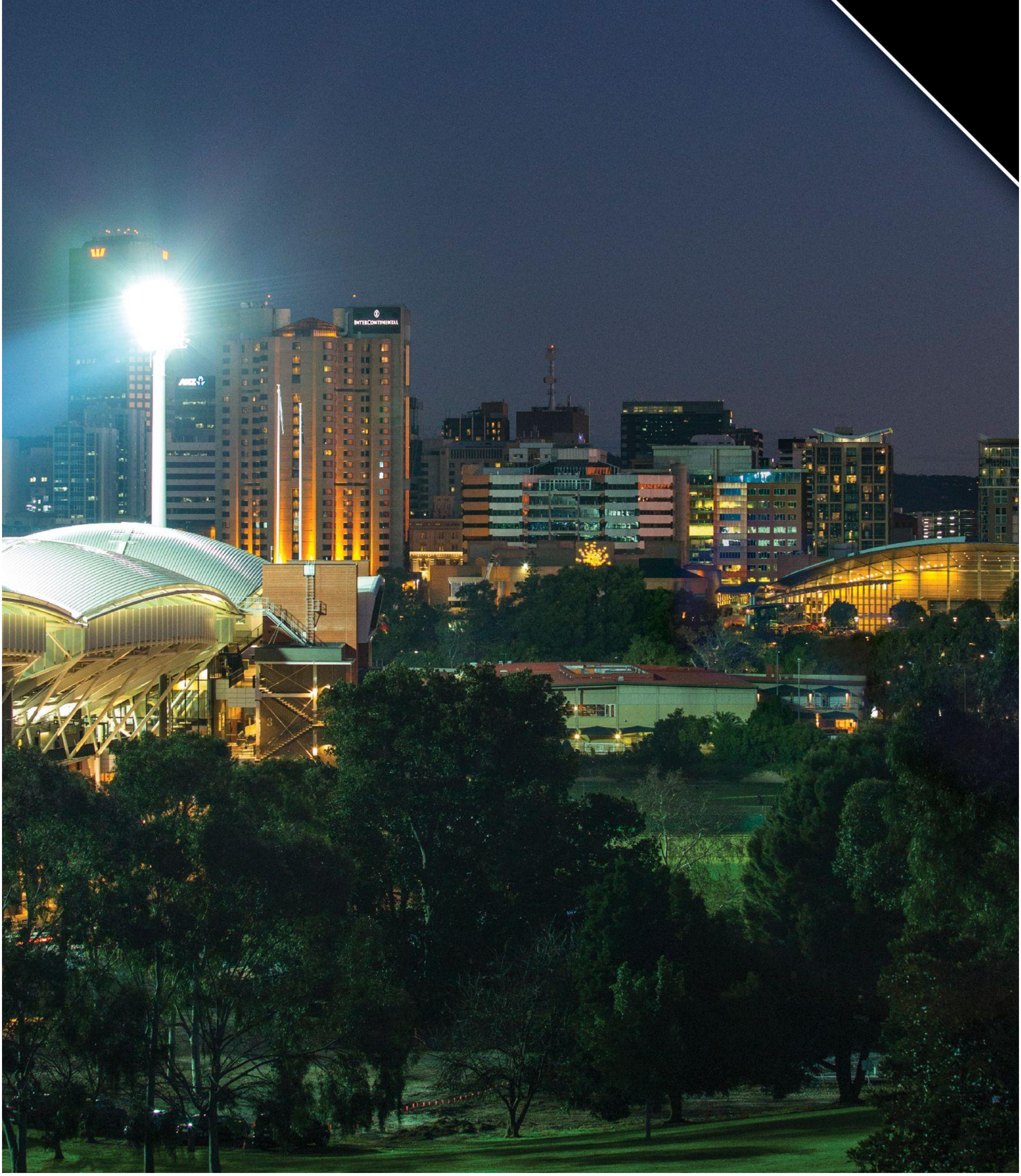
Attachment 20.62

SA Power Networks:
Asset Management Plan 3.1.05
Poles 2014 to 2025



ASSET MANAGEMENT PLAN 3.1.05
POLES
2014 TO 2025

Published: October 2014

SA Power Networks
www.sapowernetworks.com.au

OWNERSHIP OF STANDARD

Procedure 916 Annex B
Issue 2/13

OWNERSHIP OF STANDARD

Name of Standard / Manual: ***AMP 3.1.05 Poles***

Standard/Manual Owner - Title: ***Manager Network Asset Management***
Name: ***S Wachtel***

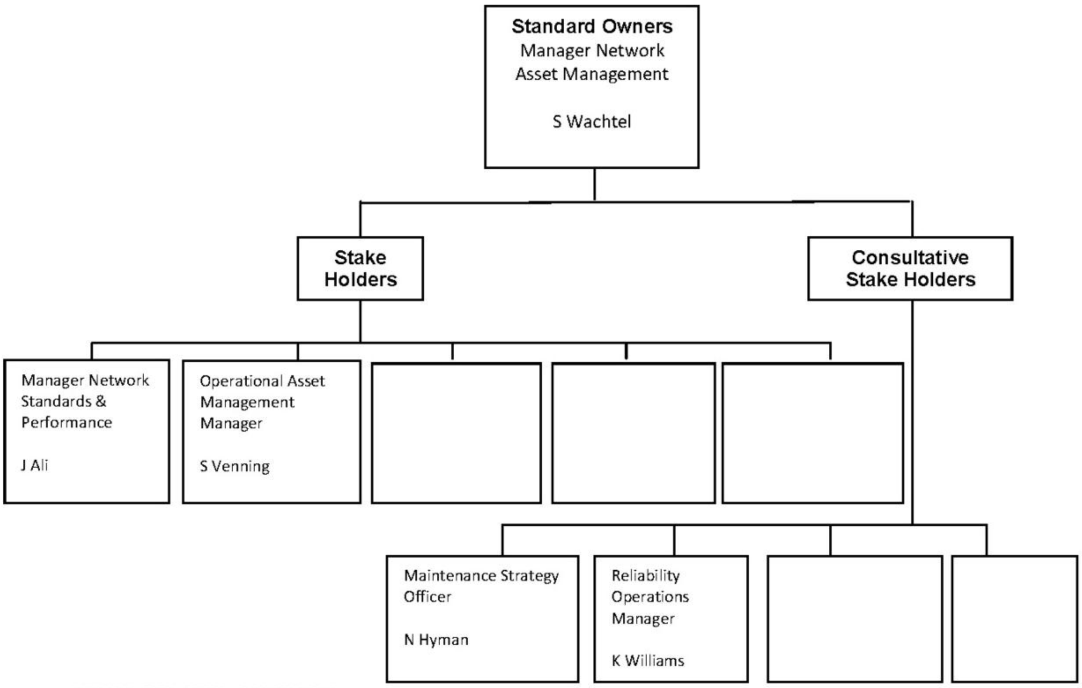
Standard Last Reviewed: September 2014

Standard Last Issued: October 2014

Review Period: 5 Years

Next Review Due: October 2019 *(ie. When the next review process is due to commence)*

STANDARD/MANUAL OWNERSHIP STRUCTURE



OTHER RELATED MANUALS

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COMMENTS

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(Asset Management Plan 3.1.05 – Poles)

DOCUMENT VERSION

Date	Version	Explanation
1/1/2009	0.1	Original AMP
29/9/2014	0.2	Updated AMP
27/10/2014	1.0	Final

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FIGURES

1. EXECUTIVE SUMMARY

1.1 Asset Management Objectives

The key asset management objectives to be achieved by SA Power Networks are:

- **Safety** – To maintain and operate assets such that the risks to employees, contractors and the public are maintained at a level as low as reasonably practicable.
- **Regulatory Compliance** – To meet all regulatory requirements associated with the Electrical Distribution Networks.
- **Environmental** - To maintain and operate assets so that the risks to the environment are kept as low as reasonably practicable.
- **Economic** – To ensure that costs are prudent, efficient, consistent with accepted industry practices and necessary to achieve the lowest sustainable life cycle cost of providing electrical distribution services.
- **Customer Service** – To maintain and operate assets consistent with providing a high level of service (safety and security of supply) to customers.

1.2 Asset Background

Poles are necessary to support the conductors of overhead power lines at a height above ground level and at a distance from all other objects which exceeds prescribed safety clearances. Poles also support other equipment associated with the SA Power Networks distribution network – including transformers, switches, reclosers, sectionalisers, voltage regulators and capacitor banks.

SA Power Networks uses the Stobie pole as the standard method of support for overhead distribution lines. There is also a small population of Municipal Tramways poles and hollow section steel poles.

We have one of the oldest distribution networks in the National Electricity Market (NEM). A large portion of our poles were installed between the 1950s and 1970s, and so, are now over 50 years old. Our Stobie poles can last this length of time, and so historically, we were not seeing a significant number of poles failures. Consequently, the planned replacement of poles was not a significant concern to us. However, as our network aged and asset failures increased, we began in 2007 to transition to a ‘replace-before-fail’ philosophy for our most critical asset.

Since that time, a number of significant events, including the Victorian bushfires in 2009, have brought a sharper focus across the industry on the safety risks posed by the failure of assets. To address these concerns, in 2010 we improved our overhead line inspection practices, reducing our inspection cycles in critical regions, in particular high corrosion zones. The need for this change was accepted by the AER in our previous regulatory proposal. We also expended significant effort improving both our manual that specifies our line inspection practices and the training and competence of our inspectors who use this manual.

1.3 Asset Management Plan Activities

To assist SA Power Networks in achieving the above objectives for poles, an asset management plan is prepared to identify the primary issues and strategies for managing poles, including the asset maintenance and operational functions of poles.

The key objectives of the AMP are essentially:

- To facilitate the delivery of our strategic and corporate goals
- The establishment of a strategic asset management framework

- The setting of asset management policies in relation to user demand, levels of service, life-cycle management and funding for asset sustainability

1.4 Asset Management Strategies

The lifecycle management of poles will assist SA Power Networks in the reliable and cost effective operation of the overhead lines network. This requires implementing the Asset Management Strategy (referenced in AMP 3.0.01 Condition Monitoring and Life Assessment Methodology

The Asset Management Strategy is:

> *"to optimise the capital investment through targeted replacement of assets, based on assessment of asset condition and risk, and also seeks to provide sustainable lifecycle management of assets through the use of condition monitoring and life assessment techniques."*

The lifecycle management of poles is comprised of multiple stages, illustrated in the figure below. The creation, implementation and monitoring of plans in the lifecycle stages are important for the effective implementation of the Poles Asset Management Plan. This will help ensure that the operation of SA Power Networks overhead lines network meets the industry and regulatory standards whilst providing optimal return to shareholders.

The primary focus of this asset management plan is to manage the poles in the Asset Operation and End of Life stages of the asset lifecycle. It is important that issues identified in any of the lifecycle stages are fed back into the other stages. This continuous feedback of information from each lifecycle stage to other stages will improve the reliability and efficiency of SA Power Networks overhead line network.

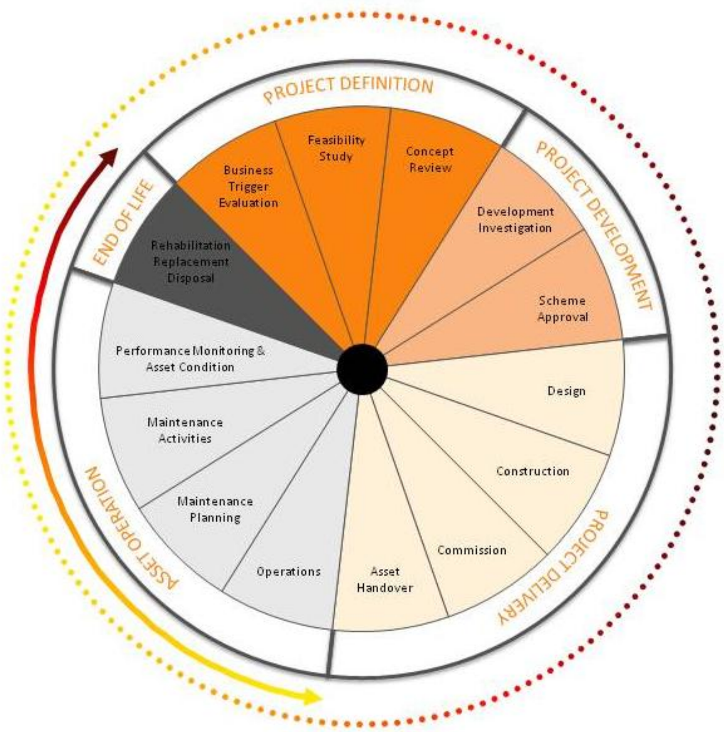

Figure 1: SA Power Network Asset Life Cycle

1.5 Expenditure

The investment program generated by the CBRM maintain risk approach seeks to maintain levels of safety and reliability at an acceptable level after considering likely population changes due to capacity upgrades, unplanned replacement and targeted replacement programs by identifying and targeting an optimal number of high risk assets.

Forecasts generated by the CBRM maintain risk approach in addition to unplanned works programs based on historical expenditure have been selected as the basis of the 2014 – 2025 forecast. Implementation of this plan:

- Maintains the level of risk associated with poles at an acceptable level
- Maintains levels of service and reliability needs necessary to meet customer expectations of network performance.
- Results in a replacement and plating program with volumes of work we believe to be required to comply with our legal obligations associated with delivering on our approved safety management plan (SRMTMP) that is approved by the Essential Services Commission of South Australia (ESCOSA) on the recommendation of the South Australian Office of the Technical Regulator (OTR);
- Has been developed utilising a well proven and well recognised methodology;
- Is broadly supported by other assessment techniques the AER could apply, including benchmarking;
- Prudently manages identified defects, allowing for critical defects to be addressed strictly within the documented remediation timeframes

The yearly capital expenditure requirement for replacement and refurbishment of poles is shown in the figure below.

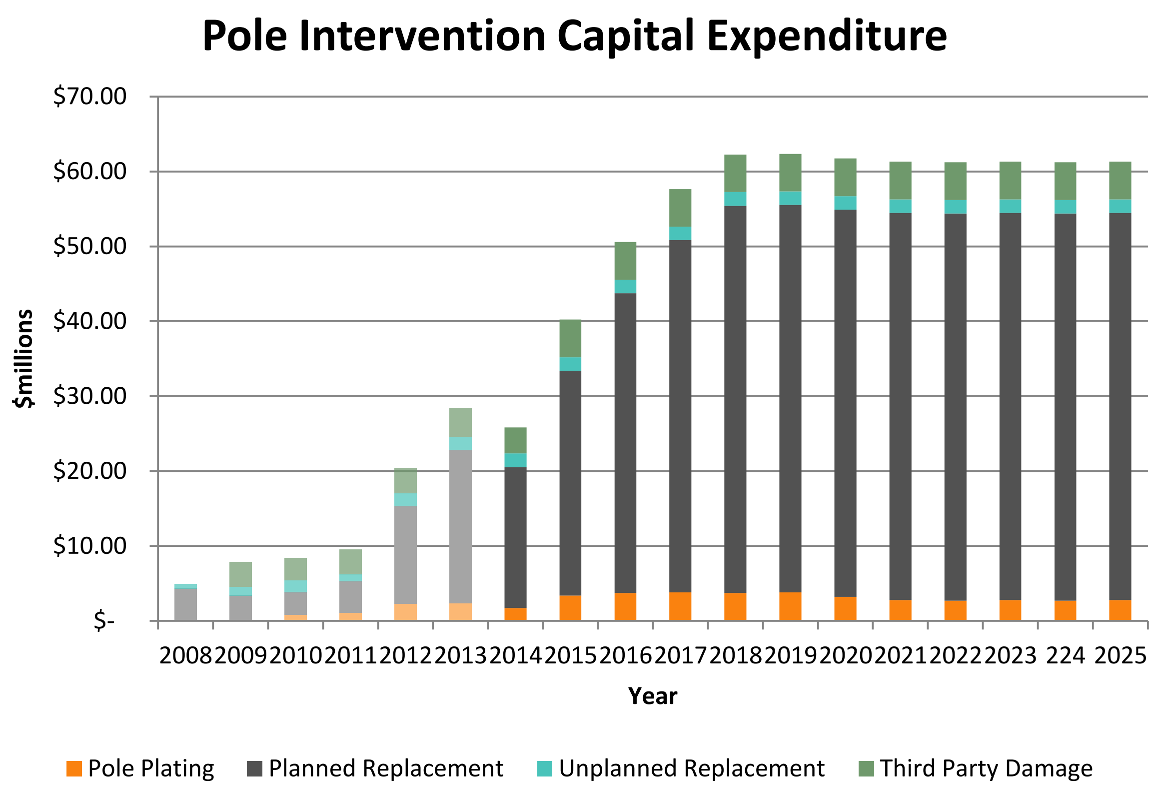

Figure 2: Pole Replacement and Refurbishment Capital Expenditure - historical and forecast

1.6 Planned Improvements in Asset Management

The forecast poles refurbishment and replacement schedule and resulting expenditure plan has been based on available asset information, historical data and guidelines from the SA Power Networks Risk Management Framework. In order to continue developing and refining expenditure forecasts, SA Power Networks aim to improve and maintain the collection of asset information, specifically targeting:

- Asset condition and defects, including categorised condition ratings/scores
- Asset faults and failures, including detail into cause and symptoms of faults/failures
- Cost of replacements, including labour and materials

2. INTRODUCTION

2.1 Background

Poles are necessary to support the conductors of overhead power lines at a height above ground level and at a distance from all other objects which exceeds prescribed safety clearances. Poles also support other equipment associated with the SA Power Networks distribution network – including transformers, switches, reclosers, sectionalisers, voltage regulators and capacitor banks.

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2.1.1 SA Power Networks Electricity Network

SA Power Networks is a distribution network service provider (DNSP) in South Australia, Australia.

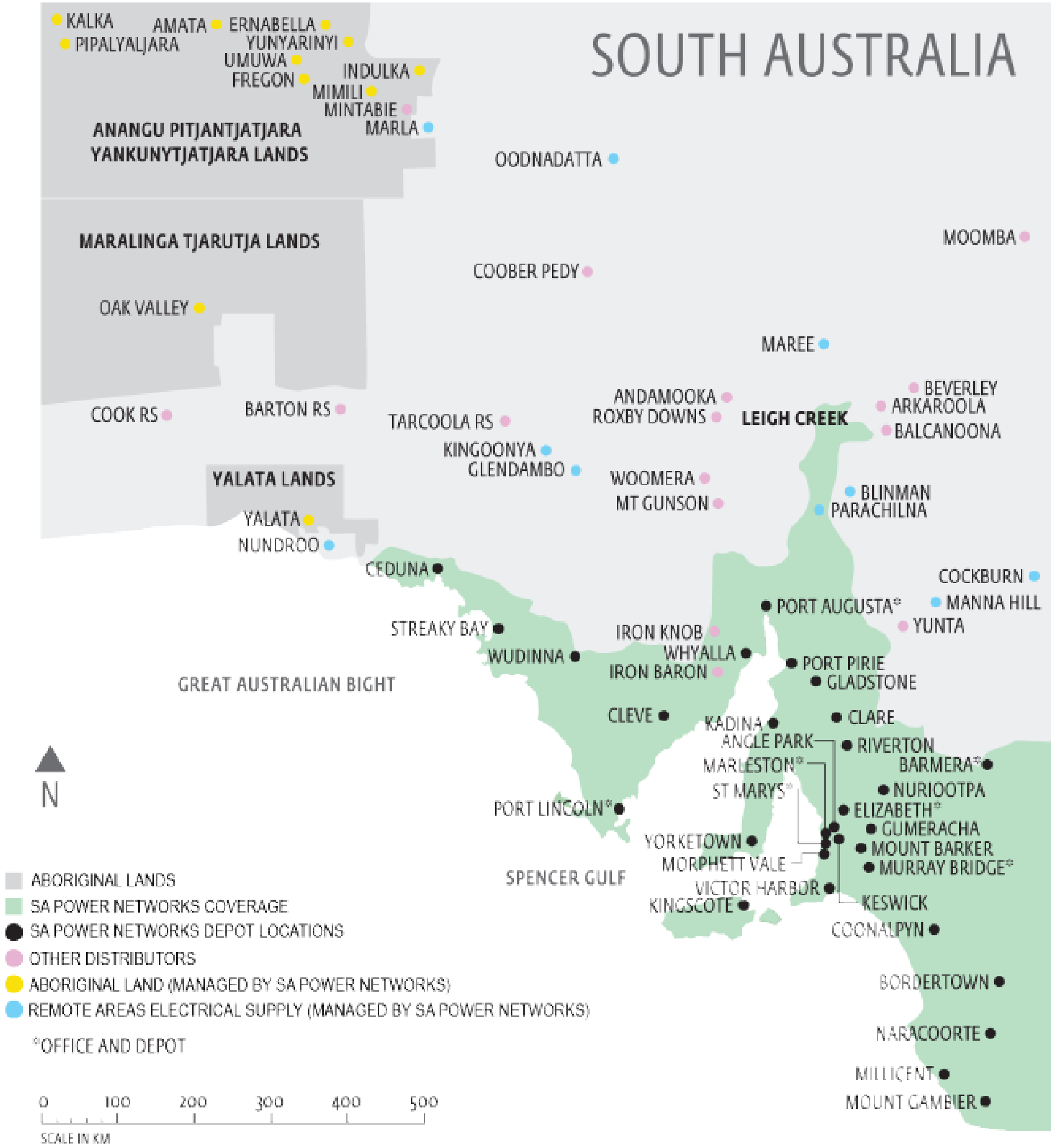

Figure 3: SA Power Networks network map

The history of SA Power Networks is as follows:

- Electricity Trust of South Australia (ETSA) Trust was formed in 1946 through the nationalisation of Adelaide Electric Supply Company.
- ETSA privatised in 1999 and split into power generation, transmission and distribution. The distribution group became known as ETSA Utilities.
- In 2012, ETSA Utilities became rebranded to SA Power Networks. The rebranding emphasised the focus on SA Power Networks core business of serving business and residential customers in metropolitan, regional and remote areas of South Australia.

