment decision making principles and high-level investment strategies. Hence the NIS facilitates testing assumptions with shareholders, and assists stakeholders in making decisions in relation to Western Power's network investments.
    - Internally, the NIS assists Western Power's decision makers at both the strategic and functional level by providing guidance when exercising discretion or balancing trade-offs. In particular it facilitates understanding and provides confidence that Western Power's investment decisions are made prudently and commercially, with appropriate consideration of risk and return on investment. Consequently, the NIS provides a critical governance vehicle within the Network Management Framework that draws together the business' network management practices to guide and shape network investment.
- **Customer Strategy** - the strategy (currently under development) for engaging with and meeting the needs of the various customer segments across all facets of the business. The strategy will support the Customer Driven Plan, and is aligned with the Customer Charter, which sets out the key features of the relationship between Western Power and its customers.
- **Financial Strategy** – Currently under development, this strategy will provide medium to long term financial direction, and supports regulatory decisions and investment opportunities with knowledge about price impacts, stakeholder requirements, shareholder funding and Western Power's financial position.
- **Regulatory Strategy** – the strategy (currently under development) for operating within an economic regulatory regime, and enables good regulatory outcomes for Western Power, and through this, good outcomes for its customers, shareholder and other stakeholders. The Regulatory Strategy integrates the features of the regulatory framework and regulatory contract into the decision making processes of Western Power.
- **Works Delivery Strategy** – the strategy for delivering the investment portfolio, and includes resourcing strategies (internal and external resources), procurement, fleet/plant, as well as work and resource planning and scheduling.

These strategies are lead decision making tools which are integrally linked and strongly interdependent. As they address core aspects of the business' network management practices they form core elements of the Network Management Framework.

Asset Strategies (Missions) - Western Power has developed a range of asset strategies (missions) specific to each major network asset type. These strategies articulate the asset's required service standard, assess the assets performance, and set out the management strategies to be applied to the asset over its life cycle. As such each asset strategy provides specific guidance on the management of the asset and defines the key investments required to achieve or maintain the required service level.

Asset strategies have been developed for the major asset types. A summary of the asset strategies is included in Chapter 7.

Together these strategies provide essential information regarding each of the N-RTF major asset types across the network that enables Western Power's asset life cycle management practices.

Key Planning Elements - Western Power's Network Management Framework includes a number of plans that capture key outcomes from the network management process. The plans are developed in an annual planning cycle that includes the cyclic collection and analysis of data and allows for the integration of the growth and non-growth investment needs. Each of these plans sets out the major capital and operating expenditure plans that drive the Approved Works Program. Consequently they present information that is essential to Western Power's network management practices. In particular:

- Network Management Plan (this document) – articulates the network management strategies as well as information regarding how network management objectives will be met within the context of the prevailing operating environment;
- Network Development Plan – captures plans relating to growth driven development. This includes new connection works for loads and generation, as well as capacity expansion related to organic growth across the network;
- Bushfire Management Plan – the Bushfire Management Plan establishes a framework of policies, processes, strategies and accountabilities to proactively manage public safety risk, personnel risk, and business risk from bushfires associated with Western Power's assets;
- Smart Grid – this embodies, Western Power's vision for a more 'intelligent' network. While this is a strategic initiative, the roadmap develops options and solutions that respond to growth, reliability, and power quality improvements as well as the customer driven demand for flexibility and choice; and
- The Annual Planning Report – is a public document that provides existing and prospective network users with information on planned development of the Western Power Network. In particular the document identifies network constraints, considers options (capital and non-capital) to address the identified constraints, and provides insight into the basis and nature of the constraint (e.g. demand forecasts, etc). Hence the Annual Planning Report provides a platform for communication with key stakeholders and insight into Western Power's network management practices that facilitate participation in resolving identified network constraints.

The Approved Works Program (AWP) - captures on an annual basis the forecast capital and operating expenditure over a rolling 5 financial year window. It reflects an optimised, prioritised and constrained view of the works program that represents the annual outworking of the business' asset management practices. Consequently the AWP is the primary deliverable of Western Power's network management processes as it captures the essential information that enables Western Power to manage the network and achieve business objectives. Further detail on the establishment and maintenance of the AWP is contained in Western Power's Works Program Governance Manual.

4.11 Network Management and IT Systems & Processes

Western Power's network management framework also involves a large number of information systems and process that further support and enable the business network management practices. For example:

- Geographic Information System (GIS);
- System Control and Data Acquisition (SCADA);
- Transmission Plant Management System (TPMS);
- Transmission Planning Investment Database (TPID);
- Network Management Information System (ISAM);
- Rating Information system;
- Forecasting, estimating and budgeting system;
- Business case and options analysis procedures;
- Financial information and accounting systems;
- Financial evaluation model;
- Network operation system and system operations manuals;
- Works management system and contractor management system;
- Training management system;
- Risk management and compliance management system;
- Safety and health management system and safety procedures;
- Emergency and crisis management, and business continuity systems;
- Environment management system; and
- Performance monitoring System.

These systems (and others) hold, structure and supply data and information that enables the network management processes across the business. In doing so, the network management systems and process enforce rigor, structure and governance within the overall network management framework, while providing transparency and supporting audit ability requirements. Hence, the network management systems and processes are essential elements of the framework that enable achievement of the network management objectives.

The Strategic Program of Work (SPOW) commenced in December 2006 with the aim of renewing Western Power's IT systems. SPOW includes the Asset and Works sub-program, which will provide an end to end business solution to address Western Power's Asset and Works system and information requirements. The Integrated Solution for Asset Management (ISAM) is part of the program and will provide an integrated asset management solution. ISAM has four major components:

- Rationalise Separate Systems into Ellipse - Western Power's current asset management applications will be rationalised into the Enterprise Resource Planning (ERP) system, Mincom Ellipse. The current Ellipse implementation does not have distribution and transmission asset and work's management as its governing theme as it was configured at a time when Generation and Retail Energy sales were important considerations. Significant reconfiguration of Ellipse is being undertaken to make it more appropriate for the networks business;
- Select, procure and implement a new GIS – The current GIS is mainframe based, which limits its further development and integration with other corporate systems;
- Integrate new systems - GIS and Ellipse together will form the asset management system, and GIS is a key component of work management suiting the geographically dispersed nature of the work force and equipment base; and
- Design and Implement new Business Processes - This project will redefine and implement asset management processes as required that are consistent with the Grand Design for Western Power's process efficiency and visibility.

The costs of ISAM are not included in this NMP.

4.12 Data management

The needs for data capture on the transmission network and the distribution network are different. Historically the transmission network assets have been closely managed due to their high value and low volume. Consequently there was high acceptance and adoption of data systems by information users and good data maintenance is available.

For distribution network assets, Western Power was an early adopter of integrating GIS (geographic information systems) into asset registration and management. An integrated dataset of distribution assets has been consolidated and maintained for over 20 years.

The demands on data availability and quality are continuing to increase. A strategy has been developed covering eight key components: Data Quality, Useability and understanding of the data (metadata), Service Performance, Data Ownership, Data sharing and provisioning / Data accessibility, Legacy data, Data Standards, and Data migration. The strategy has two important impacts for network management. These are described below.

Data quality issues are being addressed as part of our drive to achieve leading asset management practices. The majority of the data quality issues consist of incomplete data. By implementing a Large-scale Field Capture Program this issue is being addressed over the period to 2016/17.

The data capture will address:

- Transmission assets;
- Metro assets; and
- Escalation of desktop cleanses to field verification.

The data stewardship function is responsible for looking after the dataset on a day-to-day basis and maintaining and improving the quality of the dataset. The Management of Condition and Inspection Project will facilitate and drive this initiative.

5 Network Objectives, Drivers and Outcomes

This chapter describes Western Power's objectives for its network assets, the key drivers for investment, and the outcomes that are used to monitor the success of the NMP.

5.1 Network objectives

Each network objective is described in terms of the outcomes Western Power seeks to deliver or enable via the network, and the goals established to determine if the objective is being achieved. The network objectives are shown in Figure 5.1.

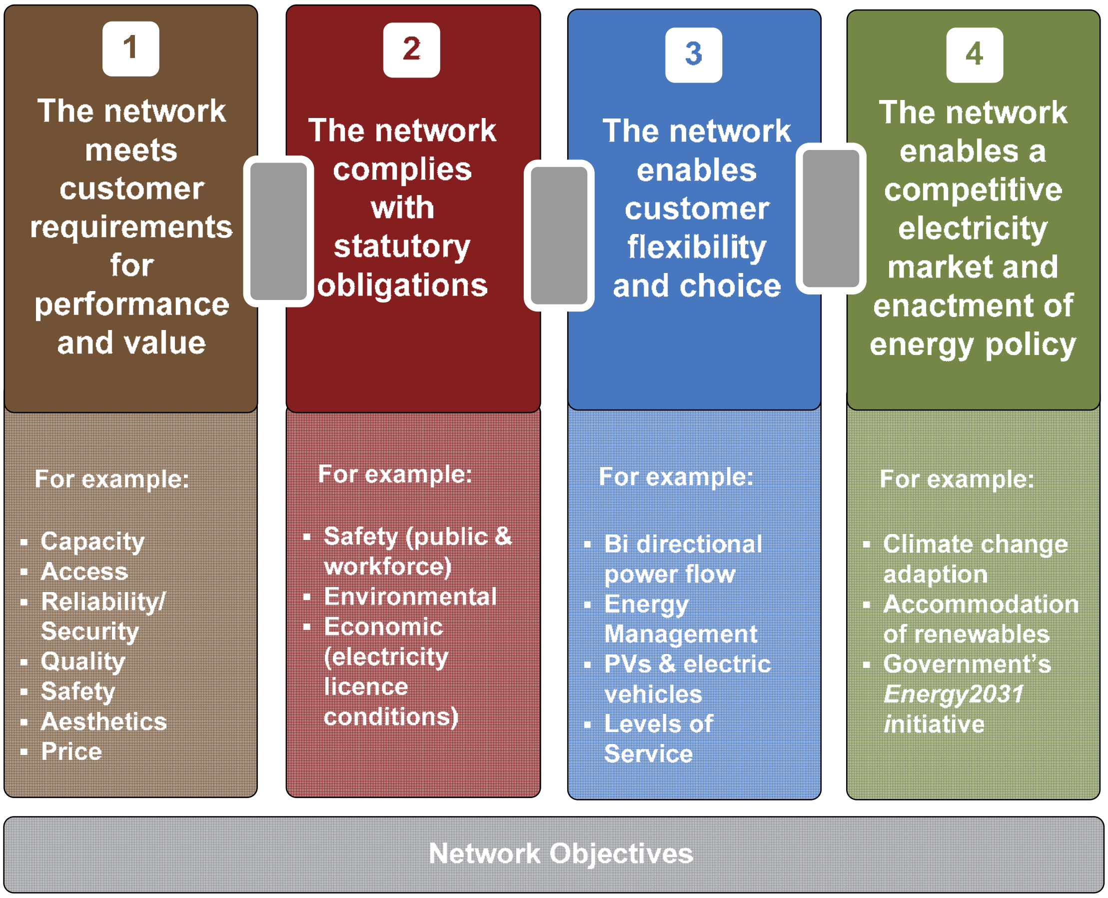


Figure 5.1: Network objectives

These objectives are not pursued in isolation. They are usually interdependent rather than discrete and efforts to achieve one objective will often contribute to the achievement of other objectives. For example, pursuing compliance is likely to result in better meeting customer requirements for performance and value.

The network objectives are described below, with further discussion in Section 9 of the Network Investment Strategy.

Customer requirements for performance and value - Western Power seeks to develop a network that meets its customer's requirements for performance, including reliability/security/quality of supply, availability of capacity (to meet growth) access (the ability to connect to the network), safety and aesthetics. Western Power also seeks to deliver value to customers, recognising their segmented nature and differing needs. In achieving this objective, Western Power proactively engages with customers to develop a mutual understanding of the trade-offs that may be necessary between performance requirements and price impacts so as to gain a clear understanding of the balance between performance and price that customers prefer.

Statutory obligations – Western Power seeks to comply with its statutory obligations which include federal and state statutory instruments such as legislation, regulations, codes and rules. These cover most aspects of its operations, including licensing, performance standards, the safety of the public and workforce, land access and environmental obligations. Statutory obligations can be split into two broad categories:

1. Obligations which are industry specific (i.e. they exist to govern Western Power in its role as a regulated network service provider) and have a direct impact on Western Power's network investment decisions. The principle sources of such obligations are Western Power's electricity distribution licence (EDL1) and electricity transmission licence (ETL2), which prescribe the applicable licensing legislation that Western Power must comply with; and

2. Obligations which are general in application but still have an impact on Western Power's network investment decisions. These include a number of environmental and safety obligations such as the Environmental Protection Act 1986 (WA), the Environmental Protection (Noise) Regulations 1997 (WA) and the Occupational Safety and Health Act 1984. These also include a range of obligations embedded in instruments such as Australian Standards or industry Codes of Practice.

Customer flexibility and choice – Western Power seeks to develop an 'intelligent network' (through the deployment of solutions such as new communication, automation, control and metering technologies). The network will empower customers through information, choice and flexibility in the way they manage their energy consumption, and will enable wide spread use of new technologies such as in-home displays, smart appliances, demand management, energy conservation, renewable energy sources and energy storage devices such as electric vehicles.

Competitive electricity market – Western Power seeks to develop a network that enables the continued evolution of a competitive electricity market and innovation in energy efficiency to drive lower energy costs. Western Power also seeks to ensure that the network enables the enactment of Government energy policy, recognising the current and emergent nature of policy.

Western Power's aim to achieve its network objectives is a journey that occurs and evolves over time. At any given point, pursuit of these network objectives is undertaken in the context of current and perceived future obligations, challenges and opportunities that exist.

Across some dimensions, the current state or performance of the network is delivering outcomes inconsistent with network objectives. In such cases, it may not be practical to achieve the desired level of performance over the short to medium term (e.g. due to funding or deliverability constraints). Instead, a realistic pathway to deliver the desired network objectives must be developed.

5.2 Network investment drivers

Network investment drivers are events, issues or factors that change the state of, or circumstances faced by, the network and apply ‘pressure’ to the network in terms of its ability to deliver the desired network objectives. They can trigger an investment response if they result in a gap between actual or predicted state and desired future state relative to network objectives, depending on the risk that the gap presents and Western Power’s risk appetite in relation to this.

The drivers can be divided into core factors, which tend to be explicitly stated and managed, and contextual factors that combine to shape Western Power’s operating environment and tend to be implicitly built into the network management approach.

The nine core factors that drive and influence the approach to network management are shown in Figure 5.2 and include the following four major investment drivers:

- Load growth;
- New connections (for both demand and generation);
- Asset condition; and
- Network reliability performance requirements.

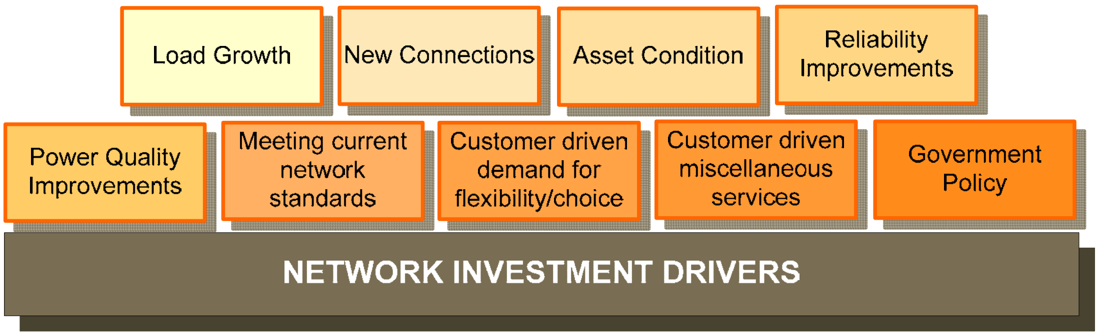


Figure 5.2: Network Investment Drivers

The contextual factors that constitute Western Power’s operating environment and consequently influence the approach to network management are:

- climatic condition;
- bushfire risk;
- climate change;

- smart grid;
- large renewable generation; and
- embedded generation.

The nine core and six contextual network investment drivers are described in the following sections.

5.2.1 Load growth

At all times the network must be able to transport the required demand for electricity from generators to customers' loads, else load shedding will occur. Peak demand is the maximum amount of electricity consumed at a single point in time. Forecasts of peak demands in specific parts of the network drive investments in the network. Over time, peak demands generally increase due to:

- organic load growth, as a result of existing customers using more electricity; and
- new loads connecting to the network, which include high volume but small-to-medium size distribution customers, and large block loads.

Western Power has an obligation to meet or manage peak demand growth to ensure that network performance is not compromised due to an imbalance between peak demand and available network capacity.

Insufficient capacity to meet peak demand can result in load being disconnected from the network to protect equipment and prevent system instability. Where load is not disconnected in overload situations, degradation of asset life can occur. In addition, overloaded plant can cause unacceptable safety outcomes (such as overhead conductors sagging below allowable electrical clearance levels).

Provision of sufficient network capacity at peak times mitigates the risk of outages, protects equipment, improves network security, reliability and safety outcomes, and achieves compliance with licence conditions.

Investments for network load growth are further discussed in Chapter 6.

5.2.2 New connections

Western Power has an obligation to provide access to its network services under the conditions of its electricity transmission and distribution licences. Western Power is therefore required to connect new loads or generators to its network, which includes an obligation to provide appropriate metering for these new connections.

New block load connections can range from large bulky loads connected to the transmission network (such as new mining projects) to small/medium enterprise loads connected to the distribution network. Similarly, new generator connections can range from large base-load power stations connected into the bulk transmission network to small renewables (such as PV cells) connected into the distribution network.

This investment driver is closely linked to the load growth driver since new loads contribute to peak demand growth and the location and size of new generation is influenced by the expected growth in demand. The key difference between this driver and the load growth driver is that this driver responds to the need to expand the network to enable physical connection of individual, known customers. The load growth driver responds to the need to expand the network to ensure future demand can be economically supplied from the shared network.

Investments for new connections are further discussed in Chapter 6.

5.2.3 Asset condition

Network performance is influenced by the condition of individual assets. Poor performance or failure of existing assets compromises Western Power's ability to maintain the quality, reliability and security of its services and the safe operation of its network.

Throughout the life of an asset, investment may be required to maintain the asset to ensure it achieves its full design life. The need to replace an asset arises when its condition unacceptably compromises performance or safety.

Investments to maintain or improve asset condition are further discussed in Chapter 7.

5.2.4 Reliability improvements

Reliability is a key measure of network performance and Western Power is required to ensure it is maintained at an acceptable level. To a large extent, reliability performance is achieved through investments driven by load growth, new connections and asset condition. However, such investments predominantly result in sustaining current levels of reliability performance. Additional, targeted investment is necessary where improvement in reliability performance is required (e.g. where there is a gap between present and desired reliability performance).

Investments to maintain or improve network reliability are further discussed in Chapter 7.

5.2.5 Power quality improvements

Power quality is the degree to which the electricity supply system is free from major distortions in supply voltage and frequency. Network power quality, as distinct from reliability, is becoming an increasingly important issue for all classes of customer. Western Power is required to ensure that the quality of electricity supplied to customers is acceptable.

Power quality management focuses on characteristics such as voltage limits, voltage flicker, waveform distortion and waveform unbalance on the network. It also focuses on the impact of disturbing loads and renewable generation. Disturbing loads and renewable energy systems can result in waveform distortion, voltage fluctuations and may cause voltage excursions outside regulatory limits. The impacts of customer loads and generating systems need to be managed to ensure they do not adversely affect other customers connected to the network.

As with reliability driven investment power quality performance is achieved predominantly through investments driven by load growth, new connections and asset condition as well as, through investments to achieve reliability improvements. However, improvement between present and required power quality performance may still exist after the application of investments associated with these drivers. Additional targeted investment may still be required to achieve improvements in power quality performance outcomes.

Investments to maintain or improve power quality are further discussed in Chapter 7.

5.2.6 Meeting current network standards

Governing standards bodies, including the International Electrotechnical Commission (IEC), Australian Standards (AS) and Energy Networks Association (ENA) issue standards and guidelines for the electrical industry, many with direct application to the Western Power Network. As new legislation, regulation and technology is introduced, and the experience with electricity networks continues to mature, existing standards and guidelines are updated and new standards introduced to meet new and emerging issues.

The nature of an electricity network is such that many of its assets have very long design lives, often remaining in service for over 40 years. Despite being installed to comply with the standards of the day, some will not meet current standards, which may be either internal or external standards. Such gaps often arise in relation to safety, environmental or regulatory (licence condition) compliance, or in meeting customer requirements. In addition, technologies associated with both primary and secondary network assets can advance rapidly.

Investment in new standards/technologies may be required to achieve better or more efficient outcomes, or to meet changing customer expectations. Equipment and technology obsolescence may also result in changing standards.

Investments applied in response to other drivers, such as load growth, new connections, asset condition and reliability or power quality improvements can all impose obligations to bring existing assets up to current standards. However, there may also be cases where a gap with current standards represents a level of risk that justifies separate investment to ensure assets are brought into compliance.

Investments to maintain or improve compliance are further discussed in Chapter 7.

5.2.7 Customer driven demand for flexibility/choice

The emergence of new technologies, increasing energy costs and sustainability considerations all influence customer behaviour and expectations. Customer requirements for flexibility and choice in the levels of performance they receive and the way they manage their electricity consumption and generation needs are increasing.

Investments in the customer driven plan to improve customer demand for flexibility/ choice are currently structured as specific projects and are not specifically covered in this NMP.

5.2.8 Customer driven miscellaneous services

Miscellaneous services include a suite of regulated, network-related activities that are requested and fully funded by the customer. These include activities such as asset relocations (e.g. requested by local governments for road works), network reconfigurations to accommodate high-load movements and local streetscape enhancement projects.

Investments to meet customer driven miscellaneous services are considered when developing asset replacement plans.

5.2.9 Government policy

There are occasions were network related investments are driven out of the need to comply with Government policy/directives (e.g. the State Underground Power Project). These are structured as specific projects and are not specifically covered in this NMP. Such investments are taken into account when developing asset replacement plans.

5.2.10 Climatic conditions

Climate plays in important role in the way that the network is managed for optimum performance, both on the supply and demand sides. Electricity consumption volumes and peaks are strongly affected by climatic conditions through consumer loads for air conditioning and heating. Likewise, the carrying capacity and performance of network assets is also be affected by parameters such as temperature and wind speed. Furthermore, climate captures the likelihood of extreme weather events such as storms, floods and heat waves that can directly damage network assets.

The Western Australian climate is unique in that the state crosses 5 different climatic zones [9] (temperate, subtropical, grassland, desert and tropical), giving a high degree of climatic variability in different regions of the network. On average, the Western Australian climate is quite warm and dry, which means that some asset design specifications and industry design standards may not align directly to the local climatic conditions.

There are different methods by which climate is factored into the management of the network, including through:

- Asset performance: Customised technical standards and design rules;
- Asset damage: Contingency plans, design rules, specific asset strategies such as undergrounding; and
- Demand patterns: Analysis of demand and consumption trends against climatic variables as part of the demand forecasting process.

5.2.11 Bushfire risk

The risk of bushfire is a particular manifestation of the climatic conditions in Western Australia. High temperatures combined with low rainfall can lead to conditions in which fires are easily ignited, spread quickly and are difficult to control. Given that all electricity networks can be sources of ignition for fire-

9 Bureau of Meteorology, “Australian climate zones - major classification groups (based on the Köppen classification)”

starts, Western Power has a targeted strategic framework to manage bushfire risk. This framework aims to minimise the risk of electricity assets causing fires and to ensure compliance with legislative and regulatory requirements. The following documents and processes are central to this aim:

- Bushfire Mitigation Strategy;
    - Bushfire Management Program;
- Bushfire Management Implementation Plan;
- Bushfire Preparedness Committee; and
- regular meetings and summary reports.

The management of bushfire risk is implemented through two main complementary avenues: development of specific programs that target bushfires, and the incorporation of bushfire risk into all relevant network planning activities. An example of this two-pronged approach is seen in the management approach to overhead carriers. Carrier asset information is broken down into bushfire risk areas and the relative bushfire risk of different assets is used in the prioritisation of asset replacement. In addition, a specific “Bushfire Mitigation Wires Down” program is developed to reduce the number of wires down incidents and includes replacement of carrier assets amongst other asset strategies.

The consideration of bushfire risk covers a wide range of asset types and asset management activities. Fire starts can be caused by assets themselves, such as overhead structures, pole top structures, transformers, switchgear and carriers, as well as general construction and operational activities undertaken by Western Power. Therefore, consideration of fire start potential is incorporated into the way these assets are managed, both in the specification, operation, maintenance and replacement phases. Western Power complements these asset based strategies with targeted operational activities such as maintenance of line clearances, vegetation management, pole top washing, applying silicon to the surface of insulators, and regular analysis and reporting of fire starts and causes. Reporting is performed both internally within Western Power and externally to stakeholders such that this information can be fed back into the development of bushfire mitigation strategies.

5.2.12 Climate Change

Climate change and the various initiatives undertaken for greenhouse gas emissions mitigation have a wide range of important implications for electricity networks. The network must adapt to both the physical impacts of the changing climate and the industry-wide ramifications of government and corporate policies for mitigation as well as public expectations.

Direct physical impacts of climate change include changes to the operational performance of networks, increased risk of equipment failure, and altered deterioration mechanisms which reduce asset life. Indirect impacts of climate change include government policy responses to reduce carbon emissions, such as incentives for distributed and large scale renewable energy connections and energy efficiency initiatives that act to reduce demand. This section deals with the direct physical impacts of climate change whereas the generation side impacts are discussed in more detail in following sections.

The physical climatic changes predicted for Western Australia includes increased temperatures, decreasing rainfall and greater variability in wind speeds. These factors would have most impact on the following areas of Western Power's operations:

- supply restoration and reliability – increased storm activity may cause increased outages and reduced network reliability. This will be managed over time through Western Power's regular reliability analysis and reporting process;
- asset design requirements – adjustments to design standards may be required such as the assumed ratings of overhead carriers given changes to ambient temperature and wind speeds. Design standards will be reviewed as required in order to ensure that they still capture the expected climatic conditions; and
- bushfire management – climatic changes are likely to increase the duration of the bushfire season and the magnitude of bushfire consequences. Western Power is managing this impact of climate change through the bushfire risk strategic framework.

The demand side impacts of climate change such as increase air-conditioner penetration combined and longer heatwaves are accounted for in the annual demand scenario planning.

Increased focus on mitigation of Western Power's own direct and indirect emissions is also a trend that may require changes to the management of the network. Depending on the evolution of relevant policies and regulations, such changes could include:

- reduced use of equipment containing SF6;
- network design to reduce electrical losses; and
- reduced operational and fleet emissions of greenhouse gases.

5.2.13 Smart grid

The smart grid concept is based on an information network embedded within the electricity network such that the operation of the network can be actively, and in some cases automatically, controlled and managed in order to become more efficient and flexible for both customers and the network operator.

Western Power's Smart Grid program will deliver a number of benefits:

- empowering customers to make more informed choices about their energy use.
- reduced operating costs through automation of systems;
- improved network efficiency through enabling technologies and practices such as Distribution System Management and embedded generation to flatten the load profile;
- improved reliability through provision of real-time network performance data to facilitate rapid diagnosis and repair activities; and

Western Power has been developing and applying smart grid compatible technologies to its network over many years. Western Power's long-term

Smart Grid vision is to create reliable and sustainable energy solutions which enable greater customer choice through the dynamic management of the integrated power system for the benefit of Western Australians.

As such, consideration of smart network concepts needs to be included in the asset management decision making process. To facilitate this, a Smart Grid Roadmap has been developed in alignment with the network investment drivers outlined in Western Power's Network Investment Strategy which underpins Western Power's regulatory obligation to undertake prudent and efficient investment.

Whilst the Smart Grid represents a paradigm shift, a building block implementation is planned by Western Power rather than a transformational change. The Smart Grid is, and will be, a continuously developing concept with its rate of implementation highly dependent on factors such as government policies, regulatory drivers and the continued development of market-ready enabling technologies. Western Power is also monitoring the development of the National Broadband Network and will continue to assess the potential for the Smart Grid to leverage off the same technology and capabilities.

An important stage of this implementation process is the commercial trial of the different elements and capabilities of smart grid solutions. Western Power is undertaking a number of trials including the Perth Solar City project that incorporates the trial of smart meters and direct load control as well as research into handling a high penetration of distributed PV. A comprehensive community engagement and behaviour change campaign has been undertaken to help residents change the way they use and generate energy. By gaining customer acceptance and encouraging the adoption of smart grid tools (such as in-home displays, direct load control and time of use tariffs) customers can achieve a reduction in energy costs. In turn, Western Power can more efficiently utilise existing resources and potentially defer costly network augmentation.

Results from all trials will be used as a basis for continued development of the smart grid under the Smart Grid Roadmap.

5.2.14 Large renewable generation

Driven primarily by the federal government Renewable Energy Target (RET), Western Power is experiencing increased connections of large scale renewable generators. This trend is expected to continue and potentially accelerate given the increasing volumes of renewable generation required by the RET out to 2020 and the impact of other factors that support large scale renewables on both the supply and demand sides including:

- GreenPower customer numbers;
- increasing fossil fuel costs;
- the likely introduction of a carbon price mechanism and the relevant carbon emission reduction targets; and
- other government support mechanisms for renewable energy.

The connection of large renewable generation can be more complex than for fossil fuel plant in that additional network support such as static VAr compensation may be required for variable generation sources such as wind power. The typically remote location of renewable plant can also require significant network augmentation. An increasing level of variable generation also has operational consequences in terms of managing power flows across the network.

The South-West area of Western Australia has excellent wind resources, which have attracted significant interest in wind generation development. However, as an isolated grid, there are limitations on the quantity of wind generation that can be accommodated without changes to various market rules and other technical factors. If there is a significant level of ambition to overcome these factors, wind development could be substantial; otherwise it is likely to be moderate.

The expected level of new large scale renewable generation is captured by the annual generation scenario modelling that is detailed in the Annual Planning Report.

5.2.15 Embedded generation

Embedded generation refers to generation connected at the distribution level of the network. The traditional network design assumed that generation was connected at the transmission level and electricity flowed down to consumers at the distribution level. Therefore, generation connected at the distribution level can change and even reverse this flow of electricity in localised areas of the network. This has technical implications for network design and operation.

As embedded generation is a growing trend, these implications need to be planned for and managed in order to maintain the network in a safe and reliable condition. There are already many embedded generators connected to the Western Power distribution network. Typical embedded generation projects range from small-scale solar PV installations on houses or commercial buildings through to larger gas or diesel generators in commercial buildings or industrial precincts.

The key technical issues associated with embedded generation units include:

- network support;
- fault level contribution;
- protection schemes;
- islanding;
- intermittent generation;
- network security; and
- compliance issues.

A formal process is established for embedded generators wishing to connect to the distribution network. A Generator Grid Connection Guide is available on the Western Power web site. This guide details the issues relating to generator connection and outlines the process for generator connection.

5.3 Linkage between network objectives and Core investment drivers

There is a direct link between network objectives and network investment drivers. Each network objective must have at least one corresponding network investment driver and each network investment driver must respond to one or more network objectives. Figure 5.3 shows the main network objectives to which each network investment driver responds. Figure 5.3 also reinforces the concept that investments made in response to one driver will usually contribute to more than a single objective.

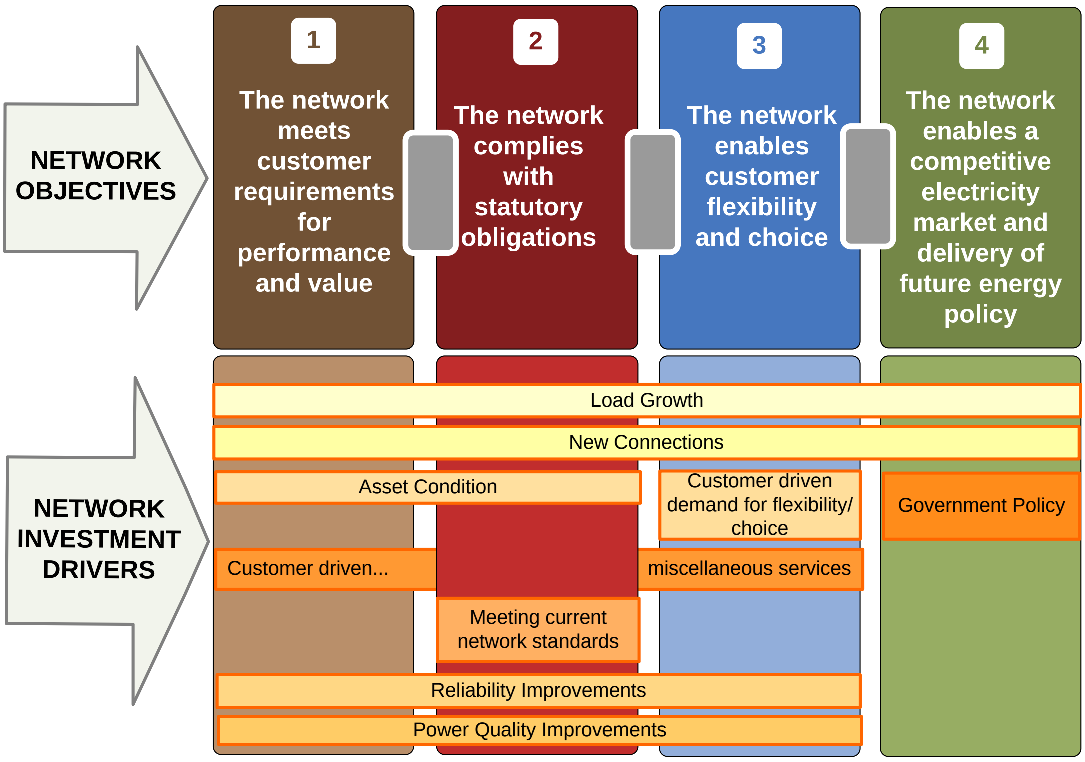


Figure 5.3: Network Investment Drivers in relation to the Network Objectives

For the period of the NMP, three key areas drive the investment program. These are:

1. Safety - this addresses the highest priority public safety risks, recognizing that all public safety risks will not be immediately resolved;

2. Growth and Security – this addresses the need to expand the network's capacity to meet growth and connect new customers, and the network's sub-optimal resilience to widespread outages; and

3. Service - this seeks to maintain current service standards, only improving service where it is valued by the customer and efficient to do so.

5.4 Network measured outcomes

Through the application of the network investment drivers, the network monitored outcomes are the network vision's translation by the network's objectives. Figure 5.4 outlines these monitored outcomes and how they relate to the network objectives.

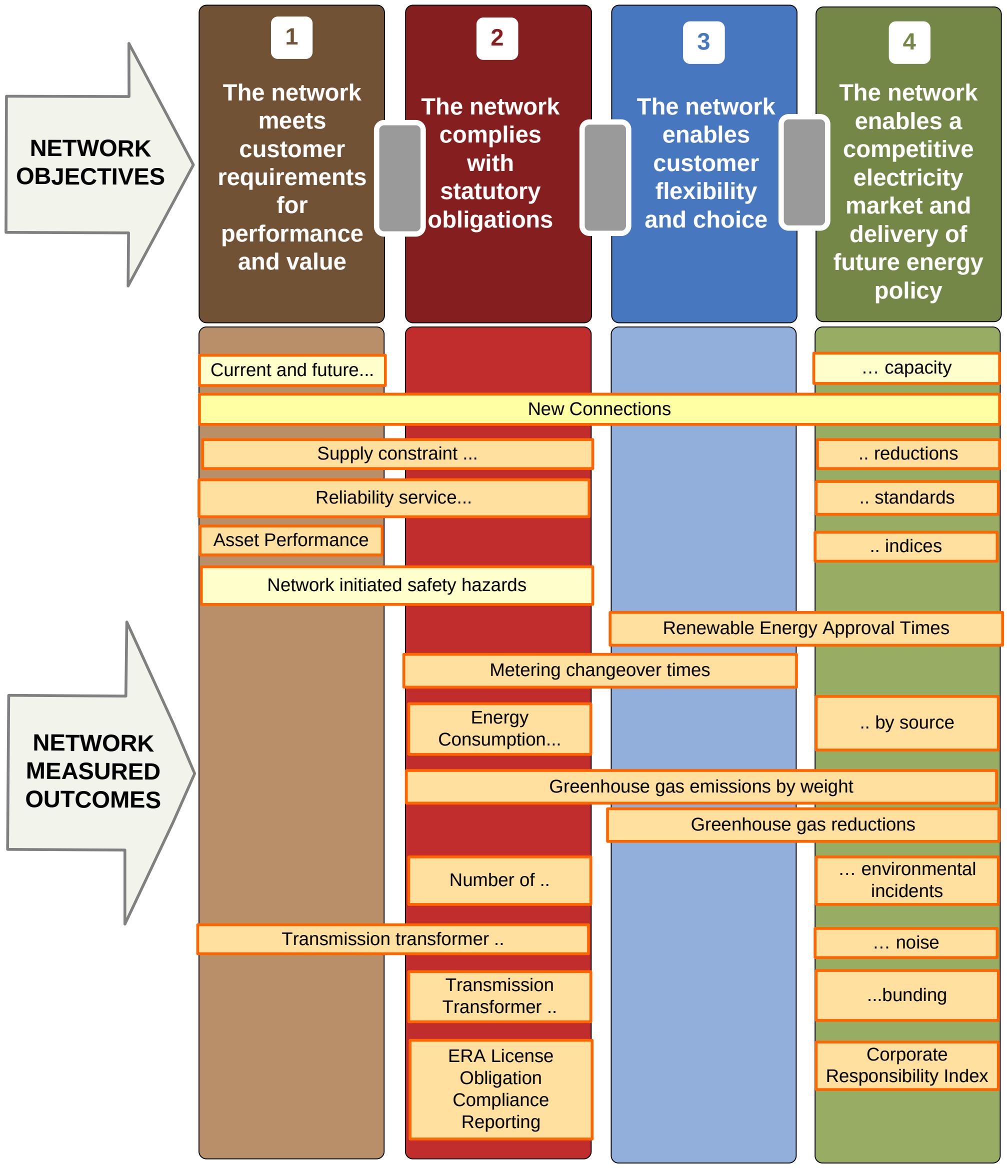


Figure 5.4: Network Measured Outcomes in relation to the Network Objectives

The outcomes describe either a single measure or KPI, or a group of measures or KPIs. These measures / KPIs are reported externally and/or internally on a periodical basis by the relevant areas of the Networks Division.

Table 5.1 shows each of the performance measures (KPIs) for the outcomes shown in Figure 5.4 grouped under the key drivers for investment.

Table 5.1: Network management plan outcomes

Outcome	Strategy	Plan
Safety		
Improve asset performance to meet legislative and customer requirements	Reduce the incidence of: • Number of pole top fires • Number of clashing conductors • Number of unassisted wood pole failures • Number of unassisted conductor failures.	Improvement plans as set out in Chapter 7
	Monitor performance: • Distribution pole integrity index • Pole inspection backlog • Pole condemnation backlog • Pole condemnation rate • Transmission line index* • Transmission substations index* • Transmission SCADA availability index • CBD SCADA availability index • Distribution Automation devices availability indices • Overall protection performance • PQ Complaints per 100,000 (12-month rolling average). *Use of these indices is being reviewed	Meet the performance targets set out in monthly reporting
Improve safety outcomes	Focus on areas of low performance: • Asset initiated electric shocks. • Asset initiated bushfires. Monitor performance	Reduce the likelihood of Asset initiated electric shocks by replacing the remaining 'at risk' twisties type Overhead Customer service Connections (OCSC's) by the end of 2014/15. Reduce the likelihood of Asset initiated fires by reducing the population of 'at risk' poor condition assets. Meet the performance targets set out in the Public Safety Management Plan (see below).
Growth		
Current and future capacity meets demand	Reduction in the number of customers at risk of being shed following credible single contingencies due to failure to meet key technical rules obligations.	Reduce the number of customers of this risk from 116,000 (June 2012) to 100,000 (June 2017)

Outcome	Strategy	Plan
	Growth by network capacity increase.	Meet the predicted peak demand of 5,061 MW by the end of June 2017
All new customers connected	Monitor performance	Connect an estimated 130,000 new customers during the period 2012/13 to 2016/17
Service		
Maintain reliability of supply	Monitor and maintain or replace assets to maintain current levels of performance. Monitor lag indicators: • System Average Interruption Duration Index (SAIDI) • System Average Interruption Frequency Index (SAIFI) • Circuit Availability • Loss of Supply Event Frequency • % Customers with outage >12 hrs • % Urban customers with >9 outages pa • % Rural customers with >16 outages pa • No of recurring trips > 5 over 30 days (cumulative)	Asset monitoring, maintenance and replacement plans as set out in Chapter 7 to meet the service standard benchmarks for reliability (see below), and the performance targets set out in monthly reporting
Meet customer expectations for the timely approval of renewable energy applications	Review time period for approval. Monitor performance	Approve within 3 weeks of receipt (under review)
Metering changeover times	Monitor performance against Metering Code Model Service Level Agreement[10]	Meter changeovers are to be completed within 5 business days for metropolitan customers and within 10 business days for country customers
Energy consumption by source	Monitor performance of: Direct energy consumption by primary energy source. Measures consumption in GJ by all facilities, vehicles and plant. Indirect energy consumption by primary energy source. This measures indirect	Reduce of indirect and direct energy consumption through energy efficiency measures. Project Vista will deliver energy

10 Available from the Western Power web site.

Outcome	Strategy	Plan
	consumption such is network losses in kWh.	reduction to Head Office and major depots. Implications of changes to Energy Efficiency Opportunities legislation on network losses to be investigated following release of draft legislation.
Greenhouse gas emissions and reductions	Monitor performance of: • Total direct and indirect greenhouse gas emissions by weight; • Other relevant greenhouse gas emissions by weight; • Initiatives to reduce greenhouse gas emissions and reductions achieved. The standard unit is tons of carbon dioxide equivalent units (t CO2-e).	Reduce indirect energy consumption through energy efficiency measures and purchase of renewable energy. Project Vista will deliver energy reduction to Head Office and major depot locations. Investigate alternatives to SF_6 for transmission and distribution equipment to reduce emissions and impact of carbon price.
Network initiated environmental incidents	Monitor performance of: • NOx, SOx, and other significant air emissions by type and weight • Total weight of waste by type and disposal method • Total number and volume of significant spills	NOx & SOx emissions limited to Ravensthorpe Power Station. Long term solution to Ravensthorpe power quality currently under investigation. Improve data collection for waste & recycling actively to track performance. Continued implementation of Reverse Logistics project to improve materials management and maximise recycling of used network assets such as transformers, overhead conductors and cables.

