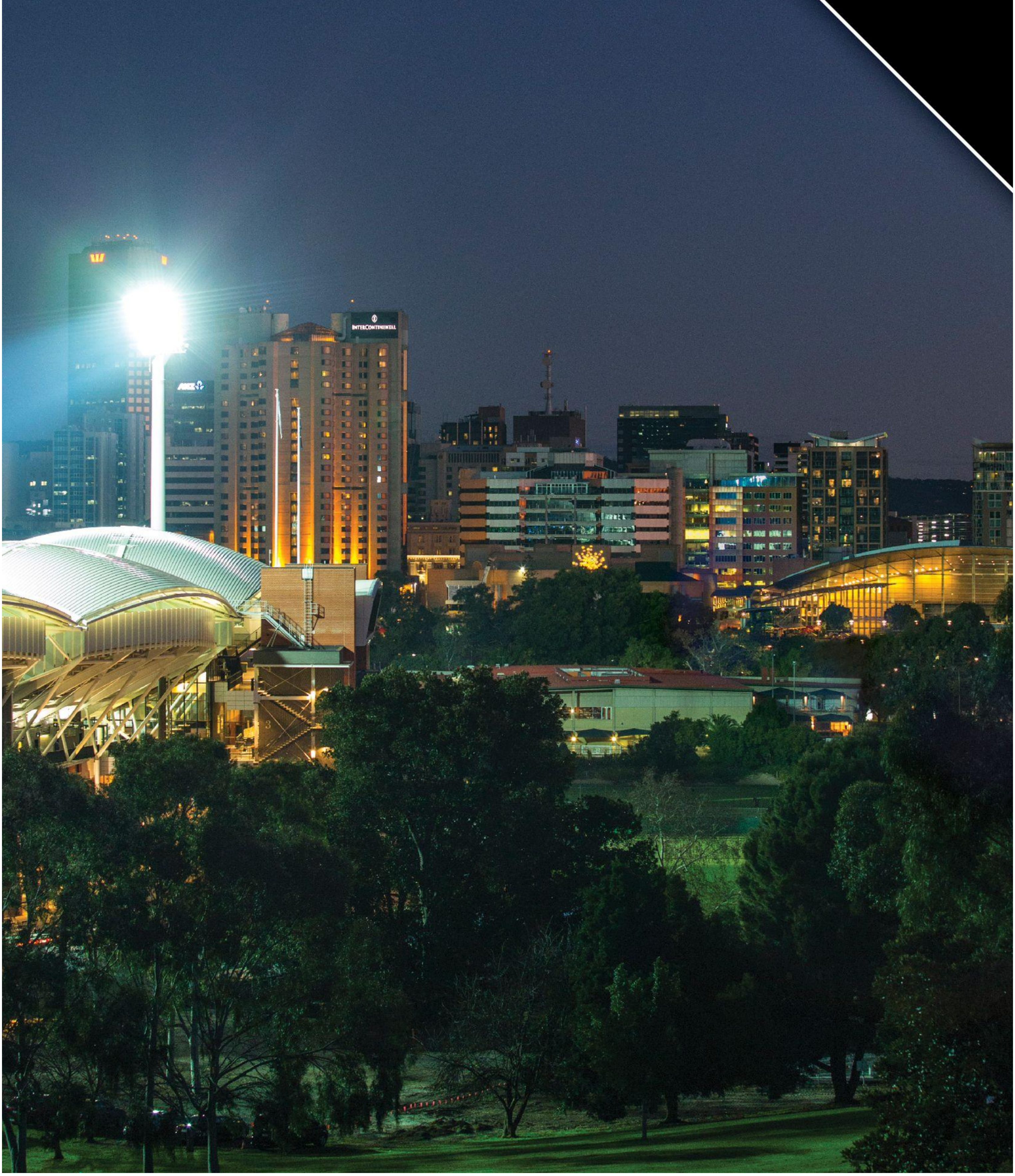
Attachment 20.63

SA Power Networks:
Asset Management Plan 3.1.10
Overhead Conductor 2014 to 2025



SA
Power
Networks

ASSET MANAGEMENT PLAN 3.1.10 OVERHEAD CONDUCTOR

2014 TO 2025

Published: October 2014

SA Power Networks
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OWNERSHIP OF STANDARD