SA Power Networks owns an extensive overhead line network to supply electricity reliably and safely to its customers

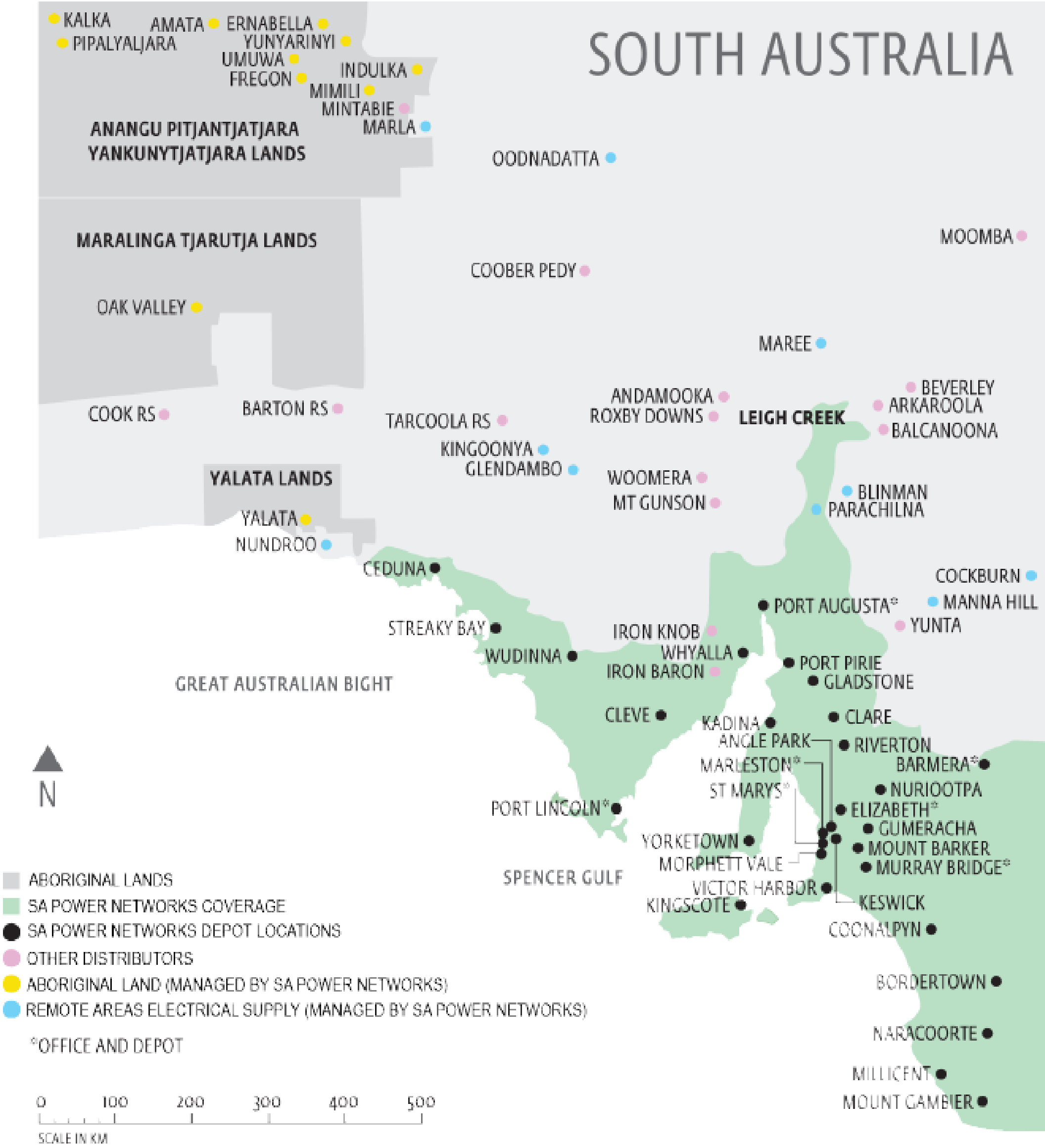

Figure 3 illustrates the expanse of SA Power Networks overhead line network in South Australia. The network is centred on Adelaide and supplies electricity to the south-east coastal region of South Australia and up towards inland South Australia. It is clear that much of the network is situated close to the coast of South Australia as that is where the majority of customers reside.

2.1.2 South Australian Environment

SA Power Networks overhead line network is situated along the coast which is constantly exposed to the saline environment. As a consequence, corrosion in the network is a cause for concern to SA Power Networks. SA Power Networks has acknowledged the impact of corrosion on the assets in the overhead line network, including poles, by identifying the corrosion zones in South Australia. Figure 4 exemplifies the levels and location of the atmospheric corrosion zones in South Australia.

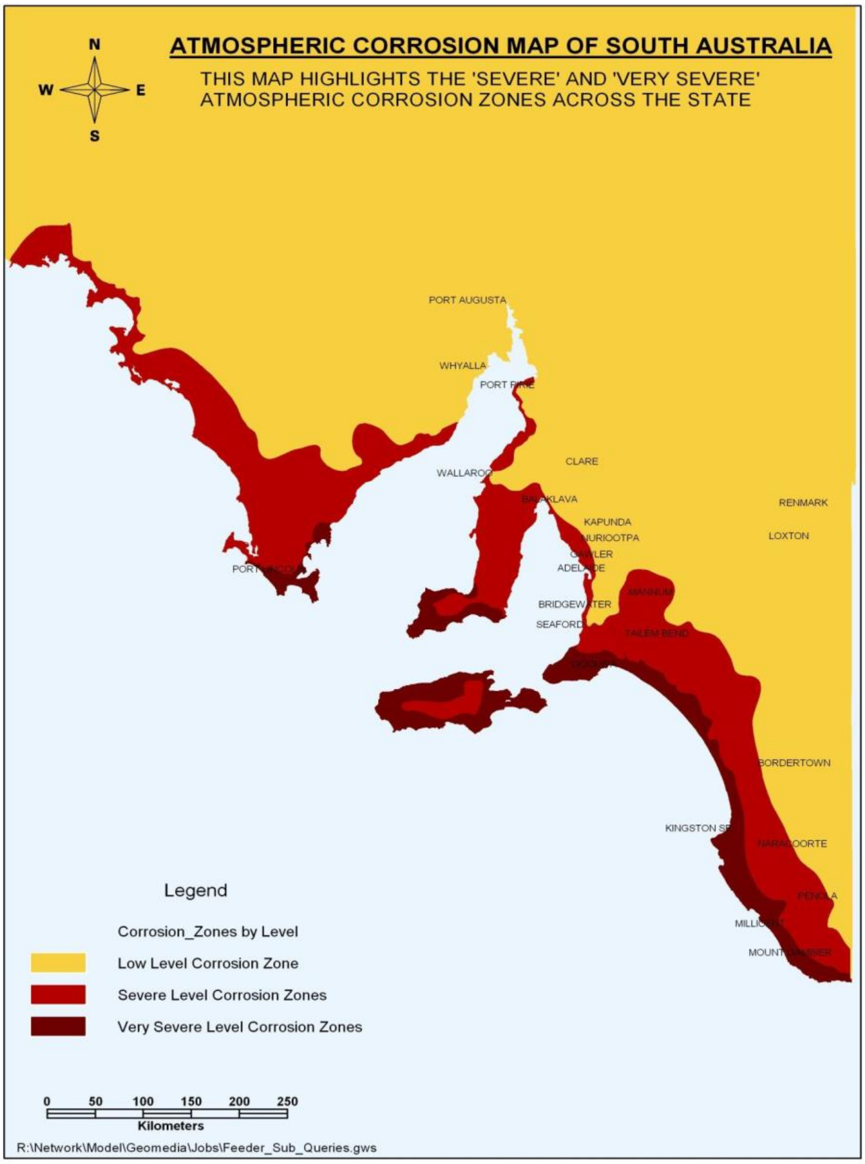

Figure 4: Atmospheric Corrosion Zone Map of South Australia

There are three levels of corrosion zones, low, severe and very severe. The severe corrosion zones extend further inland than the very severe corrosion zones due to the transfer of airborne salts by the atmosphere. Comparing

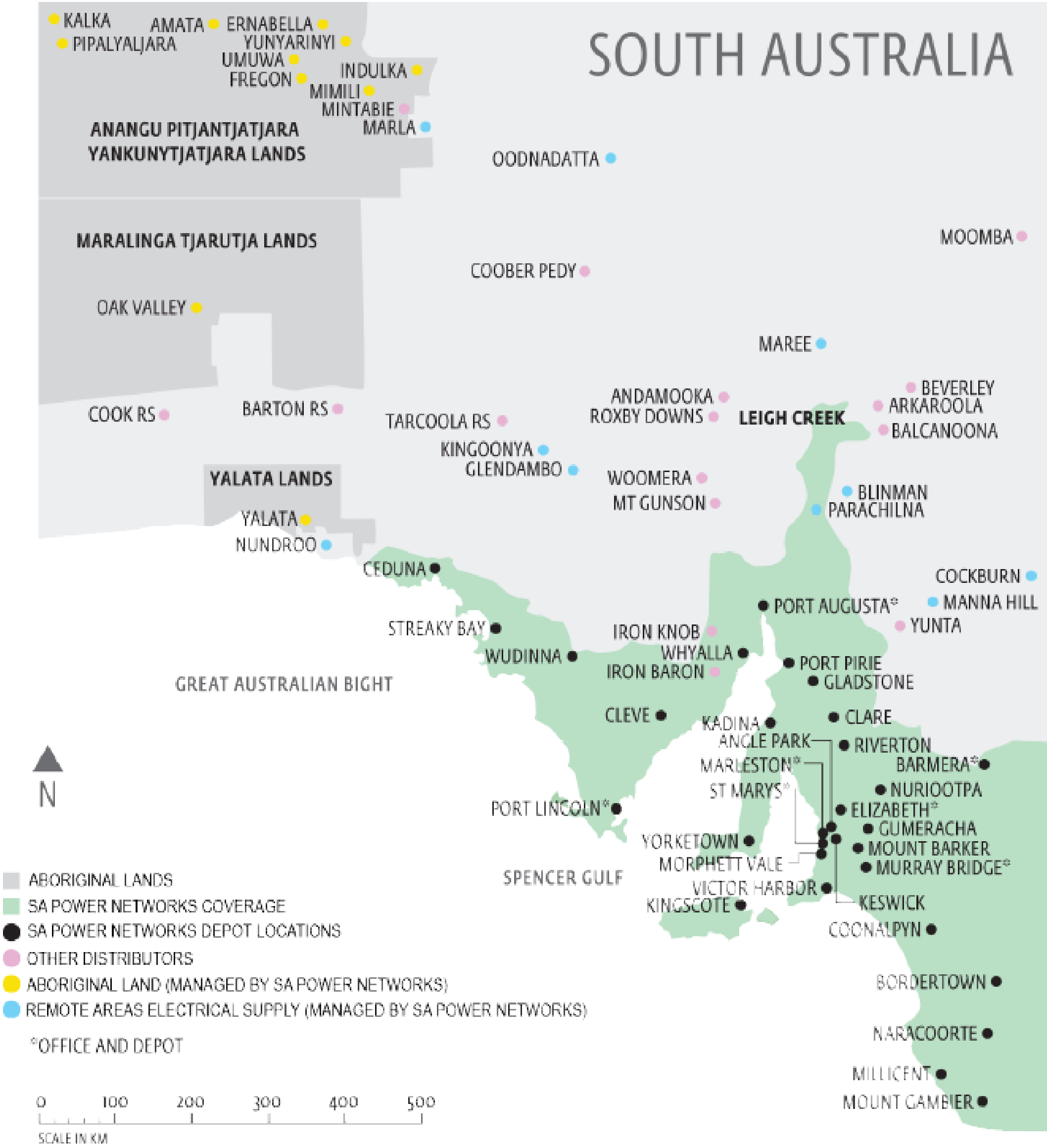

Figure 3 with Figure 4 shows that a large proportion of the distribution network is located in the severe and very severe corrosion zones.

South Australia has several natural reserves and conservation parks that are protected which SA Power Networks distribution network intersects. Operating the distribution network in bush land poses risk of bushfire. SA Power Networks has recognised the importance of minimising any risk associated with operating the distribution network in the protected natural environment by identifying the levels and location of bushfire prone areas. Figure 5 illustrates the three bushfire risk areas in South Australia.

The areas identified are high bushfire risk areas, medium bushfire risk areas, and non bushfire risk areas. High bushfire risk areas include most of the protected natural reserves and conservation parks. Medium bushfire risk area reflects the risk on developments on the fringe of dense bush land. This area consists of metropolitan, suburban, and country districts. Associating

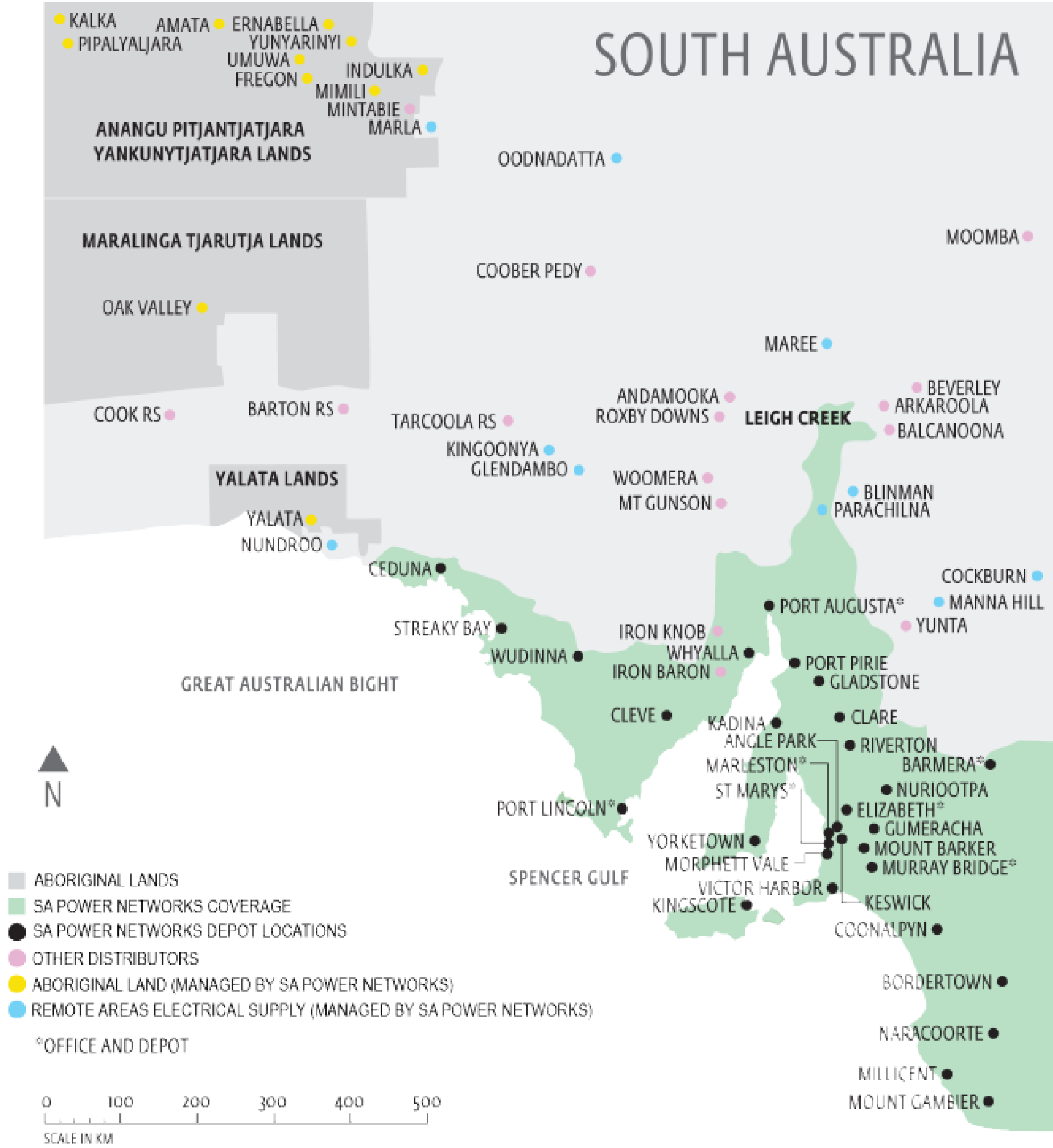

Figure 3 of SA Power Networks electricity network with Figure 5 illustrates that the distribution network is present in all of the high bushfire risk areas.

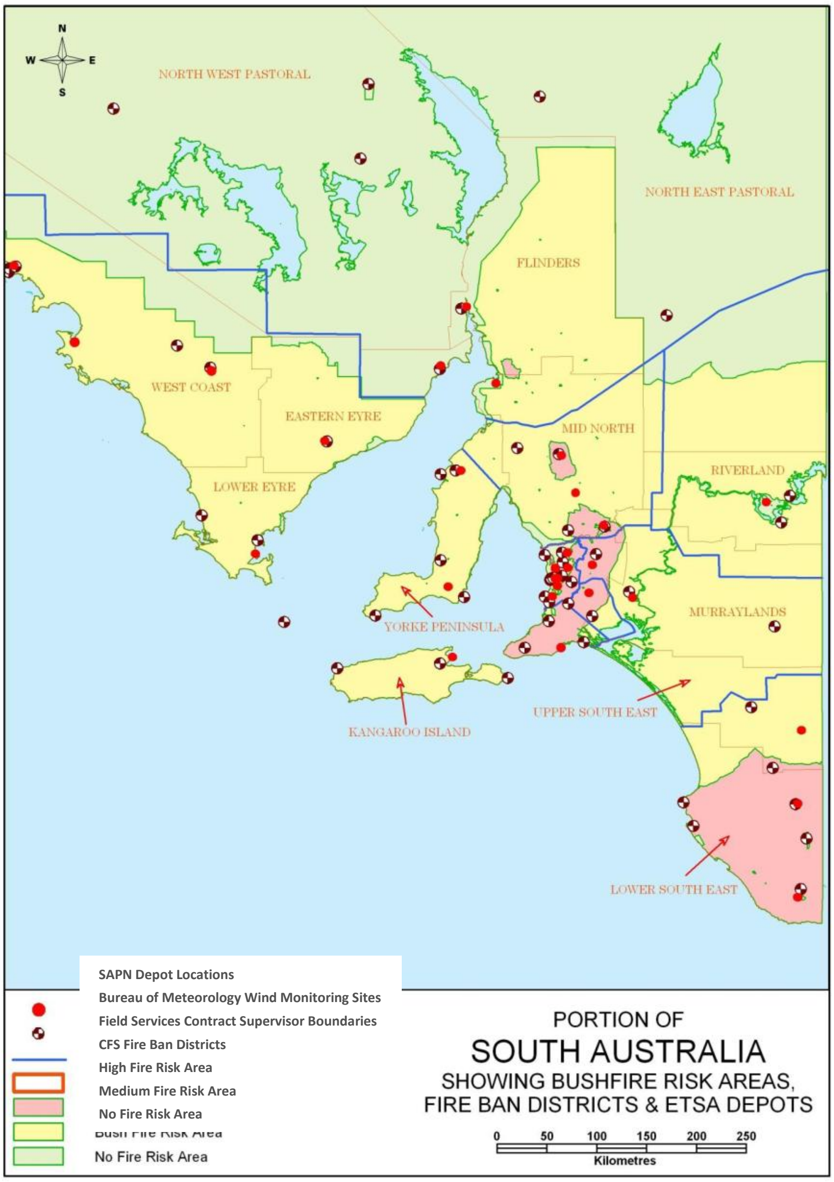

Figure 5: Bushfire Risk Areas in South Australia

The combination of all three figures shows that significant portions of SA Power Networks distribution network is located in both very severe corrosion zones and high bushfire risk areas. SA Power Networks has acknowledged this by indicating the corrosion zone level and the bushfire risk areas for each asset in SAP.

2.2 Goals and Objectives of Asset Management

The key asset management objectives to be achieved by SA Power Networks are:

- Safety – To maintain and operate assets such that the risks to employees, contractors and the public are maintained at a level as low as reasonably practicable.
- Regulatory Compliance – To meet all regulatory requirements associated with the Electrical Distribution Networks.
- Environmental - To maintain and operate assets so that the risks to the environment are kept as low as reasonably practicable.
- Economic – To ensure that costs are prudent, efficient, consistent with accepted industry practices and necessary to achieve the lowest sustainable life cycle cost of providing electrical distribution services.
- Customer Service – To maintain and operate assets consistent with providing a high level of service (safety and security of supply) to customers.

To assist SA Power Networks in achieving the above objectives for poles, an asset management plan is prepared to identify the primary issues and strategies for managing poles, including the asset maintenance and operational functions of poles.

The key objectives of the AMP are essentially:

- To facilitate the delivery of our strategic and corporate goals
- The establishment of a strategic asset management framework
- The setting of asset management policies in relation to user demand, levels of service, life-cycle management and funding for asset sustainability

2.3 Plan Framework

2.3.1 Scope

Detailed Asset Management Plans, including this document, form part of a suite of documents used by SA Power Networks in the delivery of the asset management programs, as represented in Figure 6.

The Poles Asset Management Plan ensures that the overhead line network is operating in a safe, reliable, and environmentally conscious manner. This enables the network to provide excellent customer service and optimal return to SA Power Networks shareholders.

The scope of the Poles Asset Management Plan is to detail SA Power Networks plans in managing poles between 2014 and 2025. Reference will be made to pole fittings and accessories as they are associated with the management of poles. Insulators, structures and other associated equipment will not be discussed in the plan but are assumed to be included in capital works associated with pole replacement.

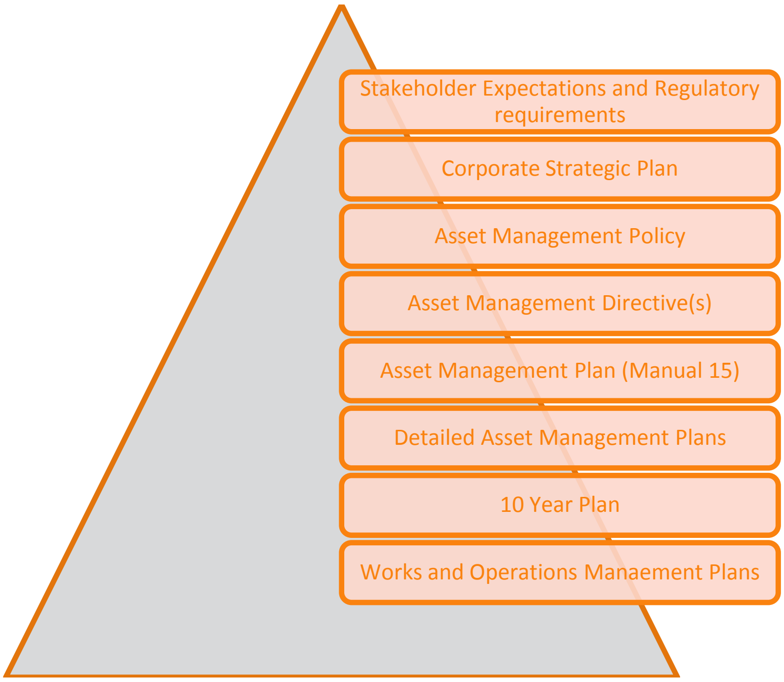

Figure 6: Asset Management document framework

2.3.2 Supporting Documents and Data

The Poles Asset Management Plan refers to the following SA Power Networks documents:

- Network Asset Management Plan Manual No. 15
- Network Maintenance Manual No. 12
- Line Inspection Manual No. 11
- Condition Monitoring and Life Assessment Methodology (CM&LA) AMP.3.0.01

The Network Asset Management Plan Manual No. 15 describes SA Power Networks management process of assets in the distribution network. The document describes the organisational strategies, process and systems to ensure economical, efficient and effective serviceability of assets in the electricity network.