Outcome	Strategy	Plan
		Track number and volume of spills with targets to be set for the 2012-13 year.
Transmission transformer noise	Monitor performance of: Western Power owned transmission transformers in terms of their noise assessment, mitigation and compliance from the operation and implement noise mitigation measures.	Bring existing transmission substations sites into compliance as set out in the *Environmental Protection (Western Power Transmission Substation Noise Emissions) Approval* 2005 by the end of AA4. New transmission substations to be constructed in compliance with the *Environmental Protection (Noise) Regulations 1997.*
Transmission transformer bunding	Monitor performance of: Oil containment of transmission transformers to limit environmental damage in the event of significant oil loss and implement mitigation strategy.	Construct all new transmission transformer bunds in accordance with AS1940. Upgrade existing transformer bunds to AS1940 based on prioritised by risk level, in conjunction with third transformer installation projects and compliance work programs (dangerous goods, fire wall and noise barrier programs to optimise projects).
Regulatory license obligation compliance reporting	Lodge with the ERA an annual compliance report covering breaches against its current license obligations for the previous financial year by August.	100 per cent compliance
Corporate responsibility index	The CRI is a self-assessment tool that benchmarks performance annually against other participants. The target for 2009/10 was 56%, a five per cent improvement on the 2008 score (52.5%). The actual score	Investigate current performance and measures by 2013/14 and implement outcomes

Outcome	Strategy	Plan
	achieved was 72.5%, representing an improvement of 35%. For this achievement, Western Power was awarded the most improved in the Bronze Category. In the following year, 2010/11, the actual score was 82% and Western Power is now recognised to be in the silver category. No target is set for this index.	

5.4.1 Reliability service standards

The service standard benchmarks are the expression of the reference services in current and future Access Arrangements. The following reliability service standards are proposed for the AA3 period to June 2017:

- System Average Interruption Duration Index (SAIDI);
- System Average Interruption Frequency Index (SAIFI);
- Circuit Availability; and
- Loss of Supply Event Frequency.

Performance against the current reliability service standards (those applicable to the AA2 period) is shown in Table 5.2 and Table 5.3. With the exception of Long Rural SAIDI and Loss of Supply events less than 0.1 System minutes, all targets were met in 2010.

Table 5.2: Distribution performance summary 2010

Service Standard Benchmark	2009/10 Actual Performance	2010/11 Benchmark	2010/11 Actual Performance	2010/11 Target Met?
SAIDI – Total network	217	224	217	√
SAIDI - CBD	1	38	1	√
SAIDI - Urban	156	162	156	√
SAIDI - Rural Short	212	253	212	√
SAIDI - Rural Long	661	588	661	√
SAIFI – Total network	2.0	2.46	2.00	√
SAIFI - CBD	0.02	0.24	0.02	√
SAIFI - Urban	1.55	1.89	1.55	√
SAIFI - Rural Short	2.33	3.06	2.33	√
SAIFI - Rural Long	4.17	4.85	4.17	√

Table 5.3: Transmission performance summary 2010

Service Standard Benchmark	2009/10 Actual Performance	2010/11 Benchmark	2010/11 Actual Performance	2010/11 Target Met?
Circuit availability (% of total time)	98.43%	≥ 98.00%	97.90%	X
System minutes interrupted (meshed network)	8.94	9.3	6.68	√
System minutes interrupted (radial network)	0.75	1.4	4.83	X
Loss of Supply Events >0.1 System minutes	27	25	18	√
Loss of Supply Events >1 System minutes	2	2	1	√
Average Outage Duration	679	≤ 764	675	√

5.4.2 Public Safety Management Plan

The Public Safety Management Plan contains KPIs that include those relating to performance of the network. These KPIs are monitored and corrective actions are taken as issues emerge. Known issues are incorporated in the asset life-cycle management plans in Chapter 7.

5.4.3 Bushfire Management Plan

The Bushfire Management Plan is produced annually with the objective of reducing the likelihood of asset initiated fires. It contains KPI's that are monitored to assess the success of the plan. These are shown in Figure 5.5 and distinguish between asset and non asset initiated fires, which is confirmed following confirmation of an investigation.

Bushfire Season Preparedness Index - This is a lead indicator that provides a pre-bushfire season risk indicator on the following areas:

- Vegetation in Extreme and High Bushfire Risk areas to be cut by November 30 of each year;
- Fuse pole clearing in Extreme and High Bushfire Risk areas completed by November 30 of each year; and

- Priority One maintenance works in Extreme and High Bushfire Risk areas that are directly bushfire related completed by November 30 of each year.

Figure 5.5 shows the number of fires that have occurred over the last 7 years and those that have been initiated by Western Power Assets.

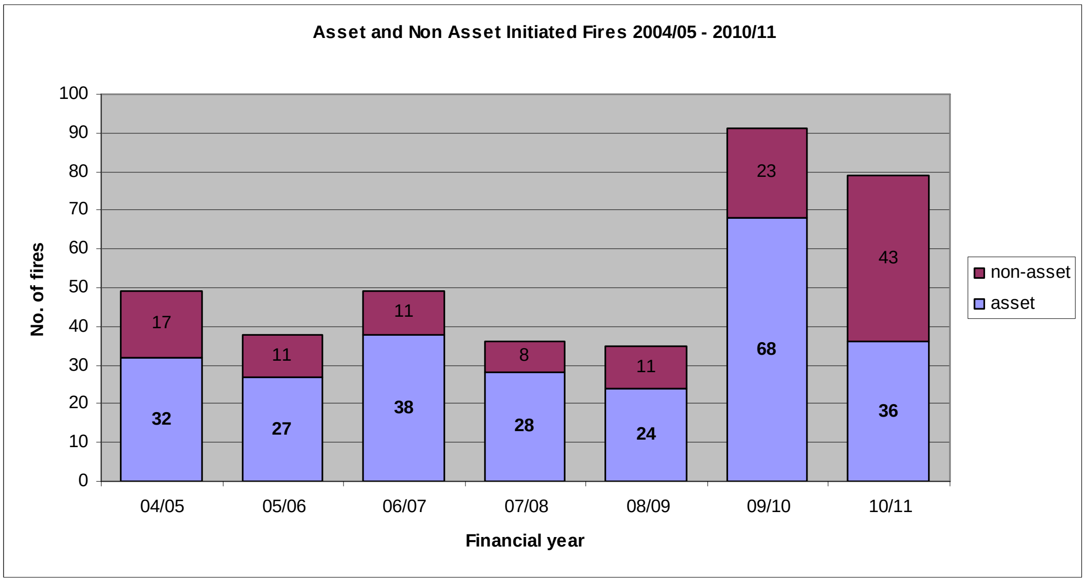


Figure 5.5: Asset and non-asset initiated fires

5.5 Alternative investment profiles

The asset replacement volumes and maintenance activities set out in this NMP have been optimised through:

- review processes of the Network Management Plan and the Transmission Network Development Plan; and
- the Network Investment Annual Planning Cycle, which provides alignment of Growth and Non-Growth planning activities.

Western Power has considered our customers' expectations and the growing needs of the state, and balanced this against risk and practical deliverability. The result is an NMP that efficiently addresses legacy issues while maintaining service and reducing risk.

Our risk management approach to asset management and works planning is cognisant of the consequences of alternative investment profiles to that proposed by this NMP. These consequences have been examined and show either an intolerable risk for the network or greater costs to customers. Table 5.4 shows the key assets categories that have been reviewed and the forecast risk outcomes as a result fo the proposed plans contained within this NMP.

Table 5.4: Risk ratings for key assets

Risk area	Current risk (2011)	Forecast risk (2017)	Risk target

Indoor switchboard	H-	M	M
Power transformer failure	H	H-	M
Transformer noise	H	H-	M
Saturated reactors	H-	M-	M-
Conductive poles	H-	L	L
Overhead service connections	H-	M	M
Pole top fires	H-	H-	M
Overhead conductor failure in extreme/high fire risk area	H-	M	M
Overhead conductor failure in moderate/low fire risk area	H-	H-	M
Inadequate ground clearance on distribution lines	H-	H-	M
Unassisted wood pole failures	H	H-	H-
Distribution transformer failure	H-	H-	M
Battery banks/chargers	H-	L	L
Outage duration not in excess of 12 hrs, 9 in 10 yrs	H-	H-	M
Outage frequency not exceeding 9 and 16, 9 in 10 yrs	H-	H-	M

Scale: Extreme, High, Moderate, Low

Table 5.5 shows the aggregate risks grouped by the major drivers for investment. It shows that the overall risk profile remains the same for the level of investment proposed in this NMP. However:

- If Western Power was to improve average service performance and had the capacity to address all public safety risks during the period, the investment proposal would result in substantially higher expenditures;
- If Western Power was to invest a reduced level of capital in public safety programs, the resultant network risk would increase from its current 'high' position to 'extreme' by the end of the period of this NMP;
- If Western Power was to invest a reduced level of capital in facilitating growth and restoring security, the network risk would move from its current 'high' risk profile to 'extreme' by the end of the period of this NMP; and
- If Western Power was invest a reduced level of capital in maintaining service, the network risk would move from its current 'moderate' risk profile to 'high' by the end of the period of this NMP.

Table 5.5: Risk ratings for main investment driver categories

Time period	Safety	Growth &	Service

		security	
Current (2011)	H	H	M
Forecast (2017)	H	H	M

Scale: Extreme, High, Moderate, Low

6 System Planning and Development (Growth)

The focus for this Plan is “In Service” asset management (Non-Growth). However, it takes into account the input of the growth of the network upon the operational expenditure and the opportunities to optimise the capital works expenditure.

6.1 Network planning overview

Western Power is responsible for preparing network development plans for ensure secure and reliable network performance in the most cost effective manner. In order to achieve this goal, Western Power prepares short term, medium term and long term network development plans taking into account the requirements of the Technical Rules, load and generation forecasts, asset management plans and it’s commercial objectives. These plans provide for :

- each individual network element to be operated within its design limits;
- the overall network to withstand credible contingencies and unplanned outages;
- quality of supply to be maintained within applicable standards;
- adequate provision for potential future growth; and
- environmental impacts being responsibly managed.

6.2 Generation scenario planning

Given the long lead time of transmission projects, a reactive approach to a generation project exposes Western Power to the risk of delays in connecting new generation. Therefore a proactive planning approach to generator connections is taken to ensure that a robust network is in place.

In order to capture the uncertainties associated with future generation developments, several generation scenarios are developed based on various influencing factors, and these identify the common network development requirements for those scenarios. The main factors considered are:

- demand growth;
- Australia’s likely Carbon price trajectory;
- gas availability for electricity generation; and
- ambition and potential for renewable (wind power in particular) generation.

6.3 Demand forecasting

Electricity demand varies continuously, and the typical trend is a growth in demand over time. The ability to forecast the demand variation to a reasonable confidence level is critical for the overall management of the network, as it affects the asset utilisation, system security and CAPEX plans.

The Independent Market Operator (IMO) publishes the Statement of Opportunities (SOO) annually, which includes a prediction of the electricity demand for the next 10 years including the network losses. Similarly, Western Power annually produces its own peak demand forecast excluding transmission losses and matches it with the overall demand forecast published in the SOO.

6.3.1 Factors affecting the demand

There are several social, economic, environmental and technical aspects that affect the movement in electricity demand. Some of these factors can be mutually exclusive while others are heavily inter-dependent. The overall impact of these factors on demand is considered when developing future predictions.

6.3.2 Demand in substations, the transmission network and individual load areas

Broadly, Western Power requires three levels of demand forecasting for an efficient and effective network planning process:

- **Substation demand**: Forecasting the peak demand at each substation is essential to evaluate the utilisation of existing substation assets and to identify any substation augmentation requirements;
- **Bulk transmission system demand**: Peak demand in the bulk transmission system is different to the summation of each substation peak demand due to variations in the timing of the substation peak demand; and
- **Demand in individual load areas**: The network is divided into load areas as shown in Figure 6.1. Demand characteristics in each load area can be different and this may cause variation in power flows in the transmission system interconnecting these individual load areas. Within each of these areas, the network is further segmented to enable forecasts of specific load areas down to individual HV feeders.

6.3.3 Weather sensitivity and probability of exceedance

The transmission network typically experiences its peak demand during summer. Depending on the maximum temperature and the number of consecutive hot and humid days, the electricity demand changes significantly.

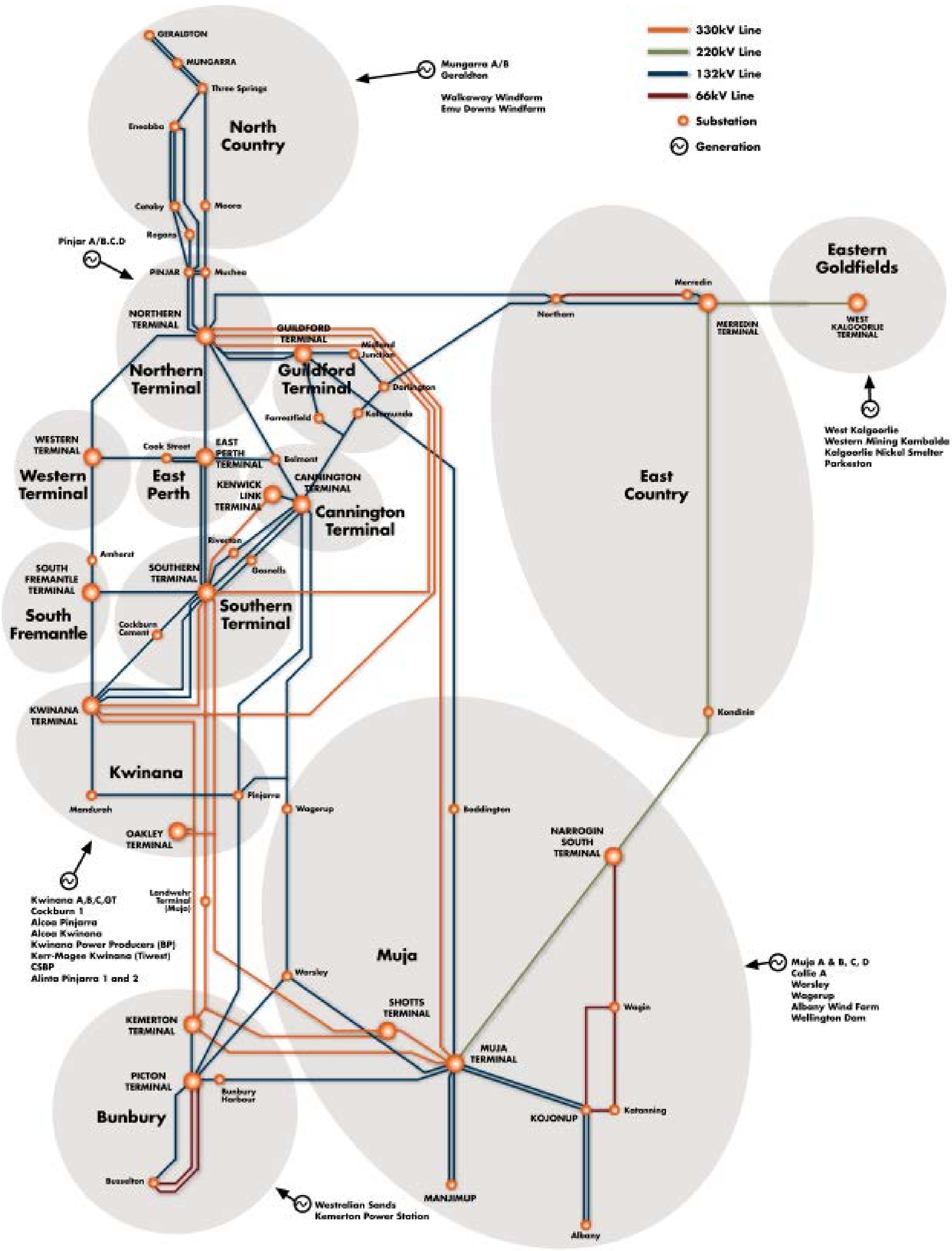


Figure 6.1: Load areas in the Western Power's electricity network

6.3.4 Forecasting methodology

Historical peak demands of each substation, excluding temporary load transfers, are modelled; a variance adjustment factor is applied. This forecast ensures that planning takes account of a 1 in 10 year load demand event as required under the Technical Rules.

6.3.5 Long term demand forecast

A detailed 20 year long-term substation demand forecast is prepared. This forecast is separated into a Summer Load Trends Report and Winter Load Trends Report. These forecasts and reports are updated annually to reflect the latest changes in demand.

6.3.6 Impact on asset utilisation

As specified in the Technical Rules, different levels of reliability must be provided such as N-0, N-1, N-1-1, 1% risk criterion and normal cyclic rating criterion at different parts of the network depending on their significance. As a result, it is necessary to maintain different levels of asset utilisation at different parts of the network to be able to provide the intended reliability.

6.4 New Customer Connections

Approximately 26,000 new customers are expected to be connected to the network over each year from 2011/12 to 2016/17.

Western Power has a legislative obligation to connect customers to the distribution network and has a set of specific requirements that must be met before connection is made.

6.5 Issues with connection and load growth

There are five common issues associated with facilitating efficient connection for new customers and meeting increasing underlying load growth on the distribution and transmission networks. These are:

- Thermal capacity constraint;
- Voltage profile and voltage stability;
- Power quality;
- Access to existing infrastructure; and
- Environmental constraints.

In addition to the common issues identified above, there are fault level and system stability matters that specifically relate to large generator connections.

6.6 Strategies to meet the demand growth

Depending on the magnitude and the criticality, Western Power uses various short term, medium term, long term or a combination of strategies to resolve issues caused by demand growth. The selection of an optimum strategy is based on a cost benefit analysis of available options.

6.6.1 Short term strategies

Load transfer: When the existing assets are forecast to be overloaded due to the demand growth, the possibility of reducing the utilisation by transferring the demand to another node is considered.

Reactive power compensation: Local reactive power compensation can improve the available capacity of transformers, transmission lines and distribution feeders. Such capacity relief can then be used to supply new demand. Therefore, when assets are forecast to be overloaded, reactive power compensation may be considered as a short-term strategy where feasible.

6.6.2 Medium term strategies

Transformer augmentation: When the existing transformers are forecast to exceed their acceptable utilisation limits, the option of adding a new transformer and switchboard to spare bays in existing zone substation sites or replacing with higher capacity transformers is considered to prevent the overload.

Line/cable upgrades: Capacity on the network may be increased by upgrading of existing conductors or cables.

New feeders: When the capacity constraints are identified in the distribution feeders, the establishment of new feeders is considered to alleviate utilization problems.

6.6.3 Long term strategies

New substations and transmission line installations: In the areas where demand growth is high and existing substations are heavily utilised consideration is given to the construction of a new substation. This level of augmentation allows for the transfer of load from heavily loaded circuits/assets to the new substation.

New lines: When medium term strategies are deemed ineffective, construction of a new line is considered to reduce the utilisation.

6.7 Demand management strategies

Demand side management (or non-network solutions) can be used as a short and medium term solution to alleviate network capacity issues such as high asset utilisation.

Western Power has commissioned five technical trials under the Smart Grid foundation project[11]. The trials are:

Smart metering trial: Western Power has installed approximately 9000 meters in the metropolitan area and 2000 meters in rural areas.

Direct load control (DLC) trial: This trial, due for completion by summer 2011/12, includes up to 350 air conditioners.

PV saturation trial: It is proposed to investigate a 30% penetration of PV on a single distribution transformer in this trial. The impact of high penetration of distributed PV systems on the performance of the network will then be monitored. Western Power plans to commence this trial in 2011.

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11 Further detail of the Smart Grid project is included in Section 5.

Heating, ventilation and air conditioning (HVAC) trial: Western Power has conducted a trial of active control of heating, ventilation and air conditioning load in a City of Perth building.

Energy edge: This trial aims at providing alternative power supply options to the customers located at the network's fringe.

In addition to these trials two Edge of Grid projects Ravensthorpe II and Green town (Denmark and Walpole) have been conducted to address specific issues associated with two remote supply areas.

6.8 Environmental approval process

Western Power is an environmentally responsible business committed to sustainable development and minimising the environmental impact of the network. Obtaining environmental approval is mandatory before initiating any development project that has a potential environmental impact.

Western Power's environmental approval process is shown in Figure 6.2.

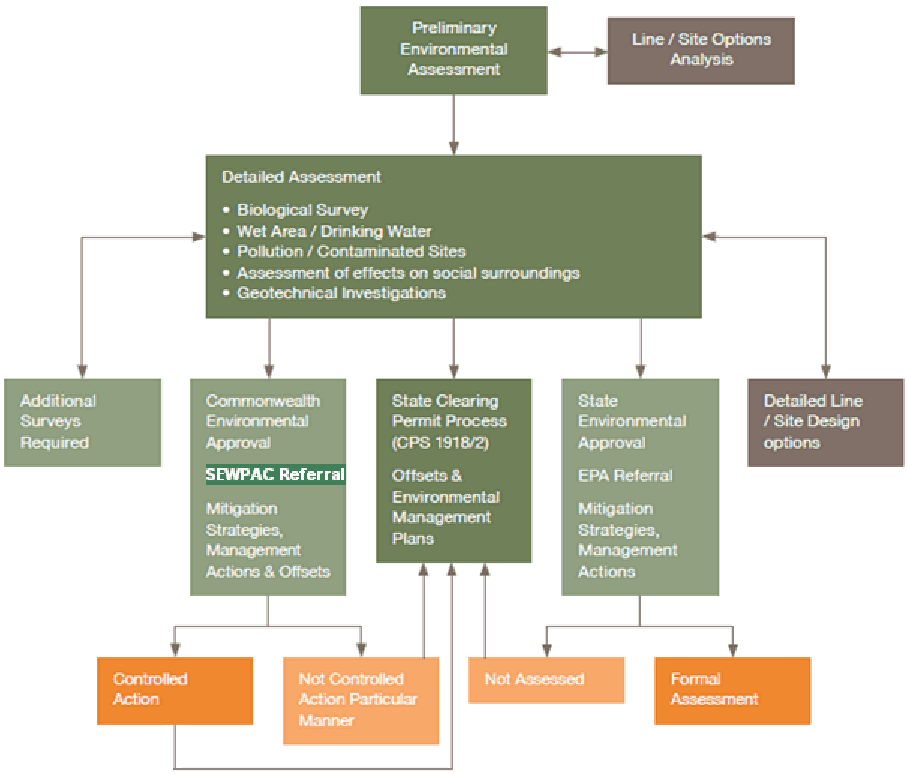

Figure 6.2: Environmental approval process

6.9 Growth related network developments

The major transmission and distribution projects for each load area are described in the Transmission and Distribution Annual Planning Report (APR).

7 Life Cycle Management Plan (Non-Growth)

This Chapter:

- profiles the transmission and distribution network to individual asset classes;
- presents the salient issues that management of these asset classes face; and
- presents corresponding maintenance, replacement and refurbishment strategies to meet the required service levels and network objectives.

It is presented in the form of individual Life Cycle Management Plans (LCMP) for each of the network asset classes.

7.1 Asset Management approach

Network assets are managed as "Run to Fail" or "Non – Run to Fail". The rationale for asset management approach adopted for a particular asset is summarised in sections 4.6, 4.7 and 4.8 of this document.

In adopting this approach for the 41 asset classes: 19 asset classes are managed as Run to Fail and 22 as Non-Run to Fail. Figure 7.1 and

Figure 7.2 provide a diagrammatic overview of this classification.

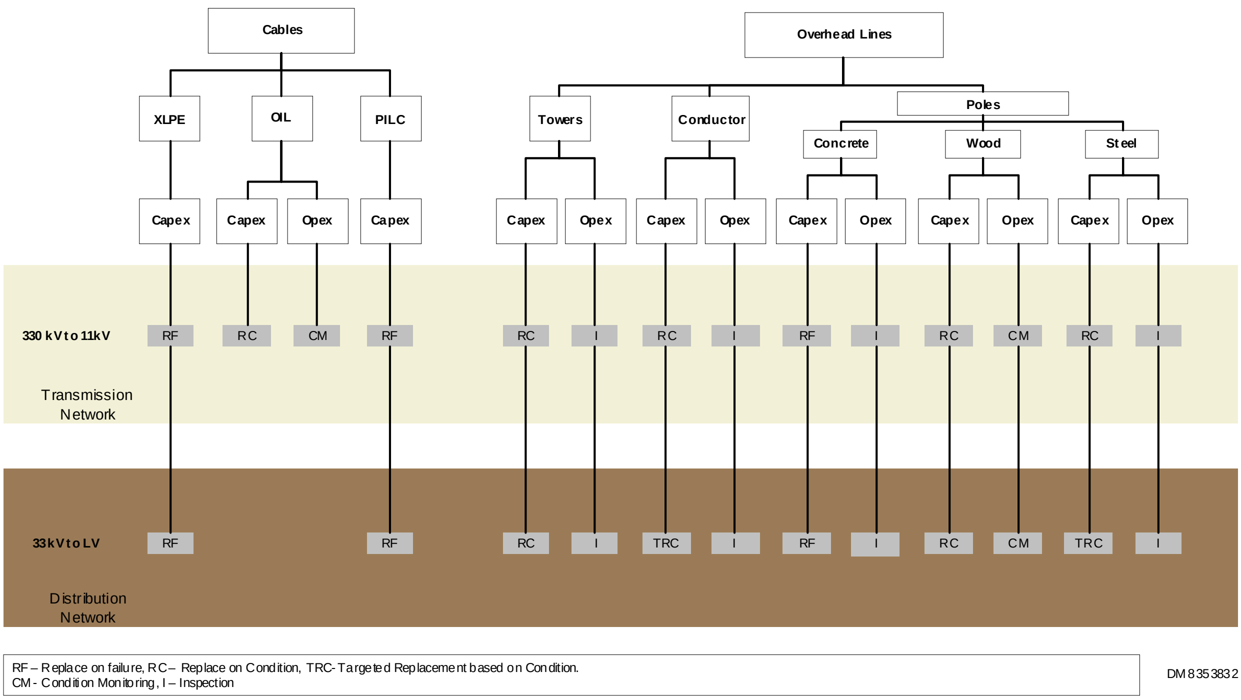

Figure 7.1: Asset management summary – Cables, towers, conductors and poles

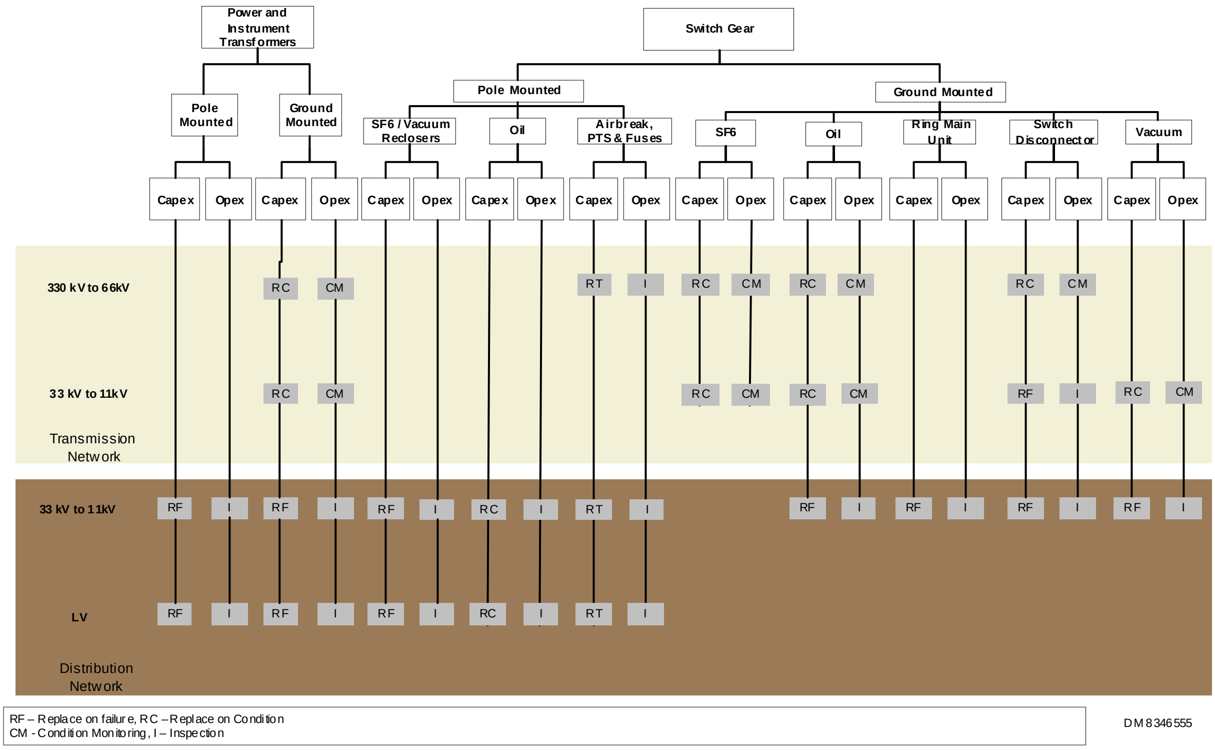

Figure 7.2: Asset management summary – Switchgear and Power & Instrument Transformers

7.2 LCMP for Run to Failure Assets

The RTF assets are managed using an approach that involve inspection of:

Assets as part of a larger inspection activity (line or substation) which are generally orientated towards identifying safety hazards:

- where no safety hazard is identified the asset is allowed to remain in service until it fails; and
- where a safety hazard is identified, it is corrected as an operational cost to the network. However if it was ascertained that the safety defect was part of an inherent problem affecting the whole of the assets population, then a programme to rectify this issue across the whole network is instituted (e.g. – overhead service connection replacement – “twisties” progam).

A list of the RTF assets is shown in Table 7.1.

Table 7.1: Run To Failure assets

Equipment Type	Equipment Code	Population
Circuit Breaker Disconnectors (Distribution)	CBDC	1,656
Circuit Breakers HV (Distribution)	CBHV	1,577
Cable Joints (High voltage)	CBJH	20,217

Equipment Type	Equipment Code	Population
Cable Joints (Low voltage)	CBLV	151
Disconnector (Low voltage overhead)	DILV	29,473
Under ground Disconnector	DISU	33,994
Distribution Transformer ≤ 300 KVA	DSTR	53,046
Fault Indicator	FLTI	1,641
High Voltage Customer Switch	HVCS	500
Isolating Transformer	ISTX	271
Kiosk	KISK	5,823
Load Break Switch	LBS	306
Non Load Break Connector	NLBC	23,809
Overhead Stay	OHST	29,644
Pillars	PILL	253,469
Power Quality Customer Meter	PQCS	39
Regulating Transformer	RGTR	349
Streetlight Control Box	SLCB	2,942
Unmetered Point of Supply	UMPS	13,207

7.3 LCMP for N-RTF assets

Each of the N-RTF asset categories has an LCMP which are set out in the remainder of this section of the NMP.

7.4 Transmission Substations

This section discusses the asset management plan for transmission terminal stations and zone substation fencing, buildings, grounds and earthing. Primary assets such as power transformers, switchgear and secondary systems (protection and communications equipment) are not covered under Transmission Substations and are discussed elsewhere in this Chapter.

7.4.1 Asset Description

The transmission network includes terminal stations and zone substations. Terminal stations and zone substations operate as voltage conversion stations transforming high voltages to lower voltages for distribution to customers and also as switching stations on the high voltage network.

Substation Fencing, Buildings and Grounds: All Terminal stations and the majority of zone substations contain mostly outdoor installations. With the exception of 2 Central Business District (CBD) zone substations of

Hay Street and Milligan Street that are indoor, multi-storey substation sites. The substation assets include:

Boundary Fence - boundary fences and gates are typically constructed of chain-mesh, palisade, weldmesh or masonry as shown in Table 7.2;

Table 7.2: Fence Types

Fence Type	Terminals	Zone S/S	Total
Chain-mesh	15	108	124
Chain-mesh / Electric	2	1	3
Chain-mesh / Beams		1	1
Weld-mesh	3	5	8
Weld-mesh / Electric	1		1
Palisade	3	2	5
Building		2	2
Masonry Wall		6	6
Total	**24**	**125**	**149**

- Buildings - buildings are a mixture of brick/concrete buildings and portable metal framed / clad buildings and are generally employed as amenity rooms (including toilets), relay rooms, control rooms, battery rooms or switch-rooms; and

- Roads, sewerage and drainage – bitumen and gravel roads, underground sewerage and underground drainage systems are part of the substation asset.

Earthing: Each terminal station and zone substation has an earthing system. The earthing system consists of the earth grid, operator earth mats, grading rings, earth electrodes, earth straps, earth switches, earth braids and portable earths. The earthing system is an essential safety system required to mitigate step and touch potential during transmission system earth faults. It also helps ensure fast short circuit protection relay operations to protect and isolate substation primary plant during short circuit to earth faults.

7.4.2 Failure modes and impacts

Failure of fences can result from deterioration of the fence condition, vandalism or unauthorised entry to the terminal station or substation. Typical defects include broken fence posts and holes in fences. Unauthorised site access can result in electrocution of members of the public, as well as leaving critical assets vulnerable to vandalism and theft.

Failure of buildings typically involves inadequate retaining walls and building structural defects which can result in exposure of equipment to the environment resulting in damage to the equipment and potentially network outages.

Failure of drainage systems can lead to environmental damage as drainage systems are designed to retain oil in the case of an oil spill.

Failure of earthing systems can result in safety risks (through step and touch potential and through failure of protection systems to operate correctly) and can lead to equipment failure resulting in network outages.

7.4.3 Age and condition

Proactive civil and structural assessments of terminal station and zone substation sites have not been undertaken. However, as conditions are identified during inspections, switching operations or at the scoping phase of project works corrective action is undertaken.

Conditions identified to date include:

- Switch-rooms not compliant to current Australian or Industry Standards, found during the planning of the switchboard replacement project;
- Poor condition of boundary fences following a security assessment of sites, conducted by a security consultant (GHD).
- Hazards in terminal and zone substation sites following an asbestos audit conducted by expert consultants (PB Power); and
- Potential substation earthing issues. Due to substation fault levels increasing over the years and improvements in design it is expected that upgrades of many earthing systems may be required. Studies are planned to quantify the necessary work.

The expected life differs for each of buildings, fences, roads and drainage systems. The maximum tenable age of the substation sites is typically 55 years.

7.4.4 Performance level

Substation Fencing: Performance is monitored by the number of unauthorised access incidents as shown in Table 7.3. Safety incidents and defect reports related to the terminal station and zone substation sites are also monitored.

Table 7.3: Substation fences and buildings performance targets

Performance measure	Target	Annual Performance (average 2006-2010)	Performance gap
Number of unauthorised acces incidents	0	72	72

Currently, there is a significant gap between actual and required performance increasing the likelihood of electrical shock incidents and the potential for a fatality. The key issues that contribute to the excessive number of unauthorised access incidents into substations are:

- Inadequate fence design (built to old standards which are now deemed inappropriate);
- Poor fence condition; and
- Inadequate signage and locking systems.

7.4.5 Asset management issues and strategies

Asset creation: The current practice for construction of new terminal station and zone substation fencing, buildings and grounds for outdoor substations includes a weldmesh boundary fence, metal framed and clad portable relay rooms and switch-rooms, bitumen roads, and deep sewerage and drainage. Indoor CBD substations are multi-storey concrete buildings.

The strategy for construction of new earthing systems is to undertake detailed computer modelling of step and touch voltages in conjunction with field earth resistivity tests and to earth any metal boundary fences. Where terminal and substation expansion/augmentation projects are undertaken, the earthing systems are upgraded to current standards.

Asset maintenance: A cyclic (monthly) inspection program covering all sites has been established to report condition of assets within substations, (buildings, roads and drainage systems). Corrective maintenance is performed where issues are identified.

Regular maintenance is carried out where vegetation such as grass, shrubs and trees are within the substation site for safety and aesthetic reasons.

7.4.6 Overview of planned works

Planned works associated with management of transmission substations are discussed in Table 7.4.

Table 7.4: Summary of strategies

Issue	Strategy	Planned/Frequency
Public and staff safety issues related to unauthorised entry into substation sites resulting in damage to fencing, vandalism or theft of property	Review of existing security systems in light of latest developments and formulate a long term strategy to address security risks	Complete formal review of long term strategy and commence implementation by December 2012
	Inspection program for all sub-stations and subsequent rectification of faults including inadequate signage and locking systems	Daily/Monthly inspection and rectification as required
	Where fences do not comply with latest design standards, are in poor condition and unauthorised access incidents have occurred – replace fencing with current standard weldmesh, palisade or masonry fencing.	Upgrade or replace the fences at 4 terminal stations or zone substations each year to bring them to latest design standard
Conditions and compliance of substation buildings	Optimise investment by replacing buildings at the same time as other asset replacement work	Replace non compliant switchroom's when associated switchgear is replaced
Asbestos and other hazardous materials at substation sites	Undertake targeted replacement programs	Remove or make safe hazardous material over a 20 year period
Unknown condition of terminal and substation earthing systems	Review current substation earthing strategy. Undertake targeted project to review status of earthing systems	Complete condition assessment of substation earthing systems by 2016/17. Implement remedial actions starting in 2013/14 or earlier.

When terminal and substation works such as fence replacement is undertaken, opportunities to integrate the works with other works such as noise mitigation works, the installation of transformer bunds and the like are identified. This will result in an optimum cost solution that addresses a range of issues identified for a particular site.

Figure 7.3 shows the forecast volume of substation sites targeted for fencing upgrades or replacement.

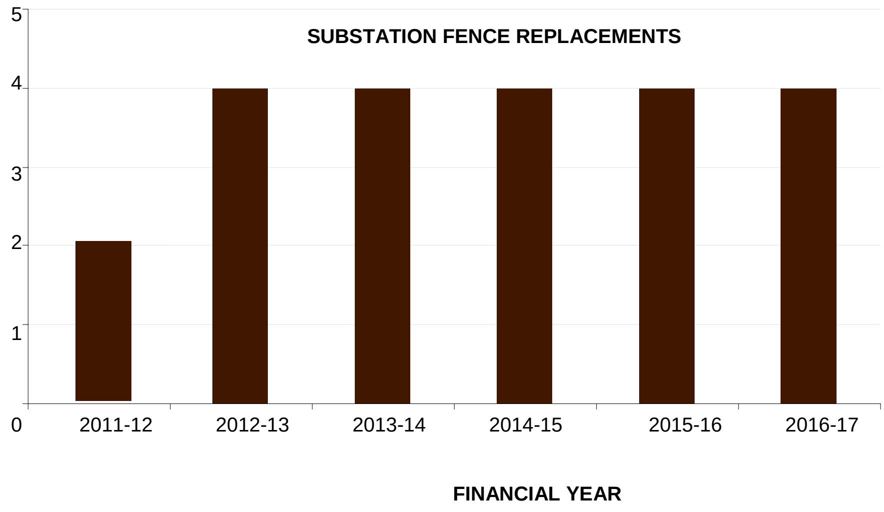

Figure 7.3: Forecast terminal station and zone substation fence upgrade/replacement volumes

7.5 Transmission Power Transformers

This section discusses the asset management plan for transmission power transformers.

7.5.1 Asset Description

Power transformers are major substation assets that operate to transform electrical voltage from one level to another. They are often fitted with an on-load tap changer (OLTC) which is used to maintain voltage levels within the required standards on the sub-transmission and distribution networks.

The transmission power transformer fleet includes:

- 339 in-service transmission power transformers;
- 7 strategic spare transformers; and
- 4 rapid response transformers.

Power transformers are located at terminal and zone substations throughout the network. Primary transmission voltages range from 330 kV to 33 kV and secondary voltages from 33kV to 6.6 kV. Transformer capacity ranges from 1 MVA up to 490 MVA. Table 7.5 and Table 7.6 show the power transformer population categorised by manufacturers, capacity and primary voltage level.

Table 7.5: In-Service power transformer population by capacity and primary voltage

Manufacturer	Capacity (Mva)	Primary Voltage						Total
		22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	
Pauwels	10-20		1					1
	30-40			1	4			5
	60				4			4
	100				1			1
VA Tech	30-40				41			41
	490						7	7
Wilson	1-10			1				1
	10-20				1			1
	20-30				1			1
	30-40			6	36			42
	100				1			1
Westralian	1-10		3	8				11
	10-20		4	21	10			35
	20-30		2	20	39			61
	30-40			5	25			30
	40-50				2			2
	60				4			4
Other	1-490	1	2	32	39	10	7	91
TOTAL		**1**[12]	**12**	**94**	**208**	**10**	**14**	**339**

[12] Associated with the Distribution network

Table 7.6: Spare transformer population by capacity & primary voltage

Manufacture	Capacity (Mva)	Primary Voltage		Total
		66 kV	132 kV	
Pauwels (Rrst)	33	1	1	2
Wilson (Rrst)	33	1	1	2
A E I	5	1		1
Electro Mekano	14	1		1
Tyree	5	1		1
	30	1		1
Westralian	13	1		1
	27		2	2
TOTAL		7	4	11

7.5.2 Failure modes and impact

Since 1997, 15 major failures have been recorded for power transformers. Root cause analysis of these failures has been undertaken and is shown in Figure 7.4 below. The primary causes are due to movement of the translate winding and tap changer failure.

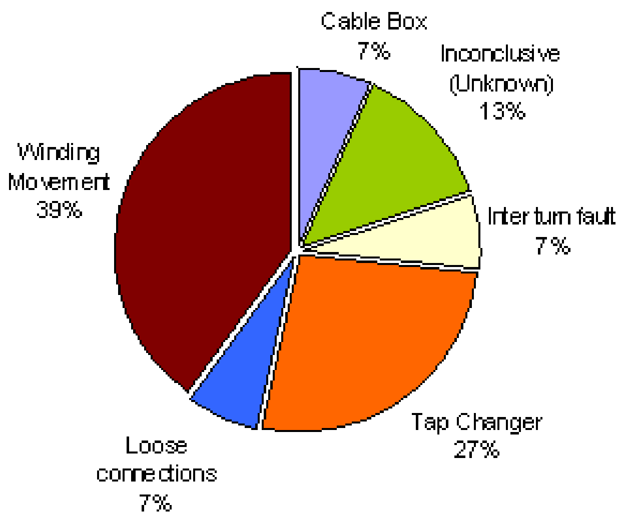

Figure 7.4: Major transformer failures (since 1997)

Failure of a power transformer unit can have major impact on network reliability. Depending on the nature of failure, failures can also result in major environmental damage (oil leaks) and/or safety incidents (catastrophic failure leading to fire).

7.5.3 Asset age and condition

A “Health Index” to categorise the condition of power transformers is utilised. Results from routine condition assessments form the main input to the health index.

The health index includes:

- Results of dissolved gas analysis;
- Results of high voltage testing;
- Defects history;
- Level of loading and utilization; and
- Risk

Depending on the outcome of the health index, transformers are placed into one of four categories: Good, Fair, Poor or Bad. The number of transformers assessed in each category is shown in Figure 7.5.