Procedure 916 Annex B
Issue 2/13

OWNERSHIP OF STANDARD

Name of Standard / Manual: ***AMP 3.1.10 Overhead Conductor***

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

Standard Last Reviewed: September 2014

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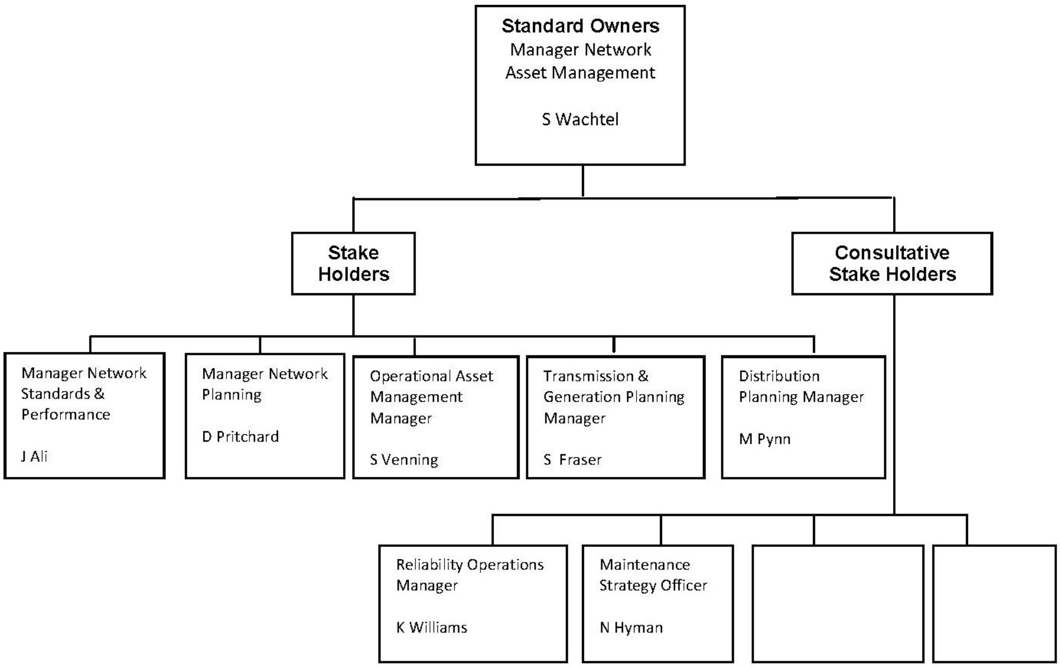
Review Period: 5 years

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 3.1.10 – Overhead Conductor)

DOCUMENT VERSION

Date	Version	Explanation
1/1/2009	0.1	Original AMP
30/09/2014	0.2	Updated AMP
28/10/2014	1.0	Final

Contents

TABLES

FIGURES

1. EXECUTIVE SUMMARY

1.1 Background

This Asset Management Plan (AMP) has been prepared for the management of overhead conductors over the period of 2014 to 2025, based on information gathered from staff and previous industry experience.

Overhead conductor is an essential part of the distribution system and must be managed in accordance with operating and maintenance requirements. The consequences of in-service failures include supply interruption, environmental, and compromises to employee and public safety.

The age profile of SA Power Networks' overhead network reflects the history of the company.

A dramatic increase in the route length of overhead conductor occurred during the period between 1955 and 1977. This coincided with the formation of ETSA and electrification of the state, an increase in electricity demand, as well as an increase in and dispersion of the population.

The average age of SA Power Networks' overhead network is 49 years, with the majority of the conductors installed in the years 1955, 1956, 1958 and 1966. Approximately 59% of SA Power Networks' overhead conductors are greater than 50 years of age with only 2% less than 20 years old.

These ages suggest that, although the network is not within its replacement cycle, it is approaching its replacement cycle. Therefore, the volume of defective conductor is likely to gradually increase over the next 10 to 20 years.