The Network Maintenance Manual No. 12 details the maintenance plans for the assets in the distribution network. The maintenance strategies adopted for each asset is described in detail. The description of the type of maintenance and sampling/inspection frequencies is provided for poles.

The Line Inspection Manual No. 11 provides a detailed guide in assessing the condition of poles, the procedures in recording the data collected during the condition assessment and prioritisation of defects. High resolution photographs of common defects of poles and the codes for capturing the common defects are provided in the manual.

SA Power Networks has developed a new asset management philosophy and approach which is discussed in the Condition Monitoring and Life Assessment (CM&LA) Methodology Asset Management Plan. The Condition Monitoring and Life Assessment (CM&LA) Methodology is to replace their existing reactive approach in managing their assets. The methodology provides a basis for the economic, reliable and safe management of assets which includes poles.

2.3.3 Structure of Poles AMP

This asset management plan is aligned to the framework outlined in International Infrastructure Management Manual (2011). and is to be implemented between 2014 and 2025.

3. LEVELS OF SERVICE

Service levels should represent the expectations that stakeholders (asset owners as well as customers) have of the assets. Desired service levels drive the strategic and operational elements of the asset management plan as assets fulfil their designed intention throughout the asset life-cycle. Issues such as cyclic or periodic replacement cycles, routine maintenance schedules and asset inspections (often part of the Routine Maintenance Plan) are all integral to Service Level provision.

3.1 Customer Research and Expectations

3.1.1 SA Power Networks Customer Research

There is no specific customer expectation survey in relation to poles which form part the overall Distribution Network. It is reasonable to expect that the information derived from customer research for the Distribution Network is applicable to its components and can be adapted to poles.

3.1.2 Network Customer Expectations

SA Power Networks' stakeholder engagement program for the 2015/16-2019/20 regulatory period included commissioning Deloitte to conduct a Consumer Consultation Survey in May 2013, and facilitate a number of stakeholder and consumer workshops held regionally and in the metropolitan area. The survey and workshops content was developed though consultation with SA Power Networks and the Essential Services Commission of South Australia (ESCoSA), and was informed by earlier work. There were 13 Key Consumer Insights as a result of this work.

The key relevant consumer insights were:

- Continue asset management and investment to driver reliability, manage risk and support economic growth. Asset management initiatives that have a direct impact on reliability and/or prevent potential safety hazards were rated as most important. Consumer priority areas included assets in high bushfire risk areas and near roads in residential areas. The priority areas for Business and Government consumers included areas that would support economic growth
- Prioritise preventative maintenance to mitigate risk. All preventative maintenance initiative should consider potential safety hazards and be completed as a priority when risks can be mitigated
- CFS Bushfire Safer Places should have continuous power. Investment in bushfire management initiatives would ensure that essential services are managed under critical conditions
- Maximise opportunities to improve the visual appearance of assets. Undergrounding of the network and substation façade treatment initiatives were universally supported, with priority areas for completion deemed to be in areas where the visual appearance of the network has the largest effect on the community
- Consider improvements in public safety and reliability in asset planning. Consumers identified high bushfire risk areas and areas where additional

safety and reliability benefits could be realised as priority areas for undergrounding the network.

On this basis, SA Power Networks considers that it is appropriate for the forthcoming 2015/16 – 2019/20 Regulatory Control Period (the 2015 Reset) to establish the reliability performance targets based on average historic performance levels, and develop a forward program of work seeking to maintain current levels of safety and reliability.

3.1.3 ESCoSA Service Standards

ESCoSA consulted with the South Australian community to develop the jurisdictional service standards to apply to SA Power Networks for the next regulatory period 2015/16-2019/20by releasing an Issues Paper in March 2013 and a Draft Decision in November 2014.

ESCoSA has formed the view (ESCoSA, Final Decision, May 2014) that consistency between the parameters of the AERs STPIS and the jurisdictional service standards is of primary importance for the next regulatory period 2015/16-2019/20in order to:

- Minimise the potential for conflicting incentives between elements of the service standard framework and the AERs pricing regime, this minimising the potential for unwarranted costs being borne by South Australian consumers.
- Ensure appropriate incentives are provided to SA Power Networks to maintain current service levels and only improve service levels where the value to customers exceeds the cost of those improvements.

The service standards set are summarised as follows:

- **Network reliability service standards and** targets – reliability of the distribution network as measured by the frequency and duration of unplanned interruptions, with network performance service standards set to reflect difference in the levels of interconnection and redundancy in the physical network across the state. The network reliability targets require SA Power Networks to use its best endeavours to provide network reliability in line with average historical performance in the period 2009/10 to 2013/14. The reliability targets exclude performance during severe or abnormal weather events using the IEEE MED exclusion methodology.
- **Customer Service standards and targets** – Unchanged from the current customer service standards and targets. SA Power Networks will be required to continue to use its best endeavours to meeting the customer service responsive targets defined.
- **GSL Scheme** – SA Power Networks will be required to continue to make GSL payments to customers experiencing service below the current pre-determined thresholds.
- **Performance monitoring and reporting** - the performance monitoring and reporting framework focus' on four particular areas of performance:
  - Reliability performance outcomes for customers in geographic regions against average historical performance
  - Operational responsiveness and reliability performance during MEDs
  - Identification and management of individual feeders with ongoing low-reliability performance

– Assessment of the number of GSL Scheme payments made in each geographic region

3.2 Legislative requirements

Under the terms of its Distribution License, SA Power Networks is required to comply with a number of Acts, Codes of Practice, Rules, Procedures and Guidelines including, but not limited to:

- Electricity Act 1996
- National Electricity (South Australia) Law Act (NEL)
- National Energy Retail (South Australia) Law Act (NERL)
- SA Electricity Distribution Code (EDC)
- SA Electricity Metering Code (EMC)
- National Electricity Rules (NER)
- National Metrology Procedures (NMP)
- ESCoSA and AER Guidelines

3.3 Regulatory Targets and Requirements

3.3.1 Performance Standards

SA Power Networks must use its best endeavours to achieve the reliability standards, as set out in Manual 15, during each year ending on 30 June.

3.3.2 Service Target Performance Incentive Scheme (STPIS)

SA Power Networks is required to operate within a Service Target Performance Incentive Scheme (STPIS), in accordance with the National Electricity Rules (NER). The intent of the STPIS is to provide SA Power Networks with a financial incentive to maintain and improve reliability performance to our customers.

The STPIS is based on annual unplanned SAIDI and SAIFI reliability performance in different feeder categories. Any departure from the specified reliability performance targets will result in an incentive or penalty to SA Power Networks via a distribution revenue adjustment.

3.3.3 Reliability

In the price-service setting process, the establishment of operational standards for the distribution network is fundamental.

For electricity distribution, the two key reliability standards set by the ESCoSA are based around the impact of supply interruptions on customers: the average annual duration of interruptions per customer (SAIDI) and the average annual frequency of interruptions per customer (SAIFI).

While there are no annual performance targets specified for the entire network (state-wide), there are implied targets based on the customer-weighted averages of the implied regional targets.

SA Power Networks' annual obligation to publicly report on low reliability performing feeders for the regulatory period is based on individual SAIDI feeder performance relative to relevant regional SAIDI targets which, on average, results in the identification of about 5% of total feeders (approximately 90 feeders) across the network throughout the regulatory period. A SAIDI threshold multiplier of 2.1 was determined for the current regulatory period, 2010/11 to 2014/15, to provide the required sample.

In assessing performance against the standards, the relevant test is two-fold: first, has the target been met?; if not, did SA Power Networks nevertheless use its best endeavours in its attempts to meet the target?

3.4 Current Levels of Service

The current Level of Service (LoS) as reported to ESCoSA for the period to 30 June published each year by ESCoSA.

4. FUTURE DEMAND

4.1 Demand Drivers

SA Power Networks identifies the following areas to be key influences on demand:

- New residential/commercial developments
- Increased air conditioner use
- New infrastructure

4.2 Demand Forecast

SA Power Networks recognises that there are alternatives to network solutions which may deliver either a lower cost or provide greater benefits to the electricity market, these solutions include and are not limited to:

- Embedded Generation
- Shifting consumption to a period outside the peak period
- Increasing customers' energy efficiency
- Curtailing demand at peak periods, with the agreement of the relevant customer(s)

4.3 Demand Management Plan

The SA Power Networks load forecast is reviewed annually after each summer peak load period. The review considers the impact of new peak load recordings, system modifications and new large load developments.

The load forecasting methodology produces 10% Probability of Exceedance (POE) and 50% POE forecasts for each element in the network

The aggregated impact of customer PV is considered in the forecasts based on measured performance of typical PV installations, installed PV capacity, time of peak demand and PV growth rate. The rapid growth of PV is anticipated to continue in the short term, and gradually slow down over the forward planning period. The rapid update of PV and adoption of energy efficient appliances has offset substation load growth, and in some instances reduced net load. The future of PV growth on peak demand is expected to be minimal as the time of peak load for most substations has shifted past 6PM, which is when PV output is approaching zero.

4.4 Key Asset Programmes to Meet Demand

Pole replacements to meet demand are covered in AMP.1.1.01 – Distribution System Planning Report (DAPR). Replacements forecast within this asset management plan assume the implementation of replacements due to network capacity and are supplemental to any replacements detailed within the DAPR.

5. LIFECYCLE MANAGEMENT

5.1 Profiling of the Poles Network

5.1.1 Context to Data

The graphs and statistics used throughout the Poles Asset Management Plan are based on data extracted from SA Power Networks SAP and other sources within the organisation. The age data used in the profiling of the electricity network reflects the date of manufacture or where available the more accurate date of installation. The data does not distinguish the manufacture and installation dates.

5.1.2 Stobie Poles

Stobie pole consist of a concrete core with two outer steel beams connected by bolts to ensure strength. The poles are symmetrically tapered at both ends to ensure that maximum width and bending strength requirements occur just below ground level. Footings incorporating reinforced concrete are used to ensure that poles are securely anchored in the ground. Sizes of Stobie poles may vary from 9m for low voltage applications to greater than 25m for transmission applications.

Stobie poles have been uses in South Australia to support overhead distribution lines for around 90 years, and were introduced due to a lack of suitable timber within the state and the high cost of importing timber poles from elsewhere. Other than metrification and the introduction of galvanised steel in the 1990s for a period of 15 years, Stobie poles have remained unchanged.

Whilst the initial cost of installing a Stobie pole is greater than its timber equivalent, they exceed the life of timber poles many times.

The estimated age distribution of Stobie poles across SA Power Networks distribution network is shown in Figure 7 below. This estimate is based on pole production records and has been refined where additional information is available on specific poles.

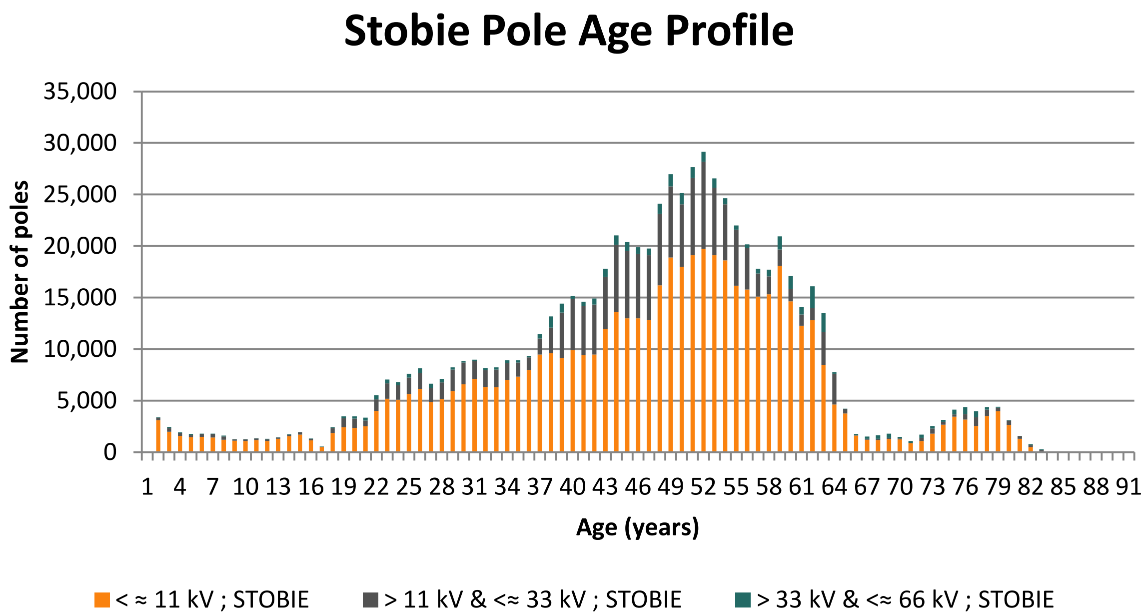

Figure 7: Stobie Poles Age Profile

Available data indicates that the number of poles recorded in each of the corrosion zones is 64% in low, 31% in moderate and 5% in high.

5.1.3 Municipal Tramway Poles

MTT Municipal Tramways Poles are of a rolled steel construction and were installed along the metropolitan Adelaide tramways. It is estimated that 173 poles of this construction are in existence on the network, with an average age of 104 years. A number of these poles are heritage listed. These poles are considered low risk poles are they are in relatively sound condition and carry LV mains or lighting.

Figure 8: MTT pole

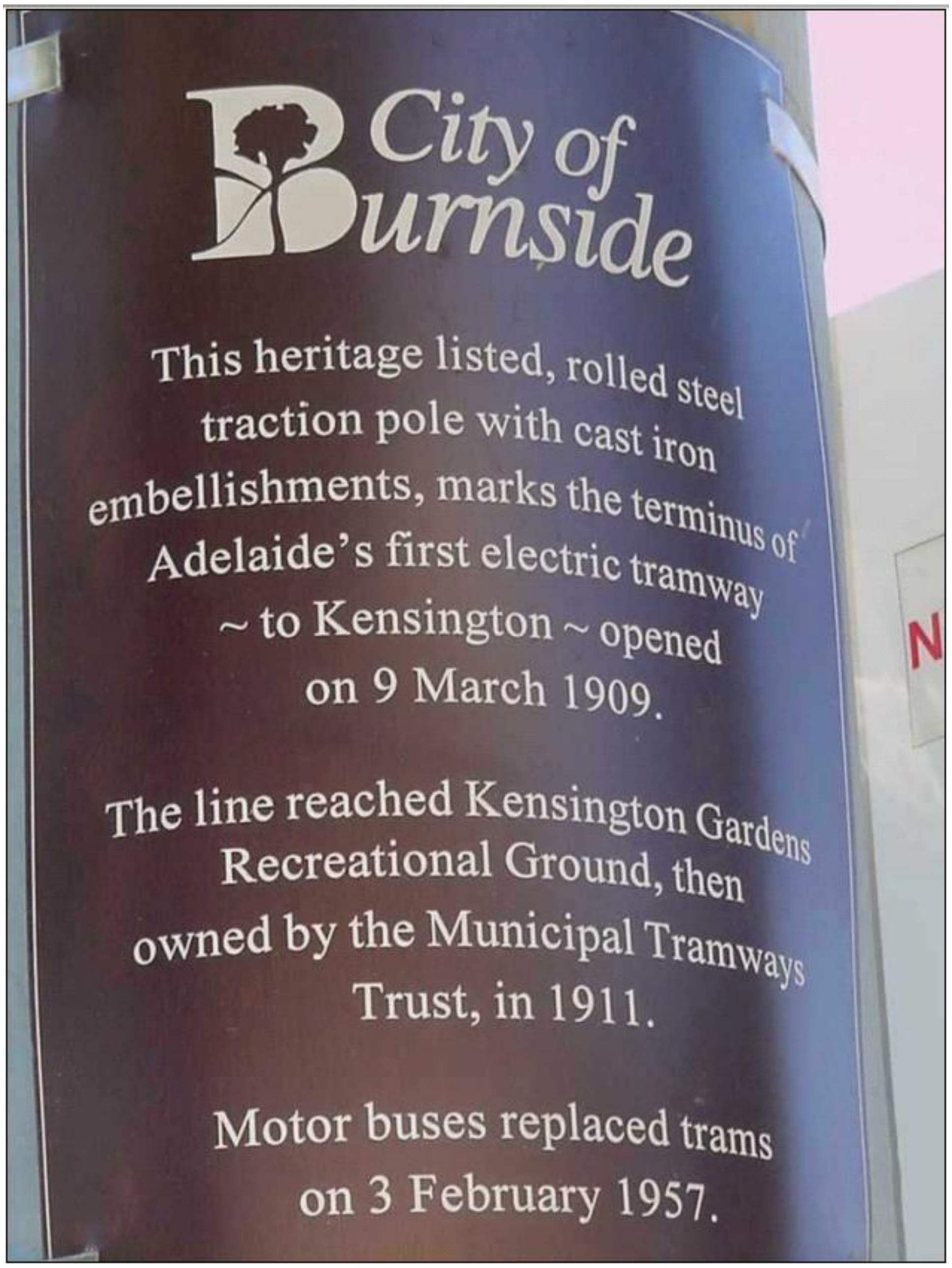

Figure 9: MTT Heritage Plaque

5.1.4 Wooden Poles

There are a small number of wooden poles installed on the network, mainly located on private land. Based on available data these assets are in relatively sound condition and pose a low risk on the network.

5.1.5 Hollow Steel LV Poles

Low voltage hollow steel poles are used for light duty customer service connections only. These poles have only been in use since 2003, and therefore the oldest poles of this type on the network are around 10 years of age. There are approximately 550 of these poles currently in service. To date, due to their relatively young age few of these poles have been inspected.

5.2 Lifecycle Management of Poles

The lifecycle management of poles will assist SA Power Networks in the reliable and cost effective operation of the overhead lines network. The lifecycle management of poles is comprised of multiple stages. Figure 10 identifies the asset lifecycle stages developed by SA Power Networks.

The creation, implementation and monitoring of plans in the lifecycle stages are important for the effective implementation of the Poles Asset Management Plan. This will help ensure that the operation of SA Power Networks overhead lines network meets the industry and regulatory standards whilst providing optimal return to shareholders.

The primary focus of this asset management plan is to manage the poles in the Asset Operation and End of Life stages of the asset lifecycle. It is important that issues identified in any of the lifecycle stages are fed back into the other stages. This continuous feedback of information from each lifecycle stage to other stages will improve the reliability and efficiency of SA Power Networks overhead line network.

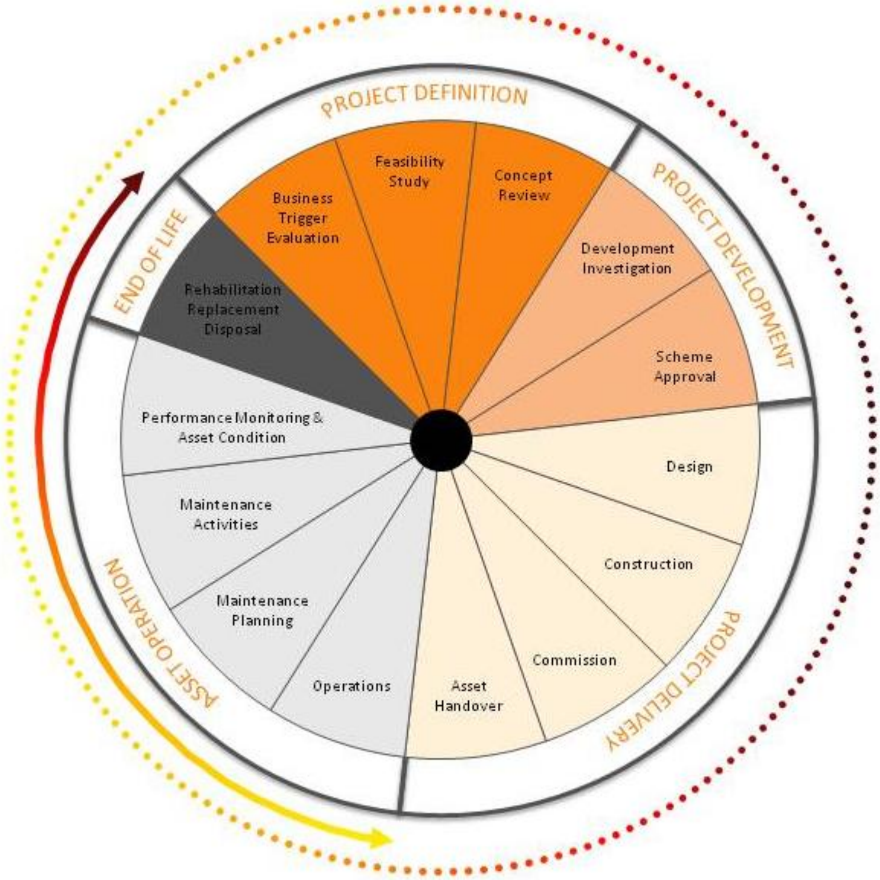

Figure 10: SA Power Networks Asset Lifecycle

It is important to recognise that poles do not have a defined life expectancy unlike other equipment, such as transformers. However, there are several factors that limit the service life of poles, including:

- Load capacity – static and dynamic load acts as a catalyst for other factors
- Corrosive atmosphere – ground level and atmospheric
- Atmospheric pollution
- Fatigue

- Installation methods, especially incorrectly constructed footings

The failure modes identified in the End of Life stage is of significant value to asset managers. An understanding of these can assist in updating assumptions made in Project Development, redefining the specification of components during Project Delivery, and improving maintenance plans in Asset Operation. The following section identifies the failure modes that are intrinsic to poles. Other factors that are not intrinsic to poles are separately identified to indicate that they can be managed to some extent by SA Power Networks.

5.3 Issues and Failure Modes

5.3.1 Stobie Poles

Ground level corrosion is the main issue with Stobie poles. The extent of ground level corrosion varies depending on the pole corrosion zone. In the low corrosion zone the extent of corrosion is less severe and hence pole refurbishment is preferred over replacement. Refurbishment can be achieved by welding steel plates across the corroded section (pole plating). In the moderate and high corrosion zones the proportion of poles refurbished in favour of replacement is likely to be less. In the high corrosion zone, above ground corrosion of steel elements becomes more prevalent. In addition, corrosion and distortion of concrete-embedded anchor bolts leads to losses/spalling of the concrete.