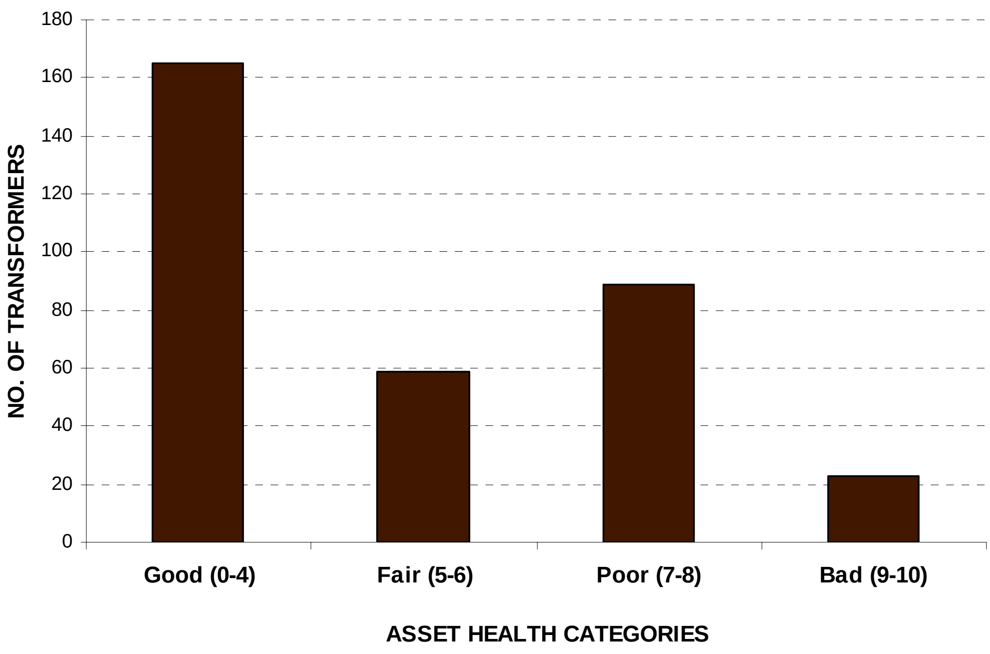

Figure 7.5: Power transformer condition rating

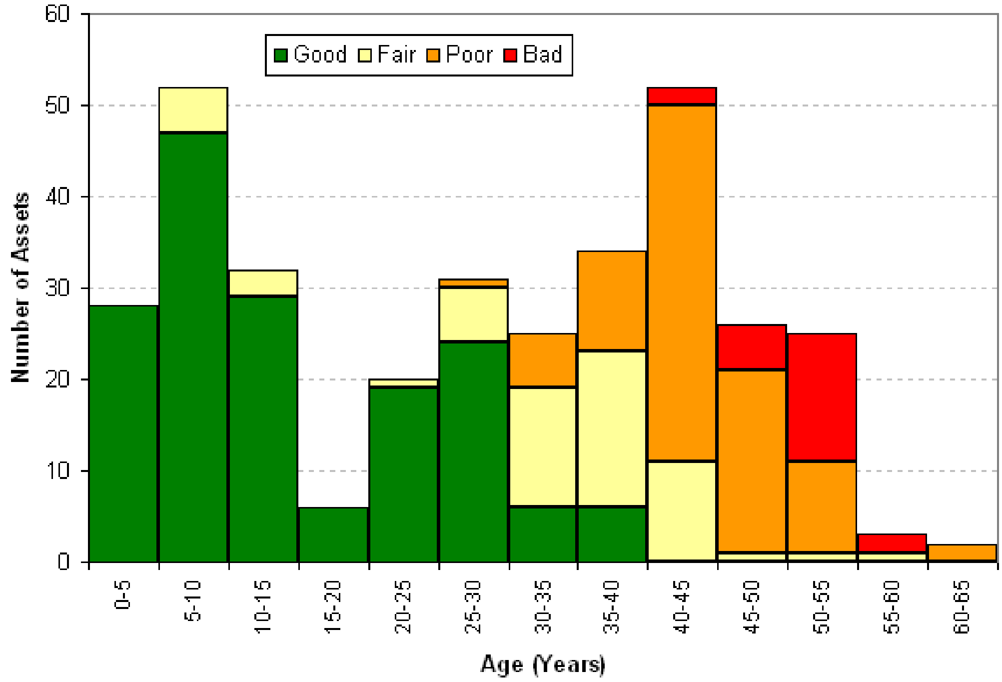

Figure 7.6: Power transformer age profile (condition assessment without influence of age)

The condition and age assessment shown in Figure 7.6 highlights the strong correlation between age and condition. Almost all transformers less than 30 years are in “Good” condition. The majority of transformers around 40 years old or greater are in “Bad” or “Poor” condition. As the transformers age, the proportion of the population in “Bad” condition is seen to increase. The figure shows that over half of the transformers older than 50 years are in “Bad” condition. In total, 7% of power transformers (24 units) are in “Bad” condition.

The volume of transformers approaching 50 years old is increasing and it can be expected that a high proportion of transformers that exceed 50 years will be in “Bad” condition. This indicates that the volume of transformers that will need to be replaced is likely to increase significantly in future.

7.5.4 Performance Level

Performance of power transformers can have an impact upon supply reliability, security, power quality (voltage), Occupational Health & Safety issues, and create environmental issues. With regard to environmental issues, specific obligations for oil containment and fire protection arise from AS 2067-2008. The obligations are to contain the oil in the event of an oil spill and to separate transformers containing a defined volume of oil (to prevent the spread of fire). Specific performance criteria have been agreed with Department of Environment and Conservation (DEC) requiring the mitigation of transformer noise.

The primary indicators, targets and current performance of power transformers are summarised in Table 7.7.

Table 7.7: Power transformer performance requirements

Indicator	Target	Performance 2010/11	Performance gap
System Minutes Interrupted (contribution per annum)	Meshed: ≤ 1.01 Radial: 0	Meshed: ≤ 1.01 Radial: 0	No gap
Failures per annum (requiring replacement or major repair)	≤ 1 failure	1	No gap
Health Index (of individual units)	No. transformers in "Bad" condition	93% compliance	7% (24 units)
Compliance with EPA noise regulations	100% compliance	86% compliance	14% (19 substations)
Compliance with fire separation requirements of AS 2067	100% compliance	83% compliance	17% (23 substations)

While the majority of power transformers are largely compliant with performance requirements, 7% of the population is classed as being in "Bad" condition (score ≥9) and do not comply with the condition score target. Hence, corrective maintenance or replacement actions are required.

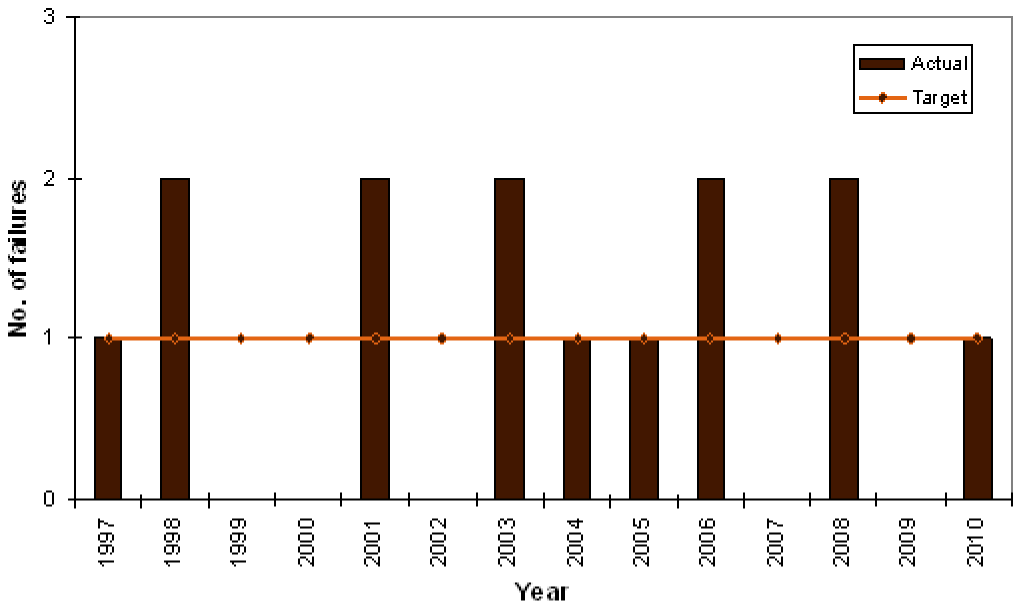

Figure 7.7: Unplanned power transformer failures

Figure 7.7 shows the number of major transformer failures[13] that have occurred since 1997. At least one unplanned transformer failure has been sustained each year with the latest at Yokine substation in January 2011. The transformer fleet has failed to achieve the targeted performance level 36% of the time since 1997.

The performance gap relating to regulatory requirements is:

- 14% (19 of 135) transmission substations do not comply with noise requirements;
- 50% (68 of 135) substation installations do not comply with oil containment requirements; and
- 17% (23 of 135) substation installations do not comply with Fire protection requirements.

7.5.5 Asset management strategies

Routine and targeted maintenance (including condition assessment) and replacement of transformers before failure are the key strategies adopted to manage transmission power transformers. Additionally, several strategies have been adopted to improve compliance with regulations relating to the environment (oil), noise and fire suppression.

Asset maintenance

Routine, preventive and corrective maintenance is carried out on all power transformers. Preventive routine maintenance includes inspection and testing to assess the condition of transformers. Details of the maintenance regime are contained in Power Transformer Maintenance Criteria.

Spares strategy

In addition to the power transformer maintenance and replacement strategies, a spares strategy to adequately respond to an unplanned power transformer failure has been developed. The spares strategy provides an optimised ‘quick fix’ long or short term solution given power transformer failure can affect a large customer numbers and have a long lead time and result in potentially long duration outages.

The spares strategy involves installation of one of the 7 strategic spare units or the temporary installation of one of the 4 rapid response transformers (RRST) upon a transformer failing. A failed transformer is either repaired or replaced. An RRST is deployed based on substation loading circumstances and the need to restore supply immediately.

RRSTs are designed for rapid connection. They are not suitable for long-term deployment. As they can be deployed quickly, restoration can be achieved within 12 hours of the transformer failure. Following deployment of an RRST the failed transformer is either repaired or replaced.

13 Failure requiring replacement or major repair

7.5.6 Overview of power transmission transformer asset management plan

Table 7.8: Issues and strategies for power transformers

Issue	Strategy	Planned/Frequency
24 transformers are in "Bad" condition.	Additional monitoring and/or maintenance. Refurbishment (Normally considered for the power transformers less than 35 years of age.) Replacement where condition assessment indicates that replacement is required and none of the other treatments mentioned are viable.	Maintain and test 70 power transformers per annum. Replace 16 "bad" condition transformers in the 2011/12 to 2016/17 period. 10 will be replaced on a like-for-like basis whilst the remaining 6 as part of network growth.
High oil moisture content affects approximately 20 power transformers (6%) and contributes significantly to the condition assessment classification in the "Poor"/"Bad" categories.	Replacement of power transformers with high moisture content. Oil dry out.	Replace 8 transformers with high moisture content in the 2011/12 to 2016/17 period. Dry out four transformer units per annum in the 2011/12 to 2016/17 period.
Potential oil spill - approximately 50% of the power transformer installations do not comply with AS 2067-2008. This standard requires that every installation containing more than 500 litres of a liquid dielectric (i.e. insulating oil) shall have provision for containing the total volume of oil in the event of a leakage that could otherwise cause environmental damage.	Installation of new transformer bunds.	Installation of new bunds at 20 substations in the 2011/12 to 2016/17 period.
Transformer noise - approximately 14% of power transformer installations (more than 50 transformers) exhibit noise levels that do not meet the required EPA service level.	Noise assessment and where compliance is not achieved, implement noise mitigation treatments.	Mitigate the noise at 9 substations in the 2011/12 to 2016/17 period.
Fire containment - approximately 17% of power transformers do not comply with the fire-separation requirements of AS 2067-2008.	Build fire separation barriers, depending on site specific circumstances and considering criticality of the units, and overall risk.	Install fire separation barriers (firewalls) at 5 substations in the 2011/12 to 2016/17 period.

Issue	Strategy	Planned/Frequency
Type issue – 29 132/22 kV Westralian transformer purchased in 1970s experience winding movements due to improper clamping during manufacturing.	Schedule transformers for reclamping based on the severity of the situation and the criticality of the unit within the system.	Re-clamp two units per annum in the 2011/12 to 2016/17 period.
Type issue – affecting Reinhausen type BC and C tap changers. This affects approximately 25% of the transformer fleet.	Replace transformer with type BC or C tap changer based condition assessment. Increase the maintenance frequency of power transformers with type BC or C from 4 to 2 ½ years.	Repair/replace 3 transformers with type BC or C tap changers in the 2011/12 to 2016/17 period.

Before any transformers are replaced, analysis of scope efficiencies that can be gained through integration with other substation projects or capacity upgrading plans is conducted. This analysis is used to help identify the replacement timing.

Figure 7.8 shows the power transformer replacement volumes planned over the period 2011/12 to 2016/17. This includes transformers that will be replaced as part of a capacity or voltage upgrade programs.

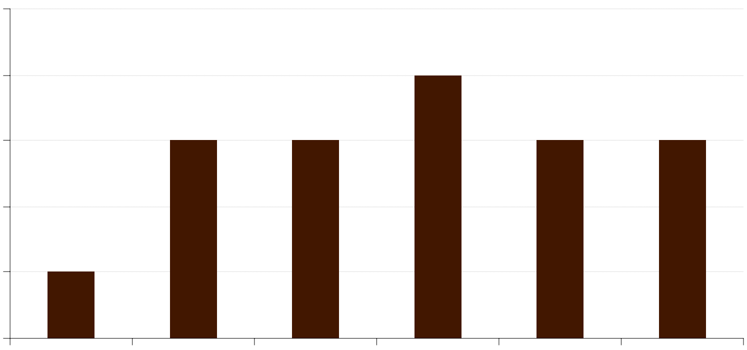

Figure 7.8: Replacement Volumes of Power transformer

7.6 Overhead Conductors

This section discusses the asset management plan for transmission and distribution overhead conductors. The towers, poles and insulators that support transmission lines are not included in this asset category.

7.6.1 Transmission Overhead Conductors

Asset Description Transmission overhead conductors and accessories for overhead line circuits such as clamps, ties, vibration dampers and terminations, operate at voltages greater than 33 kV. The conductors enable the transfer of power from generator sources to load centres. Conductors at or below 33 kV are defined as distribution and are covered in another asset category. The overhead transmission network consists of 254 circuits as shown below.

Voltage	Number of circuits	Total circuit length [km]
330 kV	21	1,076
220 kV	6	851
132 kV	160	4,576
66kV	67	1,235
Total	**254**	**7,738**

Of the four types of overhead conductors used on the transmission network, two types comprise 98 per cent of this asset. They are the Aluminium Conductor Steel Reinforced (ACSR) and the All Aluminium (AAC) and All Aluminium (Alloy) Conductor (AAAC). They are used depending span length and the type of environment in which they will operate. Table 7.20 shows the make up of the overhead network by conductor type.

Table 16: Transmission overhead conductor population

Carrier Type	% of Population	330 kV	220 kV	132 kV	66 kV	Total Circuit Length (km)[14]
ACSR – Aluminium Conductor Steel Reinforced	81%	717	846	3747	990	6,300
AAC & AAAC – All Aluminium & All Aluminiun (Alloy) Conductors	17%	359	5	807	141	1,312
SC/AC, SC/GZ – Steel Conductor Aluminium Clad Galvanised	0%	0	0	0	2	2
Cu – Copper Conductor	2%	0	0	22	102	124
Total	100%	1,076	851	4,576	1,235	7,738

14 Circuit length (km) is the length in kilometres of a transmission circuit. Single or multiple circuits may be supported on the same support. A double circuit line would have two circuit kilometres per route kilometre.

7.6.2 Failure modes and impacts

Typical defects experienced on the transmission overhead conductor system are:

- Broken or deteriorated strands due to ageing/fatigue, corrosion, or lightning strikes corrosion;
- Bird caging[15] of the strands; and
- Conductor accessory degradation such as clamps, ties, vibration dampers and terminations.

These defects can lead to overhead conductor or accessory resulting in wires down incidents, which in turn has the potential to create:

- safety impacts by causing electric shocks, serious injury or fatalities;
- property damage due to ignition of bushfires;
- damage to the environment; and
- outages affecting large number of customers.

7.6.3 Age and condition

The design life of transmission conductors is 60 years. However, the actual in-service life can be affected by:

- Quality of the design and construction;
- Loading and utilisation over the life time;
- Maintenance practices; and
- Environmental (installation) conditions.

The overall age profile of conductors by voltage is shown in Figure 7.9.

[15] Bursting of the strand formation.

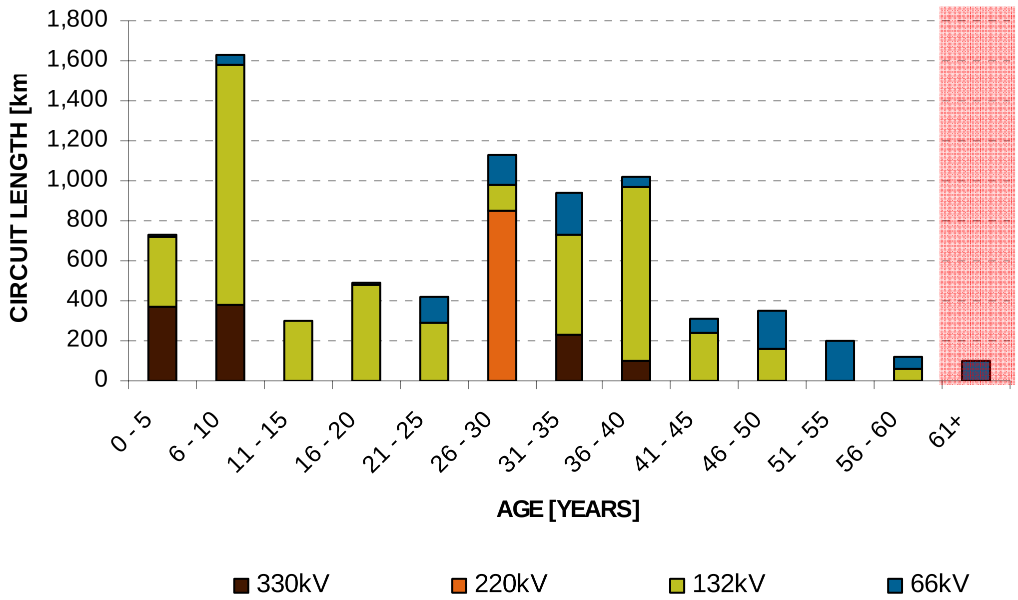

Figure 7.9: Age profile of overall transmission overhead conductors

- Approximately 70% of 330 kV conductors are less than 10 years old. The rest is 30-40 years old. The conductors and line fittings are in good condition and do not show any signs of early age decline.
- All 220 kV conductors are between 26-30 years old. The conductors and line fittings are in good condition and do not show any signs of early age decline.
- The 132 kV network comprises the largest proportion of the Western Power transmission network. Some 98.7% (4,576 km) of conductor is less than 50 years old. A small quantity (59 km) of conductor is approaching 60 years old. Defects such as broken strands or conductor corrosion and vibration damper deterioration are evident conductor.
- Although only a small amount (75 km) of conductor has been installed on 66 kV network in the last 20 years, the defect rate has been relatively low. About 8% (102 km) has just exceeded 60 years age with a further 21% (260 km) expected to reach or exceed this age in the next 10 years. About 95% (1160 km) the conductor on the 66 kV network is more than 31 years old

7.6.4 Performance Level

Three indicators are used to measure the performance of transmission overhead conductors as shown in Table 17.

Table 17: Transmission overhead conductor performance requirements

Indicator	Target	Performance 2010/11	Performance gap
Number of defects	No increasing trend i defect volumes	No increasing trend in defect volumes	No gap
Number of conductor failures	No increasing trend i failure volumes	No increasing trend in failure volumes	No gap
Compliance with regulations	Clearance of all conductors at or greater than level specified in regulations	Clearance of all conductors at or greater than level specified in regulations	No gap

Standard AS 6947 – 2009 defines the requirements for the crossing of waterways by electricity infrastructure. Previously there were 19 non-compliant transmission river crossings. The program to increase the height of the conductors over the waterways was completed in June 2011 and all waterway crossings are now compliant.

Only 1 wire down incident has occurred in the past decade (June 2009) due to a crimp connection failure. There have been 4 other incidents of conductor damage due to external forces such as vegetation interference during a storm, car versus pole, and cross-arm failure.

The overall risk of transmission conductors failing is assessed as a Medium risk.

7.6.5 Asset management issues and strategies

Asset creation

Transmission overhead conductors are selected to meet rated current, short circuit capacity, desired voltage drop and installation /environmental conditions. The preferred conductor types are ACSR, AAC and AAAC, with AAC and AAAC used in the metropolitan area and in corrosive environments.

Asset maintenance

Transmission conductors are routinely inspected to monitor condition and identify defects. Routine inspection is carried out from the ground in populated areas and by helicopter in rural areas.

Defects are identified, categorised and then prioritised for repair based upon safety, fire and supply risk. Timeframes for repair for each priority category are defined.

Table 18: Issues and strategies for transmission overhead conductors

Issue	Strategy	Plan/ Frequency
8% (102 km) of 66 kV conductor is beyond the 60 year design life. Another 21% (260 km) will reach or exceed this age in the next 10 years.	Continue routine condition monitoring. Intervene as defects become more prominent.	Carry out routine inspection. Apply Preventative Maintenance Policy requirements.
A small quantity (59 km) of 132 kV conductor is approaching its 60 year design life.	Continue routine condition monitoring. Intervene as defects become more prominent.	Carry out routine inspection. Apply Preventative Maintenance Policy requirements.
132 kV conductor exhibiting broken strands, corrosion and vibration dampers deterioration defects.	Continue routine condition monitoring. Intervene where the defects become more prominent.	Carry out routine inspection. Apply Preventative Maintenance Policy requirements.
In corrosive (coastal or industrial) environments, the inner steel strands of ACSR can rust and sometimes this cannot be picked up by visual inspection.	Apply non-destructive magnetic testing (ATTAR) with remote control equipment to detect loss of galvanising of the steel strands.	Inspect 5-yearly. Target all ACSR conductors
No structured ground clearance review process.	Assess need and recommend approach.	Implement strategy

Overview of plan

The graph below shows the volumes of planned preventive maintenance that will be carried out on transmission overhead lines in AA3.

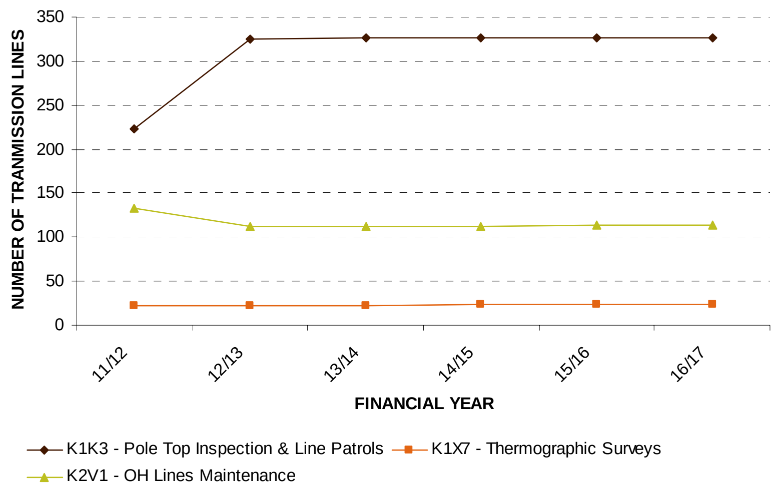

Figure 7.10: Planned volumes of transmission line preventative maintenance

No transmission overhead conductors are planned for replacement in AA3.

7.6.6 Distribution Overhead Conductors

Asset Description Distribution overhead conductors and accessories for overhead line circuits such as clamps, ties, vibration dampers and terminations operate at 33 kV or lower. They exclude Overhead Customer Service Connections and Streetlight Wires – these are discussed elsewhere in this Chapter. The types of overhead conductors used on the distribution networks are shown in Table 7.19.

Table 7.19: Distribution overhead conductor population

Carrier Type	% of Population	Total Circuit Length (km)[16]
ACSR – Aluminium Conductor Steel Reinforced	13%	9,054
AAAC – All Aluminium Alloy Conductor	6%	4,017
AAC - All Aluminium Conductor	16%	11,380
SC/GZ – Steel Conductor Galvanised	52%	36,024
SC/AC – Steel Conductor Aluminium Clad	5%	3,411
Cu – Copper Conductor	7%	5,035
Hendrix Spacer Conductor	0%	4
HVABC	0%	18
LVABC	1%	766
Total	100%	69,710

Historically, galvanised steel conductors were the most commonly used conductor on the distribution overhead networks, especially on the single phase networks. Their high tensile strength enabled conductors to be strung over longer spans, effectively longer distances to supply country areas. Copper and ACSR conductors were installed before the 1990s. Their use has diminished in favour of the aluminium conductors.

7.6.7 Failure modes and impacts

Typical defects experienced on the distribution overhead conductor system are:

- Broken or deteriorated strands due to ageing/fatigue, corrosion, or lightning strikes;

[16] Circuit length (km) is the length in kilometres' of a distribution circuit. The actual conductor length is obtained by multiplying by the number of wires per circuit.

- 'Bird caging'[17] of the strands;
- Arcing or burning from conductor clashing and inadvertent contact with vegetation, vehicles etc;
- Conductor accessory degradation such as clamps, ties, armour rods line taps and terminations; and
- Annealing due to high fault currents.

Wires down defects are separated into assisted and unassisted wires categories.

Unassisted wires down incidents relate to conductor condition and are from:

- Broken or deteriorated strands issues;
- Conductor accessory degradation; and
- Annealing.

Assisted wires down incidents are from external events; excessive wind (greater than design load) during storms, lighting activity, vegetation interference or vandalism.

Physical failure of overhead conductors or conductor accessories can lead to wires down incidents which can cause:

- safety impacts by causing electric shocks, serious injury or fatalities;
- safety impact and property damage due to ignition of bushfires;
- damage to the environment; and
- outages affecting customer supply.

Conductor clashing can initiate fires which may lead to bushfires.

7.6.8 Age and condition

The design life of distribution conductors is 50 years. In-service life, however is dependant on:

- Quality of the design and construction;
- Loading and utilisation over the life time;
- Maintenance practices; and
- Local environmental conditions.

The overall age profile of conductors by carrier type is shown in Figure 7.10.

[17] Bursting of the strand formation

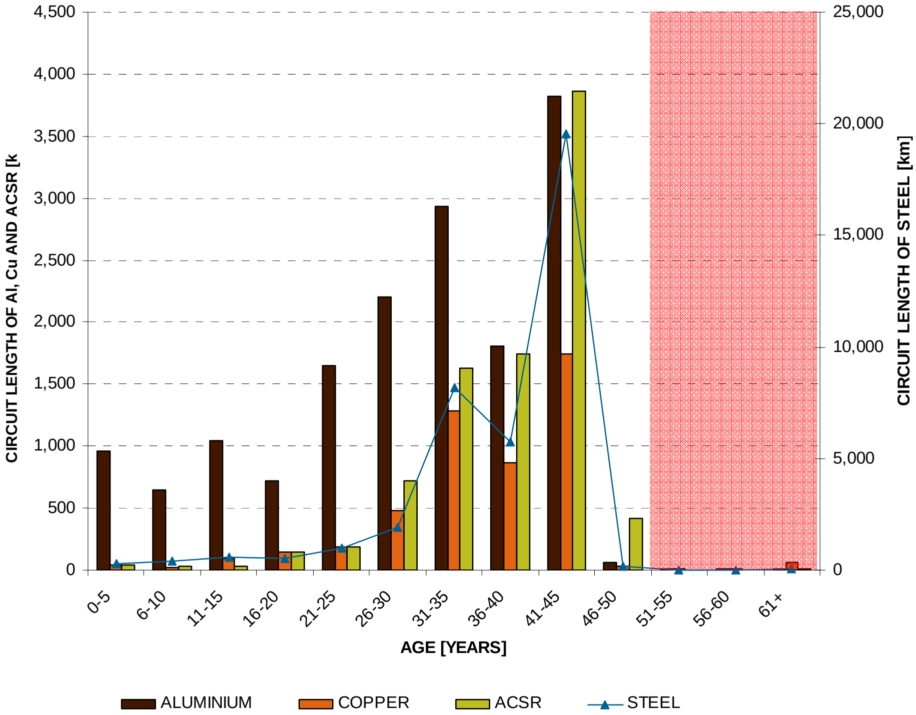

Figure 7.10: Age profile of distribution overhead conductors by type

Currently conductor age is used as a proxy for condition to identify "at risk" conductor. i.e conductors older than 50 years[18]. The age of the conductor is inferred from the pole installation date.

Table 7.20 shows volumes of "at-risk" conductor based upon age of the conductor.

Table 7.20: "At-risk" conductors by age

Conductor type	Conductor older than 50 years "At-risk" [Circuit length km]	Percentage of population "At risk"	Conductor between 40 and 50 years "Emerging risk" [Circuit length km]	Percentage of population "Emerging risk"
Steel	73	0.2%	19,748	51.3%
ACSR	7	0.1%	4,281	48.5%
Aluminium	34	0.2%	3,888	24.5%
Copper	90	1.8%	1,774	35.5%

[18] Conductor condition data at present is limited. Conductor age is therefore utilised as a proxy for condition assessment until further assessment condition data is completed.

7.6.9 Performance Level

Overhead conductor impacts directly on safety and network performance outcomes. The requirements for safety and network performance are established in regulations and in the Access Arrangement.

Table 7.21 shows the performance measure used for Distribution overhead conductor.

Table 7.21: Distribution overhead conductor performance requirements

Indicator	Target	Performance (2010/11)	Performance gap
Number of unassisted wires down incidents	Less than 360 per year	Better than target with improving trend	No gap. Potential future gap with large volume of emerging risk conductors.
Number of fires due to conductor failure	Less than 15 per year	Better than target. But performance trend declining	No gap. Potential future gap if trend continues.
Number of fires due to conductor clashing	Less than 4 per year	Better than target But performance trend declining	No gap. Potential future gap if trend continues.
Clearance across roads	100% compliance	76% compliant	Address 8,001 road crossings in AA3 and beyond.
Navigable river crossing compliance	100% compliance	80% compliant	Address 5 known river crossings in AA3 and assess risk of 6 other river crossings.

Table 7.22 shows the past performance of distribution overhead conductors in terms of unassisted wires down incidents.

Table 7.22: Historic performance of unassisted wires down incidents

Indicator	Target	10/11	09/10	08/09	07/08	06/07	05/06	04/05
Number of unassisted wires down incidents	Less than 360 per year	174	214	372	414	190	153	148

The trend in unassisted wires down incidents has been downward. However, there is a large population of conductors falling within the “emerging risk” category (Table 7.23), that could lead to increased wires down incidents. Table 7.23 shows the historic performance of conductors causing fires due to failure and clashing.

Table 7.23: Historic performance of number of fires due to conductor failure and conductor clashing

Indicator	Target	10/11	09/10	08/09	07/08	06/07	05/06	04/05
Number of fires due to conductor failure	Less than 15 per year	9	15	5	6	8	2	1
Number of fires due to conductor clashing	Less than 4 per year	3	11	4	7	7	2	0

These indicators are showing an upward trend.

Conductor clearances over land and waterways are defined in the standards AS/NZ 7000: 2010 and AS 6947 – 2009 respectively. Approximately 24% (8,244 crossings) from a total of 34,042 road crossings are assessed as non-compliant. A total of 243 of these crossings will have been rectified by the end of AA2.

A risk assessment on 50 navigable river crossings has been carried out. Twenty two of these have been assessed as being low risk and not requiring rectification. Of the remaining 28 crossings, 23 will have been rectified by the end of AA2. The remaining 5 crossings will be addressed in AA3. A further 6 river crossings are yet to be assessed for possible inclusion into future works programs.

7.6.10 Asset management strategies

Asset creation : Distribution overhead conductors is selected based on electrical factors such as rated current, short circuit capacity, desired voltage drop, and mechanical factors such as tensile strength and installation conditions. Conductor types for distribution lines have been standardised as shown in the Table 7.24 below.

Table 7.24: Preferred distribution overhead conductors

Situation	Preferred conductor	Reasons
3 ph HV. Metro and towns (bays < 60m)	AAC	Good corrosion performance. Moderate tensile strength
3 ph HV Country areas (bays > 60m)	AAAC	Good corrosion performance. High tensile strength
1 ph HV Country areas (bays > 60m)	SCAC	Good corrosion performance. High tensile strength

3 ph HV heavily vegetated areas	Hendrix Spacer	Insulated so resistant to vegetation or debris related faults
Overhead River Crossings	Hendrix Spacer	Steel centenary wire allows stringing of long spans. Insulation provides a further degree of safety if contact is made with a vessel
LV networks	LVABC	Insulated so resistant to vegetation or debris related faults

Asset maintenance: Preventive and corrective maintenance is carried out on all overhead conductors and accessories. Preventive maintenance involves 4 yearly routine inspections of the conductors and accessories as part of the Power Pole Bundled Inspection program. The program also includes condition-based maintenance to address defects identified through the inspection process. The inspection process findings are used to drive the replacement strategy for conductors and accessories.

7.6.11 Overview of plan

Table 7.25 summarises the issues and strategies for distribution overhead conductors.

Table 7.25: Issues and strategies for distribution overhead conductors

Issue	Strategy	Planned /Frequency
0.3% (211 km) of distribution overhead conductor is beyond the 50 year design life. Some 42.8% (29,188 km) to exceed this age in 10 years.	Continue routine condition monitoring. Repair or replace where the defects become more prominent.	Carry out routine inspection and condition-based maintenance. This is an ongoing program.
In Extreme and High Fire Risk Areas, 16 km of distribution overhead conductor is beyond the 50 year design life. Some 9.5% (6,488 km) will exceed this age in 10 years.	Continue routine condition monitoring. Replace unserviceable items under Bushfire Mitigation Wires Down Program. Bundle work by geographic area and with other works to attain efficiencies.	Replace 1,550 km of poor condition conductor under this program in AA3. This is expected to be an ongoing program at the current investment levels.
In Moderate and Low Fire Risk Areas, 195 km of distribution overhead conductor is beyond the 50 year design life. Some 33.3% (22,700 km) will exceed this age in 10 years.	Continue routine condition monitoring. Replace unserviceable items under Carrier Replacement Program. Work to be bundled by geographic area and with other works, if possible, to attain efficiencies.	Replace 1,073 km of poor condition conductor under this program in AA3. .
13,285 HV long bays will remain in the Western Power network at the end of AA2.	Fix long bays though HV Conductor Clashing program by installing wider cross arms to increase conductor clearance or adding additional pole mid bay to reduce the bay length.	5,724 bays actioned in AA1. 4,966 bays will be actioned in AA2. 8,904 bays will be addressed in AA3. Remaining 4,381 bays will be addressed in AA4.
14,600 LV long bays will remain in Western Power network at the end of AA2.	Address long bays though LV Spreader program by installing spreaders on LV bays longer than 45m to prevent conductor clashing.	22,030 bays will be actioned in AA2. Remaining 14,600 bays will be addressed in first 2 years of AA3.

Issue	Strategy	Planned /Frequency
8,001 (LV and HV) road crossings are not compliant with AS/NZS 7000: 2010 at the end of AA2.	Address non-compliant road crossings under the Substandard Conductor Clearance program. Re-tension conductors where the non-compliance is marginal. Lift conductors on same pole to increase ground clearance. Replace with taller pole as required or underground crossing if appropriate. Prioritise work based upon risk, where highest risk crossings are those that deviate most from the standard and are located on heavy traffic routes.	2,813 road crossings that are non-compliant by less than 0.2m will be rectified under preventative (K2KE) maintenance in AA3. 1,470 road crossings will be rectified under the Substandard Conductor Clearance program in AA3. 3,718 road crossings to be addressed beyond AA3 (in AA4 and AA5.)
The distribution overhead conductor condition data has not been captured in a structured manner.	Carry out a full survey to capture all required data and validate.	Within first 3 years of AA3 period.
5 distribution river crossings are non-compliant with AS 6947 – 2009. Risk assessment for 6 crossing not complete.	Action non-compliant river crossings under the Distribution River Crossings program. Meet compliance by removing the crossing or integrating the crossing into an existing bridge structure. Where this is not possible, lift overhead conductors to clearance standards, or lay an underground cable across the river.	5 crossings to be addressed in AA3. Complete risk assessment for 6 river crossings to possibly include in future work programs.

Figure 7.11 and Figure 7.12 show the volumes of planned capex work that will be carried out on distribution overhead conductors in AA3.

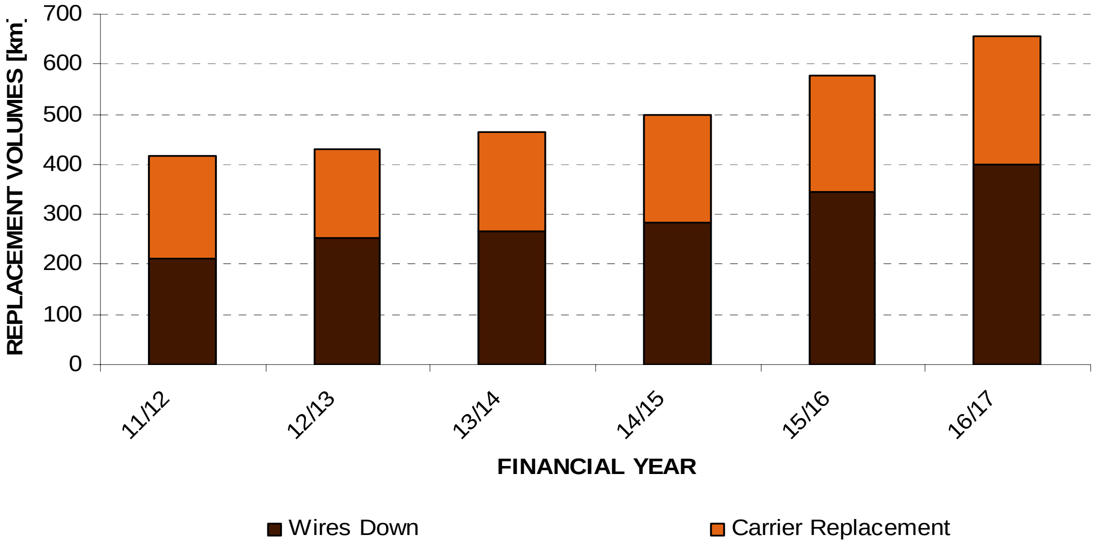

Figure 7.11: Planned volumes for replacement under Wires Down and Carrier Replacement programs

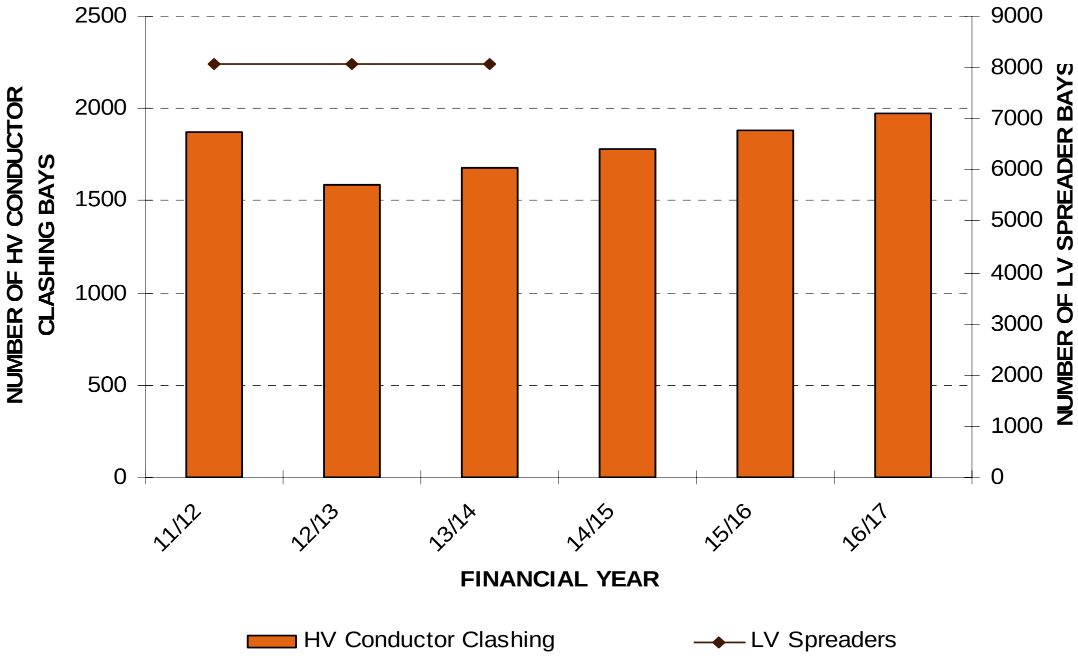

Figure 7.12: Planned volumes for rectification under HV Conductor Clashing and LV Spreaders programs

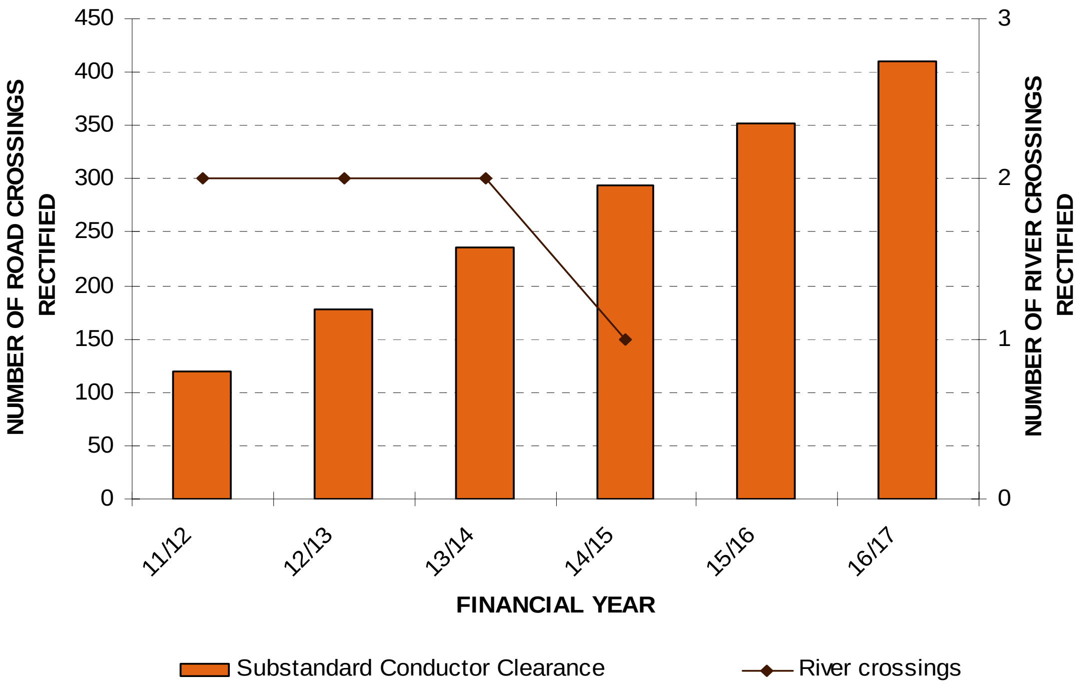

Figure 7.13: Planned volumes of road and river crossings to be rectified under the Substandard Conductor Clearance program and Distribution River Crossing program

7.7 Underground Cables

This section discusses the asset management plan for transmission and distribution underground cables.