SA Power Networks overhead line network consists of both sub-transmission and distribution voltages that range from 240V to 66kV. The majority (over 90%) of the route length of overhead conductor belongs to the distribution voltages (including SWER and the low voltage network), which reflects the nature of SA Power Networks' business. Several 66kV lines are present in SA Power Networks' overhead network.

The majority of the conductors installed and restrung between 1930 and 1949 were 33kV lines, while the majority of the conductors installed and restrung in 1955, 1956, 1958 and 1966 were SWER and 11kV lines. This pattern is due to an increase in grid connections associated with inland rural areas between the 1950 and 1970. To a lesser degree, low voltage, 33kV and 66kV lines were frequently installed throughout 1950 to 1979.

There are a number of failure modes intrinsic to overhead conductors. The failure modes that tend to define the service life of a conductor are as follows:

- corrosion – degradation of the conductor by the environment
- fatigue – degradation of the conductor or fittings by the movement of the conductor (eg by wind induced oscillations)
- annealing – loss of strength due to heating of the conductor through the electrical current they carry (particularly overheating)
- creep - stretching of the conductor due to the mechanical loading of the conductor (which is most susceptible to aluminium conductors)
- insulation breakdown for ABC and covered conductors

1.2 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, as defined in the Regulated Service Standards.

1.3 Asset Management Plan Activities

To assist SA Power Networks in achieving the above objectives for overhead conductor and feeders, this asset management plan has been prepared to identify and prioritise the primary issues and strategies for managing overhead conductors, including the asset maintenance and operational functions of overhead assets.

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 Plan Strategies

The lifecycle management of overhead conductor will assist SA Power Networks in the reliable and cost effective operation of the lines network. This requires implementing the Asset Management Strategy (referenced in AMP 3.0.01 Condition Monitoring and Life Assessment Methodology 2009-2020).

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 overhead conductor 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 Overhead Conductor Asset Management Plan. This will help ensure that the operation of SA Power Networks' overhead conductor 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 overhead conductors 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.

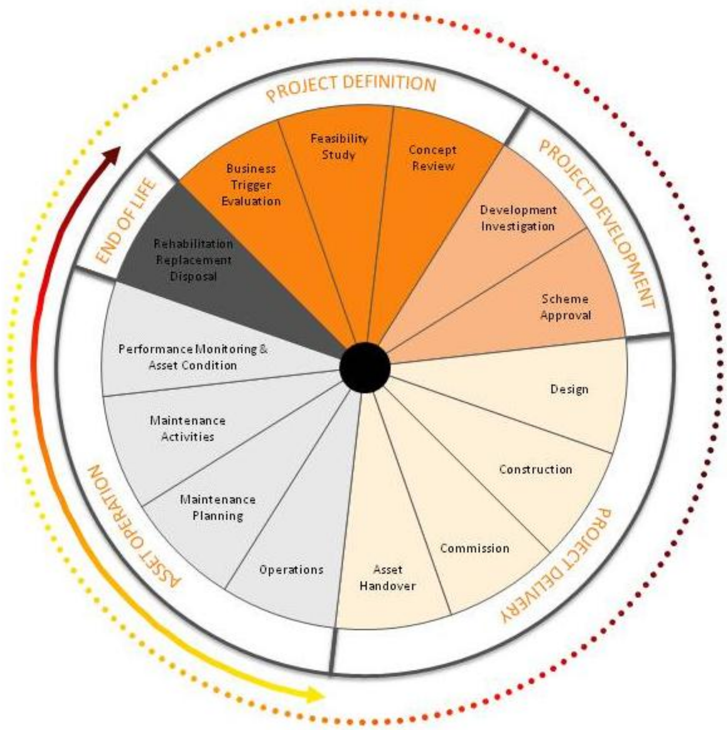

Figure 1 : SA Power Network Asset Life Cycle

1.5 Expenditure Forecast

Conductors, as an asset class, could be characterised as a high volumes / low cost replacement category. Therefore, it is more appropriate to develop a forecast that is aimed at making predictions at a more aggregate level. These models tend to average out the uncertainty that may apply at a specific asset-level in order to produce an aggregate forecast of volumes and expenditure.