The end of life of a pole is determined by the extent of corrosion, both above ground and ground level. Reaching this end of life standard, as defined in the Line Inspection Manual, does not mean that the pole will fall over, rather that the strength is diminished and there is a high probability that the pole strength will be insufficient under high mechanical load conditions. For the purposes of this plan, pole failure is considered to be when the corrosion standard is exceeded rather than when the pole falls. On average around 11 HV poles, and up to 25 LV poles, have failed per annum (since 2003) due to the effects of severe corrosion and generally during strong wind conditions.

A pole that fails and falls can have public safety, reliability and environmental consequences. Bushfire starts are the most significant consequence of a pole falling.

Figure 11: Stobie pole ground level corrosion example

5.3.2 Municipal Tramway Poles

According to recorded condition assessment, ground level corrosion is the main issue with MTT Municipal Tramway poles as well as corrosion above ground at the junction of the pole and the surrounding collar. These poles can not be refurbished so are replaced by Stobie poles on a condition basis where allowed.

5.3.3 Wooden Poles

These assets are in relatively sound condition and pose a low risk on the network. At present there are no known issues particular to this pole type in SA Power Networks distribution network.

5.3.4 Hollow Steel LV Poles

No failures of this type of pole have been recorded yet, however, it is anticipated based on the experiences of other DNSPs, that ground level corrosion will cause deterioration and failure will result in replacement.

5.4 Risk Management Plan

Risk management is the term applied to the logical and systematic method of identifying, analysing, assessing, treating, monitoring and communicating risks associated with any event or activity in a way that will enable organisations to minimise losses and maximise opportunities. The main elements of any risk management process are:

- Define the event or activity and the criteria against which the risk will be assessed
- Identify the risks associated with the activity
- Analyse the risks to determine how likely is the event to happen and what are the potential consequences and their magnitude should the event occur
- Assess and prioritise the risks against the criteria to identify management priorities
- Treat the risks by introducing suitable control measures
- Monitor and review the performance of the risk management system

Risk management is a key activity in the Asset Management process. Risk assessment and risk management is used by SA Power Networks in the decision making process for network capital expenditure and in network operations and maintenance activities.

The application of Risk Management is described in the Network Asset Management Plan – Manual 15. This describes the standard process of identifying hazards, identifying the likely causes, assessing the likelihood and consequences (risk) without controls in place and then determining practical and achievable controls followed by re-assessing the residual risks after application of controls.

Inspection and condition monitoring tasks are scheduled at standard intervals as detailed in the Maintenance Plan. Monitoring condition trends over time is a primary strategic asset management tool which tracks deterioration over time. As areas of concern are identified, condition monitoring frequencies may need to be shortened as the risk of an impending failure becomes apparent. Such deterioration can develop slowly over time, or in some cases, quickly and then requiring urgent operational actions to reduce the risk of in-service failure.

5.5 Maintenance Plan

5.5.1 Maintenance System

The Network Asset Management Plan - Manual No. 15, Network Maintenance Manual – Manual No. 12 and the Line Inspection Manual – Manual No. 11 describe the existing maintenance plan that is in place for managing the risks posed by poles in SA Power Networks distribution network.

5.5.2 Selection of Maintenance Strategy

Section 17.1 Asset Management Process – Maintenance and Replacement Process from the Network Asset Management Plan - Manual No. 15 outlines the process used to select the appropriate maintenance strategy for a pole. In accordance with the guideline, optimal and economical maintenance plans are developed and implemented. It is a process to be applied to both fault management and planned maintenance. The process is reviewed and revised as necessary every five years.

5.5.3 Implementation of Maintenance Plan

SA Power Networks utilises visual inspection and physical measurements which are used to monitor the condition of poles, for Stobie poles this is in relation to corrosion of the steel elements of the pole both above ground and at ground level and also to assess the condition of the concrete element of the pole.

The sampling frequency for visual inspection dependent on the voltage, corrosion zone and feeder categories (refer to the Network Maintenance Manual – Manual No. 12).

SA Power Networks prioritises the maintenance activities by identifying a maintenance risk value for each activity (refer to Section 9.4 of Line Inspection Manual No. 11). The maintenance risk value (MRV) takes into account the following factors:

- Consequence of failure: environmental, safety, quality, and reliability impacts
- Consequence of fire start
- Probability of failure: a qualitative measurement
- Defect severity
- Number of customers affected

The maintenance risk value (MRV) of a defect is significantly influenced by the probability of failure and severity of defect, and by other factors to a lesser degree (refer to Section 9.8 of Line Inspection Manual - Manual No. 11).

The end of life of a Stobie pole is determined by the extent of corrosion, above ground and ground level. SA Power Networks has established a corrosion level standard whereby the pole is replaced where there has been a loss of more than 50% of the of the original steel cross section at any point above ground level or where the same is true at ground level of a pole which has previously been plated.

For ground level corrosion, if the pole has not been previously plated, then the pole can be plated for steel section loss as great at 100% of the original steel cross section. Plating is the refurbishment of the pole by in-situ welding of steel plates across the corroded section, as detailed in Section 3 of the line Inspection Manual.

5.6 Repair and Replacement Plan

See Section 6.

5.7 Creation, Acquisition and Upgrade Plan

See Section 4.

5.8 Disposal Plan

SA Power Networks uses three methods when removing poles from service. Each of the methods involves the removal of the overhead structure but the location, situation and complexity of the removal will determine the method used. The methods are:

1. **Complete removal** which involves extracting both the pole and the footing from the ground either as a single unit or in sections using a crane and borer unit. The excavation is back filled and compacted back to the original ground level.
2. **Complete pole structure removal**, this is the removal of the pole in its entirety and the footing is left in the ground. This method is common where a former type footing was installed in the original construction and the footing is no longer required or is

unsuitable for the replacement pole. The former is filled with sand and soil is used to back fill the remainder of the excavation to original ground level.

3. **Cut pole removal** involves cutting the pole off approximately 450mm below ground level or as close as possible to the footing. The top section of the pole and the footing remain in the ground. The excavation is back filled with soil and compacted back to normal ground level.

All Stobie poles are transported to Angle Park salvage and sold in their 'as is' complete state for the steel scrap value. The cost involved in handling salvaged Stobie poles and the revenue raised from pole steel salvage is approximately cost neutral.

Hazardous waste is disposed of in accordance with the SA Power Networks Environmental Management Plan.

The Network Asset Management Plan - Manual No. 15 provides further information on the disposal plans.

6. REFURBISHMENT AND REPLACEMENT PLAN

6.1 Refurbishment and Replacement Plans

The repair, refurbishment (plating) and replacement plans proposed in this section are independent to each other. The refurbishment plan will indicate the most economical and effective preventative maintenance activities to mitigate existing risks. This will include the replacement or plating of the pole if the risk of operating the pole based on its current condition is high. Thus, the replacement or plating of the pole is the last step taken after the actions to prolong the life of the pole are implemented.

The replacement and plating plan is a proactive plan to target pole failures primarily due to corrosion. Corrosion is one of the primary factors in pole replacement or plating since severely corroded poles can unpredictably fail. Corrosion can also be considered a dominant failure mode due to the significant financial impact on SA Power Networks revenue.

6.2 Repair Plan

A repair strategy and plan is important as it provides a guideline on how to minimise or mitigate the risk of a defect evolving into a failure. There are very few repair options available for Stobie poles with condition monitoring being undertaken until such time as the condition of a pole deteriorates to a point where intervention through either plating or replacing of the pole is required.

6.3 Replacement Plan

Several different methodologies shave been utilised to develop the forecast replacement quantum of works over the period 2014–2015 and associated capital expenditure. Methodologies utilised were:

- Top down:
  - Considers whole fleet as a population
  - Failure rates based on SA Power Networks historical rates and industry rates
  - Replacement based on whole fleet rather than specific assets
- CBRM model:
  - Bottom-up detailed assessment
  - Takes into account specific asset, specific asset condition data, specific asset consequences and likelihood of failure

  - Can give several possible outputs; predicted replacements based on likelihood of failure, ie the health Index; predicted replacement based on maintaining a certain level of risk; or predicted replacements based on NPV
- Multi-Variable Defect Forecasting Model
  - Predictive model
  - Utilises historical volume and cost data associated with inspections, defects and interventions
  - Estimates defects, intervention volumes and costs in the future
- Historical trend – extrapolation of historical trends in numbers of replacements and spend
- AER RepEx model:
  - Top-down benchmarking mode
  - Uses age-based replacement modelling
  - Limited high level information required – asset age profile; expected life and standard deviation of expected life; historical expenditure; and average asset replacement cost
  - Simplistic approach which has limitations

The outputs from each methodology are discussed below, along with the resulting forecast expenditure profile for 2014 to 2025.

6.3.1 Top-down Methodology

AECOM were employed to develop a top-down pole replacement strategy for SA Power Networks. The full report produced is included in Appendix 9.2 and is summarised below.

The poles replacement forecast was produced based on location. The analysis was been conducted by Local Government Area (LGA) within South Australia, for each of the 71 LGAs. It was assumed that every pole within the LGA has homogenous characteristics (age, voltage and make), corrosion conditions and environmental setting (land use, propensity for bushfires and ground level corrosion rating). In order to determine these characteristics, the average of each characteristic was taken across every LGA.

No results were generated for unplanned replacement or pole plating, only for planned replacements.

The replacement capital expenditure profile for pole replacement based in the analysis undertaken by AECOM is shown in Figure 12 and Table 1 (expenditure shown in 2013 $s).

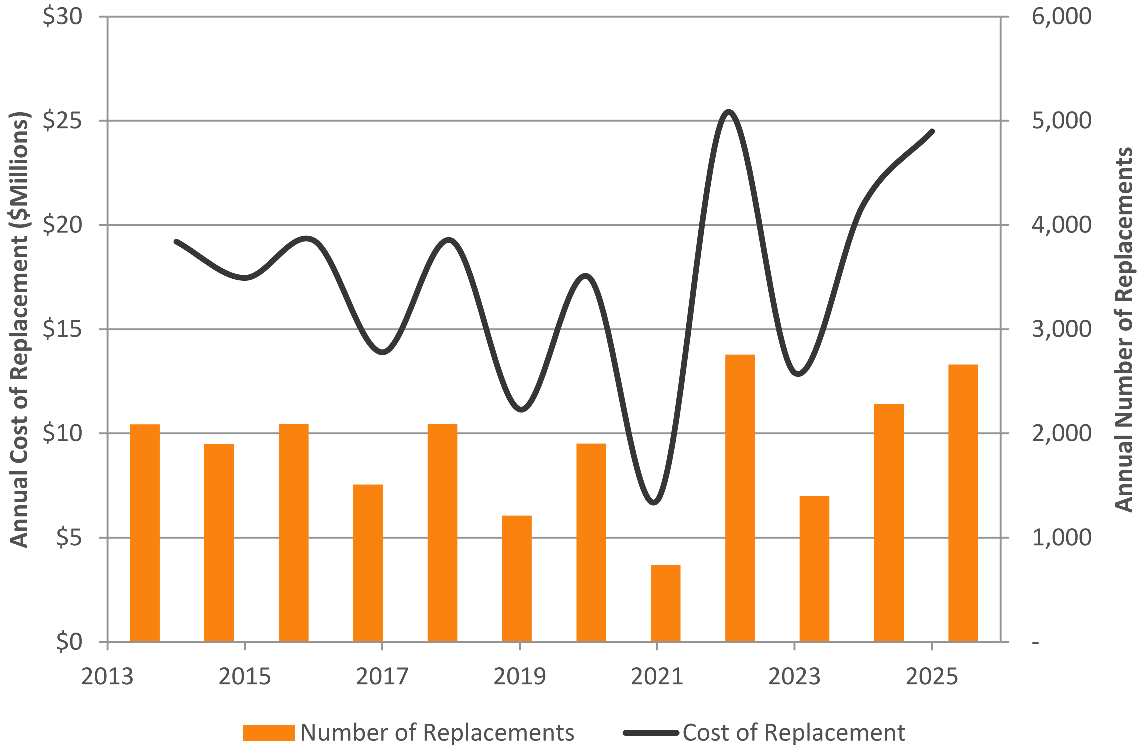

Figure 12: Forecast Poles Replacement Profile

Table 1: Annual cost ($M) and number of poles replacements

Total	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
No. of replacements	2,086	1,897	2,092	1,509	2,092	1,211	1,902	737	2,756	1,402	2,280	2,661
Cost of Replacements ($Million)	$19.2	$17.5	$19.3	$13.9	$19.3	$11.1	$17.5	$6.8	$25.4	$12.9	$21.0	$24.5

The twelve year forecast recommend an average of 1,885 poles replacements per year, at an average cost of $17.4 million per year. The targeting of poles replacements within the LGAs that pose the greatest risks to SA Power Networks provides a financially sound investment profile for risk management in the assets.

The replacement expenditure profile can be smoothed for budgetary purposes; however it currently represents the raw output from the analysis. The actual number of poles within each LGA forecasted to be replaced as well as an analysis by atmospheric corrosion zone is detailed in the AECOM report in Appendix 9.2.

6.3.2 CBRM Methodology

In 2011 EA Technology was engaged to develop a Condition Based Risk Management (CBRM) model for Poles. The CBRM model utilises information, knowledge, engineering experience and judgement for the identification and justification of targeted asset replacement.

CBRM is used as a decision support tool to assist the quantification, communication and management of asset related risk, particularly issues associated with end of asset life. The CBRM process produces computer models that provide quantitative representation of current and projected asset condition, performance and risk. Models can then be used to evaluate possible asset replacement strategies and investment scenarios to arrive at a proposal that best meets the strategic objectives of the organisation.

CBRM seeks to overcome problems of non-availability of reliable and consistent data that is necessary to construct a valid population based statistical models. This problem is particularly acute in the electricity distribution industry where assets have long lives (often many times longer than a typical computer information system), and are subject to many factors that cause asset sub populations within a general asset class to behave differently ie manufacturer make and model differences, quality characteristics, installation practices, operating environment and usage histories).

Rather than use a purely statistical representation of the asset population, CBRM models seek to make the best possible use of available information by combining asset information, operating context, operating history and condition information using rules that are consistent with sound engineering principles and asset specific operating experience. Models are adjusted and calibrated so that the output and behaviour of each model is consistent with historical observations and asset performance. Where CBRM models incorporate subjective SME judgment, it is codified by rules and is applied consistently.

CBRM offers advantages over statistical based approaches in that all available information, including physical observations of condition are incorporated into the assessment, and applied to individual assets within the model. The objective is to produce asset risk rankings and projections to inform asset management strategy as well as providing higher quantity level forecasts necessary for budget and regulatory purposes.

A full description of the CBRM methodology, as applied to Poles, can be found in Appendix 9.3.

A core feature of the CBRM methodology is the ability to age assets into the future and forecast future Health Index, Probability of Failure and Risk. This method of forecasting allows different intervention and investment scenarios to be modelled and compared.

CBRM models allow three future (year N) scenarios to be compared;

1. Y_N – No Intervention: Future projection of all assets currently in service
2. Y_N % Replacement: Replacement of a fixed percentage of the population. Replacement priority can be ranked by asset condition, asset risk or asset delta (condition) risk.
3. Y_N Targeted Intervention: Intervention program that may be configured to use the outputs of an NPV optimised analysis or independent replacement programmes.

Methodologies for asset replacement projections under these scenarios:

1. Replacement projections based purely on health index will remove those assets in poorest condition without considering criticality and consequential asset risk.
2. Constant risk projections are based on maintaining a benchmark level of asset performance (failure rate) and consequential risk over time. Forecasts are proportional to the change in risk (asset health) with time and replacements can be optimised by replacement cost and their contribution to overall risk.

3. NPV replacement projections provide a financially optimised year of replacement based on a discounted cashflow analysis of risk and replacement cost. Calculations are highly sensitive to absolute values of risk, replacement and discount rate. Inaccuracy in risk calculations will significantly distort the NPV optimised forecasts.

Each of the above methodologies has merits based on the relative strength of asset information within the model. Discussions with EA Technology recommended the constant risk approach as the most mature risk based methodology appropriate to information within the model.

The annual expenditure and replacement forecast based on a constant risk methodology is shown below in Table 2. This asset replacement program is expected to maintain current levels of safety, reliability and network performance.

This forecast does not account for other replacement programs proposed for the 2014 – 2025 period including augmentation, targeted asset replacement works and expected failure rates (unplanned replacements).

Table 2: Total number of pole interventions per annum from CBRM

	Number of Interventions												
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Plate	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	57,720
Replace	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	4,810	57,720
TOTAL	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**9,620**	**115,440**

NOTES : assumes 50% of required interventions are pole plating and remainder are pole replacement. Raw CBRM results which have not been profiled for deliverability

6.3.3 Multi-Variable Defect Forecasting Model

The multi-variable defect forecast is based on historical defect data. The model produces forecasts of the expected number of defects and expected rectification cost per defect for each location, corrosion zone and voltage level. These factors combined give a forecast of the total replacement expenditure. The forecast is calculated over a five year period and scaled up to ten years, using the assumption that defects accumulate at a constant rate.

A full description of the Internal Forecasting Methodology, as applied to Poles, can be found in Appendix 9.4.

The internal forecasting methodology has forecast a total of 12,109 defects over the next five years including P1, P2 and P3. Based on the defect remediation costs, this represents a five year forecast of $142,545,459 before adjustments. The forecast replacement expenditure is $39,912,729 (after including defects outside the inspection year) per year for ten years totalling $181,203,788 over the regulatory period. This is explained further in Appendix 9.4.

6.3.4 Historical Trend

The historical spend on conductor replacement is shown in Figure 13 below.

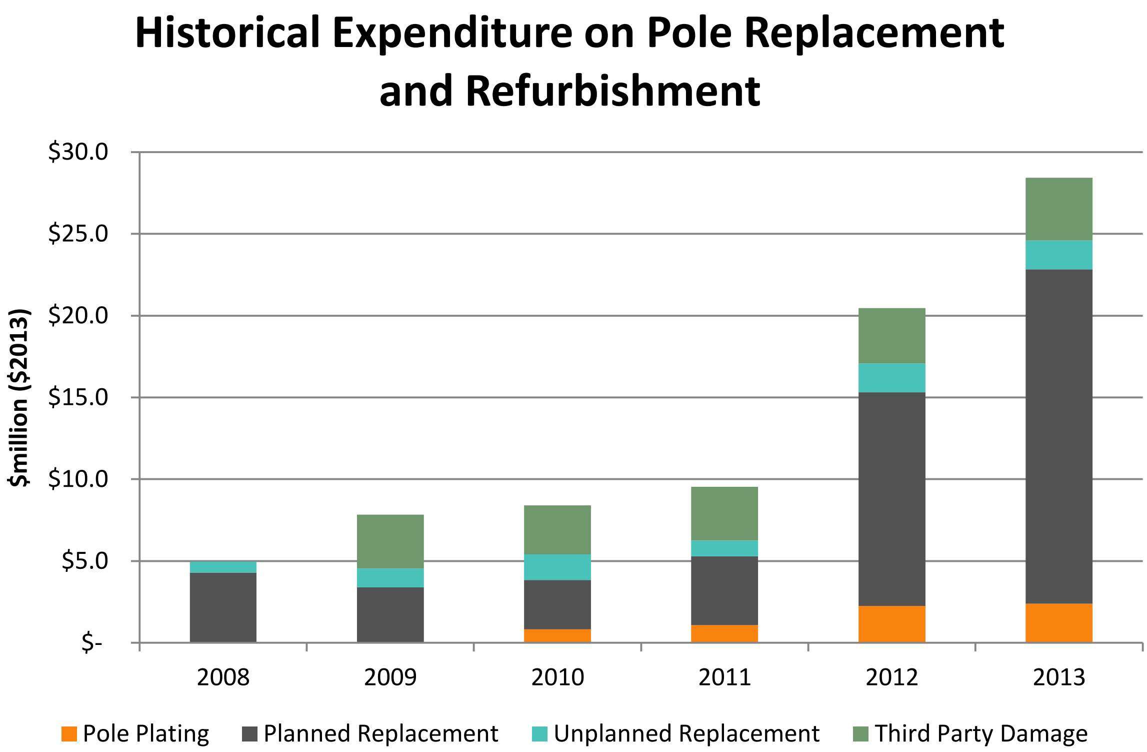

Figure 13: Historical expenditure on pole replacement and refurbishment

The numbers of poles plated and replaced historically, excluding those due to third parties, are shown in Table 3 below. As can be seen there has been a large rise in the numbers of poles replaced over recent years. Based on current defects in SAP it is predicted that the ratio of the number of poles replacements to the numbers of poles plated will plateau at around 50/50 over the next 5 years.

Table 3: Historical numbers of interventions

	2009	2010	2011	2012	2013	*Total*
Poles Plated	3210	3005	1811	917	1232	***10175***
Poles Replaced	595	493	636	1133	2428	***5285***
TOTAL	**3805**	**3498**	**2447**	**2050**	**3660**	**15460**

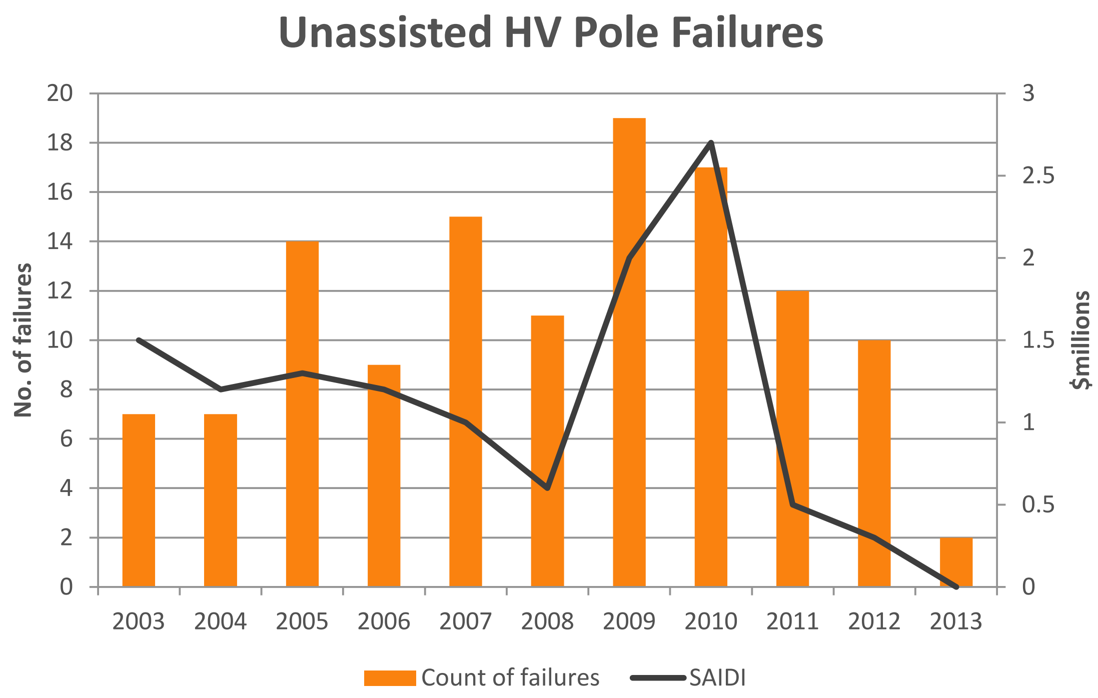

Figure 14: Unassisted HV Pole Failures 2003 to 2013

The highest cause of unassisted pole failures is corrosion with the highest failure rates experienced in the Marleston, Upper North and Eyre regions.