7.7.1 Transmission Underground Cables

Asset Description: Transmission underground cables and accessories generally operate at voltages greater than 33 kV[19]. These conductors provide the capability to transfer power from generators or power sources to load centres. Conductors at or below 33 kV are defined as distribution and are separately. The transmission underground cable network consists of 51 circuits as shown in Table 7.26.

Table 7.26: Transmission underground cable population by voltage

Voltage	Number of circuits	Total circuit length [km]
330 kV	3	0.83
220 kV	0	0
132 kV	35	36.04

[19] This excludes cables connecting the secondary winding of power transformers to respective substation switchgear within substation sites. Such cables operate at typical distribution voltages ranging from 6.6 kV to 33 kV but are deemed Transmission assets.

Voltage	Number of circuits	Total circuit length [km]
66 kV	13	15.46
Total	51	52.33

Two types of cable are in used in the transmission network as shown in Table 7.20.

Table 7.20: Transmission underground cable population by cable type

Carrier Type	Number of circuits	% of Population	Circuit Length (km)			Total Circuit Length (km)
			330 kV	132 kV	66 kV	
Oil-filled cable	10	25%	0	1.36	11.89	13.25
Cross-linked polyethylene (XLPE) cable	41	75%	0.83	34.68	3.57	39.08
Total	51	100%	0.83	36.04	15.46	52.33

7.7.2 Failure modes and impacts

Typical failure modes experienced on the transmission underground cable system are:

- Physical damage of the cable or sheath due to excavation or termite activity in the vicinity of the cable location, or damage sustained through improper installation practices;
- Deterioration of the insulating medium. In XLPE cables this can be due to moisture ingress, and in oil-filled cables, the insulation integrity can be reduced by oil leaks from the cable; and
- Electrical stresses caused by overvoltage e.g. lightning strike voltage transference.

Failure of the cable impacts:

- Reliability: the failure can cause customer outages. These outages can be extended as it takes time to locate and repair cable faults; and
- Environment: oil leaking from the cable can leach into the surrounding soil.

As cables are buried underground, the safety risk from cables is relatively low due to the limited opportunities for exposure to a cable.

7.7.3 Age and condition

The design life of oil-filled cables is 60 years, and the design life of XLPE transmission cables is 40 years. However, the actual in-service life is affected by:

- The quality of the design and construction;
- Loading and utilisation over the life time;
- Maintenance practices; and
- Environmental (installation) conditions.

The overall age profile of transmission cables by cable type is shown in Figure 7.14

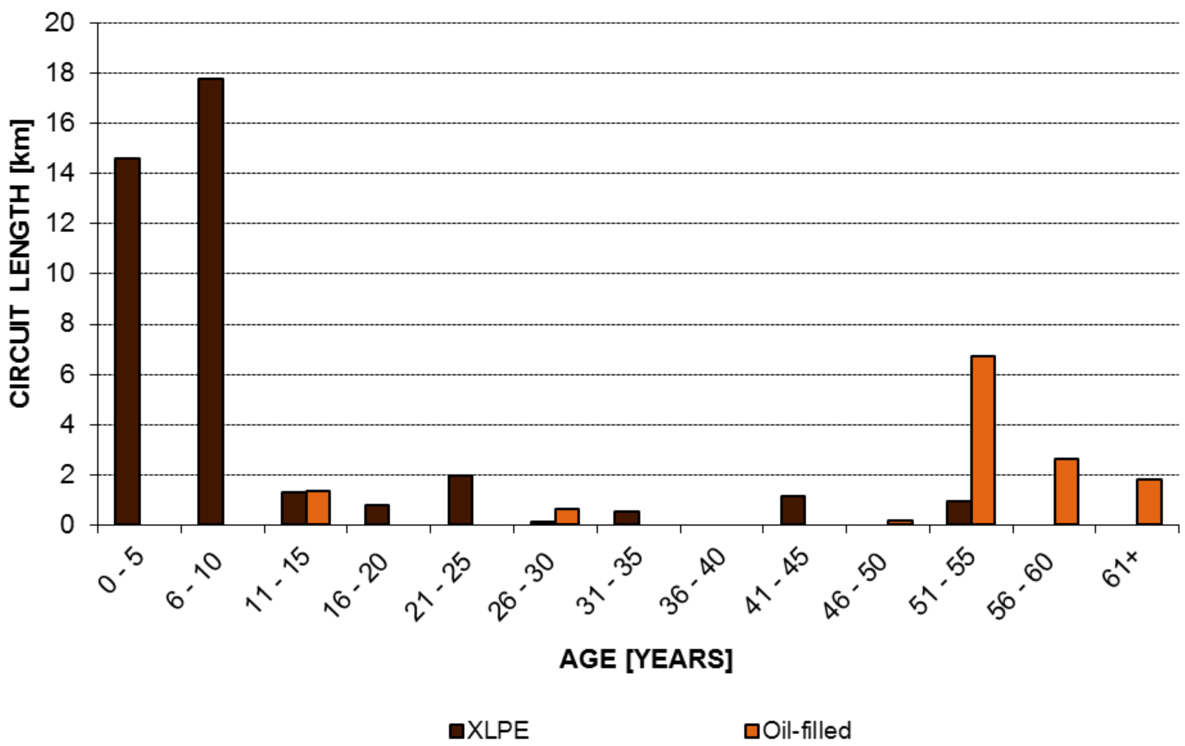

Figure 7.14: Transmission cables age profile

One oil-filled cable circuit (1.81 km) has exceeded the design life. Another 70% (9.32 km) of the oil filled cable population will approach this age in the next ten years. Some of these cables are showing signs of deterioration through increased oil leakage.

Some 93% (36.47 km) of the XLPE cables are under 25 years, with only 5% (2.06 km) exceeding design life. The XLPE cables are in good condition and are not showing signs of early deterioration.

7.7.4 Performance Level

Cable failures affect network performance and environmental obligations. Performance requirements are set out in the Access Arrangement. The

Pollution of Waters by Oil and Noxious Substances Act 1987 (WA) defines obligations covering oil leaks. The Contaminated Sites Act 2003 (WA) requirements cover reporting of these leaks.

Two indicators are used to measure the performance of transmission underground cables relating to network performance and environmental obligations as shown in Table 7.28.

Table 7.28: Transmission overhead conductor performance requirements

Indicator	Target	Performance 2010/11	Performance gap
Number of cable defects	No increasing trend in defect volumes	Increasing trend of defects especially in oil-filled cables	Yes
Compliance with environmental regulations	Oil must not be discharged onto WA land	Oil has been discharged onto WA land through oil-filled cable leaks	Yes

7.7.5 Asset management strategies

Asset creation

The preferred cable type for new cable installations is the XLPE insulated cables. These will replace all network oil-filled cables. Oil-filled cables are no longer used for new installations.

Asset maintenance

Preventive maintenance is carried out to monitor cable condition and identify defects that could lead to imminent cable system failure.

Defects or conditions identified are then rectified as soon as practicable under corrective maintenance.

7.7.6 Overview of plan

In addition to preventative maintenance, the strategies adopted to meet transmission cable performance requirements are shown in Table 7.29.

Table 7.29: Issues and strategies for transmission cables

Issue	Strategy	Planned/Frequency
14% (1.81km) of the oil-filled cables exceed the 60 year design life. A further 70% (9.32km) will exceed this age in the next 10 years.	Continue routine condition monitoring. Intervene where the defects become more prominent and rectify.	Carry out routine maintenance and repair as required.
5% (2.06km) of the XLPE cables exceed the 40 year design life.	Continue routine condition monitoring. Intervene where the defects become more prominent and rectify.	Carry out routine maintenance and repair as required.
Spares for transmission cables e.g. joints are not readily available (long lead times)	Apply strategic spares policy. Identify critical spares. Maintain sufficient spares in stock	As required.
Disposal of redundant oil-filled cables	Drain oil and seal ends of cable. Meet environmental requirements. Leave cable in situ.	As required.

7.7.7 Distribution Underground Cables

Asset Description: Distribution underground cables and accessories operate at voltages equal to or less than 33 kV. The cables are used to distribute power from zone substations to customer load centres. Distribution cables exclude streetlight cables (carriers), underground customer service connections, data and control cables.

The distribution underground cable network of high voltage (≤ 33 kV) and low voltage cables (less than 1 kV) is shown in Table 7.30.

Table 7.30: Distribution underground cable population[20]

Description	Total circuit length [km]
High voltage three phase underground cables	5,479
High voltage single phase underground cables	779
Low voltage underground cables	14,117
Total	20,375

The LV underground network comprises cables of various constructions including cross-linked polyethylene (XLPE) and paper insulated[21] cables. XLPE cables are generally Wavecon type with the neutral conductor taking the form of a layer of copper conductors applied with a non-helical lay. Paper insulated cables are either paper insulated lead covered (PILC) or Consac type, where the neutral conductor takes the form of a concentric aluminium sheath.

The two types of HV underground cable used in the network. They are XLPE which makes up about 82% of the underground cable network. PILC makes up the remaining 18%.

7.7.8 Failure modes and impacts

Typical failure modes experienced on the distribution underground cable system are:

- Cable accessory failures include:
  - Straight joints due to various reasons including installation error during the jointing process or moisture ingress through third party damage;
  - Pole top cable termination failure attributed to moisture ingress especially in older type cast iron terminations. Such as Henley Cable Boxes;
  - Physical damage of the cable or sheath due to excavation by third parties in the vicinity of the cable location;
  - Damage to the cable or sheath by termites boring into the cable; and
  - Damage sustained through improper installation practices including using poorly graded backfill material, exceeding of bending radii, and dragging the cable over rough ground.
- Cable or accessory failure impacts:

---

20 Busbar network metrics

21 Mass impregnated non-draining

- Reliability: the failure can cause customer outages. These outages can be extended as it takes time to locate and repair cable faults.
- Safety: the failure of Henley Box type pole top terminations can be explosive with the possibility of damage or injury caused by flying fragments of the cast iron cable box.

Generally, the safety risk from cable failure is low due to the cable being buried underground, providing limited opportunities for exposure to the cable.

7.7.9 Age and condition

The design life for XLPE distribution cables is 30 years and for PILC distribution cables 50 years. However, the actual in-service life is affected by:

- The quality of the design and construction;
- Environmental (installation) conditions;
- The performance of the accessories such as joints and terminations; and
- Loading and utilisation over the life time.

Generally, the design life of conductor accessories matches the design life of the associated cable.

The overall age profile of HV distribution cables by cable type is shown in Figure 7.15.

Figure 7.15: Distribution HV cables age profile

All of the XLPE cables are under the design life of 30 years.

About 10% (100 km) of the PILC has exceeded the design life of 50 years, with a further 8% (86 km) approaching this age in the next 10 years.

There are 272 Henley Cable Boxes currently in operation on the distribution network. Another 264 of these boxes were replaced during the period 2004/05 to 2008/09.

7.7.10 Performance Level

Table 7.31 shows the trends in HV distribution cable failure modes from 2005 to 2010.

Table 7.31: Trend in failure modes for HV distribution cables

Failure mode	Trend	Total failures for 2005-2010
Straight joints	Decreasing	184
Pole top terminations[22]	Increasing	14
3rd party excavations	Decreasing	124
Termites	Increasing	21
Substandard installation	Decreasing	35

Although the trend in the number of failures due to straight joints, third party excavations and substandard installation practices is decreasing, there are still a significant number of faults caused by these failure modes.

The number of faults per 100 km is used to assess the performance of distribution cables. Table 7.32 shows the historical performance of this measure for XLPE and PILC HV cables from 2005 to 2009.

Table 7.32: Past performance of XLPE and PILC HV distribution cable

Cable Type	2005/06	2006/07	2007/08	2008/09	2009/10	Trend
XLPE	2.14	1.47	1.70	1.61	1.10	Decreasing
PILC	2.08	3.27	1.29	1.38	2.40	No clear trend

The performance of XLPE cables is not deteriorating. The cables are well within the design life. The performance of PILC however has been fluctuating and needs to be monitored.

To determine whether the current performance levels are aligned with industry standards, benchmarking with other utilities should be carried out.

22 In 09/10 there were 8 Henley Cable Box failures

7.7.11 Asset management strategies

Asset creation

The preferred cable type for new cable installations is XLPE insulated cable. In locations known to have termite infestations, cables with a termite resistant jacket[23] are utilised. PILC cables are no longer used for new installations.

Asset disposal

Currently, redundant cables are not recovered from the ground following decommissioning. This may become a problem in future years with overcrowding in the standard alignment, especially in the CBD areas.

Asset maintenance

As the cables are buried and not readily accessible, the preventive maintenance activities are limited to visual inspection of the condition of pole top terminations as part of the bundled pole inspection process, and visual inspection of ground-mounted cable terminations as part of the switchgear and transformer inspections. The preventative maintenance activities for distribution cables are shown in Table 7.33.

Table 7.33: Preventive maintenance activities for distribution cables

Activity	Asset type	Frequency
Visual inspection for corrosion, loss of compound	Pole top cable terminations	Every 4 years
Visual inspection for corrosion, loss of compound or overheating	Ground mount cable terminations on switchgear or transformers	Every 2 years

Defects or conditions detected are rectified as soon as practicable under corrective maintenance.

Where in service of joints or the cable occurs, they are generally replaced under operational expenditure programs. However, if significant lengths of cable need to be replaced as a result of such failures, the cable is replaced under the capital Cable Fault Replacement program (a subset of the Carrier Replacement program).

23 Termitex added to the sheathing compound during manufacture

7.7.12 Overview of plan

Table 7.34: Issues and strategies for distribution cables

Issue	Strategy	Plan/ Frequency
About 40% of all HV cable failures in service are caused by cable accessory failures.	Develop and maintain a register of qualified and accredited jointers. Track work carried out by the jointers in DFIS/ DFMS, with re-training or certification required for repeat offenders.	To begin in 2012/13 and refine and embed process in Business as usual within a 24 month period.
25% of all HV cable About failures are caused by third party damage.	Provide accurate Dial Before You Dig information. Monitor performance of repeat offenders. Target other utilities with information sessions.	Review and improve process to minimise the likelihood of such incidents.
10% (100 km) of the PILC exceeds the 50 year design life. A further 8% (86 km) will approach this age in the next 10 years.	Continue routine condition monitoring of critical circuits. Remediate prior to failures in service.	Carry out routine maintenance.
Increasing trend of failures due to termites boring into cables.	Install termite resistant cable in areas known to be termite prone.	Progress as part of project initiatives.
Majority of the Henley Box terminations exceed the 40 year design life.	Replace these terminations under the Cable Box Replacement program with the appropriate termination kit.	Replace 236 terminations in AA3.

In AA2, a pilot project was initiated to install online condition monitoring equipment on feeder exit cables within the Hay Street and Milligan Street Zone Substations in the Perth CBD. Pending the evaluation of this project, additional condition monitoring equipment may be installed on other critical cable feeders in AA3, to better assess the condition of these cables.

In the future, investigation of cable rejuvenation techniques and a review of feeder exit cable ratings may be initiated.

Over the AA3 regulatory period, 4 km of cable per year is expected to be replaced under the capitalised Cable Fault replacement program.

Figure 7.16 shows the volumes of Henley Cable Boxes to be replaced in AA3.

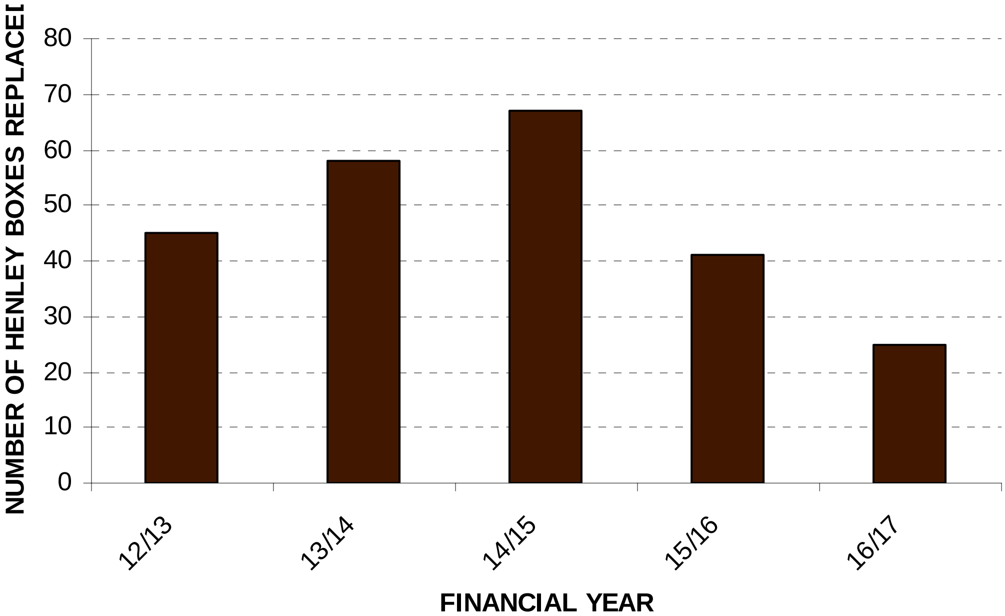

Figure 7.16: Planned replacement volumes of Henley Cable Boxes

7.8 Overhead Structures

7.8.1 Asset Description

Overhead structures comprise poles and towers used to support overhead lines and equipment in the transmission and distribution networks. They form the largest group of network assets, numbering over 790,000 individual assets. Poles are categorised and managed by design type (pole or tower), material type (wood, concrete, metal) and network type (transmission or distribution). Stay wires, which brace the poles, and cross arms and insulators, which support the conductors, as well as foundations and earthing are included as part of the structure.

The expected service life of structures (and extended life for wood poles) and population statistics are presented in Table 7.35.

Table 7.35: Overhead structure population statistics and service lives

Structure type	Transmission		Distribution	
	Life (years)	Population	Life (years)	Population
Wood pole	45 - 55	30,485	35 - 50	628,891
Concrete pole	55	1,043	55	11,628
Metal pole	55	4,846	55	1,250

Structure type	Transmission		Distribution	
	Life (years)	Population	Life (years)	Population
Streetlight pole	NA	0	45	109,114
Aus pole (wood pole on concrete & steel base)	30	2,677	30	669
Lattice tower	100	5,975	NA	0

7.8.2 Failure modes and impact

Structure (pole) failures can have significant consequences for network safety and performance. Poles that fall or lean excessively can result in live conductors coming in contact with other conductors, vegetation, people, buildings or vehicles. Such failures generally result in network outages. In some cases failures impact property and/or the public where the protection system has failed. In these instances where protection has not operated there is a risk of live conductors falling to the ground with the potential for electric shock and fire start.

Pole tops and insulators can fail by physically breaking in which case the impact is similar to structure or pole failure. Insulators can also fail resulting in leaking current which can result in pole and ground fires. The consequences can be significant particularly in areas of high bush fire risk.

7.8.3 Age and condition

Age profiles for selected pole types are shown in Figure 7.17 and Figure 7.18. Wood poles are a key focus as a large number of distribution poles are operating beyond their expected 40 year service life and further significant volumes are nearing their expected service life.

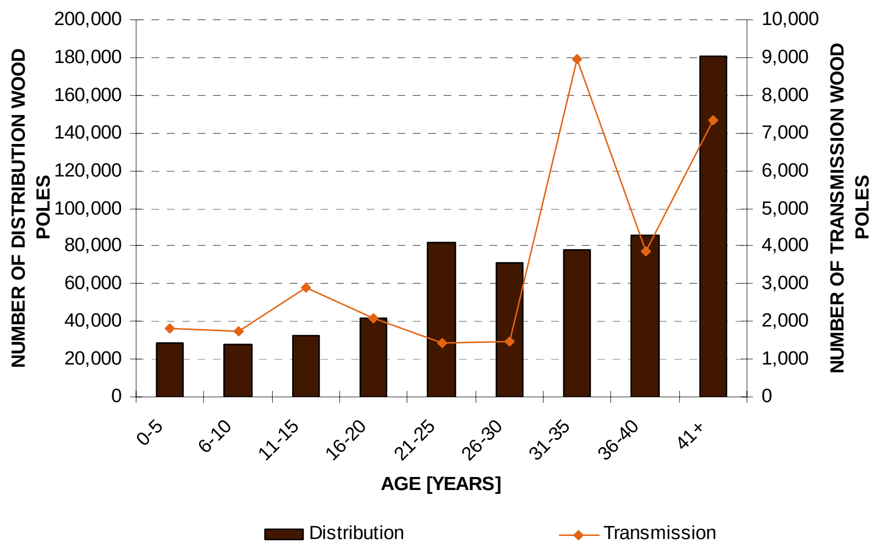

Figure 7.17: Age profile of distribution and transmission wood poles

Whilst a small number of metal streetlight poles are operating beyond their 45 year design life, another 5,000 poles are 35-40 years old and will reach or exceed their design life in the next 5 – 10 years.

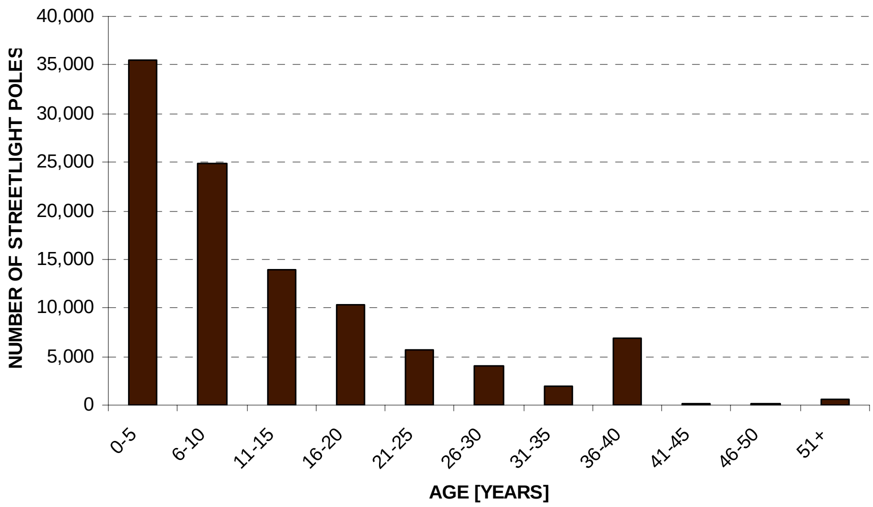

Figure 7.18: Age profile of metal streetlight poles

The bulk of the concrete pole population and lattice towers are well below their expected service lives.

7.8.4 Performance Level

The performance of structures impact directly on supply reliability, network security and network safety outcomes. Reliability and security requirements are established through the Access Arrangement and the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. Safety requirements are established through several legislative instruments and also through a specific order (001-2009) in relation to wood poles issued by EnergySafety.

The primary performance indicator used to manage wood poles is the Pole Integrity Index (PII) which equals the number of unassisted pole failures per annum per 10,000 poles. This parameter is measured separately for the transmission (TPII) and distribution (DPII) pole assets and the targets are set at levels provided by national industry benchmarks. Performance against these targets is shown in Table 7.36.

Table 7.36: Wood pole performance against targets

Indicator	Target	Performance 2010/11	Performance gap
TPII (Transmission)	1.0	5.69	4.69
DPII (Distribution)	1.43 (1.0)	1.22	No gap

Within the last 12 months, both the TPII and DPII have reversed their downward trend and are now tracking upwards. The latest TPII is well above the target, and the DPII is above the industry benchmark and nearing the target.

Overhead structures other than wood poles do not have specific performance targets set or indicators measured, but are managed according to results collected during regular inspection and maintenance programs.

7.8.5 Asset management strategies

Poles have a limited life span and can fail for a variety of reasons. The strategies for overhead structures are designed to enable poles to deliver the required functions and levels of performance in a sustainable way, at optimum whole of life cost without compromising health, safety, or environmental performance. This will be achieved by an increase in pole replacement and reinforcement rates to achieve a sustainable pole replacement rate over a ten to fifteen year period.

Asset maintenance

Routine, preventative and corrective maintenance activities are carried on overhead structures to maintain their service integrity. This is achieved through the regular inspection of these assets over their life time.

7.8.6 Overview of plan

A summary of the strategies used to manage Overhead Structures is shown in Table 7.37.

Table 7.37: Summary of strategies

Issue	Strategy	Planned Outcomes
Deteriorating condition of wood poles: The recent replacement rate of wood poles shows it is insufficient to address the portion of pole population identified as unserviceable.	Increase pole replacement and reinforcement involving: Replace sufficient distribution poles to continue to clear the condemned pole population, to reduce the DPII to better than national industry benchmark of 1.0 in accordance with the Energy*Safety* Order. Replace and/or reinforce additional distribution and transmission poles to achieve sustainable pole management over the next 15 years (by end of AA5).	Increase wood pole replacement and reinforcement rate over the 2012/13 to 2016/17 period in accordance with the overhead structure volumes below.
Pole top fires: A number of pole top fires have occurred as a result of electrical tracking across insulators or cross arm failure.	Replace deteriorated cross arms (and insulators) in high fire risk areas with steel cross arms. Apply silicon to the insulators to prevent electrical tracking.	Apply silicon to 10,000 pole top structures per annum in the period 2009/10 to 2011/12 and increase to 15,000 per year from 2012/13.
Non-compliant distribution metal poles: Metal poles are non-compliant with AS7000 step and touch potential requirements and pose a potential public safety hazard.	Re-build the Kambalda West overhead network which will remove 550 metal distribution poles.	To complete over the 2012/13 and 2014/15 period.
Stay wires underrated: 8,402 stay wires are known to be underrated, providing insufficient support.	Replace stay wires based on priority.	75% replaced by the end of June 2017.
Stay wire insulators missing: 3,246 stay wires are lacking insulators which poses a safety hazard should a stay wire fail.	Retrofit insulators.	78% retrofitted by end of June 2017.

Issue	Strategy	Planned Outcomes
870 transformer poles have been identified as having insufficient reinforcement.	Replace transformer poles.	All replaced by the end of June 2017.
140 PI structures have been identified as having a span length exceeding 350m, the wood pole PI structure design limit.	Replace all PI structures with a span of over 350m.	Complete within 2012/13 to 2016/17 period.

Table 7.38 summarises the planned treatment (replacement/ reinforcement) volumes for Overhead Structures. These volumes include the replacements planned to rectify identified key issues as well as any replacements resulting from the inspection program.

Table 7.38: Overhead structure treatment volumes

Year	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Structure	AA2 (actual)		AA2 (forecast)	AA3 (forecast)				
Transmission wood poles	406	562	1,050	960	1,050	1,450	1,540	1,540
Transmission stays	1	543	352	391	391	391	391	0
Distribution wood poles	16,967	23,080	23,027	28,500	30,000	31,500	33,000	34,500
Distribution stays	129	120	400	580	580	580	580	580
Pole tops	969	745	4,033	3,140	3,140	3,140	3,140	3,140

7.9 Circuit Breakers

7.9.1 Asset Description

Two thousand five hundred and fifty four circuit breakers are installed at 149 terminal stations and zone substations. Circuit breakers operate at voltages from 6.6 kV through to 330 kV and are categorised according to installation type (indoors or outdoors) and insulation medium (vacuum, gas (SF_6), or oil).

Circuit breakers interrupt the flow of electricity in a section of the network when an abnormal condition is identified, and thereby maintain system security, protect other network assets from damage, and ensure the safety of personnel. Circuit breakers are critical network assets and are managed as N-RTF.

Outdoor circuit breakers are deemed individual assets. However, indoor circuit breakers are installed within a switchboard and are normally maintained or replaced together. Western Powers standard switchboard incorporates 8 circuit breakers within a single switchboard.

Table 7.39 summarises the circuit breaker types and population. Table 7.40 provides circuit breaker details by voltage and installation environment (indoor/ outdoor).

Table 7.39: Circuit breaker population

Circuit breaker type		Number of units in service
Indoor	Vacuum	586
	Oil	218
	SF6	239
Total		1,043
Outdoor without CTs	Vacuum	0
	Oil	574
	SF6	833
Total		1,407
Outdoor with CTs	Vacuum	5
	Oil	52
	SF6	47
Total		104

Table 7.40: Details of circuit breaker population by voltage and installation condition

Type	11 kV	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Circuit Breakers (Outdoor)		208	305	191	616	17	70	1,407
Circuit Breakers with CT (Indoor)	470	566	7					1,043

Type	11 kV	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Circuit Breakers with CT (Outdoor)	5	36	54	7	2			104

Outdoor and indoor circuit breaker volumes by manufacturer are shown in Figure 7.19 and Figure 7.20.

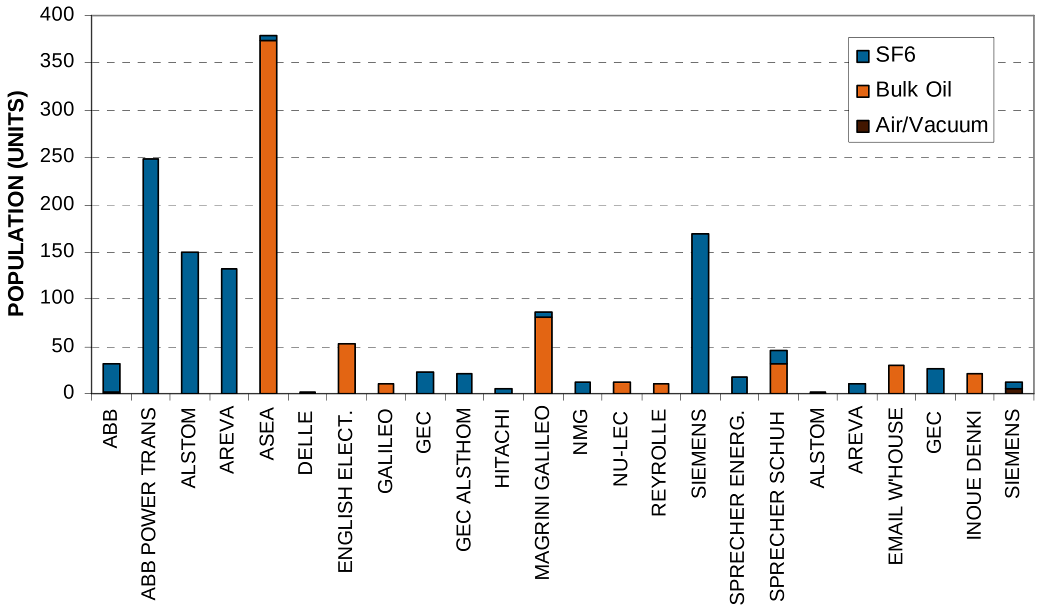

Figure 7.19: Outdoor circuit breaker type by Manufacturer

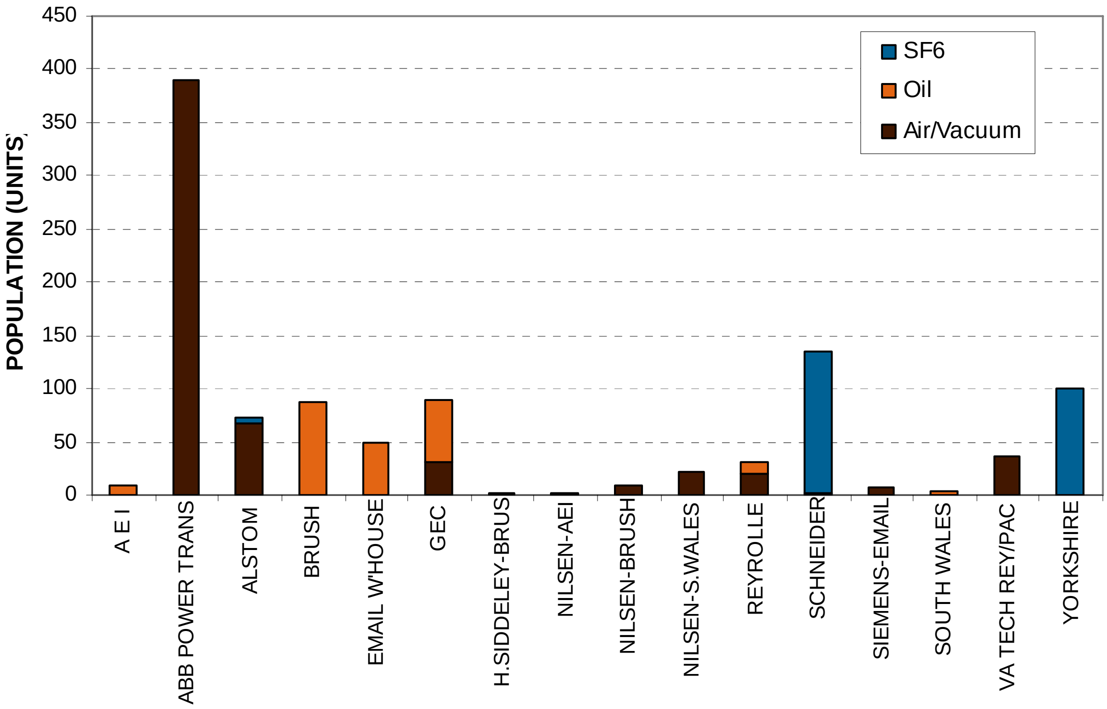

Figure 7.20: Indoor circuit breaker type by Manufacturer

7.9.2 Failure modes and impact

The breakdown of circuit breaker failure modes over the period 2000 to 2010 is shown in Figure 7.21. Some 60% of the failures are attributable to oil and gas leaks.

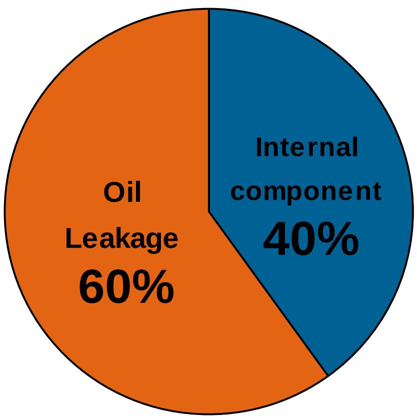

Figure 7.21: Circuit breaker failure modes

An explosive failure of circuit breakers does occasionally occur and the potential impact of explosive failure is significant including damage to adjacent circuit breakers and other equipment, fire, and injury to personnel. Circuit breakers installed within indoor pitch-filled type switchboards exposes these circuit breakers to potential faults in the switchboard. Four catastrophic failures of pitch filled type switchboards have been experienced in the last 10 years.

7.9.3 Age and condition

The age profile of the circuit breaker population is shown in Figure 7.22 and Figure 7.23. Although circuit breakers are managed based on condition, it is useful to consider the volume of assets within the expected life range of 40 + years as these are considered at risk of failure and indicate likely replacement volumes.

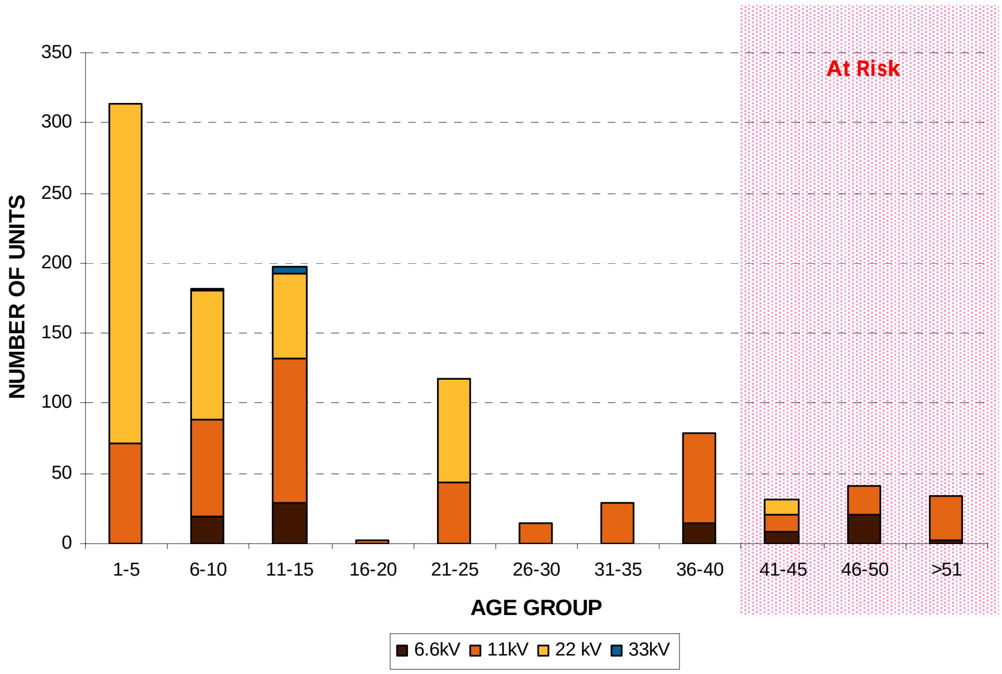

Figure 7.22: Indoor circuit breaker age profile

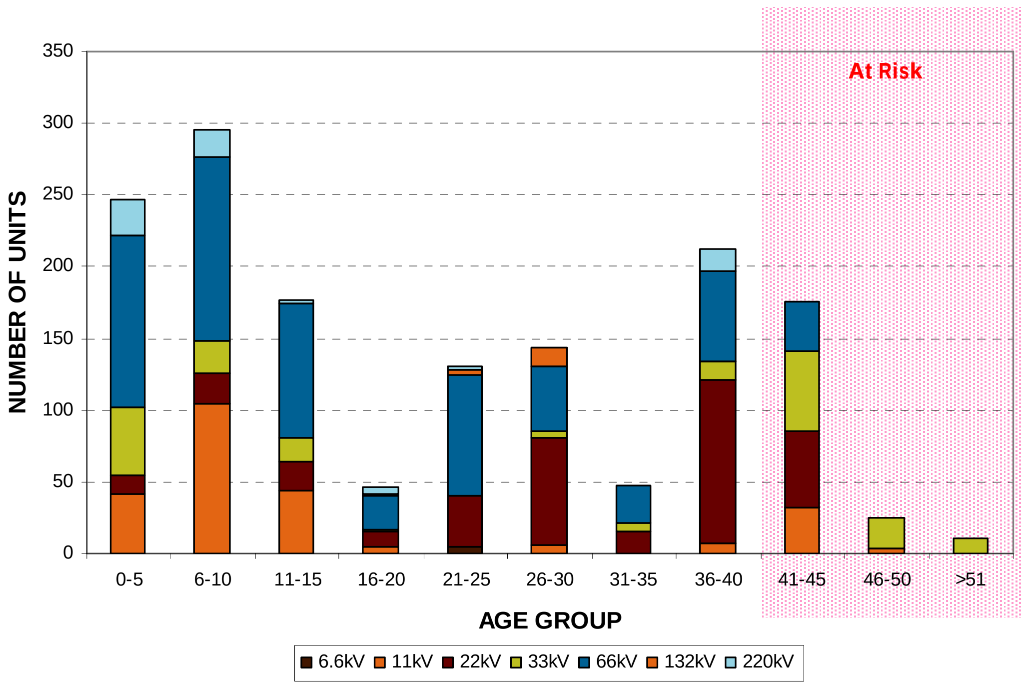

Figure 7.23: Outdoor circuit breaker age profile

Significant volumes of both indoor and outdoor circuit breakers are classed as being in “poor” or “bad” condition as shown in Figure 7.24 and Figure 7.25. The condition assessment is based on maintenance and inspection records as well as operational duty and the risk of contributed failures.

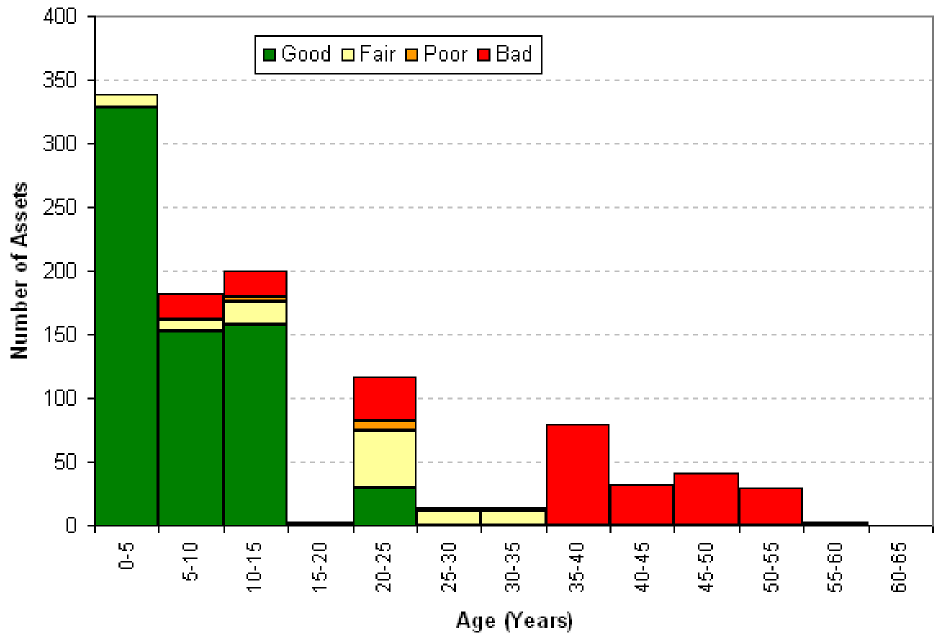

Figure 7.24: Indoor Circuit breaker condition profile

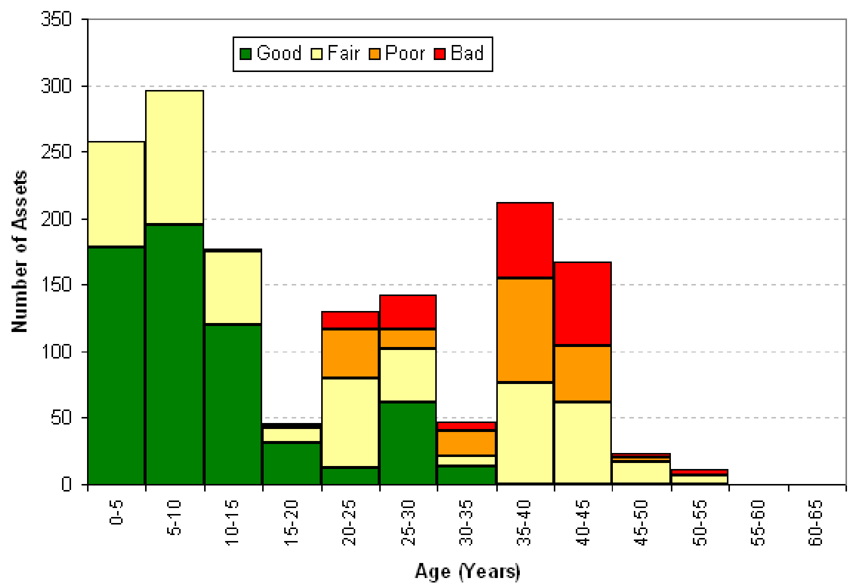

Figure 7.25: Outdoor Circuit breaker condition profile

Figure 7.24 and Figure 7.25 shows there is a strong correlation between age and condition. Most indoor circuit breakers in “Bad” condition are installed in pitch filled insulation type switchboards. In total, 35% of indoor and 31% of outdoor circuit breakers are in “Bad” or “Poor” condition.