In considering what type of forecasting approach may be appropriate, it is important to note that we do have a good general understanding of the conductor asset base at a feeder level. This understanding includes:

- historical data and trends on inspections and defects by conductor types, voltage levels, and locations
- historical failure data by feeder and therefore conductor type, location and voltage
- the age profile and location of different conductor types
- the key factors that drive the degradation and failure of different conductors types and their location (eg conductor types and corrosions zones)
- the risks associated with failure of conductors based upon their location (eg bushfire zones)

Therefore, we have a range of forecasting methods that could be suitable. These methods range from:

- historical trend models, which make a projection into the future using these trends
- more sophisticated approaches that use the existing status of the assets and simulate their aging in order to predict the future condition of assets and the risks associated with their failure

Given the good data we have available for conductors, we have elected to use a more sophisticated approach as our preferred method for preparing the replacement forecast for conductors. In this regard, we have commissioned EA Technologies to develop a forecasting model for conductors, using their condition-based risk management methodology (CBRM). This type of methodology and model has been used successfully elsewhere for both asset management and regulatory forecasting purposes. As such, we consider it a suitable approach for our circumstances.

The forecast method can be characterised as a 'delivery-adjusted CBRM model'. In this regard, a CBRM model has been used to prepare a base volume and expenditure forecast to 2025. However, the CBRM model develop by EA Technology does not allow for delivery constraints that can occurs if expenditure steps up too fast from one year to the next.

Therefore, where the CBRM model predicts a significant step up in replacement levels, we have profiled the CBRM model output to represent what we believe would be the prudent and efficient delivery profile.

CBRM is a process that transforms diverse sources of previously disconnected engineering knowledge, experience and data into a 'what if' management tool that can be used to support asset renewal decision making.

The yearly capital expenditure requirement for replacement of overhead conductor is shown in the figure below.