6.3.5 AER RepEx Model

The Australian Energy Regulator's (AER) replacement model (RepEx model is intended for use as part of building block determinations for the regulated services provided by electricity network service providers (NSPs). The RepEx model is a series of Microsoft Excel spreadsheets developed for the AER to benchmark replacement capital expenditure. It was first deployed in the Victorian electricity distribution determination for the 2011-2015 regulatory control period.

An initial version of the RepEx model has been prepared as part of the completion of the Category Analysis RIN. The results of this initial RepEx modelling are shown in Table 4 and Figure 14, and are explained in more detail in Appendix 9.5.

Table 4: Pole results from RepEx

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number to be replaced													
< ≈ 11 kV; STOBIE	919	1044	1179	1323	1478	1644	1823	2016	2224	2450	2697	2967	21763
> 11 kV & <≈ 33 kV; STOBIE	94	109	126	144	164	185	209	235	263	294	328	366	2515
> 33 kV & <≈ 66 kV; STOBIE	44	52	62	72	83	96	110	125	141	158	176	195	1313
TOTAL	1057	1205	1366	1539	1725	1926	2142	2375	2627	2902	3201	3528	**25591**
Expenditure ($millions)													
< ≈ 11 kV; STOBIE	$8.27	$9.40	$10.61	$11.91	$13.30	$14.80	$16.41	$18.14	$20.01	$22.05	$24.27	$26.70	$195.87
> 11 kV & <≈ 33 kV; STOBIE	$1.13	$1.31	$1.51	$1.72	$1.96	$2.22	$2.51	$2.81	$3.15	$3.52	$3.93	$4.39	$30.17
> 33 kV & <≈ 66 kV; STOBIE	$2.42	$2.87	$3.38	$3.95	$4.59	$5.28	$6.04	$6.86	$7.74	$8.68	$9.68	$10.74	$72.24
TOTAL	**$11.82**	**$13.58**	**$15.50**	**$17.59**	**$19.85**	**$22.30**	**$24.95**	**$27.81**	**$30.91**	**$34.26**	**$37.89**	**$41.83**	**$298.28**

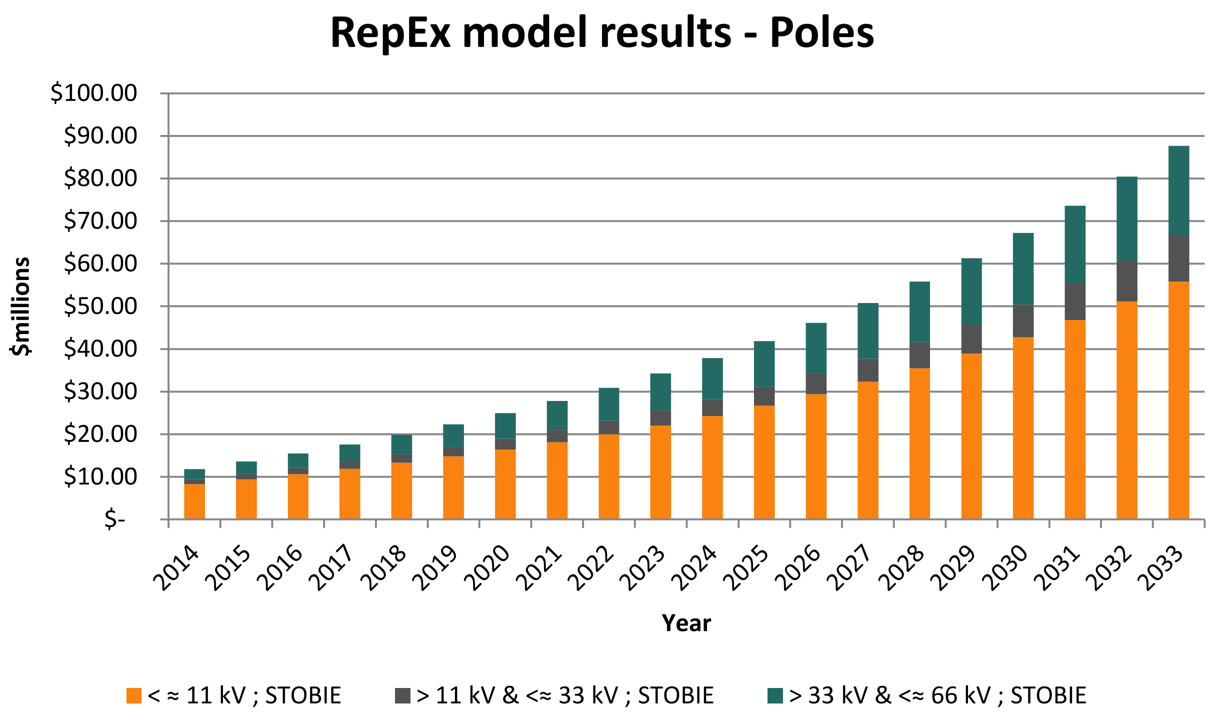

Figure 15: RepEx model results

6.4 Comparison of Outcomes

Table 5, Figure 16 and 17 below illustrate the average number of interventions, replacements and plating, for poles predicted utilising each of the above detailed methodologies. Where only a total number of replacements is calculated, for example in the RepEx model, it is assumed based on recent SA Power Networks practices that in an average year the same number of poles will also be plated, alternatively, it is assumed that the total number of interventions is double the number of replacements predicted.

Table 5: Comparison of average number of planned interventions per annum

	Historical Annual Average		AECOM Top Down	CBRM	Internal Forecasting Methodology	Repex
	2008 - 2013	2011 - 2013				
Pole Plating	**2035**	**3107**	**1885**	**4810**	**4890**	**2133**
Pole Replacement	**1057**	**1780**	**1885**	**4810**	**4613**	**2133**
TOTAL	**3092**	**4887**	**3770**	**9620**	**9503**	**4266**

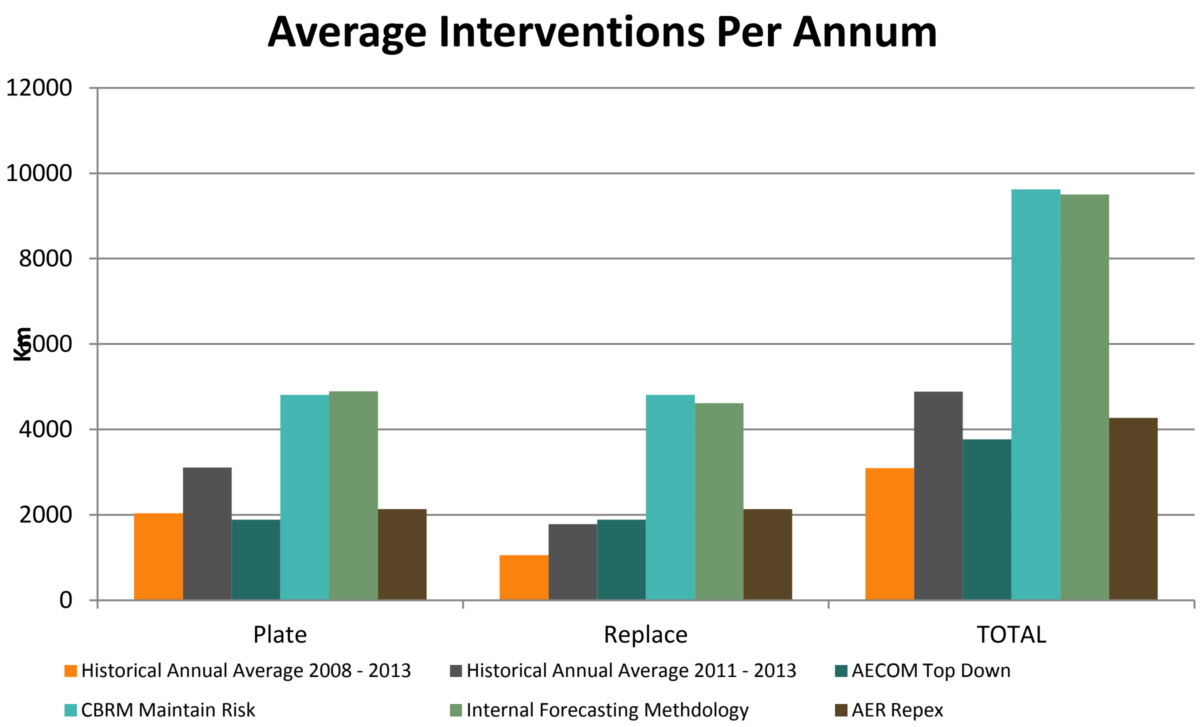

Figure 16: Comparison of average route length replacement per annum

Figure 16 illustrates the cost of predicted planned interventions each year utilising the top down, CBRM maintain risk, Internal Forecasting and RepEx methodologies. These are the model results as produced and have not been smoothed or profiled for deliverability, maintenance of workloads etc. as the final forecast will be.

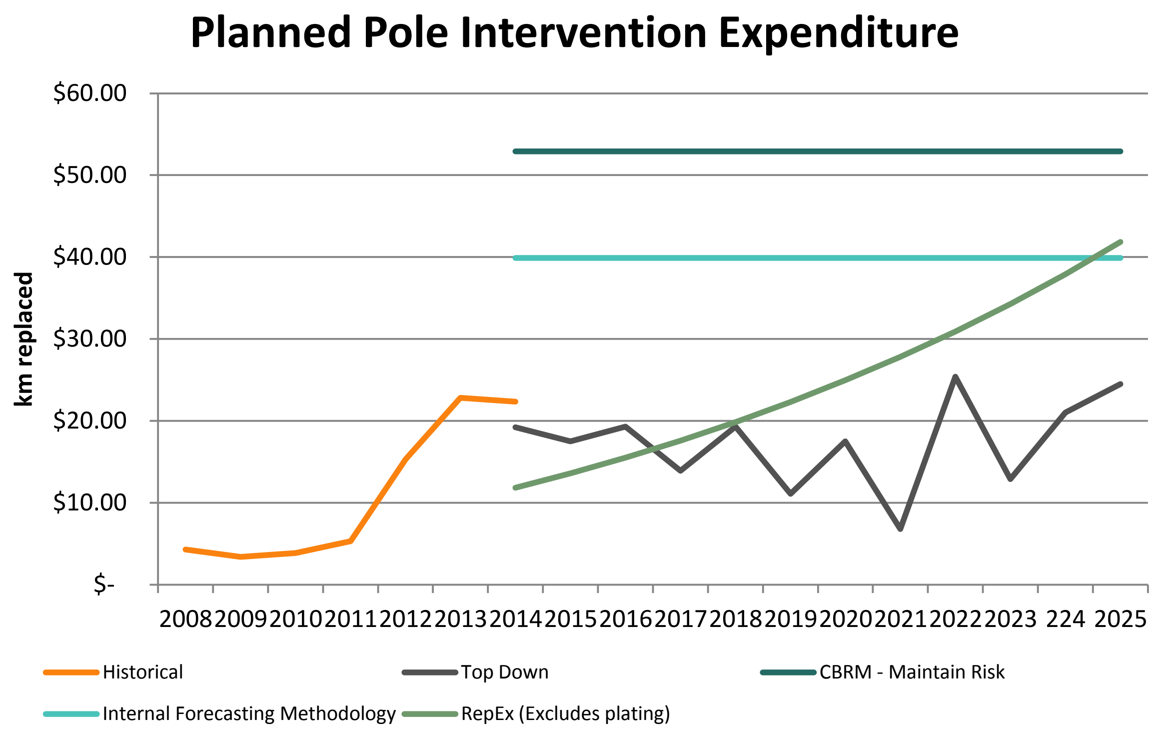

Figure 17: Comparison of capital expenditure per annum

6.5 Discussion

There are significant differences in the average annual number of pole interventions, replacements and plating, required in the 2014 – 2025 period depending on the model and methodology used.

Benchmarking techniques by necessity seek to distil a measurement problem into a model that incorporates limited available input data to produce a representation of true performance.

Each forecast methodology has its own set of specific advantages and limitations for forecasting replacement volumes and a detailed description of each model and methodology is included in the appendices and summarised below.

The AECOM replacement model provides a high level (top down) forecast that considers estimates of planned (prioritised by age based risk) replacements each year. The intention of this program is to hold the current risk profile (and level of service) constant. While endeavouring to quantify and prioritise replacements based on asset risk, the model is not fine enough to model specific risk, forecast asset performance nor model replacement scenarios.

The AER repex model provides a very high level (top down) modelling approach that considers asset age, asset life statistics and historical expenditure to forecast future replacement volumes and expenditure requirements. Forecasts do not directly factor aspects of condition, criticality or risk, nor differentiate between planned and unplanned (failure) replacement types. Replacement life within the model is used as the proxy for all factors that drive asset replacements, under the assumption that current replacement strategies and practices will remain static into the future.

As this approach relies on overarching population information only, the model does not directly allow deeper analysis of asset performance, condition trends, future risk nor changes in asset management drivers.

CBRM models are based on a (bottom up) engineering approach to the modelling and forecasting of asset performance and risk. CBRM does not in and of itself provide predictions of asset replacement requirements, but rather produces a forecast of asset performance and risk which can be used to test the benefits of intervention programs or replacement strategies. CBRM models are able to utilise detailed engineering information on asset specific condition, criticality and consequential risks to forecast and design investment scenarios that present an optimal forward program in light of current understanding of the asset base.

The relative strength of CBRM models come with their ability to leverage established data sources and understanding of asset specific performance and risk. Given the level of detailed, asset specific asset management information available for poles, CBRM is considered to be the most appropriate methodology to forecast requirements for the 2014 to 2025 period.

Within CBRM, there are a number of strategies that may be employed for planning asset replacement forecasts, each with relative strengths based on the quantity and maturity of available data. The two strategies considered most appropriate to SA Power Networks' poles CBRM model are discussed below.

The most sophisticated approach to replacement planning will be to develop a financially optimised plan based on minimising the Net Present Value (NPV) of costs associated with asset failure and the cost of subsequent replacement. NPV calculations are available within CBRM models however the approach is reliant on a literal use of calculated risk to determine timing of an optimum risk/cost trade-off and requires a high degree of confidence in the quality of calculated (absolute) risk; error or uncertainty in risk calculations significantly distorts the optimal forecast.

Further investigation is recommended to confirm that the CBRM risk projections are a correct reflection of an appropriate risk/cost trade-off. SA Power Networks does not believe current models have sufficient information available to be able to confidently apply NPV analysis within CBRM. It remains the long term strategy for CBRM implementation to be able to confidently apply NPV optimisation as a preferred methodology for replacement forecasting.

In light of current experience with CBRM models, discussions with EA Technology have recommended a constant risk forecasting methodology as the most appropriate to both strategic objectives and information confidence within the poles model.

Forecasts under this methodology are less sensitive to absolute risk calculations, considering only the changes in risk over time with the intention of maintaining existing risk exposure with time.

We have one of the oldest distribution networks in the National Electricity Market (NEM). A large portion of our poles were installed between the 1950s and 1970s, and so, are now over 50 years old. Our Stobie poles can last this length of time, and so historically, we were not seeing a significant number of poles failures. Consequently, the planned replacement of poles was not a significant concern to us. However, as our network aged and asset failures increased, we began in 2007 to transition to a 'replace-before-fail' philosophy for our most critical asset.

Since that time, a number of significant events, including the Victorian bushfires in 2009, have brought a sharper focus across the industry on the safety risks posed by the failure of assets. To address these concerns, in 2010 we improved our overhead line inspection practices, reducing our inspection cycles in critical regions, in particular high corrosion zones. The need for this change was accepted by the AER in our previous regulatory proposal. We also expended significant effort improving both our manual that specifies our line inspection practices and the training and competence of our inspectors who use this manual.

However, we have found significantly more defective poles than we anticipated, and as a consequence, we have needed to increase our volume of pole replacements (including life extensions) beyond what we envisioned. The volume of these pole replacement activities has risen from 1,827 (or 0.25% of our pole population) in 2008/09 to 5,638 (or 0.76% of our pole population) in 2012/13.

Although this represent a significant increase, our measure of the risk we carry on the network associated with defective poles has also increased four-fold over this period. In effect, our pole replacements have not been sufficient to arrest the risks as we uncover them. Furthermore, although we have targeted the higher risk regions with our new inspection practices, we have still not completed the first inspection cycle across our whole network.

Therefore, we have a need to increase pole replacements (and life extension through pole plating) in the next period if we are to arrest the increasing risk.

The investment program generated by the CBRM maintain risk approach seeks to maintain levels of safety and reliability at an acceptable level after considering likely population changes due to capacity upgrades, unplanned replacement and targeted replacement programs by identifying and targeting an optimal number of high risk assets.

Forecasts generated by the CBRM maintain risk approach in addition to unplanned works programs based on historical expenditure have been selected as the basis of the 2014 – 2025 forecast. Implementation of this plan:

- Maintains the level of risk associated with poles at an acceptable level
- Maintains levels of service and reliability needs necessary to meet customer expectations of network performance.
- Results in a replacement and plating program with volumes of work we believe to be required to comply with our legal obligations associated with delivering on our approved safety management plan (SRMTMP) that is approved by the Essential Services Commission of South Australia (ESCOSA) on the recommendation of the South Australian Office of the Technical Regulator (OTR);
- Has been developed utilising a well proven and well recognised methodology;
- Is broadly supported by other assessment techniques the AER could apply, including benchmarking;
- Prudently manages identified defects, allowing for critical defects to be addressed strictly within the documented remediation timeframes

Further explanation of the methodologies and justification for the elected preferred methodology can be found in the separate Pole Replacement Expenditure Justification.

7. FINANCIAL SUMMARY

7.1 Introduction

This section contains the financial requirements resulting from available or derived data. Information on SA Power Networks processes and procedures for budgeting and control, project ranking, business cases and regulatory tests can be found in Manual 15.

7.2 Basis of Unit Costs

Costs associated with pole replacement/refurbishment works have been developed for the categories shown in Table 6 from historical project expenditure over the period 2008 to present.

The scope for individual replacement works will vary to meet site specific needs and any subsequent requirement for upgrade of associated infrastructure to meet equipment needs, regulatory requirements and modern safe operating standards.

Unit costs in Table 6 are derived based on an average allowance for all historical costs typically required to complete a pole replacement project.

Total replacement cost for 33kV or 66kV can range from $14,500 to around $100,000 based on location, size, switching and other factors including traffic control. For this size pole the figure quoted is just the cost for the pole, whereas for other pole sizes the replacement cost includes all costs to complete the work.

Table 6: Unit Costs

Description	Cost ($000s)
Pole replacement	
< ≈ 11 kV; STOBIE	$7.6
> 11 kV & <≈ 33 kV; STOBIE	$10.0
> 33 kV & <≈ 66 kV; STOBIE	$14.5
Pole Plating	
< ≈ 11 kV; STOBIE	$0.65
> 11 kV & <≈ 33 kV; STOBIE	$0.80
> 33 kV & <≈ 66 kV; STOBIE	$1.50

7.3 Financial Statement and Projections

The anticipated total cost required per annum for the period 2014 to 2025 associated with pole replacement and maintenance is shown in Table 7 and Figure 17. This expenditure maintains the overall total predicted expenditure for the period but has been profiled to reflect a prudent and efficient delivery timeframe.

Table 7: CAPEX for replacement and plating of poles

	$millions ($2013)											
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
PLANNED												
Plating	$1.7	$3.4	$4.2	$4.9	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1
Replacement	$18.9	$30.0	$40.0	$47.0	$51.7	$51.7	$51.7	$51.7	$51.7	$51.7	$51.7	$51.7
UNPLANNED												
Replacement	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8
Third Party	$3.5	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0
TOTAL	**$22.4**	**$35.2**	**$45.5**	**$52.6**	**$57.2**	**$57.3**	**$56.7**	**$56.3**	**$56.2**	**$56.3**	**$56.2**	**$56.3**

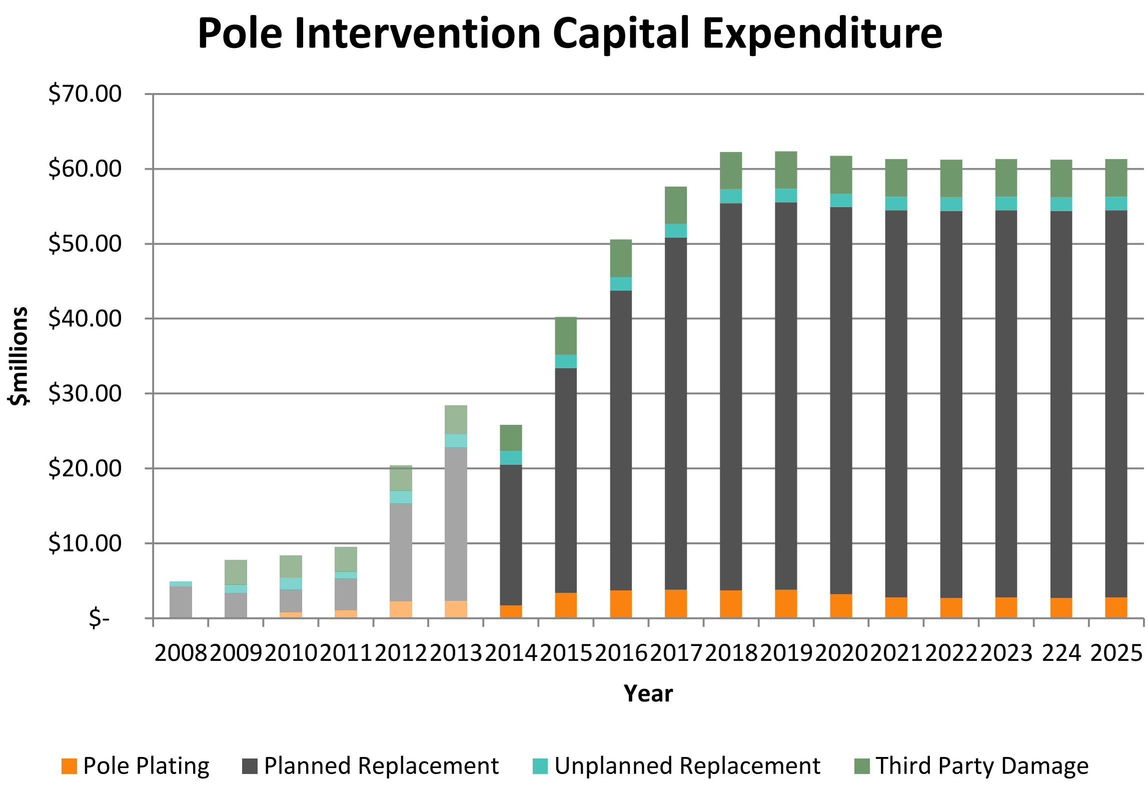

Figure 18: Pole Replacement and Refurbishment Capital Expenditure - historical and forecast

8. PLAN IMPROVEMENT AND MONITORING

8.1 Data Management System

8.1.1 Improvements to Data Management System

The effective, efficient and economical management of the overhead line network, including poles, is dependent on reliably accomplishing the following:

The determination of risk of an overhead line

The appropriate maintenance, renewal and replacement program for the overhead line based on the risk level

Maintaining the relevance of plans by adopting appropriate monitoring programs

To assist with delivering the above items, SAP has to be structured to ensure high quality, integrity and traceability of data.