7.9.4 Performance Level

The primary impact circuit breaker failure has on the network is service reliability. Other performance issues relate to environmental and safety performance. These requirements are addressed through environmental regulations and the Occupational Safety and Health Act 1984.

The primary indicators used to measure circuit breaker performance is the system minutes interrupted, the number of failures and the condition score as shown in Table 7.44.

Indicator	Target	Performance end AA2	Performance gap
System Minutes Interrupted (contribution per annum)	Meshed: ≤ 0.551 Radial: 0.001	Meshed: 0.6 Radial: 0	Meshed: 0.049 No gap
Failures per annum (requiring replacement or major repair)	Indoor: ≤ 1 failure Outdoor: ≤ 2 failures	Indoor: 1 failure Outdoor: 2 failures	No gap
Condition Score (of individual units)	< 8 (condition other than “poor” or “bad”)	Indoor: 65 % compliance Outdoor: 69 % compliance	Indoor: 35% Outdoor: 31%

Table 7.44: Circuit breaker Performance requirements

Circuit breakers performance has partially met performance. System minutes interrupted for meshed network circuit breaker was slightly above target in 2010 and significant volumes of indoor and outdoor circuit breakers are classed as being in a “poor” or “bad” condition (score ≥8).

Benchmarked Performance Results

Based on the International Transmission and Operation Survey (ITOMS) conducted in 2009, the management and performance of the circuit breaker population was found to be below average, from a cost and service level perspective as shown in Figure 7.26. (The service level is a combination measure based on breaker forced and fault outages.) The results indicate that maintenance and refurbishment costs are generally commensurate with the service level provided by the transformers.

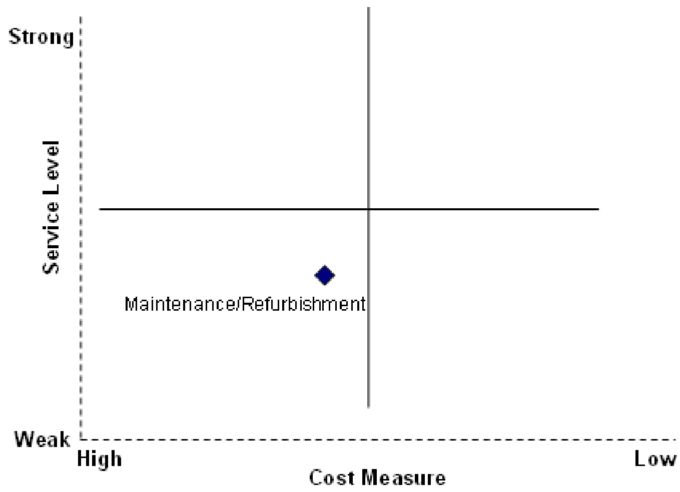

Figure 7.26: ITOMS (2009) survey results for Circuit Breakers

Defects and Major Failures

The current failure over the last 10 years has averaged less than one per annum for indoor for indoor circuit breakers and two per annum for outdoor units.

Figure 7.27 shows that indoor circuit breaker performance has met the required service level but outdoor circuit breaker performance has failed to achieve the required performance level 40% of the time since 2000.

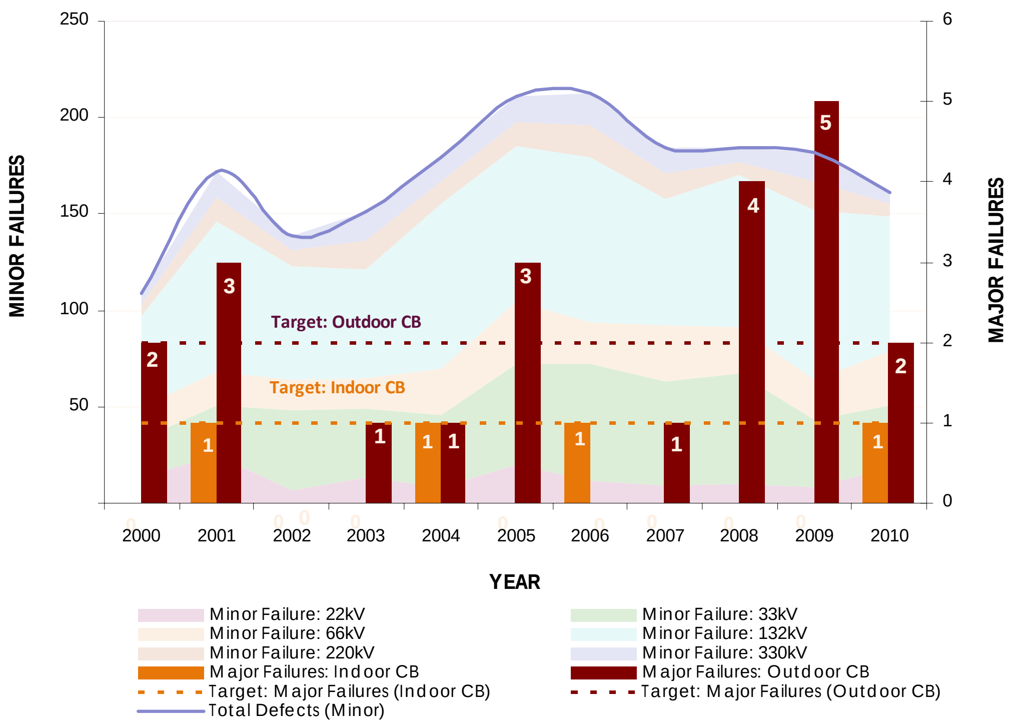

Figure 7.27: Circuit breaker failure history

Figure 7.27 shows that explosive and major failures are more likely at lower voltages.

The circuit breaker types listed below:

- GEC FK1 and FE2;
- Magrini Galileo (MMS.24C, 38MGE); and
- English Electric (OKW3),

have been identified with performance issues which result in them being classified as in “Bad” condition.

7.9.5 Asset management strategies

The following strategies are implemented to address the key issues and enable efficient and effective life cycle management of the circuit breakers.

Asset maintenance

Circuit breakers are subject to a comprehensive maintenance regime involving:

- Monthly inspections as part of the substation routine inspection;
- Level A maintenance carried out every 2 to 4 years involving maintenance of most items except the contact chamber;
- Level B maintenance every 4 to 8 years involving Level A maintenance plus dismantling of the interrupter chamber and inspection of contacts; and
- End of warranty inspection carried out 1 to 2 months before expiration of the warranty period.

7.9.6 Overview of plan

Table 7.41: Issues and strategies for circuit breakers

Issue	Strategy	Planned Outcomes
Gas leak: Outdoor SF6 circuit breakers.	Apply corrective maintenance on leaking SF6 circuit breakers.	As required
Difficulty in conducting maintenance due to unavailability of spares.	Replace units where no spare parts available.	As required
Specific operation and maintenance issues are associated with some makes of outdoor circuit breaker and there is no manufacturer support for these units and no of spare	Replace affected units.	Six GEC circuit breakers will be replaced annually until fully removed from the network. Approximately 20 Magrini Galileo circuit breakers will be replaced annually until

Issue	Strategy	Planned Outcomes
parts available. - 29 GEC (FK1 and FE2) type have been subject to SF-6 leaks and maintenance and repair difficulties. - 81 Magrini Galileo (MMS.24C, 38MGE) and 52 English Electric (OKW3) outdoor circuit breakers suffer from loss of insulation and difficulty in sourcing spares.		fully removed from the network.
Inappropriate duty: Capacitor switching typically requires circuit breakers with special duty cycle. In some cases normal indoor and outdoor circuit breakers are used for the switching of capacitors. These circuit breakers are subject to more stress due to the more onerous and intensive operating duty.	Implement a periodic circuit breaker rotation plan to minimise the impact of capacitor switching duty on standard circuit breakers.	As required based on routine circuit breaker number of operation count check.
Identified “bad” condition outdoor circuit breakers.	Replacement program	38 circuit breakers per annum over period 2012/13 to 2016/17.
Potential for catastrophic failures of indoor switchboards.	Replacement program	Replace 7 indoor switchboards over period 2012/13 to 2016/17. Replace 5 on a like-for-like basis and 2 as part of network growth.

Over the period 2011/12 to 2016/17, 228 outdoor circuit breakers and 8 indoor switchboards (64 circuit breakers) are planned for replacement as shown in Figure 7.28. Forecast replacement volumes beyond 2016-17 are to remain constant in AA4 and reduce in AA5.

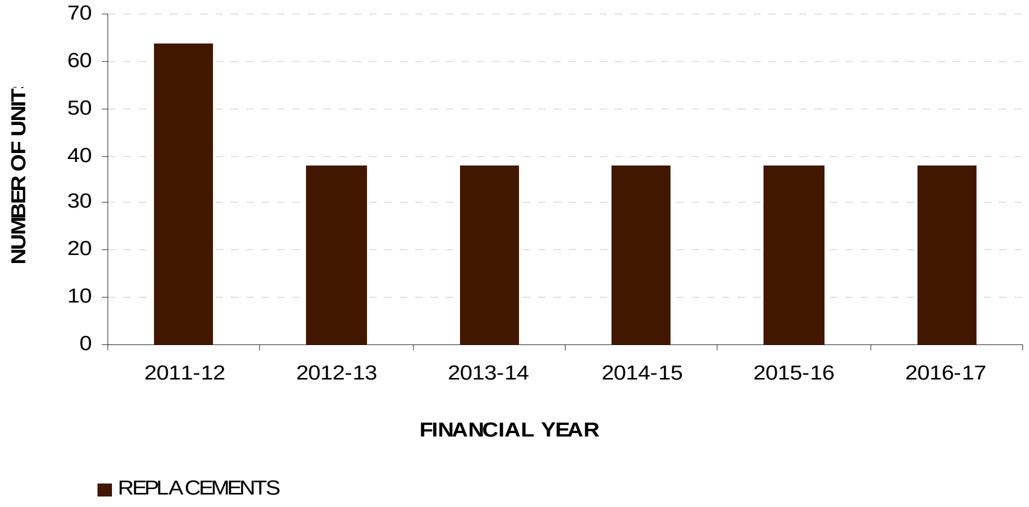

Figure 7.28: Circuit breaker replacements

7.10 Transmission Disconnectors and Earth Switches

7.10.1 Asset Description

Transmission disconnectors are normally located within substations and are used to safely isolate a part of the network or control load flows. Line disconnectors normally have integrated earth switches.

Approximately 91% of disconnectors are of the manually operated type. The remaining 9% of disconnectors are motorised. Disconnectors are made up of the following types:

- Single side break;
- Double side break;
- Centre break;
- Rocking post;
- Vertical break; and
- Pantograph.

Table 7.42 summarises the different types of disconnectors in the Western Power network.

Table 7.42: Disconnector population (Single phase)

Type	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Disconnectors	2,170	1,323	1,331	3,122			7,946
Disconnectors with Earth Switch		48	168	1,075	111	626	2,028

Type	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Earth Switches		24	22	87		12	145
Fault Throwing Disconnectors				4			4

Western Power's disconnectors are supplied by 23 different manufacturers as shown in Figure 7.29.

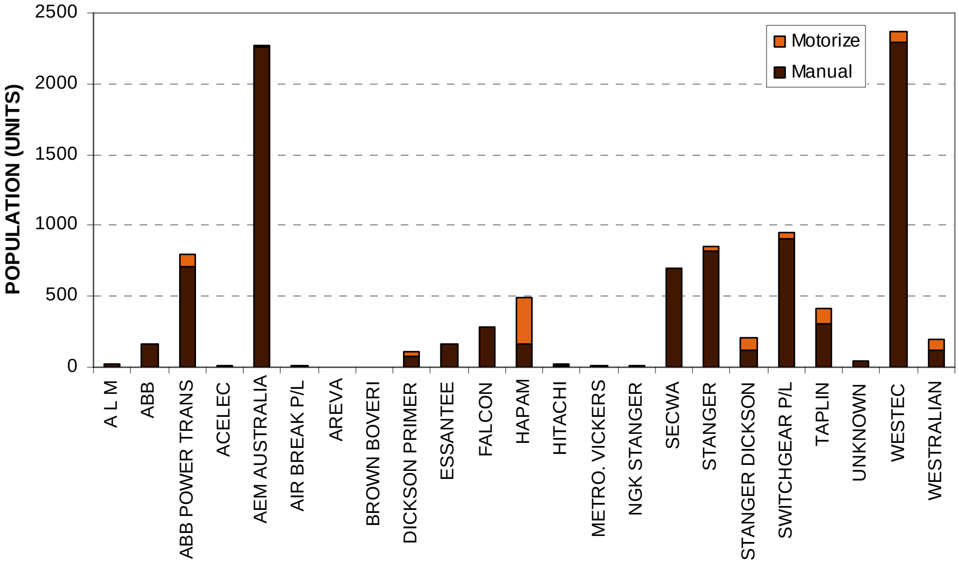

Figure 7.29: Number of disconnectors by manufacturer

7.10.2 Failure modes and impact

Disconnectors and earth switches generally fail as a result of operating mechanism failure during switching operation. This creates a safety risk to the switching operator and can also impact the network service.

Three incidents busbar disconnector failure incidents have occurred during transformer un-paralleling operations resulting in explosive failure and substation blackout.

Defect records show that disconnectors and earth switches are prone to failure across all manufacturers.

Figure 7.30 shows the disconnector defects recorded in the last 10 years by cause and manufacturer.

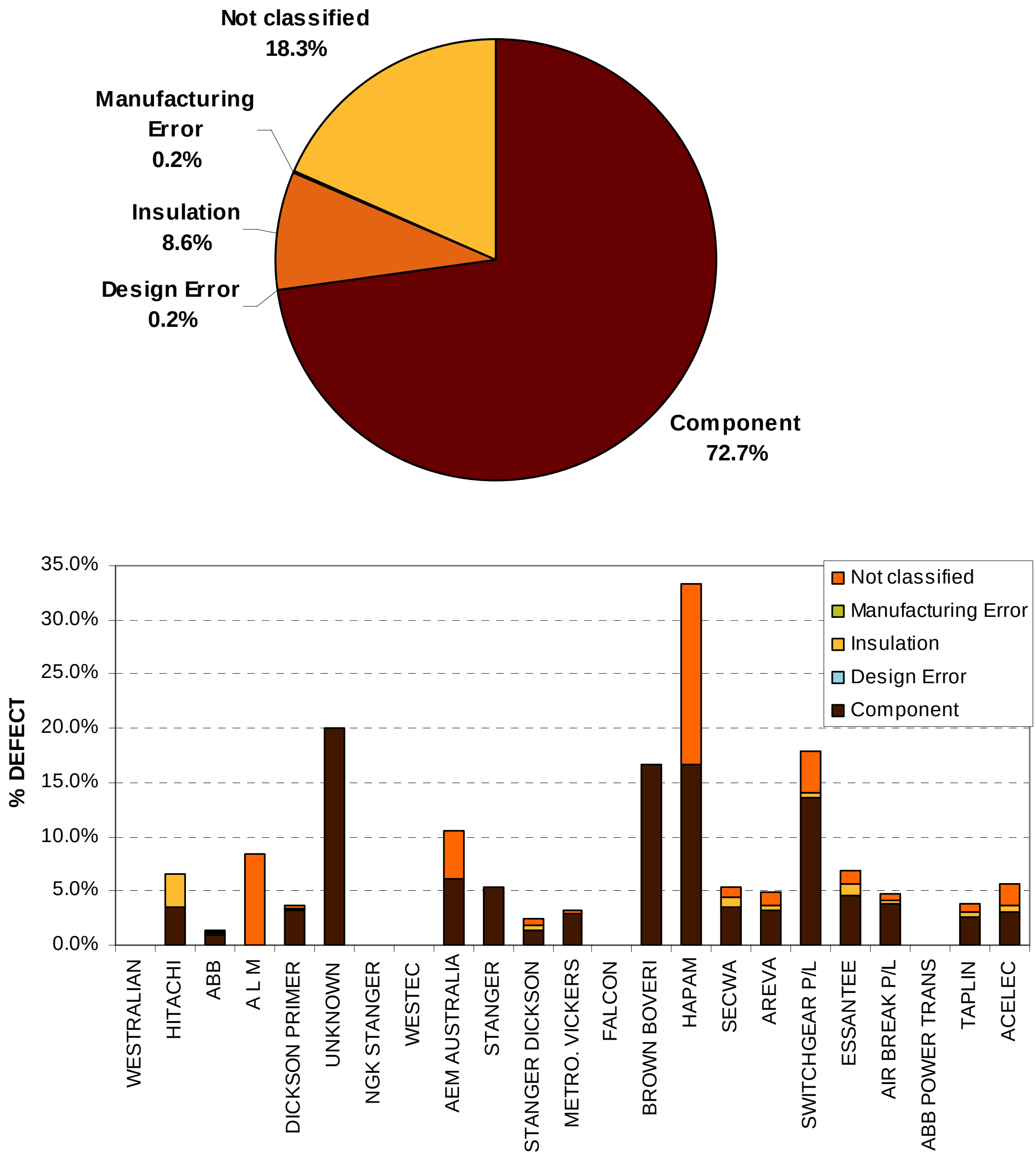

Figure 7.30: Disconnectors failure mode and manufacturer

Defect history

Western Power has on average experienced less than one disconnector failure per year in the last 10 years. Figure 7.31 shows an increasing trend of disconnector and earth switch defects mostly in the 22kV and 132kV disconnector populations. This is due to Insulator deterioration and worn mechanisms. The average defect rate is currently 38.7 failures per year.

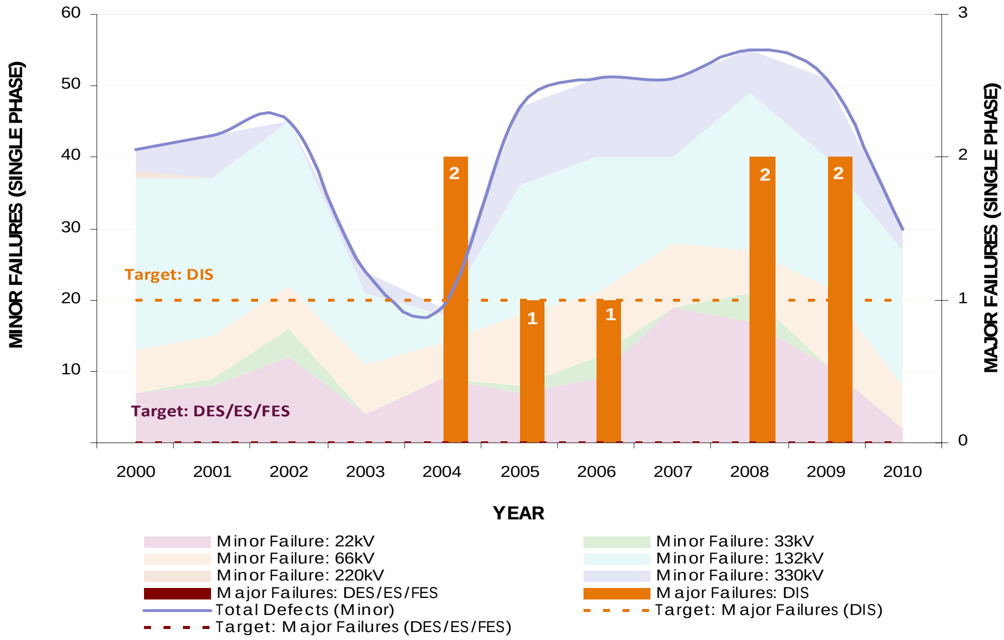

Figure 7.31: Disconnectors defects and major failures history

7.10.3 Asset age and condition

Figure 7.32 show that 6% of the disconnector population (588 disconnectors) has exceeded the 50 year design life. Another 1,785 disconnectors will also reach the end of their design life by the end of AA3. There is likely to be a need to increase the rate of replacement to manage the approaching step change increase based disconnector age and asset condition in the number of aged disconnectors.

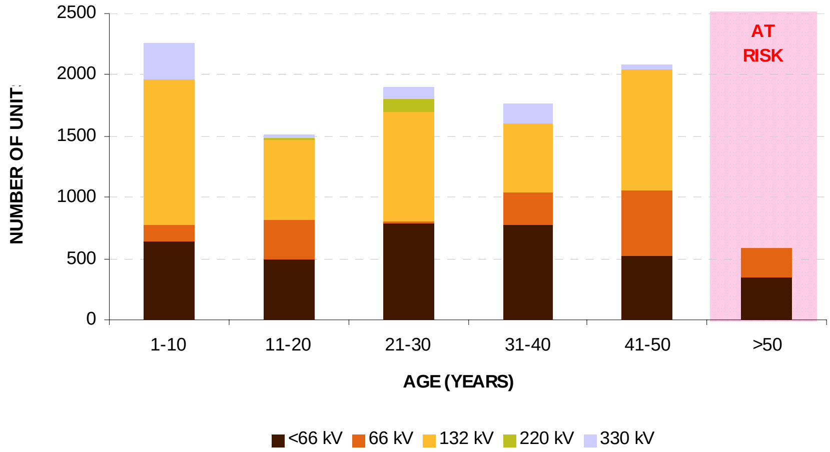

Figure 7.32: Age profile of Disconnectors

A "Health Index" has been developed for categorise the condition of disconnectors. Figure 7.33 reinforces the age profile, showing that 15% (1,558 units) of disconnectors are in "Bad" condition.

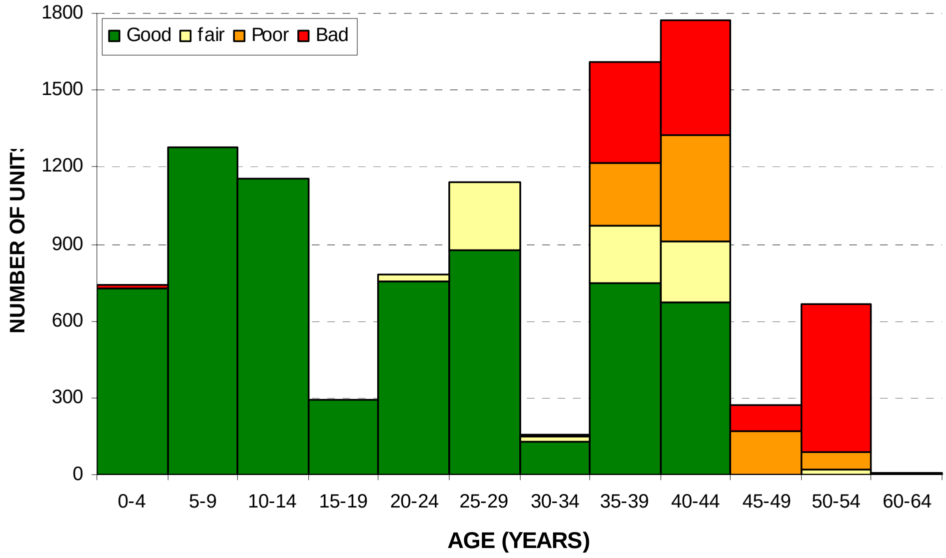

Figure 7.33: Disconnectors condition profile

7.10.4 Performance Level

The key requirements for disconnectors relate to compliance with regulations to ensure secure and reliable network operation. These requirements are summarised in Table 7.43.

Table 7.43: Disconnector performance requirements

Requirement	Target	Performance (End of AA2)	Performance gap
System Minutes Interrupted (contribution per annum)	meshed ≤ 0.79 Radial ≤ 0.558	meshed ≤ 2.41 Radial ≤ 0	1.62 (meshed)
Failure requiring replacement	DIS ≤ 1 DES = 0 ES = 0 FES = 0	DIS = < 1 DES = 0 ES = 0 FES = 0	No gap
Health Index (of individual units)	No disconnectors in “Bad” condition	85% Compliance	15% (1558 units)

Disconnectors are only partially compliant with Western Power’s performance requirements. The system minutes interrupted for meshed network disconnectors were above target for 2010.

Benchmarked Performance Results

Results from the 2009 International Transmission Operation and Maintenance Survey (ITOMS) shown in Figure 7.34 indicate that Western Power's maintenance cost and service level was ranked poor compared to other participants. Western Power implemented the consolidated asset plan in 2010 to improve maintenance cost performance and service levels.

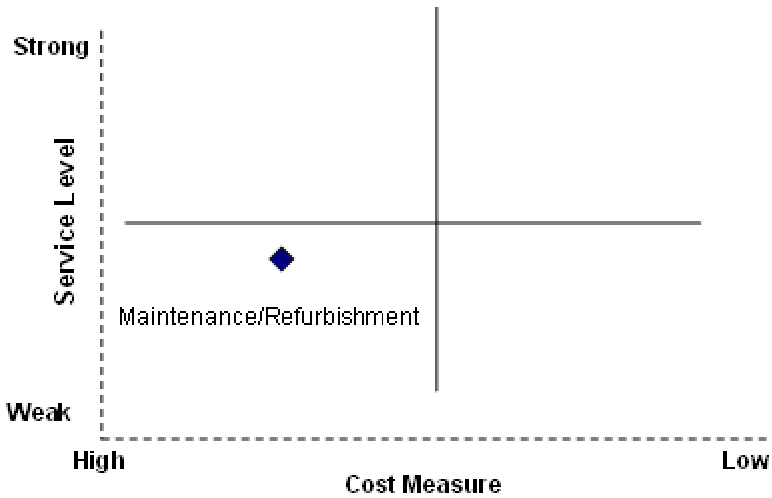

Figure 7.34: ITOMS (2009) survey results for Disconnectors

7.10.5 Asset management Strategies

Specific strategies are implemented to address the key issues and enable efficient and effective life cycle management of the disconnector fleet.

Table 7.44 provides information on the preventative maintenance undertaken for disconnectors.

Table 7.44: Preventative maintenance regime for transmission disconnectors

Activity	Frequency	Scope
Level B Maintenance (K1VA)	Every 4 years	includes inspection, maintenance of contacts and insulators and lubricating the equipment.
Thermographic surveying (K1VC)	Every year	Annual thermographic surveying of substations provides hot spot condition data.

Activity	Frequency	Scope
Substation Routine Inspection (K1X6)	Monthly	This activity is performed frequently (e.g. monthly) and consists of visual checks of such things as contacts and insulators. At this stage inspection staff may determine that further maintenance is necessary because of visible external damage or measured quantities outside set limits. For example, disconnector maintenance may become due at a certain number of operations.
Ad hoc inspections(K3V8, K4VH)	As required	Driven by repetitive faults on the equipment and the number of QT raised.

7.10.6

7.10.7 Overview of plan

Table 7.45: Issues and strategies for transmission disconnectors

Issue	Strategy	Planned Outcome
Bad condition: Approximately 15% of the disconnector population are in ”bad” condition.	Monitor and/or maintain as required. Replace disconnectors where condition assessment indicates that replacement is required.	Maintain and test 412 disconnectors per annum. Replace 80 “bad” condition disconnector units per year over AA3 (2012/13 to 2016/17).
Mechanism failure: Due to infrequent operation, the components of a disconnector (blades, contacts, linkages and other moving parts) tend to seize due to the formation of rust or salt in the mechanism. This results in resistance when opening and poor contact when closing. The consequence of poor contact results in heating and erosion of the contacts which eventually leads to a failure of the disconnector.	Monitor and/or maintain as required. Apply corrective maintenance.	Fix following Query Trouble (QT) report is raised

Issue	Strategy	Planned Outcome
Type issues identified with the 132 kV disconnectors manufactured by Switchgear P/L and Westec.	Apply corrective maintenance.	Fix following Query Trouble report is raised.
Obsolescence of parts and lack of manufacture support. 132 kV disconnectors manufactured by Switchgear P/L and Westec. 447 Switchgear P/L (DBH-4) disconnectors operate in the network.	Phase out these out these units.	Part of the 80 units per year over period 2012/13 to 2015/16.

Over the period 2011/12 to 2016/17, 560 disconnectors are planned for replacement in AA3 as shown in Figure 7.35. It is forecasted that the replacement volumes will increase in AA4 and AA5.

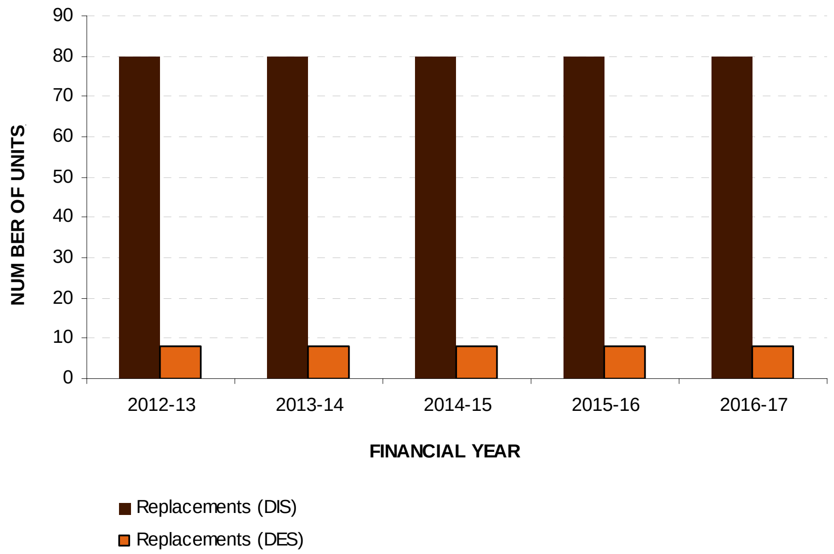

Figure 7.35: Disconnector replacements

7.11 Transmission Instrument Transformers

7.11.1 Asset Description

Instrument transformers measure either network voltage or current at a specific location for protection, control and operational purposes. Table 7.46 summarises the different types of instrument transformers in the network.

Table 7.46: Instrument transformer population

Type	11 kV	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Current Transformers	118	1,435	353	564	1,836	72	221	4,599
Voltage Transformers	2	21	58	210	886			1,177
Combined units		1	1	24	107		12	145
Capacitive Voltage Transformers					58	36	190	284

7.11.2 Failure modes and impact

The main failure in instrument transformers is oil leakage. Oil leaks on instrument transformers give rise to moisture contamination in the paper and oil insulation. This has caused several failures in Western Power's network.

Instrument transformers are critical elements of a transmission system to ensure secure operation of the network. Incorrect operation or failure can have a material impact on the safety of other equipment and the network reliability.

Failure of instrument transformer can result in loss of supply, and explosions that can endanger the safety of staff, and cause serious damage to adjacent equipment. In the last three years, Western Power has experienced several explosive instrument transformer failures causing damage to other adjacent plant assets.

7.11.3 Age and condition

Figure 7.36 shows the age profile of instrument transformers A small proportion of the population exceeds 40 years, however; a large volume of instrument transformers, particularly CTs are approaching 40 years..

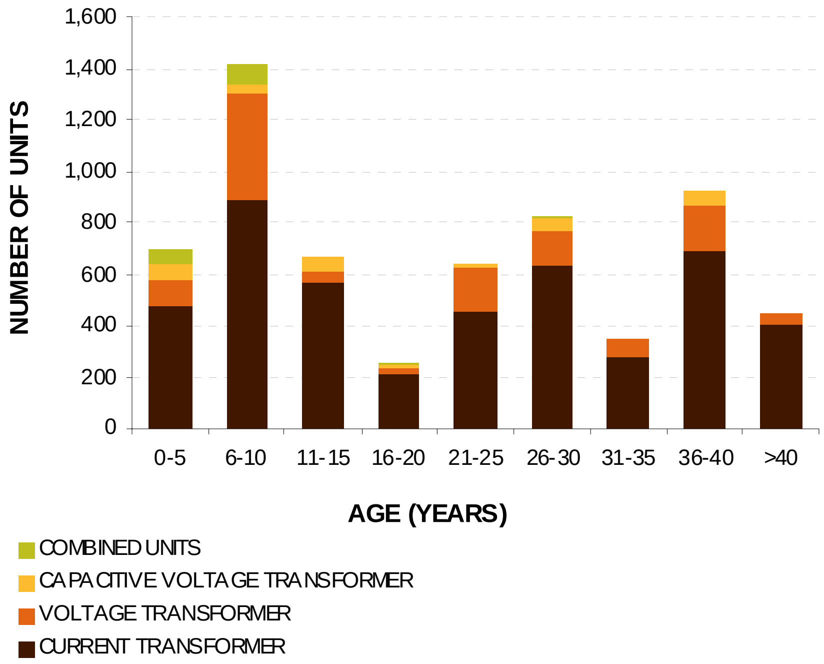

Figure 7.36: Age Profile of Instrument Transformers

The condition profile in Figure 7.37 indicates that more than 10% of both CTs and VTs are classed as being in either "poor" or "bad" condition. The condition assessment is based on diagnostic tests, inspection records and the risk of contributed failures.

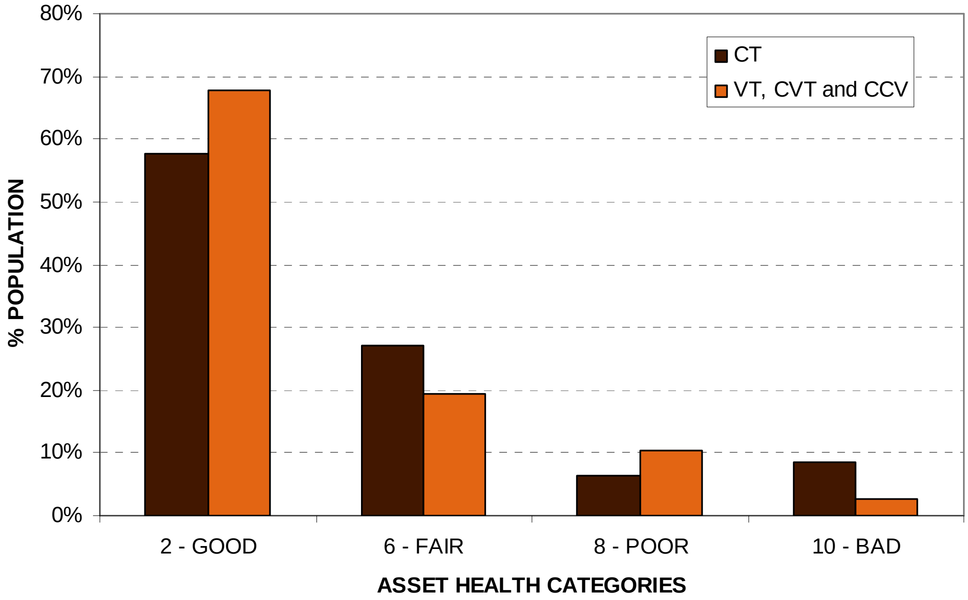

Figure 7.37: Instrument transformer condition rating

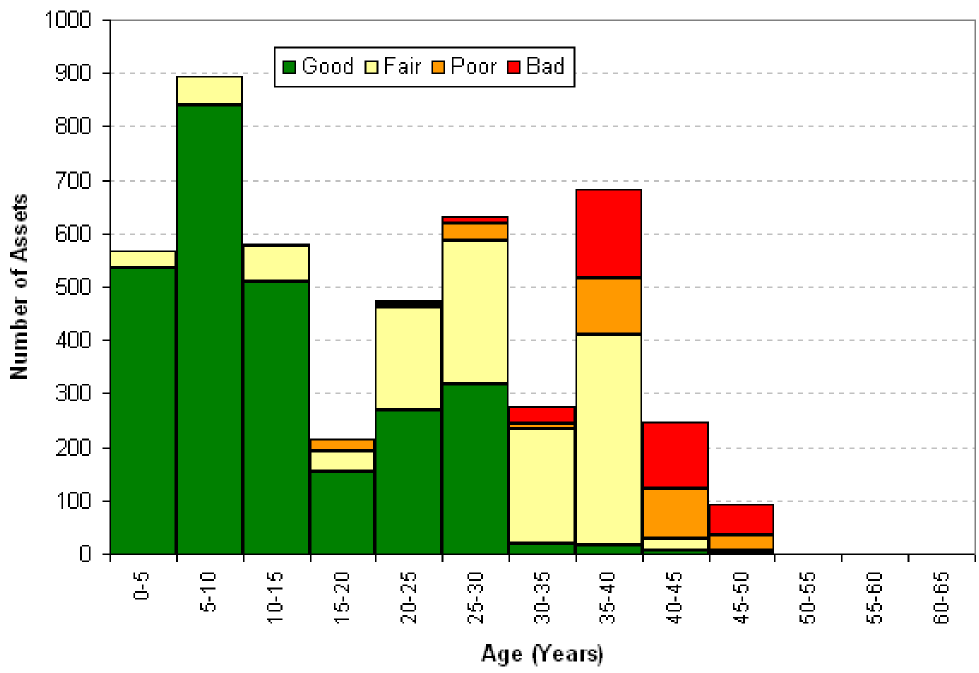

Figure 7.38: Condition Profile of Current Transformers

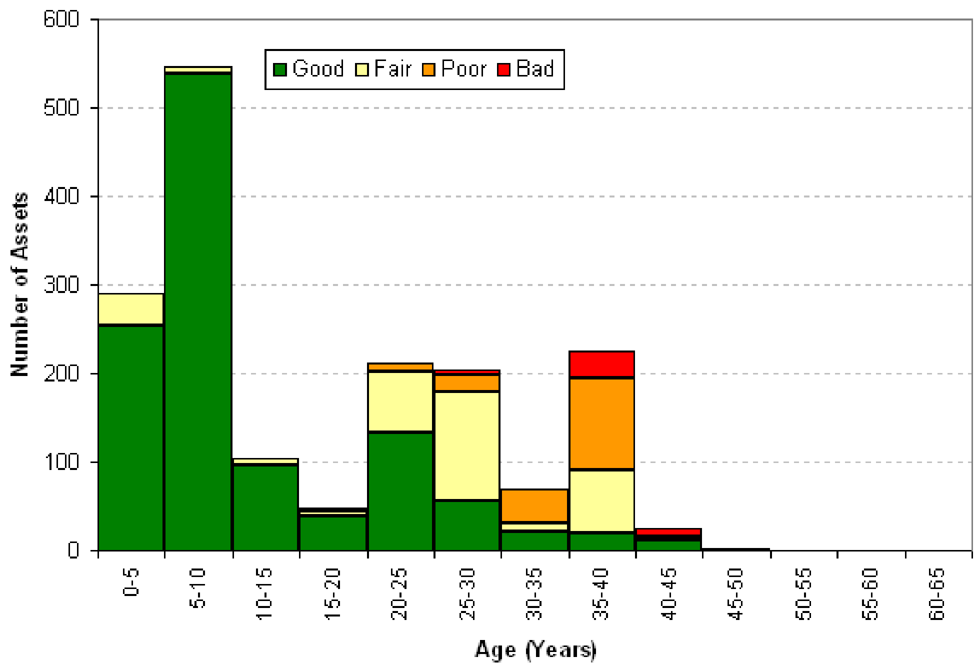

Figure 7.39: Condition Profile of Voltage, Capacitive Voltage Transformers and Combined Units

7.11.4 Performance Level

The failure of instrument transformers impacts greatly on the network is reliability. Reliability requirements for the network are established as part of the Access Arrangement. Any decrease in the performance of instrument transformers can therefore adversely affect network reliability.

Other performance requirements relate to environmental and safety performance. These requirements are established in the environmental regulations and the Occupational Safety and Health Act 1984.

The performance measures for instrument transformers are summarised in Table 7.47.

Table 7.47: Instrument transformer performance requirements

Indicator	**Target**	**Actual performance**	**Performance gap**
Contribution of instrument transformers to System Minutes	≤ 0.599 (meshed) ≤ 0.012 (Radial)	0 0	No gap No gap
Failures requiring replacement or major repair (number per year)	CT ≤ 6 VT ≤ 2 CVT ≤ 1 CCV ≤ 1	CT = 3 VT = 1 CVT = 0 CCV = 0	CT – No gap VT – No gap CVT – No gap CCV – No gap
Health Index (of individual units)	No instrument transformers in “Poor“ or “Bad” (<8) condition	CT = 87% VT = 89%	CT – 13% VT – 11%
PCB contamination (% not contaminated)	100%	85%	15%

Table 7.51 shows there are several performance gaps in particular the failure rate and the number of “poor” or “bad” condition instrument transformers. The performance gap relating to the condition of instrument transformers (e.g. CTs and VTs) is primarily due to poor high voltage test results and certain design types.

7.11.5 Strategy overview of life cycle management

Asset maintenance

Regular inspection and testing is undertaken to monitor the condition of the instrument transformer fleet. This includes specific maintenance procedures to address PCB contaminated instrument transformers.

7.11.6 Overview of plan

A summary of the strategies used to manage instrument transformers is shown in Table 7.48.

Table 7.48: Summary of strategies

Issue	Strategy	Planned Outcome
Approximately 13% of the CT population has been identified as in “Poor” or “Bad” condition. Older ASEA (IMBA) 66 kV and 132 kV CT design is inadequate due to changes in the network conditions, demonstrated by 6 CTs which have failed testing. Westralian 22 kV CTs (approximately 2% of the total CT population) have known tracking issues and suffer from severe oil leaks.	Replacement of CT where condition assessment indicates that replacement is required.	Replace 90 CT units per annum in the 2012/13 to 2016/17 period.
Approximately 11% of the voltage, capacitive transformer and combined units fleet have been identified as in “Poor” or “Bad” condition. ASEA and Haefely type 132 kV VTs (approximately 25% of the VT population) suffers from oil leaks. Koncar VTs (<10 years old) suffer from oil leaks which cannot be controlled through maintenance.	Replacement of VT, CVT and CCV where condition assessment indicates that replacement is required.	Replace 20 VTs per annum in the 2012/13 to 2016/17 period.
Approximately 350 (8%) instrument transformers are contaminated with PCBs.	Replacement of instrument transformers identified with PCBs when they have reached the end of their service life.	Replace 90 CT and 20 VT, CVT and CCV units per annum in the 2012/13 to 2016/17 period.
Instrument transformer oil leaks.	Apply Silicone compound to prevent or reduce oil leaks.	As required when oil leaks have been identified via routine inspection.

Over the period 2011/12 to 2016/17, 540 CTs and 120 VTs are planned for replacement as shown in Figure 7.40.