There are several areas of improvements necessary for the effective use of SAP. The improvements specific to SAP are listed below:

1. The objectives of SAP need to be defined
2. Record sources of data to be used in populating SAP
3. Increase awareness of importance of quality data
4. Start to record data on poles

The improvements suggested are based on the inconsistent and incomplete data recorded in SAP, which is mainly due to the lack of defined SAP objectives. Inconsistencies in the data are potentially caused by using multiple data sources. The uncertainty in the reasons for inconsistent data is due to the lack of recording the sources of the data. This reduces the traceability and the integrity of the data. For example, the number of Stobie poles in the network, and their date of installation or age, is based on pole production records as this is the best available information rather than actual installation records. This inconsistency may cause the analysis performed in Section 5 to be incorrect.

It is important that data in SAP is correctly and consistently inputted as trying to repair or merge databases later can then lead to further errors. An example of such problems is the high number of data that are classified as unknown. Personnel throughout SA Power Networks are to be made aware of the significance of quality data

Implementing the above improvements will increase the quality, traceability and reliability of the data.

8.1.2 Data Management System Improvement Plan

The objectives of SAP are to be clearly defined and documented. The objectives are to be made available and emphasised to all personnel responsible for the effective operation of SAP. The objectives are to be known by personnel that use SAP as well.

Clearly defined objectives will lead to well-structured database which will provide a solid foundation for optimally managing the data, and consequently the overhead line network.

All external databases that contain data on poles are to be linked with SAP. This includes the database managed by the Reliability Group. This will minimise discrepancies and support effective overhead line network management.

SA Power Networks to identify and validate the data sources used for SAP of the overhead line network. This will improve the traceability of data and reduce the occurrence of redundant data in SAP.

Acknowledging the high importance of quality data throughout all organisational levels in SA Power Networks will ensure that the accurate and reliable data is reflected in SAP.

A well-structured SAP will greatly assist in developing efficient maintenance plans. Identifying the key attributes of the overhead line network is part of satisfying the objectives of SAP. An example of the key attributes necessary to determine the capital cost of conductor replacement is indicated in the framework outlined Figure 19.

For each pole the following attributes are needed:

- Unique Identifier
- Bushfire Risk Area
- Fire Ban District
- Corrosion zones -Atmospheric and Ground Level
- Construction-Manufacture date or preferably if available Installation date
- Physical Size
- Owner
- Voltage (or associated Feeder(s))
- Status
- Pole Orientation
- Pole Function
- Pole Reinforcing, and if so, date of reinforcing
- Pole Plated, and if so, date of plating
- Maintenance strategy
- Ranking of failure modes (an identifier can be used)
- Number of defects since first installation

List all unplanned pole replacements with the following attributes for each event:

- Job or Work Order Number
- Date of replacement
- Cost of replacement
- Pole size
- Pole type
- Cause of failure (an identifier can be used)
- Number of customers impacted
- SAIDI cost
- SAIFI cost

List all planned pole replacements with the following attributes for each event:

- Date of replacement
- Cost of replacement
- Pole size
- Pole type
- Ranking of failure modes (an identifier can be used
- Number of defects since previous replacement (regardless of whether it was detected under planned or unplanned maintenance)

Figure 19: **Key Pole Data to be collected and stored**

8.2 Risk Management Plan

8.2.1 Improvements to the Current Plan

The present risk management plan evaluates the risks qualitatively: the improvements in Section 7.1 will increase the quality of data recorded. This will allow SA Power Networks to move towards a quantitative risk register. This new form of risk register can then be continually monitored and revised to ensure that the risks correctly reflect the status of the overhead lines network.

To assist in developing a quantitative risk register, the following improvements are to be adopted:

1. Determine the combined and individual failure rate for all failure modes.
2. Develop criticality framework.
3. Develop risk register based on improvements 1 and 2.

Continuous flow of quality data into SAP is crucial for the development of quantitative risk register.

Assuming that quality data is available to create a register, the level of risk in the SA Power Networks poles network is based on the failure rate of each pole and the consequence of failure.

The likelihood of failure or the combined failure rate (the failure rate for each failure mode and other factors) can be accurately determined based on quality data. The failure rate of all failure modes can assist in adopting the appropriate maintenance strategy for the overhead lines/segments including poled.

SA Power Networks geo-code the defects to determine the locality of defects on poles. The data collected from geo-coding of defects on poles is a significant advantage in determining the likelihood of failure of an overhead line/segment as well as the individual pole. Tagging an identifier to the data that categorises the defects according to failure mode and/or severity can help indicate the likelihood of failure. Thus, SA Power Networks can efficiently monitor the changes in risk of an overhead line/segment and/or pole before it fails.

Geo-coding of failures can provide information to help predict the time to failure and understand the causes of pole failure.

The consequence of a pole failure is measured by the criticality of the pole. Criticality is a measure of the risk of poles in the network. The criticality of poles needs to address the multiple characteristics of risk that are stated below:

- Safety risk
- Environmental risk, predominantly bushfire risk
- Performance risk, failure rate of pole and associated overhead line
- Operational risk, decrease in reliability or unable to maintain reliability
- Financial risk, costs implications as a result of the above risks

The criticality of a pole will change with the failure rate of the pole, time and other variables. Thus, the criticality of a pole is a dynamic variable that requires periodic review.

The current risk management plan does not identify the criticality of all poles. Furthermore, the current definition of criticality qualitatively captures some of the risks stated above. The Network Maintenance Manual No. 12 and Line Inspection Manual No. 11 illustrate that there is no systematic process to determine the criticality of a pole.

The criticality of poles is currently based on the information provided in Network Maintenance Manual No. 12.

8.2.2 Improvement Plan

The development of a systematic process in defining the criticality will aid in the efficient implementation of the risk, maintenance, repair and replacement plans. However, quality data is a precursor to developing the systematic process.

The traits of critical feeders are based on the magnitude of safety risk, environmental risk, performance risk, operational risk and financial risk exposure to SA Power Networks. It is important to capture the risks efficiently when determining the criticality of lines.

The impact poles have on SA Power Networks risk profile is influenced by the location of the poles in the corrosion zones and the bushfire risk areas, among other factors..

8.3 Maintenance Plan

8.3.1 Improvements to the Plan

The areas of improvements to the maintenance plan are identified below:

1. To re-organise the codes used for recording defects on poles.
2. Recognise the impact of other components on poles.
3. Link pole defects to pole failure.
4. Identify defects on LV lines separate to HV lines.
5. Identify corrosion zone and bushfire risk area during defect and fault management.

The use of incorrect codes used to record the conditions of overhead components could lead to inappropriate asset management decisions relating to risk, maintenance, repair and replacement of poles and associated components. Thus, organising codes specific to components will prevent the misrepresentation of conditions of components.

SAP does not link pole defects and pole failures. Linking of the defects to the failure is beneficial when estimating the remaining life of a pole in operation. As well as, deciding on the action necessary for the management of poles.

Identifying the corrosion zone and bushfire risk area during defect and fault management can help select the suitable maintenance activity and prioritise maintenance works.

8.3.2 Improvement Plan

Fine tuning of the maintenance codes and issuing a guideline on how to use the codes to correctly capture the conditions of poles and any other component should be performed. This will avoid misrepresentation of critical inspection data that is used when making asset management decisions.

8.3.3 Selection of Maintenance Strategy

The strategies available to SA Power Networks are condition monitoring, find and fix and run to failure, as stated in Section 5.6.

The level of condition monitoring of poles will be based on the criticality of the poles. For example, the condition of a pole that poses high risk is more closely monitored than a pole that is less risky. Risk is influenced by the likelihood of failure, which can be influenced by the maintenance activities listed in the maintenance plan.

As stated in Section 5.6, run to failure maintenance strategy is currently not used by SA Power Networks. However, the application of this strategy can be considered for poles that are not critical or the risks are very low. This will ensure that the most economical strategy is implemented for this particular group of poles in order to meet the maintenance objectives.

8.3.4 Implementation of Maintenance Plan

The maintenance manuals will include the objectives in monitoring the indicators of common failure modes and other factors or for each component. For example, the objective of monitoring corrosion is to determine the degree of severity of corrosion above ground level and at ground level. The visual inspection checklists stated in Line Inspection Manual No. 11 shall assist in field personnel achieving the objectives set for common failure modes and other factors. The attachment of high resolution photographs to the defect or condition monitored will further improve accuracy in determining the impact of the condition on the life of the pole.

Documentation of the appropriate maintenance activities necessary during Fault Management and Planned Maintenance is required. Defining the most appropriate maintenance activities will ensure that maintenance is executed consistently across the network and that the desired results are achieved.

The maintenance activities in the maintenance plan will recognise the importance of age of the pole. The age of a pole can influence the maintenance activities to be performed. By tracking the age when the defect has occurred can help determine the likely cause of the defect. For example, the primary cause of defects within the first five years of installation of the pole may be due to incorrect installation. As a consequence, an increase in awareness of the issue will result in an improvement of the design and in the inspection process during installation of the pole. Identifying such an issue on new and existing poles and rectifying it in a timely manner will lead to an improvement in the lifespan of the pole.

The corrosion zone and bushfire risk area will be recorded for pole defects and failures.

8.4 Repair and Replacement Plans

8.4.1 Improvements to the Plan

1. Developing frameworks/criteria for repair and replacement of lines.
2. Use root cause analysis when investigating failures.

The above improvements will assist SA Power Networks in improving the accuracy and reliability of the repair and replacement plans

An improvement in the repair and replacement plans is to provide a framework for the repair of defects and repair or replacement of failed poles in the maintenance plan.

At present, the replacement of poles is targeting poles that are highly likely to fail due to corrosion. The criteria are based on the limited data provided, which is pole type, corrosion zone and year of installation or plating or replacement of the pole. As a result, the budgeted number of poles that need replacement is dependent on the quality of data. As SA Power Networks take proactive actions to improve the quality of data, the criteria will evolve to help determine the accurate number of poles to be replaced.

It is important to use a reliable method when investigating the cause of a pole failure.

SA Power Networks are to prepare documents that detail the criteria and framework used to repair and replace poles. Doing so will significantly improve the effectiveness of maintenance, repair and replacement programs. Furthermore, the results from the monitoring of the plans can be used to improve the criteria. Thus, SA Power Networks can ensure that they are producing effective and relevant plans.

SA Power Networks will analyse the available data to determine the failure rate of all the failure modes and other factors for poles.

SAP and the database used by the Reliability Group will be linked to enable appropriate implementation of maintenance and replacement strategies.

8.5 Disposal Plan

8.5.1 Improvements to the Plan

An improvement in the disposal plan would be to include testing of poles to improve the maintenance, repair and replacement plans.

8.5.2 Improvement Plan

Testing of poles that have failed will improve the lifecycle management of poles. Taking advantage of the opportunity arising from the replacement of poles to inspect failure modes will greatly improve the management of poles. Testing of poles for fatigue and checking for corrosion can reduce the unpredictability of pole failures.

If poles have failed early in the life of the pole, then testing the failed pole to determine the failure mode can provide evidence to support the root cause analysis of other failures caused by the same failure mode. The result of the root cause analysis can be used to feed back into the lifecycle of poles to remove the future occurrence of similar failures.

A disposal plan that incorporates the investigation of fatigue and corrosion failures in poles and early life failures will contribute to the improvement in the lifecycle management of poles.

8.6 Monitoring Plan

8.6.1 Risk Management Plan

Monitoring the risk management plan will assist SA Power Networks in ensuring that the controls in place remain effective, and if not, they are revised in a timely manner to minimise the potential of escalation of risks.

After the development of a quantitative risk register, scheduled monitoring and updating is in order for maintenance, repair and replacement plans to remain relevant and guarantee that the risks are minimised as far as reasonably practicable and economical.

8.6.2 Maintenance Plan

A scheduled review of the maintenance plan is crucial as it will assist SA Power Networks in determining whether the plans are efficient and effective in implementing the strategies. Regular monitoring of the following indicators listed below will help determine the effectiveness of the maintenance plan in executing the maintenance strategies.

- number of planned outages and unplanned pole failures
- number of and ratio of outages under fault management against planned outages
- operational expenditure in maintaining poles
- maintenance expenditure
- the difference in agreed and completed maintenance works (backlog of maintenance tasks)

A significant number of unplanned pole failures are an indication that the maintenance plan is primarily ineffective, followed by the repair and replacement plans.

Another indication that the maintenance plan is ineffective is the high ratio of outages under fault management than against planned outages. A benchmark in the ratio of outages to planned outages will ensure the maintenance plans are economical and practical.

If there is not a positive change in the above variables, a review of the sampling frequency and maintenance activities performed will assist in determining areas of improvement and changes to be made in the maintenance system.

Monitoring of the inspection frequency is important since particular defects and failures that increase in severity will have a cascading effect on other defects and lead to more failures. As a result, the inspection frequencies of poles during condition monitoring will change as the number of, severity and type of defects and failures are recorded in SAP. Monitoring the inspection frequency is essential for critical poles since the inspection frequency will influence the likelihood of future defects and failures.

An economical monitoring program will ensure that the maintenance plans remain relevant, the strategies are implemented in the most effective manner to efficiently minimise the risks to an acceptable level, and that SA Power Networks maintenance objectives are achieved.

8.6.3 Refurbishment and Replacement Plan

A scheduled review of the below variables is required to assess the effectiveness of the criteria used to develop the strategies and plans for refurbishment and replacement of poles.

- Combined and individual failure rate
- Independent failure rate for all modes of failure
- Number of planned and unplanned outages
- SAIDI and SAIFI costs
- Average age of poles prior to conductor replacement

The increase in the average age prior to pole replacement, a reduction in the penalties, the number of unplanned outages, and the combined and independent failure rates are all positive indication that the refurbishment and replacement plans are effective. A reduction in the expenditure related to the refurbishment and replacement of poles is a positive sign that the plans are economically designed and implemented.

8.6.4 Auditing of Plans

An independent group in SA Power Networks will audit the groups responsible for the preparation and implementation of the risk, maintenance, repair and replacement plans. Their goal will be to check that personnel are competent and that their competency is reflected in the quality of the data recorded in SAP.

9. APPENDICES

9.1 Maintenance Strategy – Poles

The maintenance strategy for poles is outlined in the Network Maintenance Manual No. 12. The specific sections applicable for poles are:

- Section 6.2: Overhead Sub-transmission Lines
- Section 6.3: Overhead Distribution Assets

The Network Maintenance Manual – Manual No. 12 is currently being reviewed and revised to ensure the strategies are in-line with current industry good practice.

9.2 AECOM Replacement Strategy Report

AMP 3.1.05 FINAL
REPORT - Poles Repla

9.3 CBRM Modelling

In 2011 EA Technology was engaged to develop Condition Based Risk Management (CBRM) Models for Poles, Overhead Conductors, Substation Power Transformers and Substation Circuit Breakers. The models utilise information, knowledge, engineering experience and judgement for the identification and justification of targeted asset replacement.

CBRM determines the level of risk a particular asset exposes SA Power Networks to through the following steps:

1. **Define Asset Condition:** The condition of an asset is measured on a scale from 0.5 to 10, where 0.5 represents a brand new asset; this is defined as the Health Index (HI.) Typically an asset with a HI beyond 7 has serious deterioration and advanced degradation processes now at the point where they cause failure. Determination of the HI of a given asset is made by factoring its age, location, duty, and measured condition points. After the HI is determined, future condition of the asset is forecasted after ***t*** years.
2. **Link Condition to Performance:** If an asset has a HI less than 5.5, its Probability of Failure (PoF) distribution is random. When the HI shows further degradation, a cubic relationship is used to measure PoF against HI. Each asset class has unique events; every event is assigned a PoF model, which uses an individual failure rate based on network observations.
3. **Determine the Consequence of Failure:** The consequence of failure is divided into the following categories:
   - CAPEX: The Capital Expenditure required to remediate an event
   - OPEX: The Operational Expenditure required to remediate an event
   - Safety: The cost incurred due to death/injury to individual(s) as a result of an event
   - Environment: The cost of environmental cleanup/penalties as a result of an event
   - Reliability: Financial penalties imposed if an event causes an outage

   The consequences are individually determined for all of the events associated with the asset using criteria such as location, number of customers, load profiles, SCONRRR category, and type/model.
4. **Determine Risk:** Risk is measured in financial units; it's determined by combining the PoF consequence and criticality for every event. Criticality defines the significance of a fault/failure for an individual asset, and is determined for each of the categories listed in item 3.

CBRM also models non-condition events, which do not depend on a HI. These events are assigned to every asset and use a random failure based Probability of Failure (PoF) model. An example of a non-condition event is third party damage from a car hit pole incident.

By forecasting every asset's condition, CBRM calculates the total risk, total number of failures and HI profile for an asset group based on the following investment scenarios after ***t*** years:

1. **Do Nothing:** do not replace any assets in the group
2. **Targeted Replacement:** nominate when assets are replaced/refurbished
3. **Replace a fixed percentage of assets every year:** nominate the percentage of assets to be replaced every year and choose the priority to be HI, total risk or delta risk

CBRM identifies the level of risk exposed for an investment scenario over time. This allows the percentage used in **Scenario 3** to be determined such that a constant level of risk can be maintained, an example of this risk profile is shown below in Figure 19.

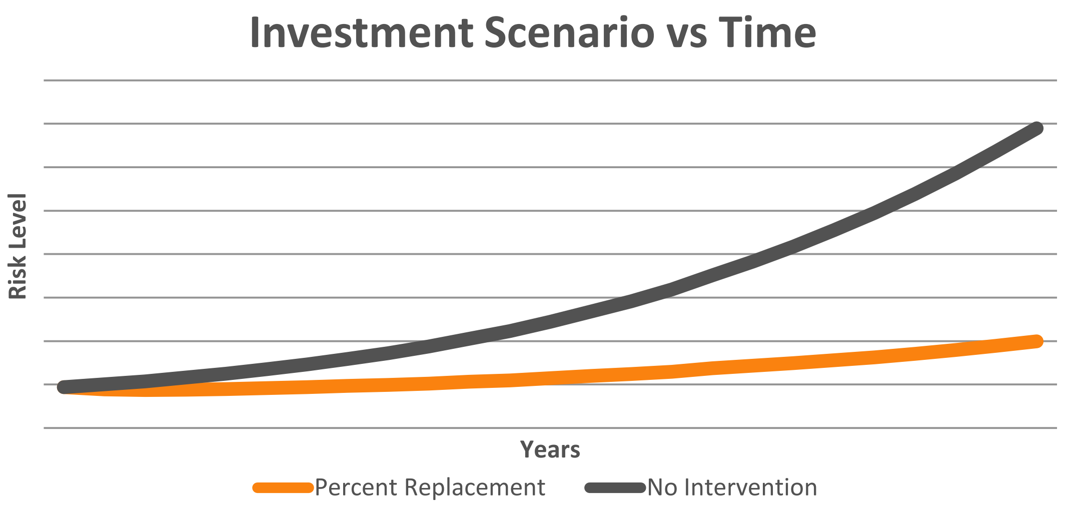

Figure 20: Example of risk profile over time output graph

CBRM determines the financially optimum year to replace a given asset by finding the right balance between delaying network investment and bearing more risk, a graphical illustration of this is shown below in **Figure 21**.

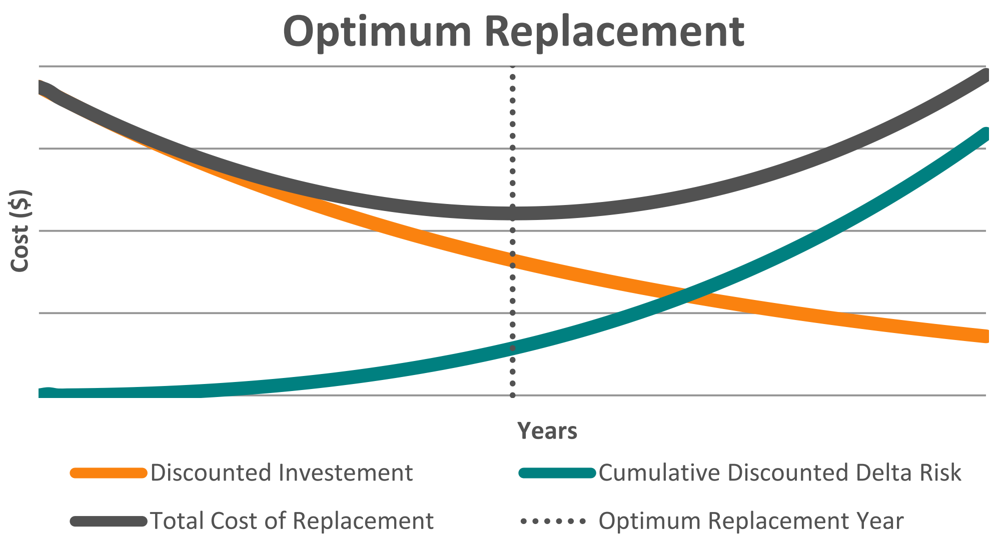

Figure 21: Example of outputs used to determine optimum replacement year

CBRM takes an NPV approach for discounted investment, where the discount rate is SA Power Networks Weighted Average Cost of Capital (WACC). The cumulative discounted delta risk is a sum of the risk beared for each year, discounted by the WACC. The total cost of replacement is the sum of the cumulative discounted delta risk and discounted investment, CBRM finds the year where this cost is minimal and identifies this as the financially optimum replacement year for an asset.

In order to accurately determine the financially optimum replacement year, an even balance between risk and unit costs needs to be achieved. SA Power Networks costing records aren't currently accurate enough to achieve the balance; however, improvements in asset records through works management programs are being undertaken. When the improvements are implemented it's anticipated that the network record accuracy will be improved to such a level that the financially optimum replacement year for assets can be correctly identified.

9.3.1 Poles Methodology

9.3.1.1 Determination of Health Index

CBRM determines pole HI1 – Age Related Health Index (HI) by calculating an ageing constant β, which is combined with the pole's age. The information used and dependencies are shown above in **Error! Reference source not found.**The value of β is determined by combining the following information:

- **Average life:** The average life of a pole varies depending on its size/type and material.
- **Location Factor:** The location factor depends on the atmospheric corrosion zone, conductor material and pollution rating.
- **Duty Factor:** The duty factor is determined using the following information:
  - *Pole Function* – For example a brace pole experiences more mechanical stress than a line pole.
  - *Highest Supported Voltage* – Higher voltage feeders require more ground clearance, which is achieved by further elevating the conductor. This leads to a stronger torque moment experienced by the pole from wind loading.
  - *Installed Pole Top Equipment* – Pole top equipment exposes more cross sectional area to wind pressure, this increases the wind load leading to a stronger torque moment applied to the pole.

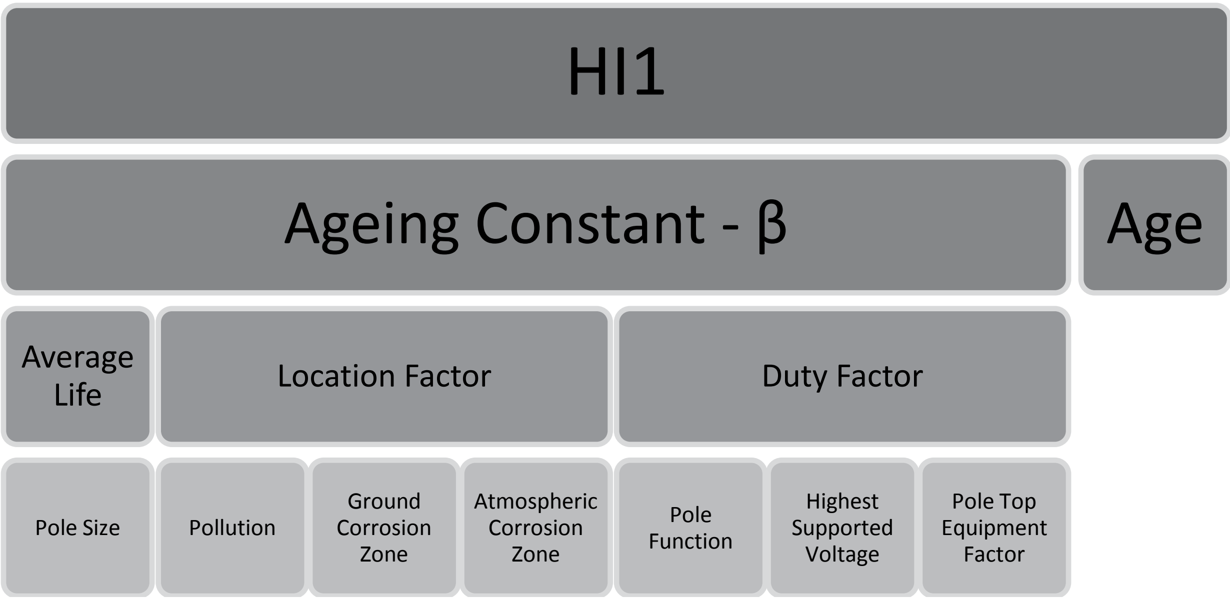

Figure 22: CBRM methodology for determining HI1

It is important to note that HI1 is capped to 4, as this indicates the pole is beginning to experience significant degradation. CBRM applies this cap because further degradation cannot be justified without condition based measurements.

CBRM creates the following interim HI:

- HI2 – HI created using observation based assessment of condition stored in defects recorded against the pole in SAP
- HI2a – HI created using visual inspection information recorded by the Priority Asset Tool (PAT,) and Service Stream
- HI2b – HI created using SAP corrosion value

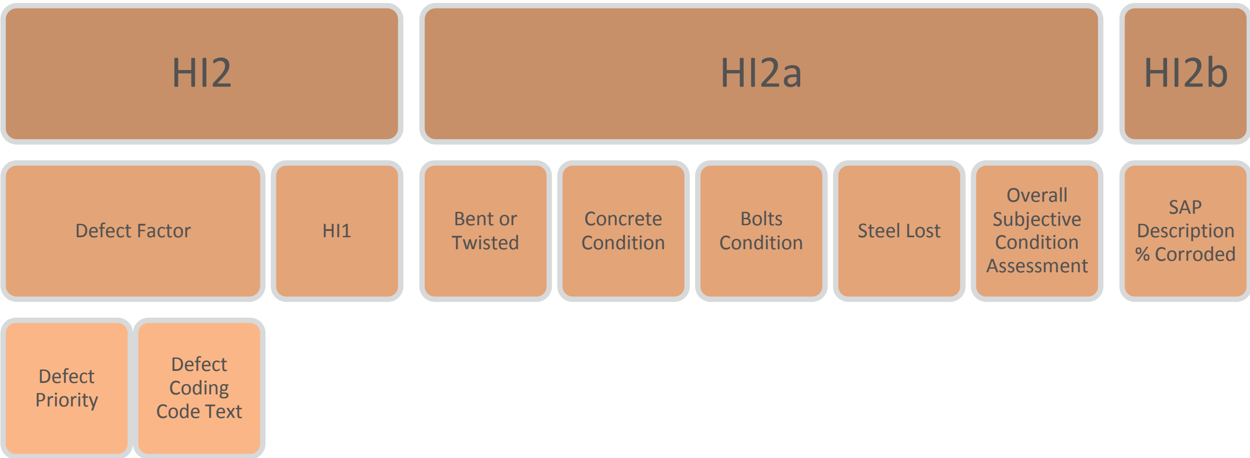

Figure 23: Interim Health Indices

HI2 is determined by combining HI1 with a defect factor. The defect factor is created by identifying all of SAP defects assigned to the pole and creating a weighted sum on the basis of each defect's priority and coding code.

HI2a is determined by identifying the magnitude of the worst condition score recorded by PAT and Service Stream.

HI2b is determined by assigning a HI based on the level of corrosion recorded against the pole in the corresponding SAP defect.

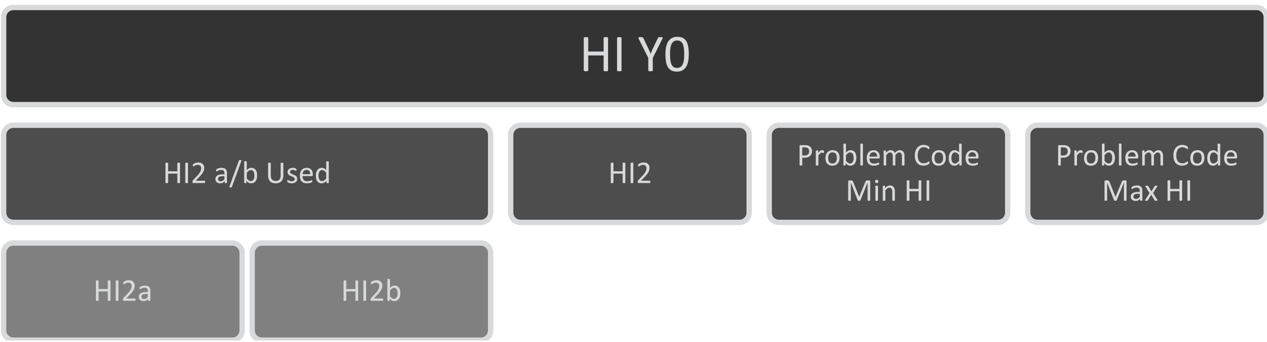

Figure 24: CBRM methodology for determining HI Y0

HI Y0 represents the pole's condition as it stands today; this is the HI which CBRM uses to represent the pole's actual condition.

HI2a/b is determined by assigning it with the value of HI2a, however if HI2a cannot be determined HI2b is used. CBRM uses the following logic to determine HI Y0 using the interim health indices:

- IF HI2a/b has a value assigned then:
  - IF HI2 is less than HI2a/b, use HI2a/b.
  - ELSE use the average of HI2 and HI2a/b.
- ELSE use HI2 bounded by the Problem Code minimum and maximum HI.

CBRM bounds HI2 when it's used alone by identifying if the Pole's Age/Size notification in SAP contains the problem code keywords: 'Corroded > 50%' or 'Corroded < 50%.' These keywords enable CBRM to determine if the pole joists have more than 50% steel loss, and therefore a minimum/maximum HI can be inferred.

9.3.1.2 Determination of Risk Consequences

CBRM uses the following events to define pole risk consequences:

- Pole Break – the pole falls over
- Replacement – the pole is replaced based on poor condition
- Plated – the pole is plated to extend its useful life
- Fire Start – the pole falls over and starts a small bushfire
- Bushfire – the pole falls over and starts a bushfire

CBRM assumes that each event results in SA Power Networks incurring financial consequences. These are divided into the five consequence categories listed above. CBRM determines the financial consequences for each of the categories, as detailed in Table 8 below.

Table 8: Financial Consequence categories

Event	CAPEX	OPEX	Safety	Environment	Reliability
Event: Pole Break Condition Non Condition	Investment in a new pole and hardware	Cost of labour to replace a pole and hardware	For each event, CBRM splits safety into three accidents: • Minor • Major • Fatality Each accident is assigned an overall consequence representing financial investment to prevent it from occurring. Each event is assigned average consequence factors for each accident. CBRM multiplies the average consequence factor by the overall consequence for each accident, and the sum of the results is the overall safety consequence for the specific event.	For each event, CBRM splits environment into six accidents: • Loss of Oil/Litre • SF6 Emission/kg • Fire • Bushfire • Waste/tonne • Disturbance Each accident is assigned an overall consequence. Each event is assigned an average consequence factor for each accident. CBRM multiplies the average consequence factor by the overall consequence for each accident, and the sum of the results is the overall environmental consequence for the specific event.	For Distribution poles, CBRM values reliability consequence by estimating the SPS penalty incurred as a result of a pole falling over. This is determined using the following information: Total Customers Supplied by the Feeder, Average Outage Duration, Value of a Customer Interruption, and Value of a Customer Minute Lost. These values depend on the pole's SCONRRR. For Subtransmission poles, CBRM values reliability consequence as load put at additional risk. This is determined by multiplying the average load lost, VCR, and a LAFF factor. The LAFF is a cubic relationship of the ratio of *Load Above Firm Capacity : Maximum Demand*
Event: Replacement Condition	Investment in a new pole	Cost of labour to install new pole			There are no Reliability Consequences associated with this event
Event: Plated Condition	Investment in material used to pate pole	Cost of labour to plate a pole			There are no Reliability Consequences associated with this event
Event: Fire Start Condition Non Condition	No CAPEX	Cost of rebuilding section of the network destroyed by a small bushfire			There are no Reliability Consequences associated with this event
Event: Bushfire Condition Non Condition	No CAPEX	Cost of rebuilding section of the network destroyed by bushfire			There are no Reliability Consequences associated with this event

It's important to note that for the Fire Start and Bushfire events a PoF modifier is used. This is a factor which scales the PoF on the basis of whether or not the pole is located in a fire risk area. Essentially the modifier pushes the fire/bushfire risk towards poles located in fire risk areas, and ensures there's no fire/bushfire risk associated with poles located in non fire risk areas.

9.3.1.3 *Determination of Criticality*

For each event, a criticality is defined and assigned to each consequence category. The criticality is normalised so that the average criticality for all conductor assets in the model is unity. The following information is used to determine criticality:

- CAPEX:
  - Number of Circuits: Poles supporting a higher number of feeders require more CAPEX during the restoration of an event
  - Pole top Equipment: Combination of all equipment supported by the pole, with weighting assigned to different equipment types
- OPEX:
  - Number of Circuits: Poles supporting a higher number of feeders require more OPEX during the restoration of an event
  - Pole top Equipment: Combination of all equipment supported by the pole, with weighting assigned to different equipment types
- *S*AFETY:
  - LV Shared on Pole: The pole supports a LV service feeder
  - Pole top Equipment: Combination of all equipment supported by the pole, with weighting assigned to different equipment types
- ENVIRONMENT:
  - Environmentally Sensitive Area: Subjective risk assessment of the vulnerability of the environment to pole damage
  - Pole top Equipment: Combination of all equipment supported by the pole, with weighting assigned to different equipment types
- RELIABILITY:
  - Major Customers: If major customers exist on a feeder, a fault exposes more risk
  - Number of Life Support Customers: Feeders supplying life support customers expose the network to more risk
  - Number of Circuits: Poles supporting a higher number of feeders expose the network to higher penalties if an outage occurs
  - Highest Voltage on Pole: Higher voltages supply more load and typically affect more customers if an outage occurs

The varying asset replacement maturity levels and their relationship to CBRM are discussed in Table 9 below.

Table 9: Asset replacement Investment Maturity Levels

Maturity Level/Complexity	Approach	Basis of CBRM Forecasts
Age based	Assets are replaced when they reach a pre-defined nominal life. Rarely used in practice	CBRM not required decisions and forecasts made from asset age profiles. This approach corresponds to the 'deterministic' option available within the RepEx model and is rarely if ever used in distribution utility practice
Asset Health based	Assets are replaced when they reach a pre-determined condition or health. Commonly used and often based on quantitative condition monitoring or subjective inspection criteria	Replacement at a pre-defined health index. The replacement health index selected will define the probability of failure. This is the basis of many existing asset management strategies where a global standard defines common 'pass' and 'fail' criteria for all assets regardless of their criticality to business objectives
Target failure rate based	The volume of asset replacements is determined so as to provide a target asset failure rate. Target failure rates will be related, but not necessarily proportional to, service levels such as SAIDI or safety objectives	CBRM model predictions of failure rate may be used to develop an intervention plan to achieve a target number of failures. While overall failure rates are managed, no consideration is given to asset criticality to business objectives.
Target risk based	The volume of asset replacements is determined so as to provide a target level of risk. Risk targets may be derived from service level targets	CBRM model predications of risk may be used to develop an intervention plan to achieve a target risk level. Inaccuracies in the absolute calculated value of risk may be minimised by setting targets in relative rather than absolute terms, for example maintaining a constant or static risk or a percentage reduction in risk.
Financially optimised	The volume of asset replacements is determined to balance the net present value of risk associated with retaining each asset in service. In principle, a financially optimised replacement plan correctly balances the impact of failure to both the network business and the community against the cost of replacement/refurbishment	CBRM NPV Optimisation. Accuracy of NPV optimisation is dependent upon the level of confidence in the absolute values of risk as these are considered by the NPV analysis as a cash flow stream. CBRM NPV optimisation should therefore only be used in situations where there is a high degree of confidence with the absolute calculated values of risk

9.4 Multi-Variable Defect Forecasting Model

The internal forecast is based on historical defect data. The model produces forecasts of the expected number of defects and expected rectification cost per defect for each location, corrosion zone and voltage level. These factors combined give a forecast of the total replacement expenditure. The forecast is calculated over a five year period and scaled up to ten years, using the assumption that defects accumulate at a constant rate.

9.4.1 Calculating the expected number of defects

The expected number of defects is calculated for each location (rural or urban), voltage (7.6kV, 11kV, 19kV, 33kV or 66kV) and corrosion zone (CZ1, CZ2 or CZ3) by summing the expected number of defects for each feeder in the matching categories.

The expected number of defects for each feeder is determined using the assumption that defects occur uniformly per unit length for all feeders with the same location and corrosion zone, and is calculated as the total length of overhead line (high and low voltage) multiplied by five years multiplied by the expected defect rate per km per year for the feeder's location and corrosion zone.

The expected defect rate per km per year for each location and corrosion zone is determined by dividing the total historical feeder defect rate per year by the total length of feeders in that location and corrosion zone. This assumes that the data sets are sufficiently large for each combination of location and corrosion zone.

The historical feeder defect rate per year is the number of defects (P1(+PZ), P2 or P3, in cycle or out of cycle) in 2012 or 2013 divided by the number of years since the last inspection and multiplied by a factor (10/11). This assumes that the expenditure forecast must include all P1, P2 and P3 defects. The factor (10/11) is to remove defects that occur outside the inspection year, based on the assumption that approximately 10% of defects occur outside the inspection year in addition to defects detected during inspection. The amount is divided by the number of years since inspection in order to determine the number of defects that occur per year, assuming that defects accumulate at a constant rate between inspections. Defects detected out of cycle are included specifically from pole inspection works from AMRS in order to form a more accurate dataset.

9.4.2 Calculating the cost per defect

The cost per defect is calculated for each location and voltage using historical data.

As most of the categories have insufficient data for average costs, the average costs are calculated based on rural 11kV (which is assumed to have a majority and a sufficiently large data set) using adjustment factors for the other locations and voltages for which there is insufficient data.

For rural 11kV, the average cost per defect is calculated by dividing the total cost of rural 11kV defects by the number of rural 11kV defects, ignoring any defects for which the cost is zero or negative, or the user status code contains 'DERR' or 'DLFL' or the system status does not contain 'NOCO'.

For other rural voltages, the cost per defect is the rural 11kV cost per defect multiplied by an adjustment factor. The voltage adjustment factor is the weighted average of the ratio of average cost per defect for the voltage to 11kV (both rural and urban) across a selection of asset categories, weighted by the number of defects. This assumes that the ratio of costs for other voltages to 11kV is approximately equal for most asset categories.

For urban voltages, the cost per defect is the rural voltage cost per defect multiplied by an adjustment factor. The urban adjustment factor is the weighted average of the ratio of average cost per defect for urban vs rural (all voltages) across a selection of asset categories, weighted by the number of defects. This assumes that the ratio of costs for urban to rural is approximately equal for most asset categories.

9.4.3 Calculating the cost of replacement

The interim value of the cost of replacement is calculated by multiplying the expected number of defects by the expected cost per defect in each location, voltage category and corrosion zone and then summing the results.

9.4.3.1 Illustration

The internal forecasting methodology is illustrated here with numerical examples from the current forecast.

Urban feeder AP125B operates at 7.6kV, is located in corrosion zone CZ2, has 5.18km of overhead lines, has experienced three P1 defects, four P2 defects and one P3 defect in 2012 and 2013 and was last inspected seven years ago. Therefore the defect rate for AP125B is estimated at 1.039 per year.

Urban CZ2 has 1763.61km of overhead line and total defect rate 480.05 per year, and therefore the defect rate per year per km for urban CZ2 is estimated at 0.2722 and the expected number of defects over five years for AP125B is estimated at 7.05.

The expected number of defects over five years for urban CZ2 7.6kV is 533.27. The expected number of defects over five years for urban 7.6kV is 533.80, and the total expected number of defects over five years is 10854.

For rural 11kV feeders, there are a total of 1019 defects included in the sample at a total cost of $9,680,045.22 and therefore the cost per rural 11kV defect is estimated at $9,499.55.

The ratio of urban to rural defect costs averages 1.2897 and the ratio of 7.6kV to 11kV defect costs averages 1.105, and therefore the cost per urban 7.6kV defect is estimated at $13,538.91.

Therefore the total cost of defects over five years for urban CZ2 7.6kV is estimated at $7,219,908, and the total cost of defects over five years for urban 7.6kV is estimated at $7,227,018.

The total cost over five years is estimated at $142,593,694, and therefore the adjusted annual cost is estimated at $39,926,234 (after including defects outside the inspection year) per year.

9.4.4 Internal forecast results detailed and explained

The internal forecasting methodology has forecast a total of 10,854 defects over the next five years including P1, P2 and P3. Based on the defect remediation costs, this represents a five year forecast of $142,593,694 before adjustments. The forecast replacement expenditure is $39,926,234 (after including defects outside the inspection year) per year for five years totalling $199,631,171 over the regulatory period. This is explained further in the following sub paragraphs.

9.4.4.1 Volume of defects

The internal model has forecast a total of 10,854 defects over the next five years (prior to inclusion of defects detected outside the inspection year). The breakdown by voltage and location is given in Table 10 below.

Table 10: Internal Forecast of the Number of Defects During the Regulatory Period

Voltage	Rural number of defects	Urban number of defects
7.6kV	33	534
11kV	1598	5091
19kV	2664	46
33kV	373	42
66kV	63	410

9.4.4.2 Cost per defect

The internal model has estimated the cost per defect for each voltage and location as given in Table 11 below.

Table 11: Internal Forecast of the Cost per Defect

Voltage	Rural cost per defect	Urban cost per defect
7.6kV	$10,497	$13,539
11kV	$9,499	$12,252
19kV	$11,002	$14,190
33kV	$19,486	$25,133
66kV	$32,360	$41,736

9.4.4.3 Cost of replacement

The internal model has forecast the total replacement cost (before adjustment) at $142,593,694 during the regulatory period, which represents $39,926,234 per year (totalling $199,631,171 during the regulatory period) after adjustment for defects detected outside the inspection year. The unadjusted totals for each voltage and location are given in Table 12 below.

Table 12: Internal Forecast of the Total Cost During the Regulatory Period (before adjustment)

Voltage	Rural cost (unadjusted)	Urban cost (unadjusted)
7.6kV	$341,660	$7,227,018
11kV	$15,184,538	$62,374,062
19kV	$29,306,551	$652,360
33kV	$7,272,675	$1,055,519
66kV	$2,048,520	$17,130,789

9.5 Repex Modelling

The Australian Energy Regulator's (AER) replacement model (repex model is intended for use as part of building block determinations for the regulated services provided by electricity network service providers (NSPs). The repex model is a series of Microsoft Excel spreadsheets developed for the AER to benchmark replacement capital expenditure. It was first deployed in the Victorian electricity distribution determination for the 2011-2015 regulatory control period.

9.5.1 Model Description

The AERs Replacement Model Handbook provides a description of the underlying premise and workings of the repex model.