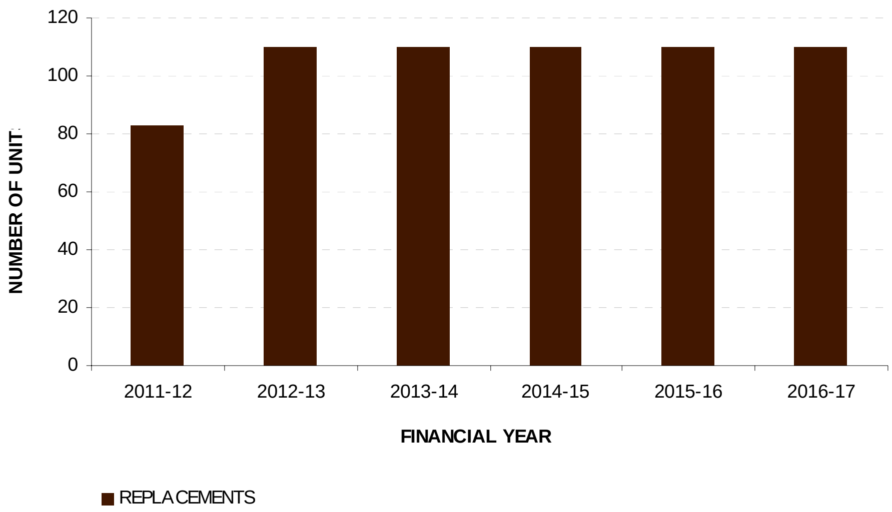

Figure 7.40: Current Transformers and Voltage Transformers replacements

7.12 Reactive Plant

7.12.1 Asset Description

Transmission reactive plant comprises capacitor banks, reactors and Static Var Compensators. These assets provide static and dynamic voltage support and power factor correction.

Reactive plant generally is located at terminal and zone substations throughout the network. Operating voltages range from 6.6 kV to 132 kV. Table 7.49 summarises the different types of reactive plant in the transmission network, and Table 7.50 provides a breakdown based on manufacturer type and insulation medium.

Table 7.49: Transmission reactive plant population

Type	Operating voltage (kV)							Total
	6.6	11	22	29.5	33	66	132	
Capacitors	11	56	166	-	94	3	11	341
Reactors	33	140	460	50	94	9	48	834
Static Var Compensators	-	-	-	-	2	-	1	3
Grand Total	44	196	626	50	192	12	60	1178

Table 7.50: Transmission reactive plant population by manufacturer type and insulation medium

Manufacturer Type	Capacitor Banks			Reactors				SVC	Total
	Oil Insulated	Air Insulated	Others	Oil Insulated	Air Insulated	EP	Others		
ABB	24	0	0	0	6	0	0	1	31
ABB POWER TRANS	31	15	0	0	0	0	0	0	46
ASEA	14	0	46	0	0	0	0	0	60
BICC	20	0	14	0	0	0	0	0	34
NISSEN	74	0	0	3	0	0	0	0	77
NOKIAN	84	0	0	0	279	0	0	0	363
HAEFELY	0	0	0	0	80	0	0	0	80
TRENCH	0	0	0	0	275	3	155	0	433
OTHERS	19	0	0	18	13	2	0	2	54
Grand Total	266	15	60	21	653	5	155	3	1178

Western Power's capacitor banks range from 1.1 MVAr to 115.1 MVAr with a total reactive capacity of 2880 MVAr.

Error! Reference source not found.: Capacitor Bank Population against capacity (MVAr) of each unit

7.12.2 Failure modes and impact

Insulation breakdown resulting in equipment flashover is the major cause reactive plant failure.

7.12.3 Asset age and condition

Figure 7.41. The expected life of reactive plant is 35 years with only 2% of the current population exceeding this.

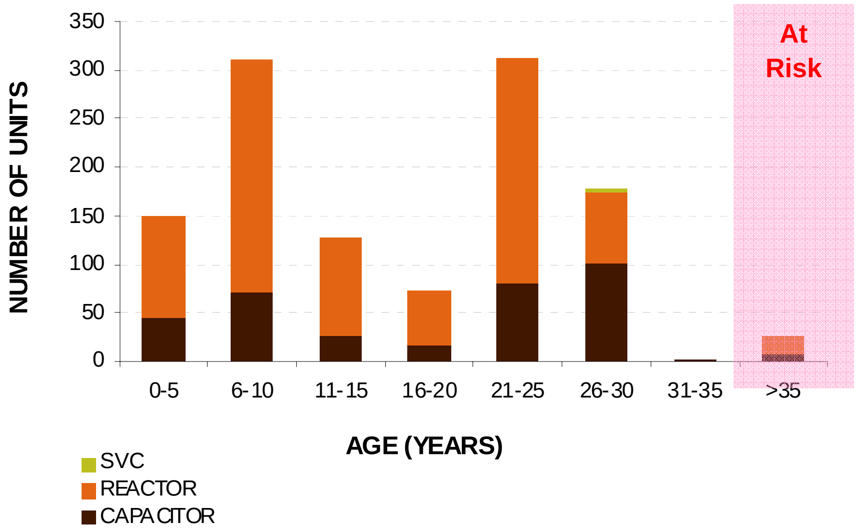

Figure 7.41: Transmission reactive plant age profile

Reactive plant on Western Power's network is in reasonably good condition. This is mainly attributed to the assets being relatively young in their asset life cycle. However, the SVC located at West Kalgoorlie and Merredin Terminal substations have been assessed in "Bad" condition.

In particular the condition of the two saturable reactors (part of each SVC) has deteriorated extensively and substantial cost is involved in fixing the problem permanently. In addition, the cooling systems (reactor coolers) have suffered from severe oil leaks with the coolers prone to heavy clogging, requiring extensive maintenance. The programmable logic controller (PLC) which also forms an integral part of the SVC is obsolete with little manufacturer service support available.

7.12.4 Performance Level

The indicators used to measure the performance of reactive plant are shown in Table 7.51.

Table 7.51: Reactive plant performance requirements

Indicator	Target	Performance 2010/11	Performance gap
System Minutes Interrupted (contribution per annum)	Meshed: ≤ 0.008 Radial: 0.000	Meshed: ≤ 0.008 Radial: 0.000	No gap

Indicator	Target	Performance 2010/11	Performance gap
Failures per annum (requiring replacement or major repair)	CAP ≤ 1 RE ≤ 2 SVC ≤ 1	CAP ≤ 1 RE ≤ 2 SVC ≤ 1	No gap
Condition Score (of individual units)	< 8	< 8	No gap

Reactive plant is currently meeting the required performance levels.

Benchmarked performance results

Based on the latest International Transmission and Operation Survey (ITOMS) conducted in 2009, the management and performance of the reactive plant population was found to be strongly performing with a low cost and high service level as shown in Figure 7.42.

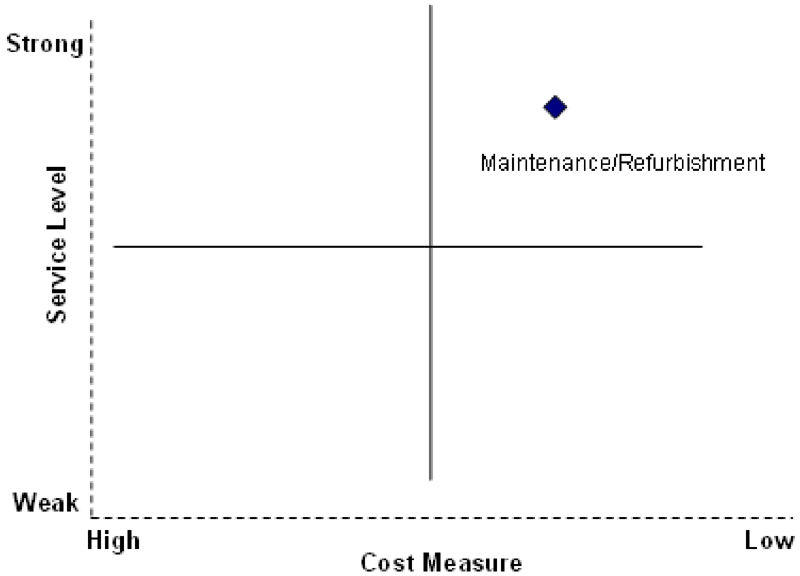

Figure 7.42: ITOMS (2009) survey results for reactive plant

Defects and Major Failures

Whilst there have been no major failures of reactive plant in the last 10 years, a number of minor failures have been experienced. Figure 7.43 shows the volume of minor failures each year and the voltage level of the failed plant.

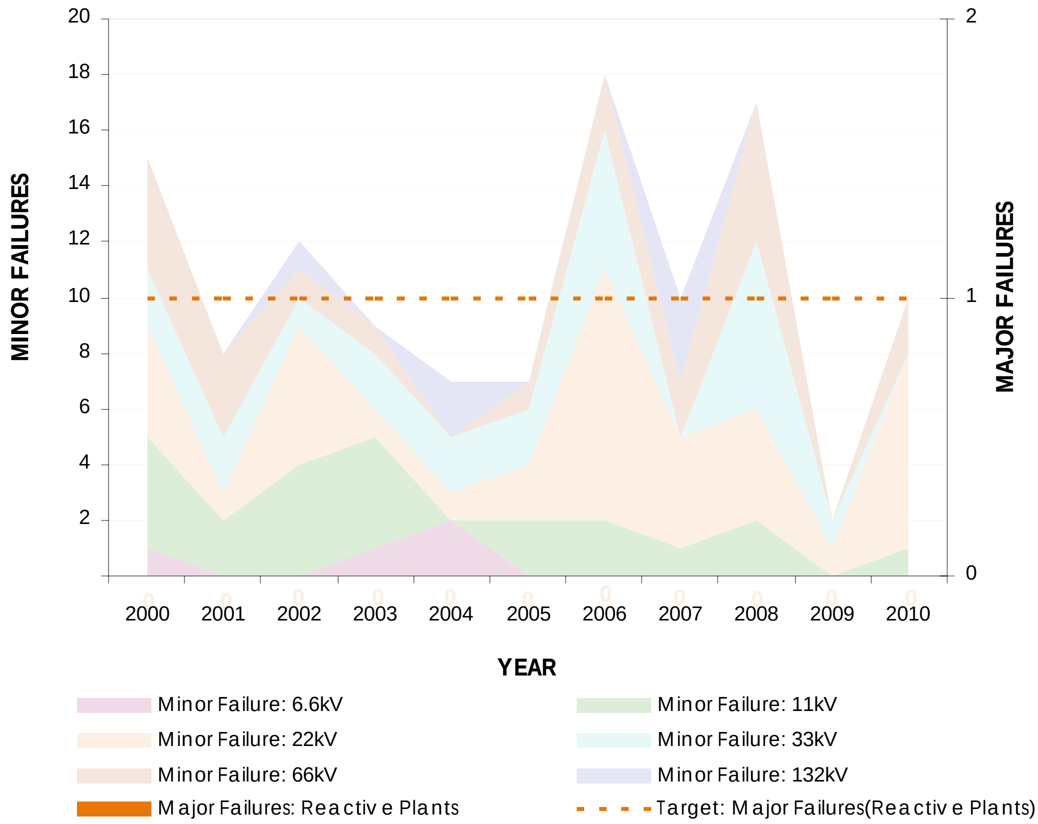

Figure 7.43: Reactive plant failure comparison in the last 10 years

7.12.5 Strategy overview of life cycle management

Asset maintenance

Reactive plant is subject to routine maintenance, limited to periodic inspections to identify any visible damage or deterioration that has occurred since the previous inspection. Capacitor bank and reactor maintenance involve two maintenance service types. The first, Level A is routine visual inspection. The second, Level B involves operational checks to confirm oil or gas levels in switches and correct operation of control units and switches.

7.12.6 Overview of plan

In addition to maintenance, the strategies adopted to meet reactive plant performance requirements are shown in Table 7.52.

Table 7.52: Issues and strategies for reactive plant

Issue	Strategy	Planned Outcome
Two Static Var Compensators (SVC) each comprising two saturable reactors, a cooling system and a Programmable Logic Control (PLC) unit in poor condition. One unit is located at West Kalgoorlie, the second at Merredin.	Additional monitoring and/or maintenance.	Monitor/Maintain as part of the routine substation inspection.
	Replace SVC system.	Begin preliminary work to replace the West Kalgoorlie SVC in AA3 (2012/13 to 2016/17). Begin preliminary work to replace the Merredin unit during AA4.
Incidents of flashover on capacitor banks caused by building up of dust.	Regular site inspection and maintenance.	Monitoring/Maintenance are conducted as part of the routine substation inspections (i.e. Monthly)
Reactor failures in-service inside the capacitor compound due to weeds causing arcing.	Regular site inspection to Keep site clear from weeds.	Monitoring/Maintenance are conducted as part of the routine substation inspections (i.e. Monthly).

7.13 HV Distribution Ground Mounted Switchgear

7.13.1 Asset Description

Distribution Ground Mounted High Voltage (GM HV) Switchgear consists of Ring Main Units (RMUs), RMU automation equipment, Switch disconnectors, Fuse switches and Circuit Breakers. GM HV Switchgear does not cover ground mounted transformers as these items are subject to separate plans.

GM HV Switchgear is used to provide a connection point for new installations, isolation of supply during faults, and for maintenance and flexibility of network operation. The switchgear operates at voltages of 6.6 kV, 11 kV, 22 kV or 33 kV.

The population of equipment is as shown in

Table 7.53. The main manufacturers are Areva (31%) and Schneider (31%) followed by Alstom (19%), F & G (9%) and Long & Crawford (7%). The remaining (3%) are split between eight other manufacturers.

Table 7.53: Ground Mounted HV Switchgear Population

General switchgear type	Total number
Ring Main Unit[24]	5,098
Switch disconnector (HV)[25]	12,101
Fuse-switch[26]	7,648
Circuit Breaker[27]	4

7.13.2 Failure modes and impact

Typical defects identified on Ground Mounted HV Switchgear are:

- Corrosion;
- partial discharge; and
- low SF6 gas pressure.

Failure of Ground Mounted HV Switchgear typically leads to network outages and if, catastrophic failure occurs, can lead to serious injury or fatality of an employee or member of the general public. Other possible impacts from failure are oil spill, SF6 gas leakage and fire.

7.13.3 Age and condition

The expected service life of Ground Mounted HV Switchgear is 35-45 years. However, the in-service life is dependant on a range of factors including:

- Environmental conditions;
- quality of the construction;
- the number of switching operations; and
- maintenance cycle and practices.

The age profile of Ground Mounted HV Switchgear is shown in Figure 7.44. While the majority of Ground Mounted HV Switchgear is younger than 30 years, approximately 15% is greater than 40 years old and are likely to be approaching the end of their operational life.

[24] The Ring Main Units in this population data encompass some or all of the Fuse Switches, Circuit Breakers and HV Switch Disconnectors
[25] As per DFMS, switch disconnectors and fuse switches are uniquely identified. The total number includes stand alone and those that are part of RMUs
[26] As per DFMS, fuse-switches are uniquely identified. The total number includes stand alone and those that are part of RMUs
[27] Yorkshire YSF5 models are the only switchgear with circuit breaker functionality (CBD installations)

Figure 7.44: GM HV Switchgear (RMU) age profile

7.13.4 Performance Level

The primary impact that failure of GM HV Switchgear has on the network is service reliability. Reliability requirements for the network are established as part of the access arrangement. Other performance requirements relate to environmental and safety performance. These requirements are established in the environmental regulations and the Occupational Safety and Health Act 1984.

The performance measures for GM HV Switchgear are shown in Table 7.54.

Table 7.54: GM HV Switchgear Performance indicators

Indicator	Target	Actual performance	Performance gap
Percentage of switchgear requiring replacement before the end of its expected life	< 2.2%	2.82	0.62
Number of switchgear failures per financial year	<10	12	2
Percentage of switchgear for which Level C maintenance is overdue	< 50%	80%	30%
Percentage of switchgear with defects not rectified	< 5%	9%	4%

The performance gap results from previous maintenance practices and spare parts issues. Routine C level maintenance was not carried out on the GM switchgear and when a program of C level maintenance was commenced, it was initially resource constrained. Shortage of spare parts for some types of RMU also affected performance.

An issue has arisen affecting a specific type of RMU (Hazemeyer). These units pose a safety risk and a program to replace all of these units will be completed by the end of the AA3 period.

7.13.5 Asset management strategies

Asset maintenance

Preventative maintenance and proactive replacement is undertaken based on condition assessments made during the cyclic inspection program. Maintenance intervals vary from every 3 to every 9 years depending upon type and manufacturer.

7.13.6 Overview of plan

A summary of the strategies used to manage HV GM Switchgear is shown in Table 7.55.

Table 7.55: Summary of strategies

Issue	Strategy	Planned Outcome
Corrosion; OR Potential environmental damage including oil leaks & SF_6 gas leaks; OR Corona/Partial discharge.	Identify as a part of ground mounted substation inspection program.	2 yearly inspection cycle except CBD. Annual inspection in CBD.
	Rectify any defects as a part of GM switchgear maintenance program.	Prioritise according to urgency.
	If beyond repair replace the RMU under HV RMU replacement program.	Prioritise according to urgency and spare parts availability. Approximately 40 replacements per year.
In-service failure.	Replace failed units reactively.	Approximately 12 replacements per year.
Safety risk – Hazemeyer HV switchgears.	Replace the RMU under HV RMU replacement program.	Prioritise according to urgency.
Shortage of spare parts for some RMU types.	Use RMUs removed from service for spare parts. Target RMUs with shortage of spare parts for replacement.	Target Siemens 8CK1 and Brown Boveri RGB RMUs for replacement and reuse parts from removed units.

Figure 7.45 shows the forecast RMU replacement volumes for the next 6 years.

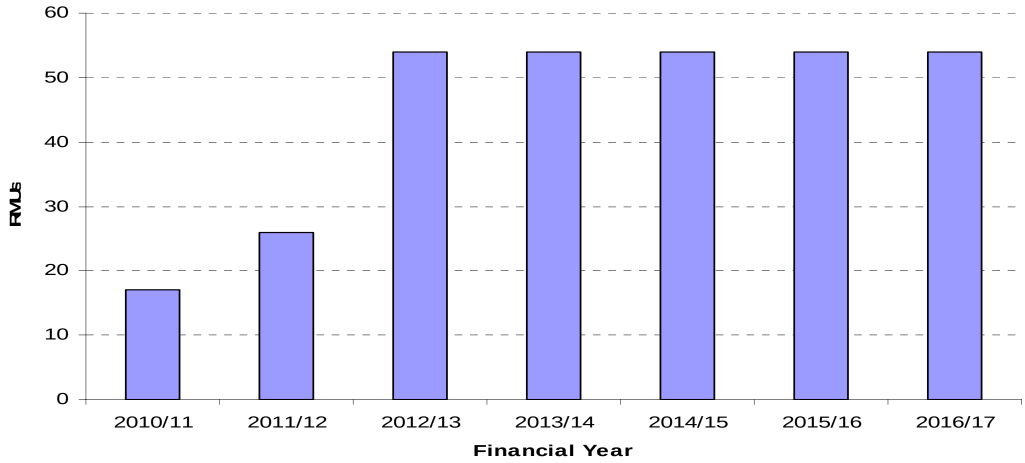

Figure 7.45: Forecast RMU replacement volumes

7.14 Distribution Overhead (HV) Pole Mounted Equipment

7.14.1 Asset Description

The Distribution Overhead (HV) pole mounted equipment comprises items mounted on poles in the distribution system including reclosers, sectionalisers, pole top switch disconnectors, and expulsion drop out fuses. The plan does not include poles, crossarms, insulators or conductor as these items are the subject of separate plans.

Reclosers: These operate when faults occur by interrupting permanent faults and limiting interruptions due to transient faults to a very short duration thereby preventing asset damage and reducing the impact of potential network outages.

Reclosers can be classified based on the number of phases they control and the type of controller:

- three-phase or single-phase; and
- control: electronic or hydraulic.

Hydraulically controlled reclosers cannot be automated. Electronically controlled reclosers are more flexible, and more easily customised and automated. Automation of reclosers is important, particularly in bushfire areas, as the operation of a recloser can lead to bushfires and so suppression of reclosers on days of extreme fire risk is desirable.

Table 7.56: Total recloser fleet by classification

	1-ph		3-ph	
Type of Control	Telemetry	Non-telemetry	Telemetry	Non-telemetry
Electronic	308	28	868	25
Hydraulic	4	410	9	37
Unknown		4		10
Total	312	442	877	72

Sectionalisers: Sectionalisers operate as isolating devices. They are installed downstream from a recloser, and in the event of a fault, the sectionaliser counts the number of operations of the recloser. After a preset number of operations of the recloser, the sectionaliser will open its contacts whilst the network is in a temporarily de-energised state, so as to isolate only the faulted section of the network.

Most sectionalisers are single-phase (99%), and about 17% of these are the older, electro-mechanical type. Table 7.57 shows the population breakdown.

Table 7.57: Sectionaliser population

Type	Number of units in service
Electro-mechanical	151
Hydraulic	4
Electronic	659
Unknown	100
Total	917

Pole Top Switch Disconnectors (PTSDs): 11,676 PTSDs are installed on the network. These units comprise three, single phase disconnectors ganged together to give simultaneous operation and are used to manually isolate HV 3 phase line sections of the distribution network.

Expulsion Drop out Fuses (EDOFs): Operate when the current flow exceeds the rating of the fuse and protect transformers, cables and network spurs from overload and fault conditions. EDOFs can also assist in minimising the effects of outages by isolating faulty parts of the network, thereby enabling unaffected parts of the network to continue functioning.

EDOFs are designed to activate a releasing mechanism when they operate. This operation results in the fuse carrier “dropping out” and hanging downwards which facilitates identification of a blown fuse and assists repair crews to identify faults quickly. However, EDOF operation can also result in the expulsion of sparks which can ignite fires at the base of poles and the units are therefore a risk in fire prone areas.

Approximately 32,500 EDOF’s are installed on the network. The proportion of EDOF’s in each of the fire risk areas is shown in Figure 7.46. More than one third of the population is located in “Extreme” or “High” fire risk areas.

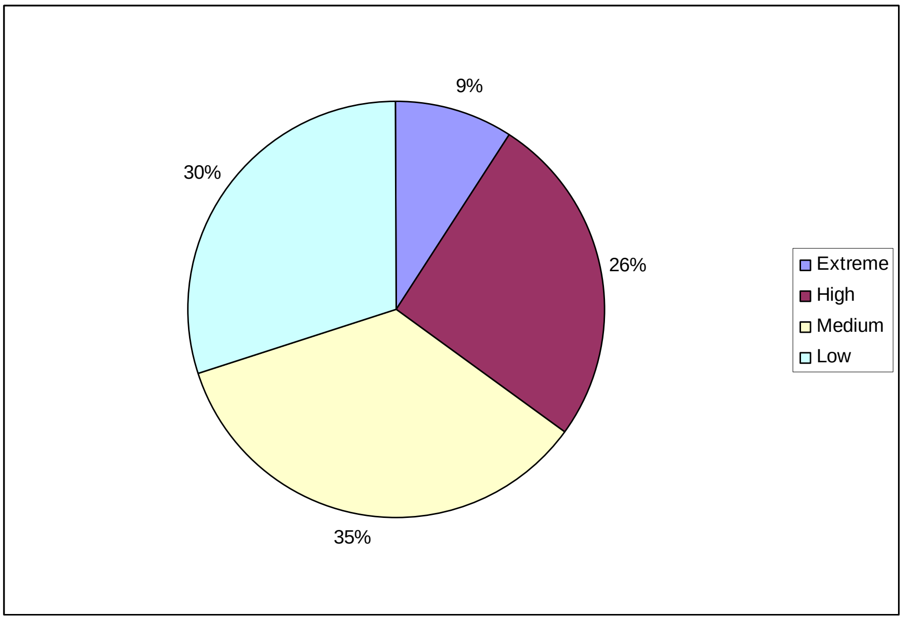

Figure 7.46: EDOF distribution by fire risk area

7.14.2 Failure modes and impact

Reclosers: The impact of recloser failure depends upon the mode of failure. A failure to open when a fault occurs has serious impact as it can lead to network damage, extended network outages, safety and bushfire impacts. A failure of recloser to close (after it has opened) has a network service reliability impact.

Sectionalisers: Typically fail due to mechanical breakdown, rust (housing) and oil leakage. Failure of a sectionaliser will only result in increasing the numbers of customers affected by a network outage.

Pole Top Switch Disconnectors: PTSDs failures are generally caused by mechanism breakdown resulting in an operator not being able to open or close the switch. The impact of this is extended network outages and extended fault finding time.

Expulsion Drop Out Fuses: EDOFs generally fail when the mechanism jams resulting in operation of the fuse without the fuse “dropping out”. This leads to extended outages as faults take longer to find.

7.14.3 Age and condition

Reclosers: The average age of reclosers is 8.5 years for the electronic controller type and 23 years for the hydraulic controller type. Expected recloser life is 45 years. Currently, there are 30 units that have passed the expected age. 60% of the total population is less than seven years old. Figure 7.47 shows the age profile by controller type.

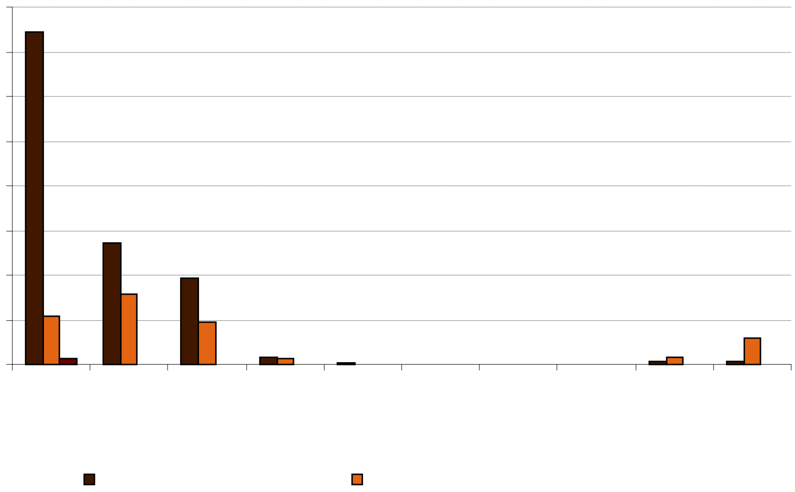

Figure 7.47 Recloser age profile

Most sectionalisers are less than 25 years old however there is a significant population in the 40 to 45 year age range as shown in Figure 7.48.

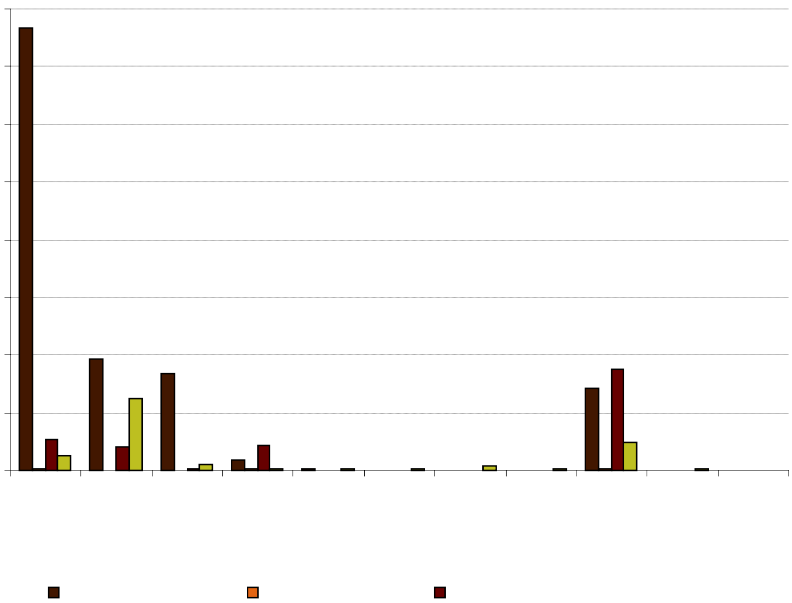

Figure 7.48: Sectionaliser age profile

Pole Top Switch Disconnectors: Currently, 42% of the PTSDs have exceeded their expected life of 35 years as shown in Figure 7.49. A proportion of those PTSDs that have exceeded their expected life will be condition assessed and replaced as required.

Figure 7.49: Pole Top Switch Disconnector age profile

As PTSDs are not a key component of the network during normal operation they can remain on the network in an inoperable condition. There are currently 1,500 PTS identified as "unserviceable" due to earthing system breakdown.

Expulsion Drop Out Fuses: The age profile of EDOF's is shown in Figure 7.50. More than half of the EDOF's are over 35 years old. (Note this is the age of the carrier mechanism. The fuses will be younger in situations where the fuse has blown and been replaced.)

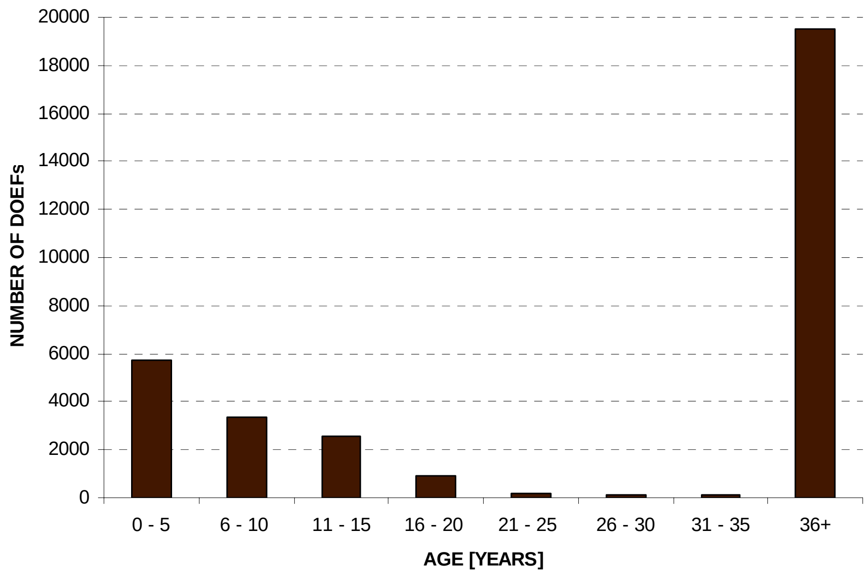

Figure 7.50: Drop out expulsion fuse age profile

A program to replace EDOF's located in the Extreme and High Fire risk Areas is will be completed in 2011/12 and will result in the replacement of

35% of EDOFs. This will have a significant impact on the overall age profile.

7.14.4 Performance Level

The performance indicators for Distribution Overhead (HV) are shown in Table 7.58.

Table 7.58: Performance Indicators for Distribution Overhead (HV)

Performance Indicator	Target	Actual Performance	Performance gap
Number of failed reclosers per financial year	<1%	0.9%	No gap
Number of hydraulic reclosers replaced per financial year	15	9	6
Percentage of reclosers with defects not rectified, per financial year	< 5%	4.4 %	No gap
Number of failed sectionalisers per financial year	<2%	0.6%	No gap
Percentage of sectionalisers with defects not rectified, per financial year	< 5%	0.5%	No gap
Number of Westec sectionalisers replaced per financial year	8	2	6
Number of PTSD failures per financial year	<50	74	24
% of PTSDs with unsatisfactory earthing, that is, without earthing mats or with corroded down earths.	<5%	10.5%	5.5%
Percentage of PTSDs with defects not rectified. (Excludes earthing related defects)	< 5%	3.4%	No gap
Number of EDOF caused bushfires per financial year	1	1 (7 fires in 6 years)	No gap
Number of EDOF's with manufacturing defects replaced per financial year	0	Program underway	9385

Reclosers: Reclosers have historically failed at a rate of 13 per year. No change in this rate is evident.

Sectionalisers: Electro-mechanical types particularly suffer from age related deterioration. There is an average of 8 in service failures per year. Further, a type issue affects 114 Westec type electro-mechanical sectionalisers resulting in poor reliability of these units.

Pole Top Switch Disconnectors: PTSDs have failed mainly as a result of condition or vandalism at which time it poses a safety risk. Approximately 1500 units have been identified as unserviceable.

Expulsion Drop Out Fuses: There are 9385 EDOF's that have been identified with manufacturing defects affecting the fuses ability to drop-out and operate correctly.

7.14.5 Asset maintenance

Distribution Overhead (HV) assets have been incorporated into the Overhead Switchgear Bundled Inspection Program. All items are repaired based on condition except for automation and communications components which are reactively repaired on failure through the Request for Repair (RFR) process.

7.14.6 Overview of Plan

Table 7.59: Summary of strategies

Issue	Strategy	Planned Outcome
Hydraulic controlled reclosers cannot be automated. This impedes the bush fire mitigation plan in extreme and high fire risk zones.	Replace hydraulic reclosers with new electronic reclosers to provide remote control and monitoring functionality to meet bushfire risk management objectives.	Proactive replacement of all 3-phase hydraulic reclosers in Extreme, High and Moderate Bushfire Risk Areas by the end of June 2017. Proactive replacement of half of the remaining 1ph hydraulic reclosers not addressed by the above program. A total of 50% of hydraulic 1-ph reclosers will be replaced during AA3 period.
Reclosers - older units, particularly near coastal areas suffer from corrosion. This can also impact on oil management and associated environmental compliance issues.	Strategy to identify poor condition reclosers (corrosion etc) Inspect and condition as part of routine bundle inspection. Consolidate recloser range of stock. Replace obsolete units as part of managing	Upgrade reclosers in High fire risk areas first, followed by moderate etc. Inspect annually.

Issue	Strategy	Planned Outcome
	the risk of in-service failure.	
Poor reliability of Westec sectionalisers.	Proactive program of replacement of Westec sectionalisers.	8 replacements over 2011/12 to 2016/17 period. All sectionalisers to be replaced over a 15 year period.
PTSD Earthing system breakdown resulting in the manual operating switch becoming conductive and providing a hazard to personnel and the public.	Inspect PTSD units as part of bundled inspection program. Issue portable earth mat and work practise manual with updated instruction	Inspect PTSD every 4 years and repair as required.
PTSD failure.	ALCA modelling has been used to identify the optimum level of replacement based on predicted failures. Establishment of program to replace PTSDs.	Replace 151 switches per year over the 2011/12 to 2016/17 period.
1,500 PTSDs identified as “unserviceable” due to earthing system breakdown.	Repair earthing.	In addition to the 151 switches p.a. above replace an additional 99 unserviceable units to make a total of 250 units
9,385 EDOF’s have a manufacturing defect affecting the fuses ability to “drop out” and thereby operate correctly.	Program to replace the 9,385 units has commenced. These EDOF’s are located in the Medium and Low Fire Risk Areas. Defective EDOF’s in “extreme” and “High” risk areas are being replaced with Fault Tamer fuses. This program is addressing both the manufacturing defect and bushfire problems in these areas.	Program is planned to continue until the end of June 2017 (AA3) by which time all the defective units will have been replaced. This program increases in volume each year as delivery capacity increases.
EDOF’s have the potential to initiate a bushfire when it operates due to the expulsion of molten materials.	The current mitigation strategy is a pole base clearing program to reduce the likelihood of a fuse initiating a bush fire.	Ongoing until units replaced with “Fault Tamer” units.
	Program to replace EDOF’s with non-expulsion type	This program is expected to be completed by the end of

Issue	Strategy	Planned Outcome
	“Fault Tamer” fire safe fuses at 11,246 locations defined as Extreme” and “High” fire risk areas.	AA2.

The planned replacement volumes for Distribution Overhead (HV) are shown in the following charts and tables.

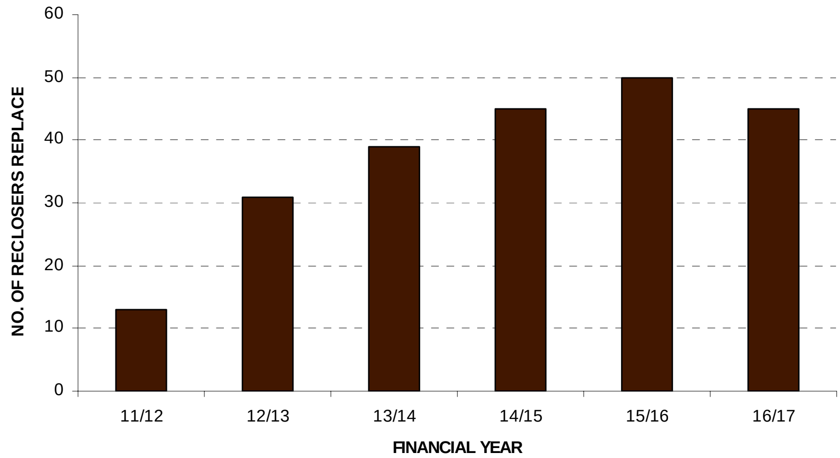

Figure 7.51: Recloser replacement volumes

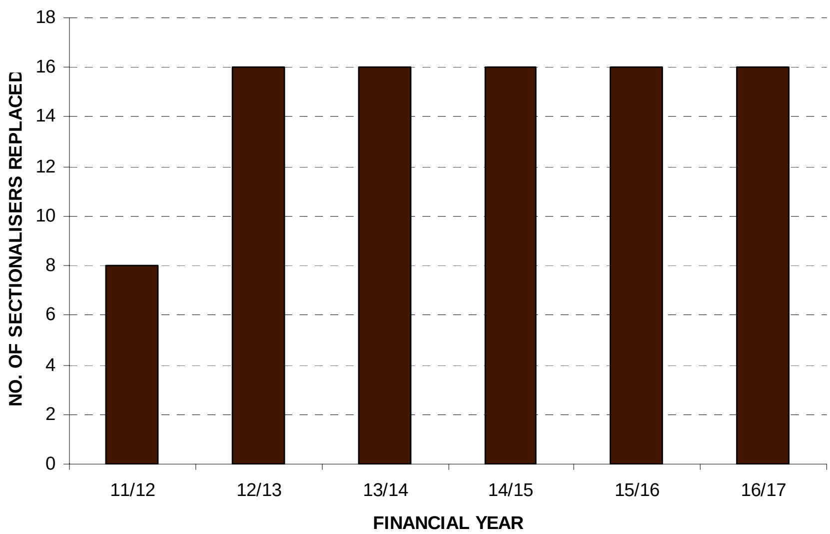

Figure 7.52: Sectionaliser replacement volumes

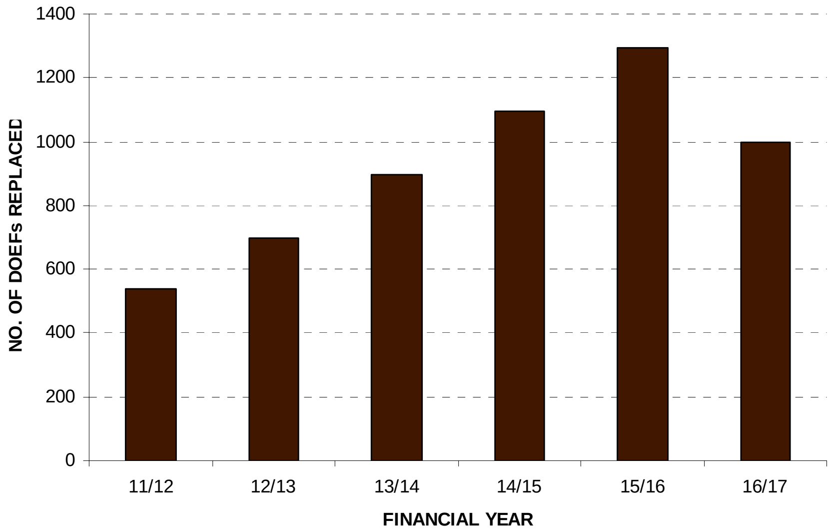

Figure 7.53: EDOF replacement volumes

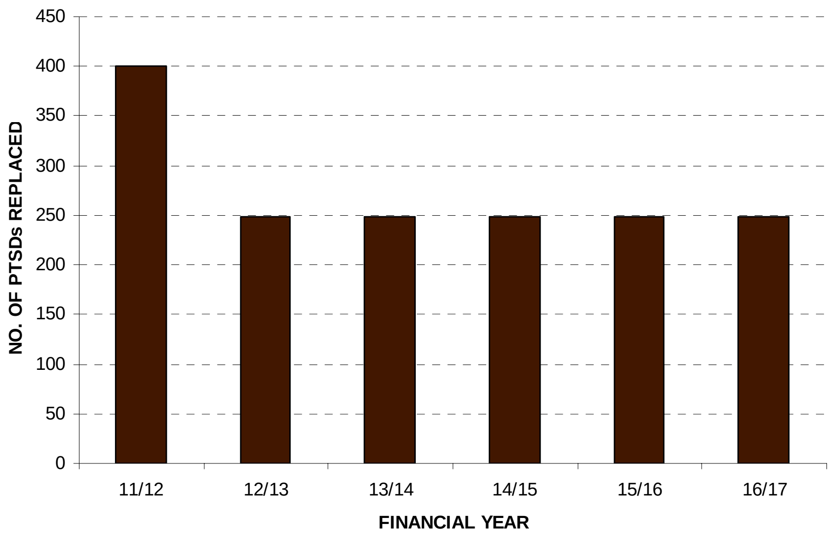

Figure 7.54: PTSD replacement volumes

7.15 Distribution Transformers

This section summarises the asset management plan for distribution transformers.

7.15.1 Asset Description

Distribution transformers are used to transform high voltages, typically 6.6 kV, 11 kV, 22 kV or 33 kV, down to the low voltages (480V, 415 V or 240 V) used by most electricity consumers. The distribution network utilises two types of transformer: pole mounted and ground mounted. Pole mounted and ground mounted transformers with a rating of less than 300 kVA are RTF assets. Ground mounted transformers rated 300 kVA or above is managed as N-RTF assets.

10,600 ground mounted distribution transformers N-RTF are installed on the distribution network, as shown in Figure 7.55. The main manufacturer of these transformers is ABB (74%), followed by Westralian (21%). The remaining (5%) of transformers are divided between seven other manufacturers.

Table 7.60: Ground mounted distribution transformer population (≥ 300 kVA)

Capacity (kVA)	% of Population	Total
300	7%	724
315	24%	2527
500	30%	3171
630	16%	1704
750	<1%	19
1000	20%	2103
1500	<1%	4
Unconfirmed	3%	348
Total		10,600

The volume of pole mounted distribution transformers with capacities of < 100 kVA are shown in Table 7.52. Ninety-four percent of these are 25 kVA or less and these are generally installed in isolated and sparsely populated areas. Of the transformers that are ≥ 100kVA, 84% of this population have capacity sizes of 100kVA & 200kVA respectively.

Table 7.61: Pole mounted distribution transformer population

< 100 kVA Capacity (kVA)	% of population	Population
5	18%	8,249
10	58%	27,152
20	1%	416
25	17%	8,104
50	2%	1,016
63	4%	1,923
75	<1%	2
Total	100%	46,862
≥ 100 kVA Capacity (kVA)	**% of population**	**Population**
100	30%	2,986
150	<1%	1
160	5%	530
200	54%	5,331
315	11%	1,094
Total	100%	9,942

7.15.2 Failure modes and impact

Transformers typically fail due corrosion of the main tank or radiator fins resulting in leaking insulating oil potentially resulting in environmental damage and failure of the transformer. Transformer failure generally results in a network outage with the impact of the outage in proportion to the transformer size.