The underlying premise of the model is that age is proxy for the many factors that drive individual asset replacements. The AER notes that with time, network assets age and deteriorate. This can affect their condition, which in turn can impose risks associated with the asset's failure such as network performance, safety, environmental damage and operational risks.

The model simplistically predicts the volume of replacement based on the age of system assets on the network. To do this, the model requires information on the age of assets, and the likely age of replacement. As a final step the model predicts the total expenditure by multiplying volumes by the average cost of replacing an asset in that group.

The repex model can be manipulated in a number of ways to test the replacement capex proposed by the DNSP. In the first instance, the AER uses the information provided in a DNSPs RIN to derive results for the model (termed the 'base case'). The steps involved in the 'base case' are explained in the AERs handbook and are summarised below.

1. Asset categorisation and grouping - The model requires the NSPs network asset base to be broken down into a number of discrete asset categories. This categorisation is required to reflect variations in asset lives and unit costs between different asset types. The AERs regulatory proposal RINs for mandate high level categories, but provide the ability for DNSPs to include lower level sub-categories.
2. Inputs – The key inputs required by the repex model relate to the age profile of each subcategory of assets, the mean age of replacement, and the unit replacement costs of assets within this group. These are collected by the AER as part of the RIN and are described below.
    a. Age profile - Reflects the volume of the existing assets at the various ages within the asset category at a static point in time. The model allows the installation dates to go backwards up to 90 years from the current date of the age profile.
    b. Mean age and standard life - These two parameters define the probability distribution of the replacement life for the asset category. The AER assume a normal distribution around the mean.
    c. Unit replacement cost - This parameter defines the average unit cost to replace one unit within the asset category. This unit cost must reflect the volume unit used within the age profile.
3. Outputs - The model takes these inputs and produces the following outputs for each asset categories:
    a. Age and asset value statistics and charts of the age profile - The model provides summary information of the age profile. This is presented at the

asset category and asset group level. This covers information such as total volumes and replacement costs, proportions of the total network, average ages and lives, and proportions of aged assets.

b. 20-year replacement forecasts - Based upon the input data, the model produces year-by-year forecasts of asset replacement for the following 20 years. The forecasts prepared include individual asset category forecasts and aggregated asset group forecasts.

The 20 year replacement forecasts are based on a function within the model that provides a probabilistic estimate that an asset in the group will be replaced at a specific age. The model assumes that the probability is normally distributed around the mean age, taking into account the standard deviation.

9.5.2 SA Power Networks Model

A SA Power Networks repex model has been prepared as a comparator to the other methodologies utilised to develop the forecast expenditure for Poles. The following steps were undertaken in development and calibration of the model.

9.5.2.1 Population of 'Tables' Sheet

The 'Tables' worksheet holds the data required to intialise the repex model.

The 'Asset group names' table holds the names for each of the asset groups, these have been populated to match the Catgory Analysis RIN to allow diret transfer of data from one model to the other.

The now parameter represnts the year that the age profile represents, that is the latest instalaltion date in the age profile, this was set to this year (2014).

The recursive parameter was set to 1, thereby forcing the model to perform a recursive caculation of replacement volumes, that is forecast replacement volumes in one year will themsevles be used to calculate replacenmetn volumes in later years. This is viewed as the most accurate methodology according to the AER model guide.

The First Year parameter was set to '0' to make the first year if the forecast 'now', ie 2014, as the first yar of the age profile does not contain a significant number fo assets.

9.5.2.2 Population of 'Asset Data' Sheet

The 'Asset Data' worksheet within the repex model contains the data required to represent the SA Power Networks asset base. This worksheet has been populated with asset data in the same categories, and with data in the same columns, as the Category Analysis RIN.

The methodology parameter was set to '2' to cause the model to replace all assets assuming a normal distribution, ie the methodology as set out in the AERs Replacement model handbook guide, as SA Power Networks understand this to be the preferred methodology of the AER.

The profile type parameter was set to '3' to cause the model to assume the age profile is defined in terms of the installation date, to allow data to be directly utilised from the Category Analysis RIN, tab 5.2, where the age profile is given in terms of installation date.

The unit costs were populated with the unit costs detail in Section 7.2 above. The unit costs from the Category Analysis RIN were not utilised for the reasons described below.

For the Category Analysis RIN the unit costs were derived from work orders within SAP. An issue has been identified where it appears that not all costs are being correctly booked/allocated to work orders within SAP resulting in lower than expected unit costs. Examples of incorrect booking/allocation found were bundling of work making it difficult to separate out cost to replace components, work orders with no materials allocated, incorrect booking of labour, or no cost allocation although work has been completed..

The unit costs utilised were instead developed by subject matter experts and were based on information in addition to that held in SAP against work orders. These unit costs, as previously explained, are through to be typical unit costs for the type of replacements expected and more representative of the actual cost than those in the Category Analysis RIN. Use of the unit costs, as previously detailed, also ensures consistency of unit costs across the methodologies utilised for development of the forecast.

The replacement life mean and standard deviation (SD) were populated through calibration of the model, described in more detail below.

9.5.2.3 Model Calibration

It is understood that In addition to the 'base case', the AER also undertakes a calibration exercise to' fit' the function of the model to historical replacement volumes and costs of the DNSP. This involves:

- Using historical replacement volumes over the most recent 5 years of actual data to adjust the mean replacement life until the forecast volume of replaced assets in the first year of the forecast period equals the average actual volume.
- Adjusting the unit replacement cost to reflect most recent data on the costs of replacing assets.
- Re-calibrating the model (ie: refreshing the outcomes) to allow for the new data.

The AER also note that as part of its calibration technique, it may use other scenarios such as usingasset life and unit costs of other DNSPs that it has collected through the benchmarking process.

A calibration exercise was undertaken replicating the process SA Power Networks understands the AER will undertake, as described above.

The following steps were undertaken by SA Power Networks to calibrate the model:

- Worksheet 'Notes' was utilised for the calibration calculations
- For each asset category the following data can be found in the 'Notes' worksheet:
  - 'Original Life' – the average or expected life of the assets based on subject matter experts opinion, repored in previous AMPs or from other sources
  - 'Calibrated Life' – initially set to the same values as 'Original Life', linked to the mean life in the 'Asset Data' worksheet and changed during the calibration process as described below.
  - 'Calibration Factor' – calculated by divifing the 'Calibrated Life' by the 'Original Life'
  - 'Average of Actual Volume Replaced' – caculated from the average historicla replacements from 2008 to 2013 for each asset sub categroy from the Category Analysis RIN
  - 'Model Volume RRR Historic' – linked to the first years replacement quantity forecast in the 'RRR hist forc' worksheet, which when uncalibrated predicts the replacement volumes based on data input which do not necessariliy take into account historical behaviour.

- The model is calibrated by utilising the GOAL SEEK function in MS Excel. Using the GOAL SEEK function the 'Model Volume RRR Histroic' value for each asset sub category is set to match the 'Average of Actual Volume Replaced' by changing the 'Calibrated Life', thereby forcing the first year of replacements wihtin the model to match historcial behaviour/replacement volumes.

This calibration, and the results below, resulted in mean replacement life of around 90 years for Stobie poles. This is greater than the expected average life normally quoted for Stobie poles of on average 70 to 75 years.

9.5.2.4 Model results

The results of the Repex modelling are shown in Table 13 and Figure 24 below.

Table 13: Pole results from RepEx

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number to be replaced													
< ≈ 11 kV; STOBIE	919	1044	1179	1323	1478	1644	1823	2016	2224	2450	2697	2967	21763
> 11 kV & <≈ 33 kV; STOBIE	94	109	126	144	164	185	209	235	263	294	328	366	2515
> 33 kV & <≈ 66 kV; STOBIE	44	52	62	72	83	96	110	125	141	158	176	195	1313
TOTAL	1057	1205	1366	1539	1725	1926	2142	2375	2627	2902	3201	3528	**25591**
Expenditure ($millions)													
< ≈ 11 kV; STOBIE	$8.27	$9.40	$10.61	$11.91	$13.30	$14.80	$16.41	$18.14	$20.01	$22.05	$24.27	$26.70	$195.87
> 11 kV & <≈ 33 kV; STOBIE	$1.13	$1.31	$1.51	$1.72	$1.96	$2.22	$2.51	$2.81	$3.15	$3.52	$3.93	$4.39	$30.17
> 33 kV & <≈ 66 kV; STOBIE	$2.42	$2.87	$3.38	$3.95	$4.59	$5.28	$6.04	$6.86	$7.74	$8.68	$9.68	$10.74	$72.24
TOTAL	**$11.82**	**$13.58**	**$15.50**	**$17.59**	**$19.85**	**$22.30**	**$24.95**	**$27.81**	**$30.91**	**$34.26**	**$37.89**	**$41.83**	**$298.28**

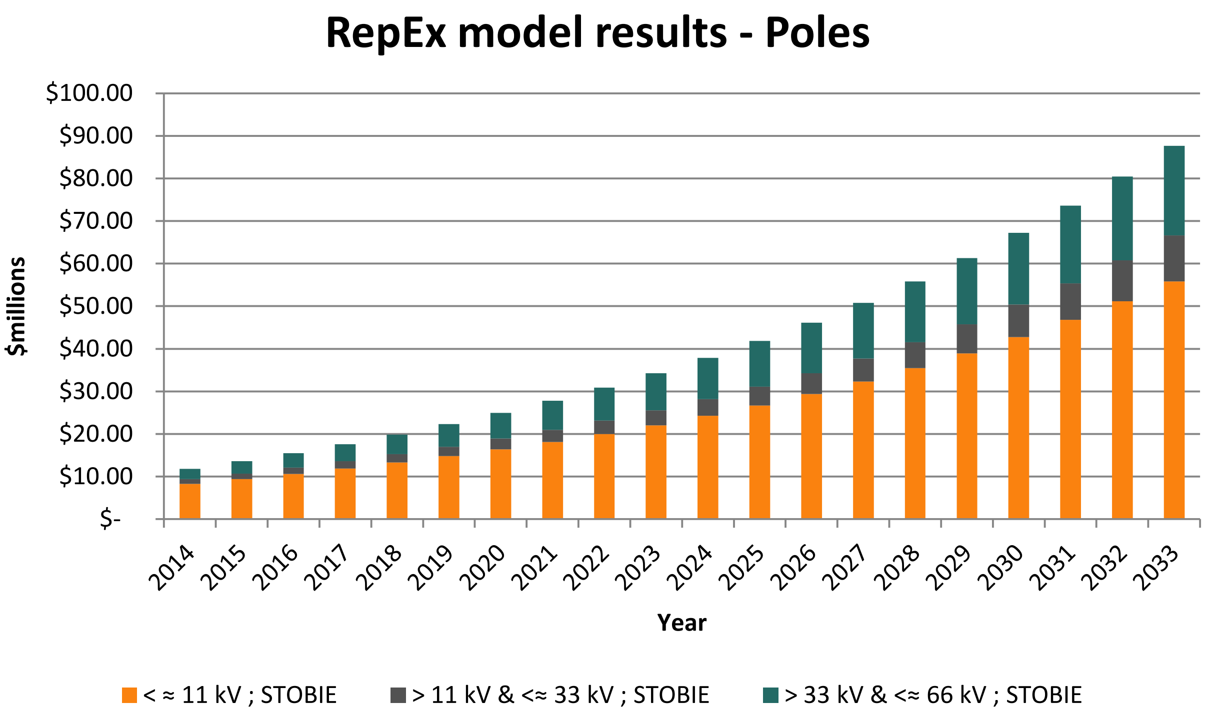

Figure 25: RepEx model results

9.5.3 Limitations and deficiencies of the repex model

In preparing our expenditure forecast SA Power Networks have sought to test whether the repex model can provide an indicator of the efficiency of our replacement forecasts utilising other methodologies. Our review has been limited to a high level conceptual examination of the mode and creation of the model detailed above.

SA Power Networks considers the repex model to have number of shortcomings including weaknesses in the model construct, the underlying data quality and statistical validity, and the application of the model by the AER. These deficiencies are explained in greater detail below.

9.5.3.1 Deficiencies with model construction

It is important to recognise that a model is an abstract reflection of complex reality, and will therefore never be perfect. Modelling is a key tool used to predict the future, and is therefore used by a prudent network planner to varying degrees in developing forecasts of volumes and unit costs. The key question is whether the construction of the repex model can lead to an accurate prediction of the replacement level that a prudent and efficient DNSP would incur in their circumstances.

A key premise of the repex model is that age asset is an accurate proxy for the likely time that an asset is replaced. There is little doubt that an asset's condition deteriorates with time, and will exhibit a higher probability of failure towards the end of its life. However, we consider there is a high degree of variability around a 'mean' age of replacement that limits the accuracy of its use in predicting volumes of replacement. Even with technologies that experience uniformity in failure mode, there are cases where a prudent DNSP will replace an asset much before, or after, the mean age of replacement. These natural variations in 'wear and tear' of the asset relate to:

- Innate differences in the manufacturing quality of the asset and the installation process and complexity.
- Operating and topological differences when the asset is used over time, for instance an asset installed in coastal regions will exposed to a more corrosive environment than one in the arid areas of the state.
- Differences in maintenance of similar assets over time. For example, some of SA Power Networks' assets were previously owned by local councils, each which had a different approach to maintenance. Obviously, assets that were well maintained over time will exhibit longer lives even if there is uniformity in failure modes.

The likely age of replacement will also depend on the consequences of failure. A prudent DNSP will often undertake proactive replacement programs that strive to replace assets before they fail in service, particularly to mitigate high safety or reliability consequences. For instance, an asset located in a high bushfire risk area is more likely to be replaced that one in an isolated area when there is a chance of failure resulting in a fire start. This means that assets which have uniform failure modes may have very different replacement ages.

Using age as a proxy also fails to take into account other drivers of capex such as duty of care programs. In these cases, age (ie: deterioration in condition) is not the primary driver of replacement but rather the need to ensure our assets meet modern day safety or environmental standards. A key example is clearance heights for feeders, which may not meet a required standard for public safety.

For this reason a prudent asset manager uses a greater variety of tools and information to forecast replacement programs than age based modelling. For instance, for large and costly assets on the sub-transmission network, the prudent asset manager would look to conditional data of the individual asset, and undertake granular risk-consequence analysis.

For categories of assets that contain a high population, the asset manager may use more high level tools such as models. However, the model would be configured to best reflect the individual circumstances of the DNSP and the condition of the asset base. While age based analysis may feature in such analysis, it is likely that a prudent asset manager would also use other data sources to guide its forecasts including conditional data from inspections, failure mode analysis, trends in failure rates, and consequence of failure analysis.

Sub-categories may not be sufficiently granular to reflect replacement age

A key assumption of the repex model is that individual assets in a population share common characteristics, and accordingly that there can be a level of accuracy in predicting replacement costs and age. The repex model allows DNSPs to identify sub-categories of assets under the AERs major categories of assets. For example, a DNSP can provide data on feeder by voltage and/ or technology type so as to group assets with common failure modes and likely similar replacement ages.

However, there are a diverse range of technologies on a DNSPs network, which means that subgroups will rarely contain assets with similar failure modes. In some cases, this issue arises due to a lack of quality data on asset age profiles and replacement lives for assets, which mean that technologies need to be clustered together. This means that even at a sub-category level, the mean age of replacement will be imprecise.

Average unit costs do not provide a realistic estimate of costs

The repex model uses 'average' unit costs for sub-categories of assets to predict the likely levels of expenditure of a DNSP. We consider that this is a problematic assumption and does not provide a realistic expectation of unit costs. Each replacement job is likely to be different due to site specific factors, even when there is sufficient uniformity in the asset being replaced.

On the sub-transmission parts of the network, costs become very site specific and may be impacted by the type of job being undertaken. On the 11kV and distribution network, an averaging approach may provide a more accurate indication of future costs. In these cases, there is a greater population of assets and potentially less variation in scope differences. Even in these cases, there is likely to be significant variation in the types of jobs being undertaken and the complexity of the task.

A prudent network asset manager may not be able to accurately forecast the cost of each individual project but would seek to identify whether there are differences in the type of project being constructed and account for this with different unit rates for particular jobs. In contrast, the repex model is limited in its inability to account for variations and distributions around the mean, and may be impacted by outliers in costs.

A further limitation with using average costs is when the asset has a long delivery time as is the case with sub-transmission major projects. In these cases, the expenditure and commissioning of the asset can be separated by many years, leading to a mismatch in average unit costs for a particular year.

9.5.3.2 Problems with data quality and statistical validity

An axiom of modelling is that underlying data should be accurate and reliable, and should meet the key principles underlying statistical validity. In the sections below we note that the repex model fails to meet these conditions.

Data quality and accuracy

The underlying data on age of assets, replacement ages and expenditure costs can be highly unreliable and accurate for certain asset categories.

Statistical validity

We note that the AER's repex model handbook does not identify a quantitative statistical test for evaluating the effectiveness of the repex model. We consider that the results of the repex model for each sub-category may fail to meet one or more of the following principles underlying statistical validity:

- Sample size – We consider that for many sub-categories (for example, sub-transmission assets) there are insufficient samples to be confident in the outputs of the model.
- Sample representative of population – For the reasons noted above, we consider that the underlying data for each sub-category is unlikely to contain asset technologies with different failure characteristics and therefore cannot be used accurately to predict replacement age.
- Algorithm is sound – An algorithm sets out the calculation steps involved in developing the function that is used to predict the outputs. We note that the AER has generally used information on the mean and standard deviation to 'fit' a normal distribution. This is a very broad assumption, and reflects the lack of samples to derive a more precise algorithm. The algorithm would likely be

different for each sub-category, and this means that the replacement density curve is likely to be very imprecise.

- Model outcomes holds outside data range - In many cases, there is insufficient data to know when the asset is likely to be replaced. In some cases, the technology may only be first exhibiting signs of failure, which we know will increase rapidly in the forthcoming regulatory period based on inspection of the equipment.

9.6 Abbreviations

ACCC	Australian Competition and Consumer Commission.
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMP	Asset Management Plan. A document that provides the high level asset management framework and lifecycles for SA Power Networks.
AS	Australian Standard.
AS/NZS	Australian / New Zealand Standard.
A to O	Authority to Operate SA Power Networks plant by SCADA control.
AWS	Advanced Works Scheduling.
BESS	Best Endeavours Service Standards.
BFRA	Bushfire Risk Area.
BOM	Bureau of Meteorology.
Business Plan	The overall budget program for SA Power Networks.
CAIDI	Customer Average Interruption Duration Index. It is the average supply restoration time for each customer calculated as SAIDI / SAIFI.
CAPEX	Capital Expenditure Budget.
CB	Circuit Breaker.
CFS	Country Fire Service.
CIS - OV	Customer Information System – Open Vision.
CLER	Customer Lantern Equipment Rate.
CPI	Consumer Price Index.
CRC	The Capital Review Committee (CRC) comprises the Chief Executive Officer (CEO), Chief Financial Officer and General Manager Corporate Affairs (as the Asset Owner).
Detailed Asset Management Plans	A set of AMPs which sit under the high level Asset Management Plan (Manual 15).
Disposal	Removal of assets from the asset base.
DMS	Distribution Management System.
DNCL	Distribution Network Controller Level.

DPTI	Department of Planning, Transport & Infrastructure.
DUOS	Distribution Use of System.
ECR	Emergency Control Room.
ElectraNet	The South Australian electricity transmission network owner and planner.
EMG	Executive Management Group.
ENA	Energy Networks Association.
ESCOSA	Essential Services Commission of South Australia.
ESAA	Electricity Supply Association of Australia.
ESDP	Electricity System Development Plan.
FDI	Fire Danger Index.
FDL	Fire Danger Level.
FS	Field Services is the internal construction workgroup of SA Power Networks.
FSB	Facilities Systems Branch.
FTE	Full Time Employees.
GIS	Geographic Information System.
GSL	Guaranteed Service Level.
HBFRA	High Bushfire Risk Area.
HV	High Voltage.
IEC	International Electro-technical Commission.
IEEE	Institute of Electrical & Electronics Engineers.
IPWG	Inspection Planning Working Group.
IRR	Internal rate of return is discount rate which produces a present value of zero when applied to the proposed cash flows.
IVR	Interactive Voice Response.
JSWM	Job Safe Work Method - Document that describes a safe system of work on a particular item of plant at a particular location.
JSWP	Job Safe Work Procedure - A document that describes a generic safe system of work on plant and equipment used to build and maintain the Electricity Distribution system.
LGA	Local Government Area.
LV	Low Voltage.
MAIFI	Momentary Average Interruption Frequency Index.
MV	Medium Voltage.
NBFRA	Non Bushfire Risk Area.
NER	National Electricity Rules.

NIEIR	National Institute of Economic and Industry Research.
NM Group	Network Management Group. This group represents the Asset Manager role for managing the distribution business on behalf of SA Power Networks.
NOC	Network Operations Centre.
NPV	Net Present Value is the present value of all expected benefits, less the present value of all expected cost of the project.
O&M	Operations and Maintenance.
OMS	Outage Management System
OPEX	Operating Expenditure Budget.
PAW	Pre-arranged Work.
PCB	Polychlorinated Biphenyls.
PI	Profitability index is defined as the ratio of discounted benefits to discounted costs.
PLEC	Power Line Environment Committee
PV	Photo Voltaics
QMS	Quality Management System.
RCM	Reliability centred maintenance.
Refurbishment	Work on an asset which corrects a defect and/or normal deterioration and result in an extension to its expected end of life.
Repair / Maintain	Work on an asset which corrects a defect allowing the asset to operate to its expected end of life.
Replacement	Complete change over of 'old for new' asset.
RFP	Request for Proposal.
RIT-D	Regulatory Investment Test – Distribution.
RIT-T	Regulatory Investment Test – Transmission.
RTU	Remote Terminal Unit.
SAIDI	System Average Interruption Duration Index specified in minutes per customer per annum.
SAIFI	System Average Interruption Frequency Index specified in outages per customer per annum.
SAP	Asset and fault records database.
SA Power Networks	The South Australian electricity distribution network owner and planner.
SCADA	Supervisory, Control and Data Acquisition.
SCO	System Control Officer.
SCONRRR	Standing Committee on National Regulatory Reporting Requirements
Services	Services Department. This group manages core services dealing directly with individual residential or business customers.
SNC	Senior Network Controller.
SOC	Senior Operations Controller.
SOP	Safe Operating Procedure – Document that describes safe operating work procedure.
SPS	Service Performance Scheme – see STPIS.

SSF	Service Standard Framework.
STPIS	Service Target Performance Incentive Scheme.
TF	Transformer.
UFLS	Under-frequency load shedding.
UID	Underground industrial development.
URD	Underground residential development.
WARL	Weighted Average Remaining Life.

9.7 References

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