Transformers also fail due to overloading with impact similar that of a deteriorated transformer. However, network peak loads occur after sustained periods of high ambient temperature and this can result in multiple transformer failures and widespread network outages. For example, in February 2004, 52 transformers failed during a sustained period of high temperatures, causing supply interruptions to approximately 4,500 customers, with durations of around 9 hours per customer affected. Pole mounted transformers of 100kVA and 200KVA rated are not fused on the LV side and present additional network risks when severely overloaded.

7.15.3 Identification of Overloaded Transformers

This process commences around March/April of each year, when customer consumption data becomes available during elevated summer temperatures. The load forecasting tool (DNAT-LFM), is a software application tool that uses customer consumption data, the number of customers supplied from a transformer, the capacity of the transformer and peak loading of the HV feeder to determine the level of utilisation of each transformer in the Western Power network.

A criterion of 135% loading and a Transformer Utilisation Factor (TUF) of >0.5 has been established to determine whether a transformer requires upgrading. The validity of the predicted loading is verified prior to replacement.

7.15.4 Age and condition

The expected service life of transformers is 35 - 45 years. However, the actual life is dependant on a range of factors including:

- quality of the construction;
- load and utilisation over the expected service life; and
- environmental conditions.

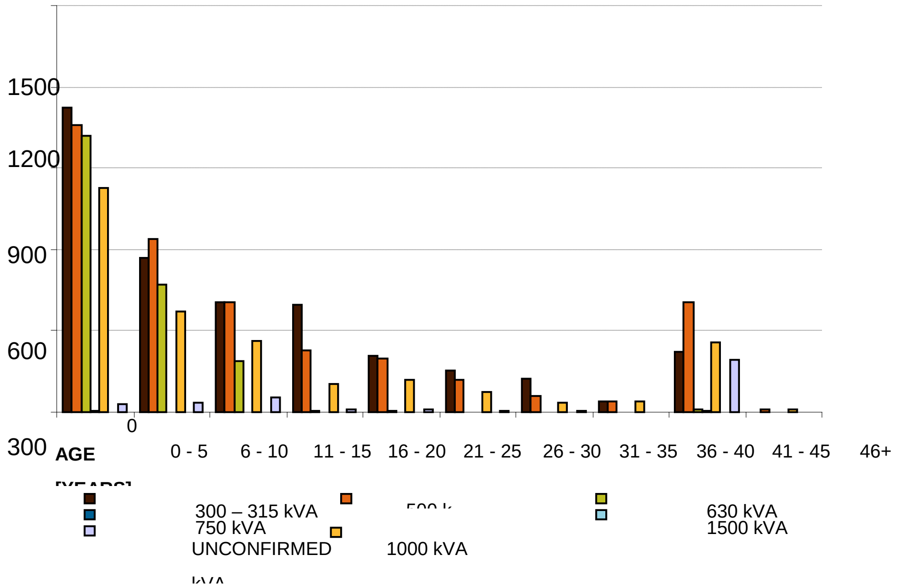

Figure 7.55: Ground mounted distribution transformer ≥ 300 kVA age profile

The age profile of ground mounted distribution transformers ≥ 300 kVA is shown in Figure 7.55. While the majority of these transformers are younger than 30 years, approximately 11% are greater than 40 years old and are likely to be approaching the end of their operational life.

Table 7.62 shows the loading distribution across the population of transformers >100 kVA rating capacity. 22.5% of the population are operating at less than 10% of capacity whilst 250 transformers (1.4%) are loaded above cyclic rating (≥140%).

Table 7.62: Existing transformer loading (capacities ≥100 kVA)

Number of transformers	Transformer Load(%)	Percentage of Population
4,058	0-10	22.5%
12,371	10-100	68.5%
1370	100-140	7.6%
250	140-180	1.4%

There is a strong link between overload and transformer failures. Overloading generates excessive heat in the windings of the transformer that deteriorates the winding insulation to the point that it causes internal short circuits.

7.15.5 Performance Level

The performance measures for distribution transformers are shown in Table 7.63. All performance measures are currently being met.

Table 7.63: Performance indicators for distribution transformers

Performance measure	Target	Actual performance (2010/11)	Performance gap
Percentage of N-RTF distribution transformers requiring replacement before the end of expected life	< 2%	1.1%	No gap
Number of N-RTF distribution transformer failures per year	≤ 2%	1%	No gap
Percentage of N-RTF distribution transformers with outstanding defects	< 5%	3%	No gap
Percentage of overloaded (>135% nominal rating) distribution transformers	≤1%	<1%	No gap

7.15.6 Asset management issues and strategy

Distribution transformers are inspected as part of the substation inspection program according to the prescribed intervals, where a condition assessment is undertaken.

7.15.7 Overview of plan for ground mounted transformers

A summary of the strategies used to manage Distribution Transformers is shown in Table 7.64.

Table 7.64: Summary of strategies

Issue	Strategy	Planned Frequency
Corrosion/rust on Tx tank and radiator fins (≥ 300 kVA). Identification as a part of ground mounted substation inspection program.	Rectify defect by touch up paint as a part of substation maintenance program (K2KJ).	Prioritise according to urgency.
	If severe replace transformer as part of the replacement program.	Prioritise according to urgency.
Oil leaks (≥ 300 kVA).	Rectify minor oil leaks as a part of substation maintenance program (K2KJ).	Prioritise according to urgency.
	Replace transformer with major oil leaks under Tx replacement program.	Prioritise according to urgency.
Fault on transformer < 300 kVA.	Replace when fault identified through outage or through incidental report.	Replace when identified.
Overloaded transformers < 100 kVA.	Upgrade when alerts are raised through complaints of repetitive fuse operations and overload is verified.	Respond to identified overloads.
Overloaded transformers< 300 kVA.	Upgrade when loading at 130% loading has been.	Respond to identified overloads.
Management of decommissioned transformers	Review current management process	Reviewed process finalised by start of AA3

Figure 7.56 shows the forecast volumes of distribution transformers to be replaced in the next 6 years.

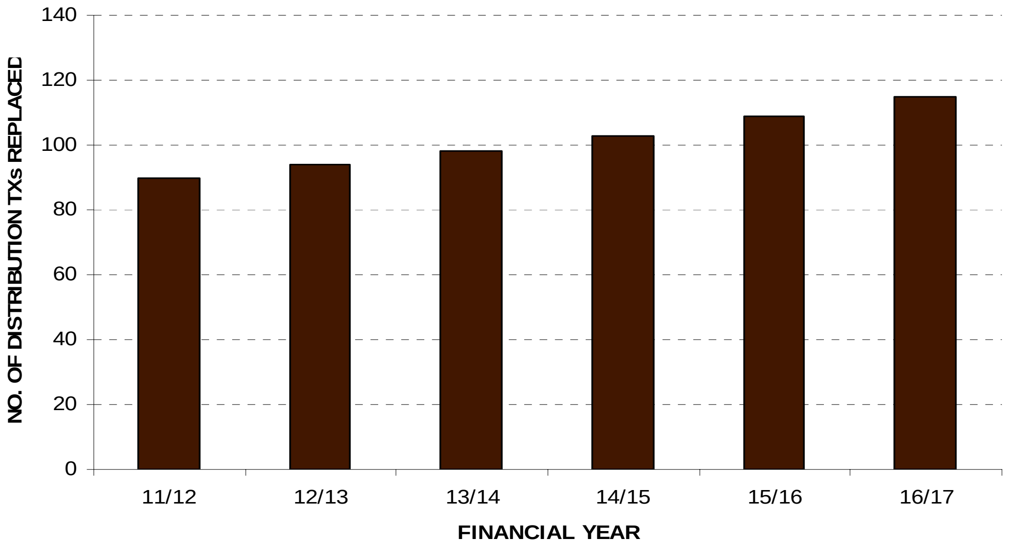

Figure 7.56: Forecast N-RTF distribution transformer replacement volumes

7.16 Street Lighting

This section describes the lifecycle management plan that applies to streetlights.

7.16.1 Asset Description

The network incorporates over 220,000 streetlights. 101,000 are mounted on dedicated poles and the remainder are mounted on distribution poles. A small number of streetlights are also mounted on transmission poles. This plan does not include the metal poles as these are the subject of another plan.

The major component of a streetlight is the luminaire. It is an enclosed lamp fitting to carry replaceable globes and control wiring to operate the globes. Most streetlights are fitted with a Photo Electric (PE) cell for dusk to dawn switching of luminaires. The luminaires are attached to the poles by mounting brackets or outreaches.

Luminaires mounted on dedicated metal poles are supplied by underground cables. Those on overhead line poles are connected either to the low voltage (240 Volts) main conductors if fitted with PE cells or to the streetlight switchwires on those poles. Streetlight switchwires are part of an older design that incorporated time clocks to switch the streetlights. Time clocks are being phased out and replaced by PE cells.

Figure 7.57 shows a breakdown of the streetlight globe types. Note this excludes streetlights that are owned by third parties such as Local Government Authorities. These assets typically are found in areas such as Council Parks. They are not managed by Western Power.

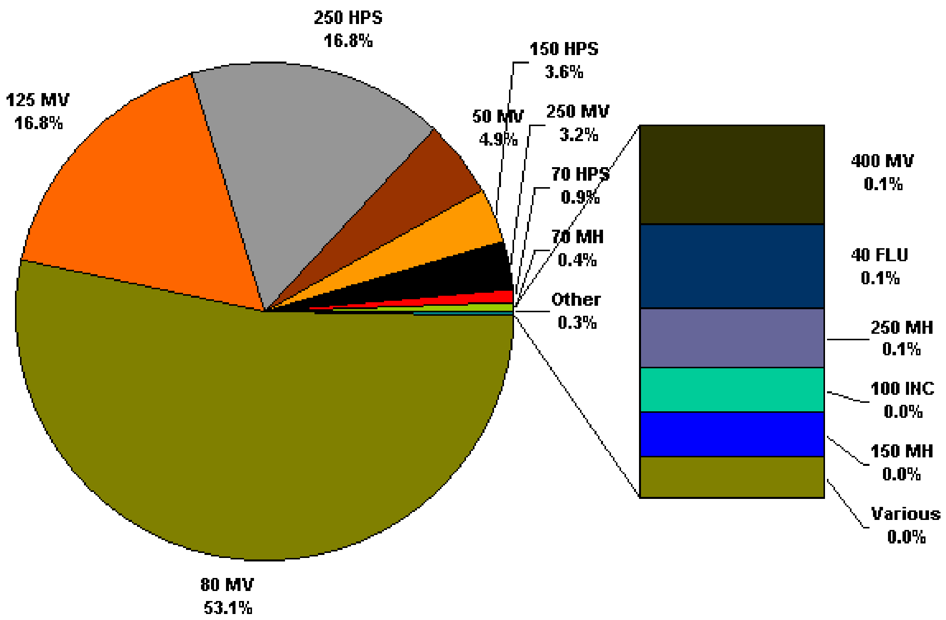

Figure 7.57 Streetlight types by globe type

The predominant type of streetlight is the 80W Mercury Vapour type (80MV). This type is now being progressively phased out and replaced with more energy efficient compact fluorescent streetlights.

7.16.2 Failure modes and impact

Streetlights suffer from deterioration and failure. Deterioration occurs as the globe ages resulting in reduced light output. Failure can result from component failure, such as the globe or PV cell failing, or a failure of the cable or service that supplies the luminaire.

Streetlights provide illumination for roads and public areas. Failure of streetlights can result in issues such as safety of pedestrians and poor visibility resulting in motor vehicle accidents.

Physical failure of switchwire can lead to wires down incidents. These incidents create a risk of electric shock resulting in serious injury or fatality. However, a greater impact from switchwire is the risk of injury that involves the switchwire being energised (live) at certain times of day and de-energised the remainder of the time. There have been a significant number of near misses, starting in 2002, and one fatality in 2011 as a result of switchwires.

7.16.3 Age and condition

Approximately 25% of luminaires have exceeded the expected life of 20 years and the proportion of luminaires that exceeds the expected life is increasing each year. As the units age, the condition deteriorates eventually resulting in failure.

A large majority of switchwires are old and in poor condition. Broken switch wires and low clearance incidents (switchwire faults) are occurring more frequently.

7.16.4 Performance Level

Performance levels for streetlight repair times have been agreed with the electricity retailer (Synergy). Historical performance is shown in Table 7.65.

Table 7.65: Streetlight average repair times

Region	Agreed repair time	Actual 2006/07	Actual 2007/08	Actual 2008/09	Actual 2009/10	Actual 2010/11
Perth Metropolitan Area	≤ 5 days	7.2 days	9.6 days	3.7 days	2.0 days	1.4 days
Major Regional Towns	≤ 5 days	n/a	n/a	n/a	n/a	1.5 days
Remote and Rural Towns	≤ 9 days	5.7 days	5.6 days	4.1 days	1.7 days	1.7 days

Performance levels have been met in all regions for the past 3 years.

7.16.5 Asset management strategies

Asset maintenance

Streetlight maintenance involves inspection, periodic replacement of globes and reactive repair of faults. Streetlight inspection is carried out in conjunction with the periodic replacement of globes. Reactive repair of faults is carried out following identification of the fault during the inspection or as the result of a reported fault.

A summary of the strategies used to manage streetlights is shown in Table 7.66.

Table 7.66: Summary of strategies

Issue	Strategy	Plan/Frequency
Light output deteriorates.	Bulk Globe Replacement (BGR) program.	All globes replaced in each 3 year period.
Wiring failure at streetlights on metal poles.	Inspect and correct wiring when globes replaced and during any visit to repair a fault.	All inspected every 3 years.
Switchwire deterioration.	Program to remove switchwire prioritised by suburb based on reported electric shocks.	Replace 680 kms per annum. (3,400 kms approx) to complete program by end of 2016/17.
Luminaire deterioration	Inspect during BGR and when fault reported and replace where units are found to be unserviceable.	Estimated volume - 5,000 luminaire replacements per year.

7.16.6 Overview of plan

Figure 7.58 shows the forecast total streetlight luminaire replacement volumes.

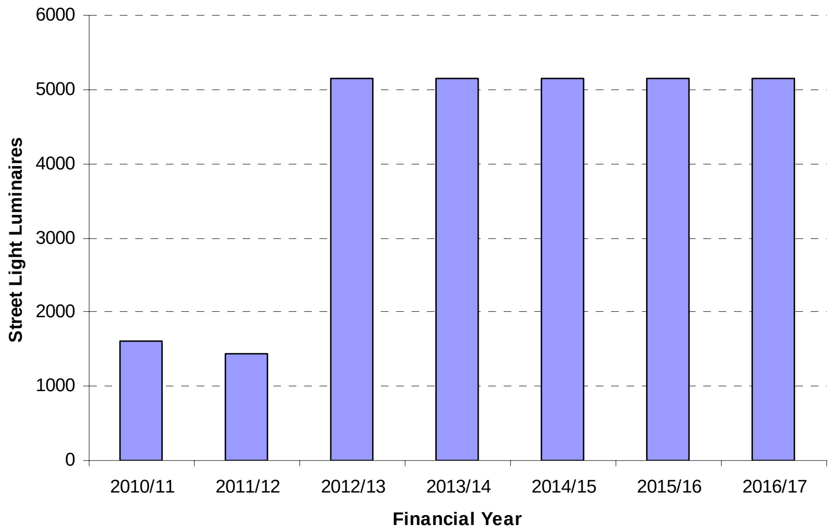

Figure 7.58: Forecast Luminaire replacement volumes

7.17 Protection Relays

This section describes the lifecycle management plan for protection relays.

7.17.1 Asset Description

The main function of a protection relay is to identify abnormal operating conditions in the network and send appropriate tripping signals to the circuit breakers. The circuit breakers then rapidly operate to isolate the affected sections so that the rest of the network can operate normally.

In performing this function, protection relays work as a scheme. A protection scheme may consist of one (or sometimes more) main measuring relay(s) and several auxiliary relays (used for tripping and flagging). Typically protection relays obtain appropriate input signals from local instrument transformers and other relays installed at various network locations via communication channels.

The network comprises 5,435 protection schemes with 29,859 individual protection relays in-service at terminal stations and zone substations. Figure 7.58 summarises the different types of protection schemes and number of relays deployed in the network.

Table 7.67: Protection relay schemes

Protection Equipment by Scheme Type	Number of Schemes	Number of Relays
Busbar Protection (BB)	443	1,996
Capacitor and Reactor Protection (CAP/RE)	384	2,144
Bus and Circuit Breaker Protection (CB)	867	3,357
Feeder Protection and Load Shedding (FDR)	1,074	5,461
Fault Recording (FR)	51	169
Generator and Gas Turbine Protection (GEN)	45	464
Line Protection (LN)	1,087	6,543
Transformer Protection (TX)	1,229	9,041
Frame Leakage Protection (FRL)	10	10
OTHER	245	674
Total	5,435	29,859

Protection relays can be broadly categorised into three groups based on their construction; electromechanical[28], solid-state[29] and numerical[30]. These construction types represent the historical evolution of different relay technologies. Table 7.68 summarises the relays based on their construction type.

Table 7.68: Protection relay types

Construction Type	Number of Relays	Proportion
Electromechanical Relay	21120	70.7%
Solid-State Relay	5200	17.4%
Numerical Relay	3367	11.3%
Other	172	0.6%

7.17.2 Failure modes and impact

Failure of a protection scheme is typically caused by one of the following:

- involuntary or incorrect operation due to inherent defects in particular models;
- settings errors or inappropriate settings;
- design errors;
- breakers failing to trip;
- loose wires or PCB cards;
- human error;
- incorrect firmware;
- defective or out-of-tolerance relays;

[28] Electromechanical relays are the oldest generation of relays having moving parts. A scheme may require one measuring relay for each protection function. These relays are simpler to understand and easier to set using dials and plugs.
[29] Solid-state relays are the next generation of relays with electronic components using analogue techniques for signal processing. Like their electromechanical counterparts, they do not have in built self-monitoring features to report internal failures. Settings are done by means of switches, knobs and jumper connections.
[30] Numerical relays are the current generation of relays. They are programmable, versatile (complex schemes can be created), multifunctional and use digital techniques for signal processing. These relays are characterised by their ability to self-monitor and report most internal failures. A single numerical relay could provide almost all the protection, control, SCADA, metering, event and waveform recording functions. These relays require detailed settings preparation and the settings take the form of a proprietary software file to be down loaded using a PC or alternatively by means of a key pad mounted on the relay.

- communication system failures; and
- end of life of internal batteries needing replacement
- alarm (SCADA) failures
- incorrect CT ratios
- isolation links left open

Whilst individual protection relays may have little impact, failure of a scheme to operate can result in primary asset failures.

7.17.3 Age and condition

Protection Relays are typically assigned an expected life of thirty years for electromechanical relays, and twenty years for numerical and solid-state relays. The age profile of the existing relay fleet indicates that approximately 28% of electromechanical relays and approximately 36% of numerical and solid-state relays have exceeded the expected life. Aged relays have an increased probability of failure.

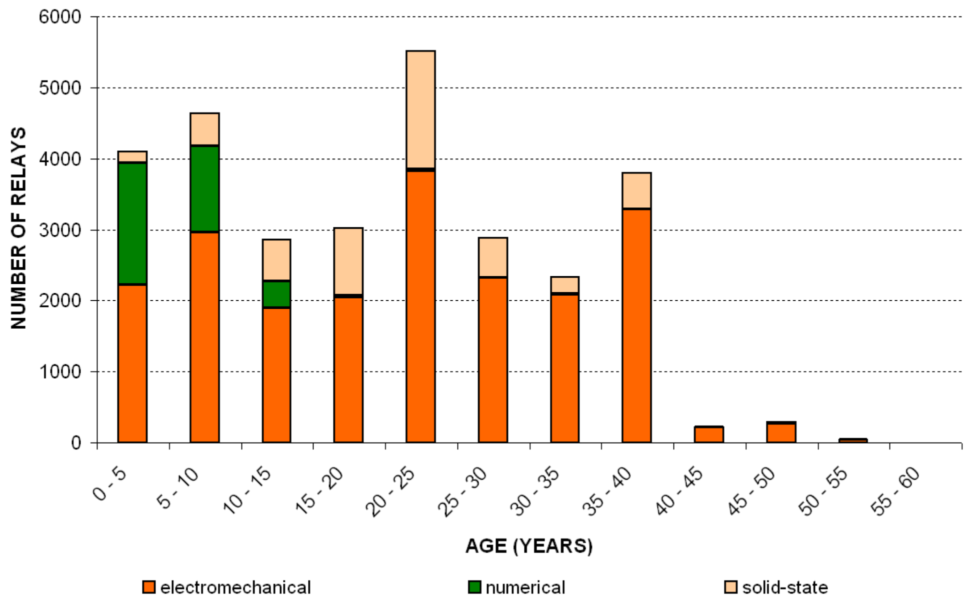

Figure 7.60: Protection relay age profile

7.17.4 Performance level

The performance of protection schemes impacts directly on supply reliability, network security and network safety outcomes. Reliability and security requirements are established through the Access Arrangement and the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. Safety requirements are established through several legislative instruments.

The performance of protection systems and associated circuit breakers is monitored by:

- Overall Protection Performance Index (OPPI)[31];
- Overall Fault Performance Index (OFPI)[32]; and
- Relay failure rates.

Figure 7.59 shows the historic performance of protection systems against the OPPI. With the exception of the June 2010 financial year, performance has been within 2% of the target. Two factors contributed to the decline of OPPI in 2010 and they were:

- several mal-operation incidents of Frame Leakage Protection in Milligan St and Piccadilly substations; and
- incorrect operation of GE type T60 (transformer protection) and F60 (feeder protection) relays throughout the network.

This decline has been arrested as these issues are being gradually resolved although more work may be required before a recurrence can be ruled out.

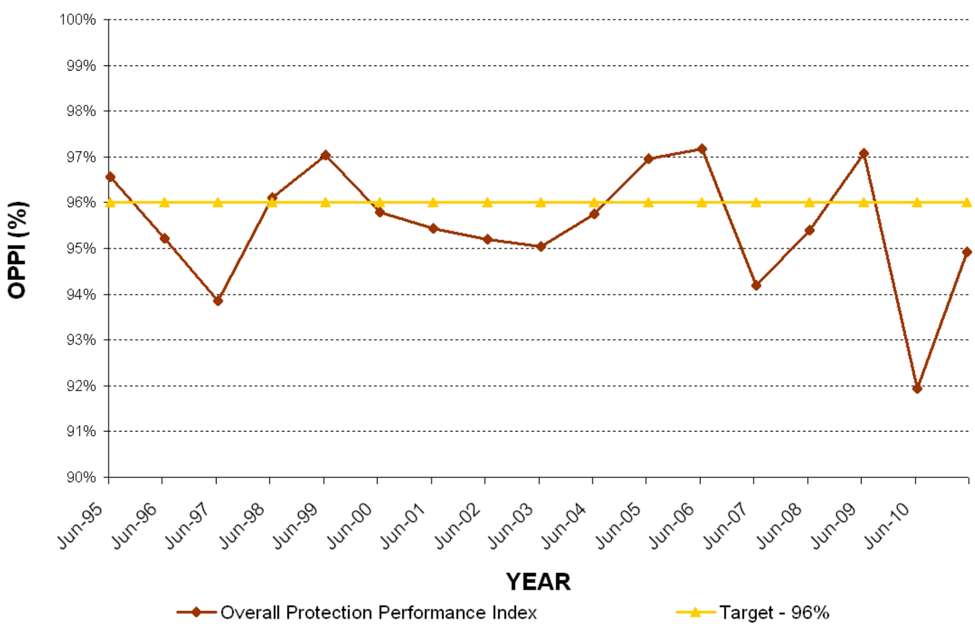

Figure 7.59: Western Power Overall Protection Performance Index (Yearly average)

Performance of the protection schemes is affected by type issues and CBD Frame Relay Protection scheme operation.

Type issues relating to relatively new GE numerical protection relays include:

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[31] This is measure of correct protection operations versus all protection operations including the ones caused by human errors in the last 12 months.
[32] This is measure of correct circuit breaker operations versus all circuit breaker operations including the ones caused by human errors in the last 12 months.

- T60 transformer protection relays have been identified as causing partial (or total) blacking out of substations by inadvertent operation without primary faults;

- F60 feeder protection relays have been identified as causing partial (or total) blacking out of substations by going into a lockout mode while clearing faults; and

- L90 line protection relays going into failure mode when the communication channel is restored after fading out.

The number of relays and schemes potentially affected by these issues is shown in Table 7.69.

Table 7.69: GE Protection Relays

Relay Type	Number of Relays	Number of Schemes
T60	118	66
F60	89	56
L90	131	69

The Frame Leakage Protection schemes in CBD substations have caused major power disruptions in the Perth CBD and Goldfields areas.

Two false trips in response to external cable feeder faults at Milligan Street substation.

Four false trips in response to external cable feeder faults at Piccadilly substation.

7.17.5 Asset management strategies

Routine preventative maintenance and testing forms a major part of the protection relay maintenance strategy. Defects identified during testing or following faults are corrected as required. 406 maintenance work orders are raised annually.

Spares strategy

Sufficient spares are held to enable a least cost approach for regular maintenance and emergency conditions. The stocks are replenished on an ‘as required’ basis. The spares are initially acquired when a new model is introduced to the system (under the same project)

7.17.6 Overview of plan

A summary of the strategies used to manage Protection Relays is shown in Table 7.70.

Table 7.70: Summary of strategies

Issue	Strategy	Planned Outcome
Specific issue associated with GE relays Type F60 feeder protection relays go into ‘error mode’ during the auto-reclose cycle while clearing a fault causing the transformer to trip resulting in a blackout. This has raised concerns on the performance of all F60 feeder relays in the network. T60 operating on transformer inrush inadvertent activation of T60 inputs used for routing transformer mechanical device trip commands inadvertent activation of LV Restricted Earth Fault (LV REF) of T60	Investigating issues with manufacturer, reviewing settings and undertaking firmware changes.	Coordinating with manufacturer to resolve in 12 months.
CBD Frame Leakage Scheme failures Frame leakage protection on 11kV switchboards at Milligan St, Hay St and Piccadilly substations operated for external feeder faults when the frame insulation is compromised say by incorrectly terminated cables.	Install monitoring schemes so operational personnel are alerted when this protection scheme is compromised.	To complete project by 2013/14.
Aged relays with high failure rates, deficit of spares and withdrawal of manufacturer support.	Protection schemes replaced. (May be bundled with primary plant replacement or carried out independently under a separate program.)	5 to 10 schemes per year depending on need and timing of primary plant projects.
Inadequate working space behind protection panels in early generation relay cabins.	Replace buildings with transportable relay rooms at identified sites using the latest IEC61850 technology.	To complete project by 2015/16.

Table 7.71 shows the forecast volume of protection schemes that will be replaced (capex) or subject to maintenance (opex) during the period 2012/13 to 2016/17.

Table 7.71: Forecast volumes of protection schemes

Type	Volume					
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
CAPEX	10	10	10	10	10	10
OPEX	406	406	406	406	406	406

7.18 DC Systems

This section describes the life cycle management plan for direct current (DC) power supply systems located at zone and terminal substations.

7.18.1 Asset Description

The Direct Current (DC) supply system provides a constant power supply for protection and SCADA equipment used to monitor, control and protect primary equipment in the terminal stations and zone substations. The DC supply system includes a battery bank so that protection and SCADA can continue operating when a fault occurs that interrupts the normal AC supply.

The main components of a DC supply system are the battery charger, battery bank, battery paralleling board and structures including the battery room and battery racks. Table 7.72 shows the volumes of each of the key components. Most substation DC supply systems include 3 battery banks; a 50 V bank for SCADA and two 110 V banks for protection. In some cases the 50 V charger system is also duplicated (i.e. two chargers catering for a single 50 V bank) and some older 32 V and 230 V banks still remain.

Table 7.72: DC system asset population

System voltage	Battery bank	Charger	Paralleling board
32 V	47	47	18
50 V	165	199	19
110 V	302	302	17
230 V	2	2	3

The battery bank is the component which requires the most maintenance and management. The most common battery technology used is Nickel Cadmium (NiCd) with smaller numbers of valve-regulated lead acid (VRLA) and vented lead acid (VLA) units. Service lives have been developed based on operational experience for specific manufacturers, battery models and operational environments.

Table 7.73: Battery bank population

	NiCd	VRLA	VLA
Population (banks)	466	24	26
Service life (years)	20 - 25	7 - 15	15

7.18.2 Failure modes and impact

Failure of DC supply systems results in loss of protection and SCADA systems and may in some extreme cases lead to potential catastrophic asset failures and public safety issues. Although the DC systems are duplicated (N-1 criteria), some functions such as feeder protection and circuit breaker controls are fed from only one system.

Batteries cells commonly fail due to ageing, excessive cycling (charging and discharging), high ambient temperatures and overcharging. When a cell fails this typically results in circuit failure. In some cases a cell failure has the potential to cause fire and/or failure of a scheme.

7.18.3 Age and condition

Service lives for batteries can be highly variable depending on small changes in operating environment, charging/discharging duty and manufacturing methods. This is evidenced by a spread of actual in-service lives ranging from 5 years less than expected life to 10 years longer than the expected life. The expected (or the ‘design’ life) is usually assigned by the manufacturer based on certain specific service conditions (e.g. ambient temperature). This could vary between 17-25 years depending on the battery technology and the manufacturing method.

The key indicator for the battery bank as a whole is the capacity test. A capacity of less than 30% is a trigger for battery bank replacement. 25 battery banks have been identified as having less than 30% capacity (including 6 banks with poor physical condition) and these have been placed in a replacement project to be completed in 2011/12. 50 battery chargers require upgrade to incorporate a boost facility. NiCd battery manufacturers have indicated that boost charging is advisable to help preserve battery performance.

7.18.4 Performance level

The performance of DC systems can impact on supply reliability, network security and network safety outcomes. Generally the DC systems are expected to have 100% availability although there is no performance target specifically set for DC systems. The systems are currently performing adequately as a result of effective inspection, maintenance and asset renewal regimes that are in place.

7.18.5 Asset management strategies

Due to the criticality of the assets and the variability in battery life, preventative maintenance is performed on battery banks and battery chargers in accordance with specified maintenance criteria.

7.18.6 Overview of plan

A summary of the strategies used to manage DC systems is shown in Table 7.74.

Table 7.74: Summary of strategies

Issue	Strategy	Planned Outcome
Battery issues: - Insufficient remaining capacity (<30%) - Cell degradation - Manufacturer specific degradation issues	Carry out maintenance and condition assessment.	In accordance with maintenance policy. Replace as required.
Chargers of earlier generations lacking 'boost' facility.	Charger replacement program at 50 identified sites (40 in AA3). Phase out older 32 V and 230 V systems when they are due for replacement and replace with 110 V systems.	Largely complete during AA3. Bundled with the safety upgrade project discussed below.
Cluttered working conditions inside battery cabinets leading to the risk of electrolyte splashing and soft-tissue injuries.	Upgrade battery stands at identified sites by relocating to new safe and spacious ergonomically friendly cabinets and replace the batteries and chargers if necessary.	Began in 2011/12 and to continue until 2016/17. Upgrade/replace 77 DC systems and associated ageing battery banks and chargers. Prioritise based on risk assessment.

Table 7.75 summarises the planned replacement volumes for DC supply system assets.

Table 7.75: DC supply system replacement volumes

Year	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Component	AA2 (forecast)		AA3 (forecast)				

Year	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Component	**AA2 (forecast)**		**AA3 (forecast)**				
Battery banks	29	25	26	38	17	21	19
Battery chargers	0	0	5	5	8	12	10

7.19 Communication Sites and Structures

This section describes the lifecycle management plan for structures that are used to support communications equipment.

7.19.1 Asset Description

Communications sites and structures house or mount communications equipment in shelters or on physical structures such as masts, poles and towers. Communications equipment is installed at 726 locations throughout the network. 191 of these locations are communication sites that contain radio equipment and an associated structure (mast, tower or pole). The volume and type of structures are shown in Table 7.76.

Table 7.76: Population of Communications sites with associated radio Equipment

Type	Volume
Masts (supported by guy wires)	87
Towers (lattice structure – self supported)	45
Poles	59
Communications Building	108
Communications Hut	11
Communications Shelter	52
Equipment within Substation Building	20

7.19.2 Failure modes and impacts

Communications site and structure failures have generally been identified and repaired before they affect the network. The failures that have been noted are typically related to corrosion and environmental effects, and necessitate mast repair or shelter replacement.

In April 2007, the Porongurup's communications site was completely destroyed by fire and illustrating the potential consequences of site and structure failures. The potential impact of such a catastrophic failure (besides the cost to re-establish the infrastructure) is the loss of SCADA, protection and all other communications links to sites beyond the failed site.

This risk is mitigated by alternate communications routes in many cases.

7.19.3 Asset age and condition

Half of the communications structures are over 20 years old, with approximately 12% over 30. The effects of this advanced age are most apparent in the condition of the 19 shelters that have been assessed as severely corroded. These shelters have multiple rust holes, become a vermin nesting ground and are no longer strong enough to risk opening both doors at once in the presence of wind.

Six mast and tower structures have been identified that do not have an impediment (such as a fence or anti-climb barrier) to members of the public climbing them and being exposed to radio radiation. This is contrary to the licences issued by ACMA for the radio equipment use.

7.19.4 Performance

There are no performance targets specifically set for communications sites and structures. An inherent requirement is that structures are available 100% of the time to support or protect the communications equipment. Sites and structures are also required to comply with a range of standards governing loading, access, security and safety.

Two areas have been identified where the communications sites and structures do not meet required performance requirements. The first of these is 12 sites where the required consumption meters are not installed. The second 15 are sites do not meet the requirements of AS 1170.2, which outlines the minimum requirements for structural integrity of masts and towers with respect to the loading of these structures imposed upon by actions of wind. (Revision of this standard, (AS/NZS1170.2), imposes more stringent requirements.)

7.19.5 Asset management strategies

Communication structures are maintained on a three yearly program. Communications buildings are maintained annually. Maintenance involves inspection and remedial action for minor issues. Any non-critical issues are scheduled for corrective maintenance.

7.19.6 Overview of plan

The strategies adopted to manage issues identified on communications sites and structures are shown in Table 7.77.

Table 7.77: Issues and strategy for communications sites and structures

Issue	Strategy	Planned Outcome
Corroded/degraded structures.	Planned replacement and regular maintenance of affected structures.	Replace 19 shelters between 2012 and 2017 to maintain required integrity.
Some communications structures have been identified as lacking the access control required by their radio communications	Install anti-climb treatment applied to rectify the situation.	6 sites to be rectified in 2013/14 to achieve coverage with access control and requirements of Communications licence.

licence conditions.		
Prior to the disaggregation of Western Power, no low voltage AC meters were installed at communications sites. Following disaggregation there is now a regulatory requirement to install AC meters.	Install AC meters.	12 sites to have meters installed in 2012/13 to achieve required compliance.
A number of sites are potentially non-compliant with AS 1170.2 requirements.	Phased upgrade of masts and towers	15 towers – 2011/12 to 2014/15. 3 poles – 2014/2015 to achieve compliance with AS 1170.2 by 2016.

Table 7.78 and Table 7.79 summarise the volumes of maintenance and capital items planned over the 2010/11 to 2016/17 period.

Table 7.78: Communications structures capital works plan forecast volumes

Year	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**
Activity	**AA2**		**AA3**				
Tower Reinforcements (Dist)			5	5	5		
Install anti-climb fittings (Trans)				6			
Wood Pole Replacement					3		
Shelters Replacement (Dist)						10	9
Ac meters			12				

Table 7.79: Communications sites capital works plan forecast volumes

Year	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**
Activity	**AA2**		**AA3**				
Install AC meters (Trans)			12				
Site Security Access Control (Trans)				1			

7.20 Meters and Services

This section describes the approach to managing revenue (customer) meters and low-voltage services.

7.20.1 Asset Description

Customer Service Connections are the low voltage services that connect the low voltage distribution network to individual customer properties. Customers can be supplied from either an overhead or underground service connection. At each connection point, one or more meters are provided to measure the power consumed by and individual customer.

Overhead customer service (OCS): There are 410,000 OCS connections in the network. Each OCS connection incorporates an aerial service cable from the overhead low-voltage ‘street mains’ to a connection box at the customer’s Point of Attachment (POA) for connection to the electricity meter. The POA may be mounted on either of the barge board, a Goose Neck bracket, or the fascia at the customer’s premises, or on a metal pole.

Prior to 2003 the majority of OCSs were PVC insulated twisted pairs and preformed steel wire helical terminations, consisting of a piece of wire wound round the service wire and then looped over the bracket or an insulator attached to the bracket. These are referred to as ‘Twisties’.

Underground customer service (UCS): UCSs are either the type which runs from the low voltage main cable to a pillar or the type that provide connection from the overhead LV via a cable which runs down the pole and then underground to a pillar. The UCSs do not currently exhibit any issues and are managed as RTF assets.

Meters: An electricity meter is located close to the customers POA for the low voltage service. Both electromechanical and electronic meters are installed in the network as shown in Table 7.77. Electronic meters can be either accumulation meters with functionality similar to conventional electromechanical meters, or “smart” meters which record and store energy consumed in 30 minute intervals. Both electromechanical and electronic meters are utilized in single and three-phase applications. Larger customers are supplied with CT meters. The volume of meter types is shown in Table 7.80.

Table 7.80: Meters population[33]

Meter type	Volume
Mechanical single phase	403,883
Mechanical 3-phase direct connect	274,042
Mechanical 3-phase CT	661

33 Meter population at March 2010.

Meter type	Volume
Electronic single phase	186,322
Electronic 3-phase direct connect	97,920
Electronic 3-phase CT	10,057
Total	972,885

7.20.2 Failure modes and impact

Services: Failure of an individual service can result from deterioration of the connections, brackets or clamps, deterioration of the cable or from damage to the cable. Most failures are the result of age or vibration based deterioration. Other common causes of failure are damage to OCSs from tree branches and damaging UCSs during digging.

Whilst an individual service failure may generally be seen as loss of supply to a single customer, failure of the service has the potential to cause an electric shock and a high safety risk. A fatal electric shock has resulted from faulty OCS services.

Meters: Mechanical meters fail through wear and mechanical faults. Electronic meters generally fail due to a failure of an electronic component. The failure of a mechanical meter can result in inaccurate measurement of energy or no measurement of energy. The failure of an electronic meter is most likely to result in no measurement of energy.

The impact of failure of an individual meter is minor as it affects only a single customer and where the meter measures no energy the failure is relatively easy to detect. The failure of a meter to accurately measure energy is more difficult to detect and as this type of fault tends to affect a batch (or type) of meter, the result can be inaccurate measurement over a period of time.

7.20.3 Age and condition

Services: Approximately 25% of the total OCS connections (twisties) have exceeded their expected physical life of 30 years. The condition of Twisties is poor as these have deteriorated due to age.

Meters: Meters are generally in good condition as their condition is monitored through a program of sample testing and, where faults or inaccuracy is detected, the meters are replaced.

7.20.4 Performance Level

Services: The most significant impact of a service failure is the safety impact. A program of OCS replacement has been implemented as a result of identified safety issues. The performance of this replacement program is the primary indicator used to measure performance of the services as shown in Table 7.81.

Table 7.81: Services performance requirements

Indicator	Target	Performance 2010	Performance gap
% of OCS replacement program carried out	100%	>100%	No gap

Meters: Meters are required to accurately record energy consumption. Four classes (accuracies) of meter are used depending on the volume of energy recorded. The required accuracies are defined in the Section 14 of the Electricity Industry Act.

A number of meters which are part of a population that has been identified for replacement due to accuracy requirements have had their replacement deferred pending a decision on the adoption of interval (smart) meters.

7.20.5 Asset Management Strategies

Asset Maintenance

Services: The whole OCS population inspected was to determine the location of the degraded services.

Meters: Meters are tested for accuracy using random sampling techniques. Sample sizes are defined in the Metering Management Plan and where a population of a particular type of meter is found to be inaccurate, refinement of the population and further testing is carried out before replacement of a subset of the population occurs. Individual meters that fail accuracy tests are replaced as part of this process.

7.20.6 Overview of plan

Table 7.82: Asset Management Plan for OCSC and meters

Issue	Strategy	Planned Outcome
Services:		
Electric shock Incidents from OCSs are occurring despite the replacement of nearly 50% of the suspect Twistie population.	Carry out an inspection of all existing OCSs to improve the selection of Twisties and other OCSs for replacement or repair.	One off inspection beginning January 2013. Periodic inspection in future to assess safety.
	Replace Twisties as quickly as resources permit.	Ongoing replacement program will reduce the likelihood of electric shock. This program has already resulted in the replacement of over 100,000 and will result in replacement of all Twisties by July 2015.
Meters:		
Some 280,000 meters	Implement program to	280,000 meters replaced

which are part of a population that has been identified for replacement have had their replacement deferred pending a decision on the adoption of interval (smart) meters.	replace meters with smart meters.	during 2011/12 to 2016/17 period.

Services: The forecast volume of OCS replacements is shown in Figure 7.60. The replacement program will be completed by June 2015 and no replacements are planned in subsequent years.

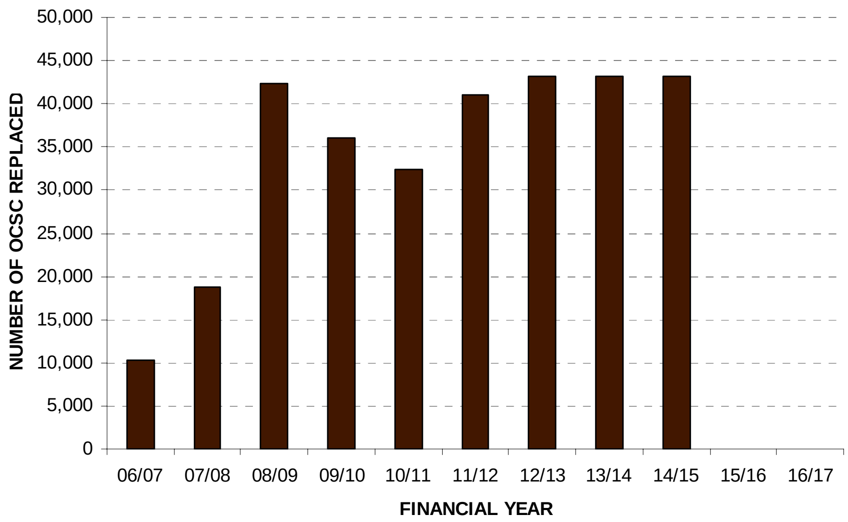

Figure 7.60: Historical and forecast OCS replacements

7.21 Surge Arresters

7.21.1 Asset Description

There are some 2,110 surge arresters with operating voltages from 11 kV to 330 kV installed at substations or on poles throughout the transmission network. Surge arresters are also utilised on the distribution network however, these are managed as RTF assets and are not included in this plan. The main function of surge arresters is to limit surge voltages caused by lightning to prevent any serious damage to the primary plant and prevent the occurrence of explosive failures the network. Surge arresters installed on the Western Power network are shown in Table 7.83.

Table 7.83: Transmission surge arrestor population

Type	11 kV	22 kV	33 kV	66 kV	132 kV	220 kV	330 kV	Total
Gap				93	125		45	263
Metal-oxide	54	84	75	254	1,179	63	138	1,847

7.21.2 Failure modes and impact

Over the last 10 years, Western Power has experienced six explosive failures of gap type surge arrestor resulting in damage to adjacent plant equipment. Although surge arresters typically fail in the mode described above, safety is a significant issue as both gap type and porcelain surge arresters have failed explosively causing safety hazards to personnel and the public.

7.21.3 Age and condition

The age profile of transmission surge arresters is shown in Figure 7.61. Only a small proportion of the population exceeds 40 years.

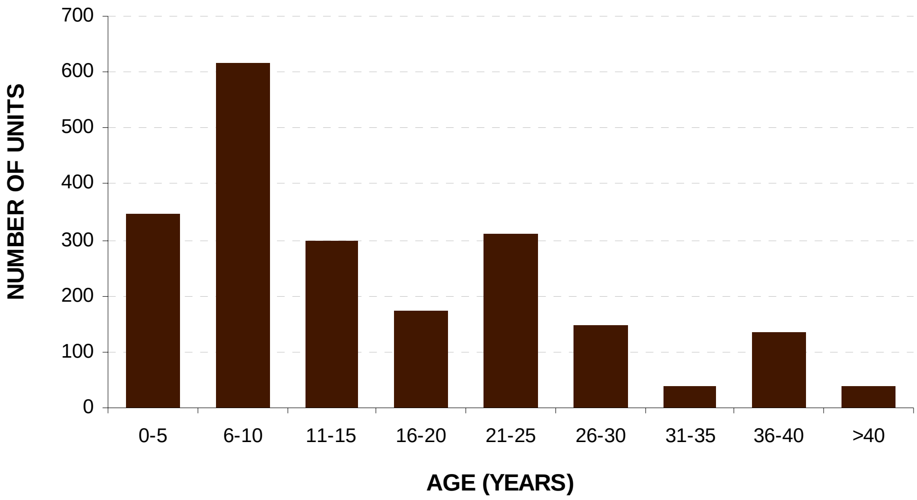

Figure 7.61: Transmission surge arrester age profile

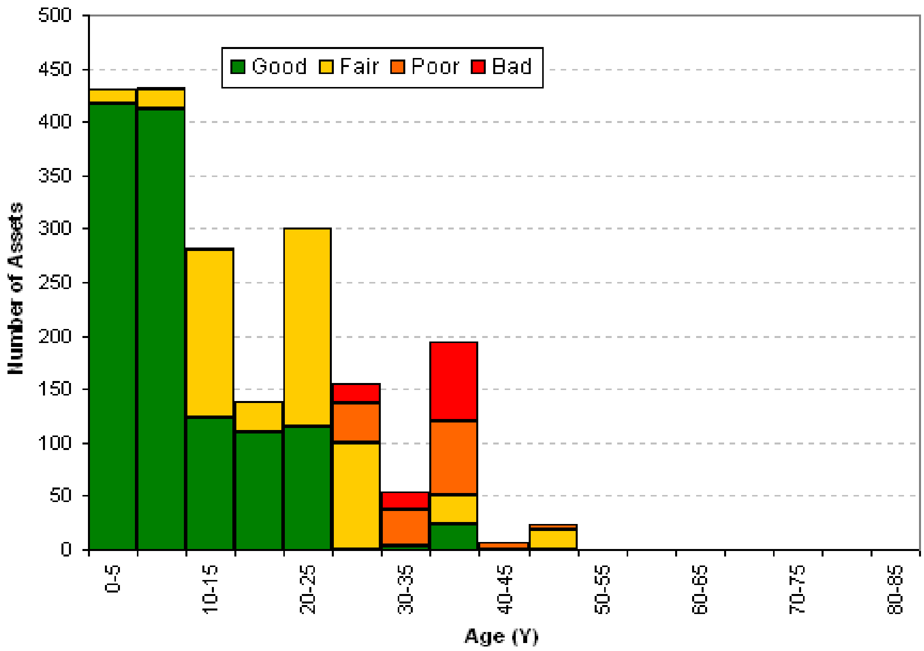

Figure 7.62: Transmission surge arrester condition profile

Figure 7.62 shows condition profile of Transmission Surge Arresters. The high proportion of “Bad” condition surge arresters is predominately due to “Poor” test results (low insulation resistance) because of deteriorating insulation material. The majority of surge arrestor identified in “Bad” condition are “gap type”. In addition, analysis has also indicated that 5% of surge arresters have failed high voltage tests due to low insulation resistance. This issue has also led to them being classified in “Bad” condition.

7.21.4 Performance Level

The primary impact that failure of surge arresters has on the network is reliability. Reliability requirements for the network are established as part of the access arrangement. Any decrease in the performance of surge arresters will adversely affect network reliability.

The performance measures for surge arresters are shown in Table 7.84.

Table 7.84: Performance requirements for surge arresters

Indicator	Target	Performance	Performance gap
Contribution for surge arresters to System Minutes	≤ 0.044 (meshed) ≤0.000 (Radial)	≤ 0.044 (meshed) ≤ 0.000 (Radial)	No gap
Failure requiring replacement or major repair	SA ≤ 3	SA ≤ 3	No gap
Composite assessment of the condition of individual surge arresters	< 8	< 8	No gap

Surge arresters are currently meeting all performance requirements.

7.21.5 Asset management strategies

A cyclic inspection program forms a major part of the transmission surge arrester maintenance strategy. The primary purpose of the inspection is to test the insulation resistance to ensure it is within acceptable limits, and to monitor the surge counters.

7.21.6 Overview of plan

A summary of the strategies used to manage surge arresters is shown in Table 7.85.

Table 7.85: Summary of strategies

Issue	Strategy	Plan/ Frequency
Approximately 12% of surge arresters are a gap-type. The gap type units have been found to deteriorate and lose functionality as a result of moisture breaching the gap chamber of the unit. They have ceramic insulation that can also shatter creating an explosive failure. This can cause potential injury to personnel working on sites.	Replacement of surge arresters where condition assessment indicates that replacement is required. Priority for replacement is based on the type of surge arresters and the condition assessment score.	Replace 42 surge arresters per annum in the 2011/12 to 2016/17 period.
Surge arresters that fail in service.	Replace on failure.	Less than 5 transmission surge arresters are expected to fail in service annually.

Over the period 2010/11 to 2016/17, 210 transmission surge arresters are planned for replacement as shown in Figure 7.63.

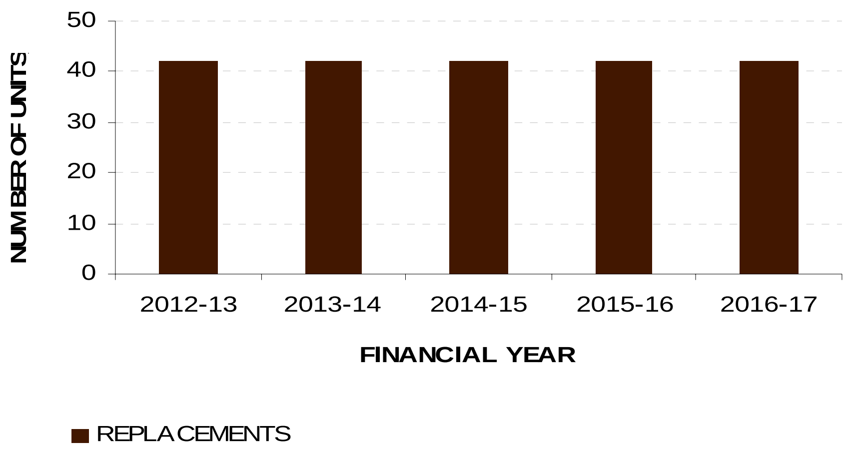

Figure 7.63: Transmission surge arrester replacement volumes

8 Integration of the Works Plans – Growth and Non-Growth

Western Power's in-service asset management planning process is focused on achieving a balance between risk, performance and cost as per good industry asset management practice (PAS-55).

Western Power's "Risk management framework" approach is applied to identify our key network/asset risks using the "Corporate Risk Assessment Criteria" (DM#6242026) to assess each risk. These are then ranked to ensure each risk is given the appropriate focus in the planning process. This process has identified a number of high priority safety risks such as electric shocks, eg. twisties, broken conductors, bushfires, pole top fires, clashing conductors, etc.

Performance is considered through a combination of factors such as asset age/condition, reliability, power quality, utilisation, and capacity for LV planning.

Age and condition information is obtained through the "State of the Network" reports which provide key information about the current health of the in-service asset base and network.

Reliability and power quality information is derived from the "Service Standard Performance Report" (Reliability only) and the "Reliability and Power Quality Report".

Capacity and utilisation information is obtained through the development of the "Capacity (Load Area) Report" and the "Distribution Overload Transformer Report".

Costs are taken into account through asset life cycle costing and a process of optioneering is deployed to ensure the most appropriate options are selected that optimise management of in-service assets.

Figure 8.1 illustrates the approach in developing the Network Management Plan

In summary, this commences with an Asset Management policy which leads to the development of asset strategies aligned with the asset management policy which are then taken into account in the development of the Network Management Plan. The following areas of in-service asset management are considered in this process:

- Asset creation (limited to LV planning and in service enhancements);
- Asset replacement/refurbishment; and
- Asset maintenance.

This process also includes consideration for the impact on both the network planning &development and customer driven plans.

Once the Network Management Plan is developed and externally driven plans are taken into account, supporting business cases are developed, the sponsor's statement of intent is ratified, and a deliverability assessment is made leading to the development of the production plan and deliverability of the works program.

This approach is integrated into the overall business planning processes through alignment with the annual planning cycle as shown in Figure 8.2.

The annual planning cycle includes consideration of a number of optimisation points throughout the planning cycle to ensure a consistent and transparent process for effective optimisation and prioritisation of network investments.

Western Power has recently implemented an optimisation project within the Network Investment Strategy work stream to ensure these optimisation points are effectively utilised to achieve this objective.

As a part of project development, the project team, with input from various stakeholders, developed the following definition of 'optimisation':

Optimisation is a state of continually making and improving on sensible, prudent investment choices. The aim is to deliver maximum benefit for the investment made, throughout the life of the project/program lifecycle. This can be achieved by having a committed, collaborative approach to effective communication, clarity of processes and desired future state of the network.

'Optimisation' occurs slightly differently at each phase:

- Initiation – Needs/Drivers;
- Scoping – Costs vs. Benefits; and
- Planning – Solutions.

Prioritisation is defined as follows:

Means to put tasks in the best order so as to facilitate and better ensure complete and timely task accomplishment in advance of actual need.

Effective prioritisation requires taking the following into account:

- Multiple needs require consideration;
- There are many influences on prioritisation; and
- Applying constraints filters determines the requirement to prioritise.

These definitions will continue to be refined and developed with input from across the business as the optimisation process matures.

Once the works program has been developed and is underway, the asset manager/sponsor monitors the progress of works and assesses the technical performance of the assets leading to continuous improvement of the asset management processes.

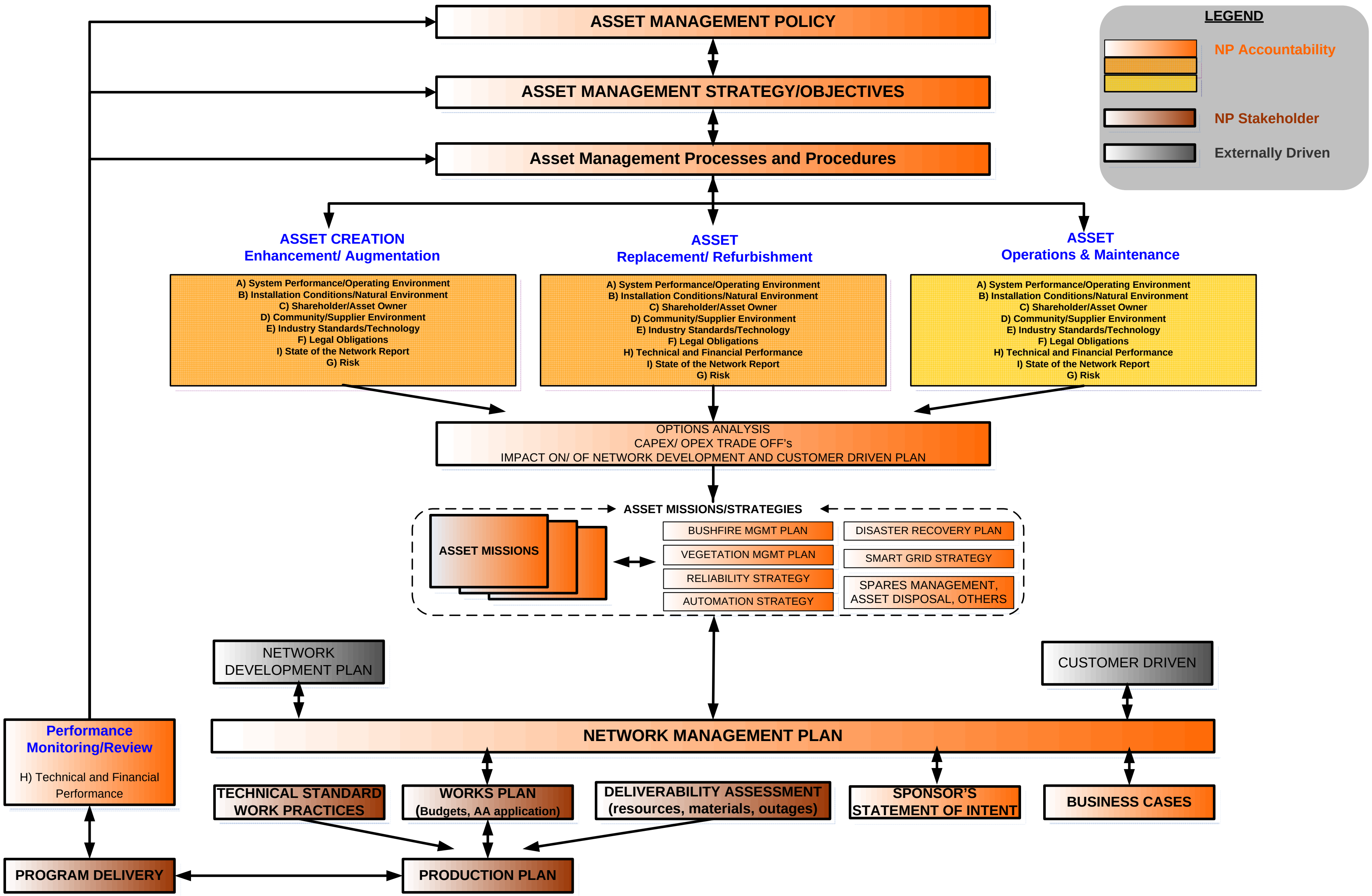
ASSET MANAGEMENT POLICY
ASSET MANAGEMENT STRATEGY/OBJECTIVES
Asset Management Processes and Procedures
LEGEND
NP Accountability
NP Stakeholder
Externally Driven
ASSET CREATION Enhancement/ Augmentation
A) System Performance/Operating Environment
B) Installation Conditions/Natural Environment
C) Shareholder/Asset Owner
D) Community/Supplier Environment
E) Industry Standards/Technology
F) Legal Obligations
I) State of the Network Report
G) Risk
ASSET Replacement/ Refurbishment
A) System Performance/Operating Environment
B) Installation Conditions/Natural Environment
C) Shareholder/Asset Owner
D) Community/Supplier Environment
E) Industry Standards/Technology
F) Legal Obligations
H) Technical and Financial Performance
I) State of the Network Report
G) Risk
ASSET Operations & Maintenance
A) System Performance/Operating Environment
B) Installation Conditions/Natural Environment
C) Shareholder/Asset Owner
D) Community/Supplier Environment
E) Industry Standards/Technology
F) Legal Obligations
H) Technical and Financial Performance
I) State of the Network Report
G) Risk
OPTIONS ANALYSIS
CAPEX/ OPEX TRADE OFF's
IMPACT ON/ OF NETWORK DEVELOPMENT AND CUSTOMER DRIVEN PLAN
ASSET MISSIONS/STRATEGIES
ASSET MISSIONS
BUSHFIRE MGMT PLAN
VEGETATION MGMT PLAN
RELIABILITY STRATEGY
AUTOMATION STRATEGY
DISASTER RECOVERY PLAN
SMART GRID STRATEGY
SPARES MANAGEMENT, ASSET DISPOSAL, OTHERS
NETWORK DEVELOPMENT PLAN
CUSTOMER DRIVEN
Performance Monitoring/Review
H) Technical and Financial Performance
NETWORK MANAGEMENT PLAN
TECHNICAL STANDARD WORK PRACTICES
WORKS PLAN (Budgets, AA application)
DELIVERABILITY ASSESSMENT (resources, materials, outages)
SPONSOR'S STATEMENT OF INTENT
BUSINESS CASES
PROGRAM DELIVERY
PRODUCTION PLAN

Figure 8.1: Network Performance – Asset Management Process

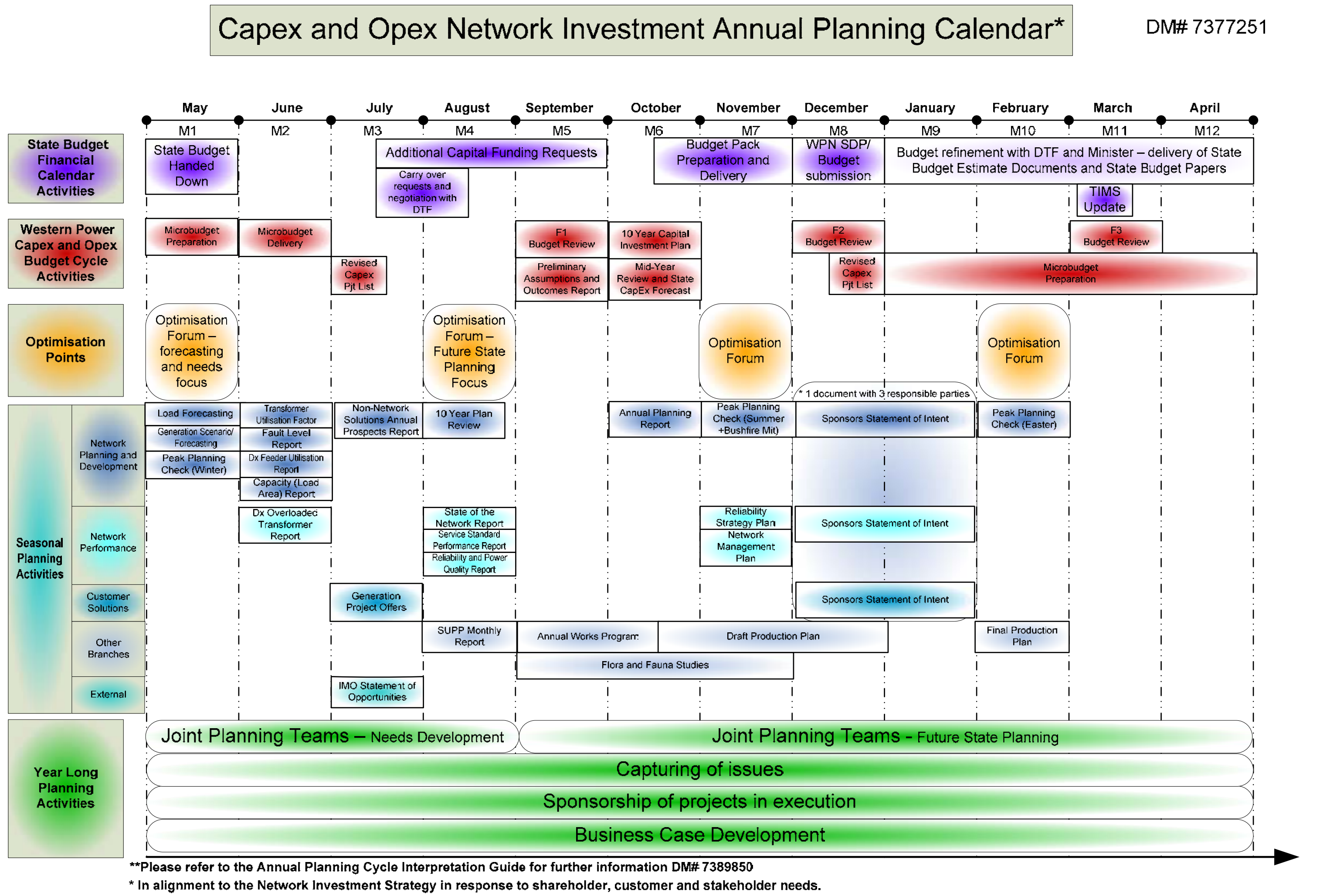

Figure 8.2: Annual Planning Cycle

9 Delivery Strategy

This chapter provides an overview of the strategy adopted to deliver the program of works resulting from the NMP. The program of works resulting from the NMP, along with other works such as network capacity development projects, is combined to form an Approved Works Program (AWP).

The Works Delivery Strategy for the AWP is documented in DM#7850453. The Works Delivery Strategy document details the delivery strategies that have been developed for each of the Customer Service, Distribution and Transmission Divisions and explains how these individual strategies have been consolidated into a network and portfolio view.

9.1 Works Delivery Framework (WDF)

An overarching framework guides the development of Western Power's delivery strategies. At the portfolio level, the WDF sets the works delivery vision, objectives and guiding principles to secure the efficient and effective delivery of the AWP. The delivery vision provides for the efficient and effective delivery of the AWP as follows:

- the AWP will be developed through a collaborative and iterative process between Networks and Operations, such that it is optimised for efficient delivery and Western Power's objectives can be met; and
- the AWP will be delivered efficiently through implementation of the Balanced Portfolio strategy, supported by resource planning, sourcing and procurement processes. Appropriate performance measures and benchmarks will be developed and applied.

The WDF guides decisions in optimising field workforces and other resources to achieve cost efficiencies by minimising mobilisation and demobilisation costs, minimising skills shortages and allocating sustainable work volumes and mixes.

9.2 Balanced Portfolio

The purpose of the Balanced Portfolio is to optimise the work volumes and mix across delivery channels so that:

- The flexibility and responsiveness of Western Power's cost structure to changes in work volumes is improved;
- Core competencies are maintained and developed;
- Western Power maintains control over high risk delivery areas;
- Western Power positions itself to obtain value for money from its suppliers;
- Western Power maintains an informed buyer status;
- External delivery channels have transparency on likely work volumes and mix to encourage investment in capability and capacity (people and plant); and
- Benchmarking across delivery channels of like work categories can be utilised to nurture competition and continuously improve performance.

9.3 Delivery model

The program of works is delivered by three services divisions of the Operations group:

- Customer services: Construction of customer driven new assets, construction, replacement & refurbishment, and maintenance of meters and streetlights;
- Transmission services: Construction of new transmission network assets, replacement & refurbishment of transmission assets and maintenance of transmission assets; and
- Distribution services: Construction of new distribution network assets, replacement & refurbishment of distribution assets and maintenance of distribution assets.

Work generated by each of the three services divisions is delivered through one of five delivery channels:

- Internal – Western Power employees;
- Alliance – Virtual teams with employees from Western Power and contractors are established to achieve a common outcome;
- Performance based contract – Three major DDPs (Distribution Delivery Partners) are engaged in a relationship based model underpinned by traditional contractual arrangements;
- Standard contract – Works typically involving large projects are delivered using a standard contract such as AS 4000; and
- Preferred vendor – Pre-qualified vendor model delivers specific parcels of work at pre-agreed rates.

The proportion of work delivered by each of the channels for each division is shown in Table 9.1.

Table 9.1: Work by delivery channel

	Delivery channels				
	DDP	**Alliance**	**PV**	**Standard contract**	**Internal**
Customer services	20%	50%	20%		10%
Transmission services	75%				25%
Distribution services	45%	15%	20%		20%

10 Financial Summary

Western Power is in the early stages of the Access Arrangement process with the ERA. This will determine the level of funding approved by Government that covers the period of this NMP. Once agreed funding details will be incorporated into the Western Power Approved Works Program, the key aspects are described below.

10.1 Expenditures associated with the plan

For both opex and capex, distribution expenditure is greater than its transmission counterpart due to the relatively larger volume of distribution assets.

The most significant expenditure trend is the rate of increase in both distribution and transmission asset replacement over the 6-years of the plan. This reflects the aging asset base, the poor current condition of many of the assets, and the relatively low rates of asset replacement in the past. Several individual transmission network assets of high value also are scheduled for replacement in the period, for example two SVCs.

Another clear trend is the increase in both transmission and distribution preventive condition based opex. This expenditure is increasing as the assets are aging and their condition tends to deteriorate with age. Despite the relatively higher asset replacement expenditure, a larger volume of assets will be moving into a later stage of life where increased maintenance is required to keep them in service. Undertaking maintenance on the basis of condition of the asset is a cost effective technique for most asset categories.

Additionally, ground mounted distribution assets have been moved from a RTF asset management basis to a managed asset strategy basis with a corresponding increase in inspection and testing expenditure.

11 Network Management Plan Monitoring and Improvement

The Network Management Plan is reviewed on a regular basis to ensure the best balance between risk, performance and cost is achieved, to ensure it is relevant to the current business objectives, to address any stakeholders concerns, to embed any identified improvement opportunities and to ensure the document is current and relevant.

There are a number of key factors which must be considered when reviewing the Network Management Plan. They are the result of internal, external or system influences and include:

- Stakeholder feedback – Feedback can come from a variety of stakeholders including customers, community, external regulators (EnergySafety, ERA), department of treasury and finance, impacts from other areas of the business, etc.
- Sponsor Requirements – This takes into account the requirements of each in-service asset manager in the review process. This includes consideration for secondary systems, plant and equipment, poles and structures, conductors and associated equipment.
- Legislation/Regulatory compliance, Australian Standards and Industry guidelines – This ensures the plan takes into account that external obligations, standards and guidelines are embedded into the overall review/development of the Network Management Plan. These may lead to changes to both the cost and timeliness of planned works.
- Work Practices – Changes in work practices can impact asset management planning through altering resource requirements and costs of implementation and it is important to understand and take into account the impact of these changes on the Network Management Plan as well as associated strategies.
- Asset Management Practices – Changes to asset management practices are included in the review of the Network Management Plan as this impacts the overall approach to in-service asset management.
- Business Strategic Objectives – It is important to review changes to the overall business strategic objectives as this can impact the focus of the Network Management Plan. This includes consideration for changes to the Asset Management Policy.
- Strategic Initiatives – There are a number of key business initiatives aimed at improving Western Powers management of the South West Interconnected System. Many of these initiatives have an impact on the in-service asset management function and it is imperative these improvements are embedded into the Network Management Plan and associated strategies.
- Emerging and alternative technologies - New technologies and alternative technologies (such as non network solutions, edge of grid solutions, etc) are considered where appropriate in the review process.
- Health, safety and environmental concerns – Emerging and existing issues associated with safety & health (such as pole top fires, clashing conductors, unassisted wood pole failure, etc) can lead to increased safety incidents and hence a negative reputational impact. Environmental impacts are also taken into account (such as bushfire management, noise mitigation, oil spills, etc).

- External/Internal Audits/Reviews - The results of various audit activities can initiate a review of the Network Management Plan through recommendations/findings resulting in the need to enhance our asset management approach.

External audits/reviews include:

  - ERA Asset Management Review (every 24 months but can be extended or reduced based on the results of the most current review)
  - Technical Safety Audits (these occur on an ad hoc as determined by EnergySafety based on emerging/existing safety concerns)
  - Annual Reliability and Power Quality Audit (audit against its compliance with Part 2 of the Code or an instrument under Section 14(3).)
  - License Performance Audit (every 24 months or less as determined by the ERA).

- Financial considerations – Budgets can change based on current business priorities and it is important that any changes as well as the impacts are articulated in the Network Management Plan during the review process.
- Performance considerations – Western Power's asset/network performance is assessed against a number of performance measures (such as SAIDI, SAIFI, number of electric shocks, condition, age, capacity, etc). It is important to review the business performance against key performance criteria and make adjustments where necessary to the Network Management Plan to ensure ongoing alignment with performance targets.
- Failure events/near misses – Failure events are a good lagging indicator of the health of the network and can be used to understand asset management maintenance requirements. This information will assist in the development of the overall maintenance strategies.
- Asset Data and Information Systems – Data and information management systems are crucial for providing key information in assisting the asset managers in deciding appropriate strategies to optimise management of the network/assets. Enhancements to these systems improves decision making.
- Work Program Changes - A number of factors could affect the delivery of planned works these changes are reflected back into the Network Management Plan (as well as associated strategies). These changes occur for a number of reasons including increasing/decreasing costs, labour resourcing, unforeseen issues in implementing the planned works, etc. Further, the impacts of the changes are considered and documented.
- Risk Management - Key asset management risks are identified through the corporate risk management criteria and asset risk management procedure. An annual review of asset risks is completed to assess existing risks and to identify new risks and controls. These risks are assessed and ranked for consideration in the review of the network management plan.

11.1 When is the Network Management Plan Reviewed?

The Network Management Plan is reviewed as follows:

- Whenever one or more of the identified internal, external and system influences changes.

- An Annual formal review is conducted taking into account changes to any of the identified internal, external and system influences. This review is aligned to the requirements of the annual planning cycle.
- All changes to the Network Management Plan and other key controlled documentation are managed through the Branch Document Control procedure. This contains the process for major and minor revision to key documentation. All key branch documentation is managed through a Branch document register including review dates and review periodicity.

Note: Responsibility for conducting ad hoc and annual reviews resides with the in-service asset management function within the Asset Management Systems section of the Network Performance Branch.

11.2 Who is involved in the Review (Governance)?

A number of key areas should to be consulted and involved where appropriate during the review process. They include:

- Strategic asset management;
- Standards/Design;
- IT Systems support;
- Operational asset management;
- Project Management;
- Capacity Planning;
- Customer Access;
- Finance;
- Auditing;
- Compliance;
- Risk Management; and
- Environment

A formalised governance framework and team must be developed for conducting annual reviews which details organisational areas of the business aligned to the functional areas detailed above. This includes defining roles and accountabilities against individuals from each identified organisational area.

11.3 How do we Continuously Improve the Plan?

Continuous improvement of the Network Management Plan will be achieved through:

- The Asset Management Review Process – The Network Performance - asset management process requires an annual review of the in-service asset management technical and financial performance. The results of the review are fed back into the asset management policy, strategies, plans and processes/procedures to continuously improve the asset management system. It is the responsibility of each asset manager to conduct a review of the assets under their responsibility and to ensure this information is considered during the annual review of the Network Management Plan.

- Benefits Realisation – As per the requirements of the works program governance model sponsors are required to conduct a benefits realisation for each project/program of works completed (refer to DM#: 6236807). Any benefits achieved are taken into account during the review process.
- Benchmarking – A number of benchmarking activities are conducted which are aimed at understanding the effectiveness of Western Power's asset management practices against other utilities to gain an improved understanding of Western Power's positioning against best practice asset management (ITOMS, reliability performance and targeted asset benchmarking). The results of these activities will be taken into account during the review of the Network Management Plan.

11.4 How do we review the Network Management Plan?

1. Commence Review

Reviews of the Network Management Plan occur whenever a change occurs to any of the internal, external or system influences to ensure the plan is up to date. An annual review is also required considered changes to all of the factors listed earlier in this section.

2. Identify Review Considerations

Identify all external, internal and systems influences which need to be included for consideration in the review process as listed earlier in this section of the plan.

3. Identify Review Team

Identify all stakeholders who need to be engaged in the review process (a table has been included in this section as a guide).

4. Develop Review Governance Framework

This requires the list of accountable areas and individuals to be reviewed for currency before beginning the review. This must be updated in the new version of the Network Management Plan.

5. Address Review Considerations

This step in the process requires the reviewer to engage and seek all required inputs from each of the identified stakeholders from step 4.

6. Continuous Improvement

Seek inputs from each of the approaches discussed earlier in this section being:

- Asset Management Reviews
- Benchmarking
- Benefits Realisation

Relevant improvements are included as inputs in the review of the Network Management Plan.

7. Develop Draft Network Management Plan

Once all information is obtained by taking into account the various considerations and key stakeholder requirements the Network Management Plan is updated with the required enhancements with assistance where required from the stakeholder groups.

8. Approve, publish and communicate

Once the plan is drafted it needs to be reviewed and endorsed by the In-Service Asset Manager (Network Performance Branch Manager) and approved by the Asset Management Executive Manager (General Manager, Networks). Once approved the plan is published on Busbar and communicated to relevant stakeholders.

9. Ongoing Monitoring

Implementation of programs of work supporting the Network Management Plan are monitored on an ongoing basis by the project/program sponsors to ensure works are progressing in a timely manner, on schedule and to the required quality. Further, technical performance measures supporting the plan are also monitored on an ongoing basis. Where these measures are identified as underperforming/over performing the Network Management Plan is reviewed and updated as appropriate to optimise overall network performance.

This requirement is highlighted in the "Network Performance Asset Management Process" .

Figure 11.1 illustrates the overall review process.

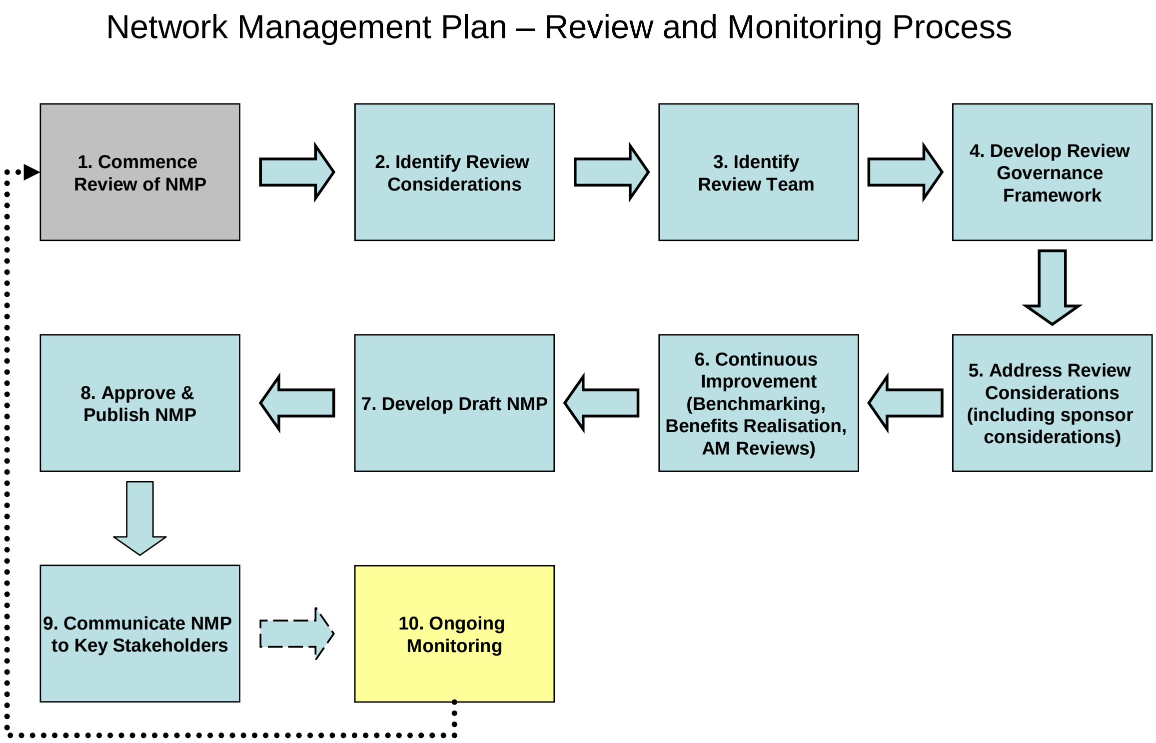

Figure 11.1: Network Management Plan Review Process

12 Glossary

AA	Access Arrangement
AA3	Access Arrangement covering the period 2012/13 to 2016/17
AC	Alternate current
Access Code	Electricity Networks Access Code 2004
ALCA	Asset life cycle analysis
AMS	Asset Management System
APR	Transmission and Distribution Annual Planning Report
AS	Australian Standards
ASEA	Allmänna Svenska Elektriska Aktiebolaget – Swedish manufacturer of electrical plant
AWP	Approved Works Program
Busbar	Western Power Intranet
Capex	Capital Expense
CBD	Central Business District
CCTV	Closed circuit television
CRI	Corporate Responsibility Index
CT	Current transformer
DC	Direct current
DLC	Direct load control
DOEF	Drop Out Expulsion Fuse
DSM	Demand side management
Dx	Distribution
EDL1	Western Power’s electricity distribution licence
ENA	Electricity Networks Association
EPA	Environment Protection Authority

ERA	Economic Regulation Authority (Western Australia)
ETL2	Western Power’s electricity Transmission licence
GJ	Giga Joules (10^9 Joules)
GTE	Government Trading Enterprise
HV	High voltage – generally more than 440 volts
HVAC	Heating, ventilation and air conditioning
IAM	Institute of Asset Management
ICT	Information and Communication Technology
IEC	International Electrotechnical Commission
IIMM	International Infrastructure Management Manual
IMBA	Model type for ASEA current transformers
IMO	Independent market operator
IPWEA	Institute of Public Works Engineering Australia
ISAM	Integrated Solution for Asset Management
ISO	International Standards Organisation
ITOMS	International Transmission Operations and Maintenance Study – consortium of companies that work together to compare performance and practices
KPI	Key performance indicator
kA	Kilo Amps
kV	Kilo Volts (measure of electrical potential)
kVA	Kilo Volt Amps
LCMP	Life cycle management plan
LV	Low voltage – generally less 440 volts
MW	Mega Watts (measure of the active component of electrical demand)
MVA	Mega Volt Ampere (measure of electrical demand)
NBN	National Broadband Network
NiCd	Nickel Cadmium

NIS	Network Investment Strategy
NOx	Nitrous Oxide
NMP	Network Management Plan
NRTF	Non-Run To Failure
NP	Network Performance – WP Branch
NPD	Network Planning & Development - WP Branch
NRMF	Network Risk Management Framework
O&D	Overlaps & Dependencies
OCS	Overhead customer service
OH&S	Occupational Health & Safety
Opex	Operating Expense
OPPI	Overall Protection Performance Index
PCBs	Polychlorinated biphenyls - toxic persistent organic pollutants
PII	Pole Integrity Index
PILC	Paper Insulated Lead Covered
POA	Point of attachment
PoE	Probability of exceedance
PPR	Project planning report
PTS	Pole top switch
PV	PhotoVoltaic
RAB	Regulated Asset Base
RFR	Request for fault repair
RMU	Ring main unit
RTF	Run To Failure
SA	Surge arrestor
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

SCADA	Supervisory control and data acquisition - computer systems that monitor and control industrial, infrastructure, or facility-based processes
SCI	Statement of Corporate Intent
SDP	Strategic Development Plan
SF_6	Sulphur Hexafluoride
SOx	Sulphur Oxide
SUPP	State Underground Power Project
SVC	Static Var Compensator - an electrical device for providing fast-acting reactive power on high-voltage electricity transmission networks
SWIN	South-West Interconnected Network
SWIS	South-West Interconnected System
Technical Rules	Rule for the SWIN detailing the technical requirements to be met by Western Power on the Transmission and Distribution systems and by users who connect facilities.
TIPD	Transmission Investment Planning Database
TPMS	Transmission Plant Management System
Twisties	An aerial service cable from the overhead low-voltage ‘street mains’ to a connection box at the customer’s Point of Attachment (POA) for connection to the electricity meter
Tx	Transmission
VLA	Vented lead acid
VRLA	Valve-regulated lead acid
WEM	Wholesale Electricity Market
SOO	Statement of opportunities
UCS	Underground customer service
XLPE	Cross-linked polyethylene – used as insulation for high tension (high voltage) electrical cables

APPENDIX A – Remaining Life Empirical Formulae Substation Primary Plant (Outdoor)

For **power transformers** (TX) and **circuit breakers** (CB) operating at transmission voltages at 132 kV or greater:

$$RL = R - Y + IF(\frac{A}{P} = 1, E, \frac{-P}{A}) + IF\,\frac{(D = 0, E, -FV^{2} - (DPU_{year+1} - DPU_{year)})}{E^{2}} + L$$

For circuit breakers (CB) less than 132kV and circuit breakers housed with current transformers (CBC):

$$RL = R - Y + IF(\frac{A}{P} = 1, E, \frac{-P}{A}) + IF\,\frac{(D = 0, E, -FV^{FV} - (DPS_{year+1} - DPS_{year)})}{E} + L$$

For **all other plant**:

$$RL = R - Y + IF(\frac{A}{P} = 1, E, \frac{-P}{A}) + IF\,\frac{(D = 0, E, -FV^{FV} - (DPS_{year+1} - DPS_{year)})}{A} + L$$

Where:

RL : Remaining life (calculated)

R : Recommended life for asset type

Y : Age of the plant reviewed

P : Total units purchased per specification

A : Remaining units active

D : Number of defects (per specification) over the past 5 years

DPUx : Defects (per unit) trend for year x

DPSx : Defects (per spec) trend for year x

L : Externally entered life extension

FV : Number of violent defects per specification

E : Life extension variable (5 years is the default)

The DPU and DPS trend is derived using the last five years of plant defect data with the least square method to calculate the best fit.

Indoor Switchboards

For Indoor Switchboards the remaining life is:

$$RL = R - Y$$

Transmission Structure, Lines and Cables

For Structures, overhead lines and underground cables:

$$RL = R - Y$$

Secondary Assets

The following formula is used to calculate the Remaining Life of a Protection Relays.

$$RL = R - Y + E(E_M + E_P + E_T + E_F)$$

Where:

EM	IF(M=0,1,-M)
EP	IF(P=0,1,-1)
ET	IF(T=1,1,0)
EF	IF[IF=0,1,IF(N<=100,-0.5*F,IF(N<=500,-0.3*F,-0.2*F)]
M	Major Mal-operations or Failures to Operate
P	Performance Gaps
T	Modern Technology
F	Relay Failures
N	Total No. of relays installed

The formula above is used for the cases where the recommended life of the asset is represented by:

R	40 for hardware and simple attracted armature relays(e.g. Interposing CTs, Trip relays and Auxiliary relays)
R	30 for Electro Mechanical relays(e.g. Distance, Differential, Overcurrent, Auto Reclose relays, timers)
R	20 for Static and Numerical relays (e.g. Distance, Differential, Overcurrent, Auto Reclose relays, timers)
Y	Age of the Asset, E = Life Extension Factor (5 years is the default)