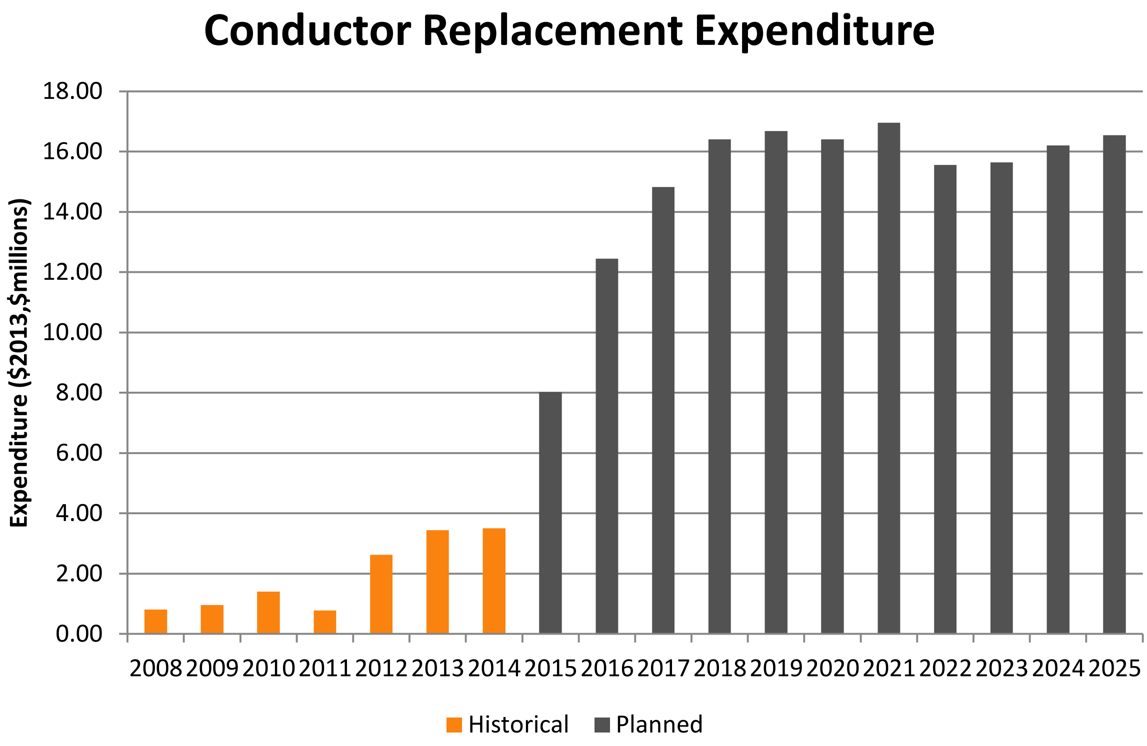

Figure 2 : Overhead Conductor Replacement Capital Expenditure - historical and forecast

Given the bottom-up method we have used to prepare the overall replacement capex forecast, we believe the conductor capex forecast discussed here should be fully allowed for in the capex forecast that will be included in SA Power Networks building block proposal to the AER.

The National Electricity Rules broadly requires that the capital expenditure forecast in the building block proposal should reflect[1]:

[1] NER 6.5.7 (a) - capital expenditure objectives, and 6.5.7 (c) – capital expenditure criteria

- the prudent and efficient costs
- to comply with our legal obligations, and/or
- maintain safety, security and reliability

We believe that the conductor replacement capex forecast, discussed here, meets these requirements for the following reasons:

- The need to replace the conductors reflects a prudent approach to meet our legal obligations associated with operating a safe network as outlines in the Electricity Act and Regulations, and the ESCOSA approved Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), and the regulatory requirement to maintain the performance of our network in the face of its continued aging.
- We have used a reasonable approach, given our circumstances and the available data, to determine the volume of replacements to meet these requirements. This approach (the CBRM model) has been used elsewhere for preparing forecasts for regulatory purposes. The approach has made use of a wide range of available data, and key assumptions have been calibrated to reflect our historical circumstances.
- We have used various alternative approaches to validate the magnitude of replacement in this forecast, and verify that it reasonably reflects the position required to manage risk our back to acceptable levels in accordance with our SRMTMP. Most notably, we have used the AER repex model and found that such a model, calibrated as we understand the AER will apply, forecasts a higher capex than we are proposing here.
- Given our forecasting approach is calibrated to reflect history, it inherently allows for the prudent and efficient solutions to address conductor in poor condition (eg continuing to maintain the conductor or replace it), which allows for the prudent and efficient trade-off between capex, opex and reliability.
- We have allowed for the efficient unit cost for the replacements. Our unit costs have been determined directly from recent historical replacement costs. The management and delivery of our services has been found to be good practice; and hence it is reasonable to accept that these historical unit costs reasonably represent efficient costs. This view is also supported by the AER's benchmarking, which suggests we are at or near the efficient frontier.
- The annual profile of the forecast has been adjusted (downwards) to reflect a prudent and efficient delivery timeframe. In this regard, the rate of increase has been reduced to align with increases we have achieved recently.

1.6 Planned Improvements in Asset Management

The forecast overhead conductor 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 asset categorised condition ratings or scores
- Asset faults and failure statistics, including failure mode analysis
- Cost of replacements, including labour and materials

2. INTRODUCTION

2.1 Background

2.1.1 Overhead Conductors

Overhead Conductor forms an essential component of SA Power Networks distribution network. Industry practice suggests that conductor operation is compromised when the mechanical strength is compromised. Beyond compromising the operation of the network, fallen conductors can present a significant bushfire ignition risk, and a risk to public injury and electrocution.

2.1.2 SA Power Networks Electricity Network

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

The history of SA Power Networks is as follows:

- Electricity Trust of South Australia (ETSA) Trust was formed in 1946 through the transfer of ownership of Adelaide Electric Supply Company to State ownership.
- ETSA was privatised in 1999 and split into power generation, transmission and distribution. The distribution group became known as ETSA Utilities.
- In 2012, ETSA Utilities was rebranded as SA Power Networks. The rebranding emphasised the focus of SA Power Networks' core business as a DNSP 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' network coverage within South Australia. The network is centred on Adelaide and supplies electricity to the south-east coastal region of South Australia towards inland South Australia and west to Ceduna. 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.

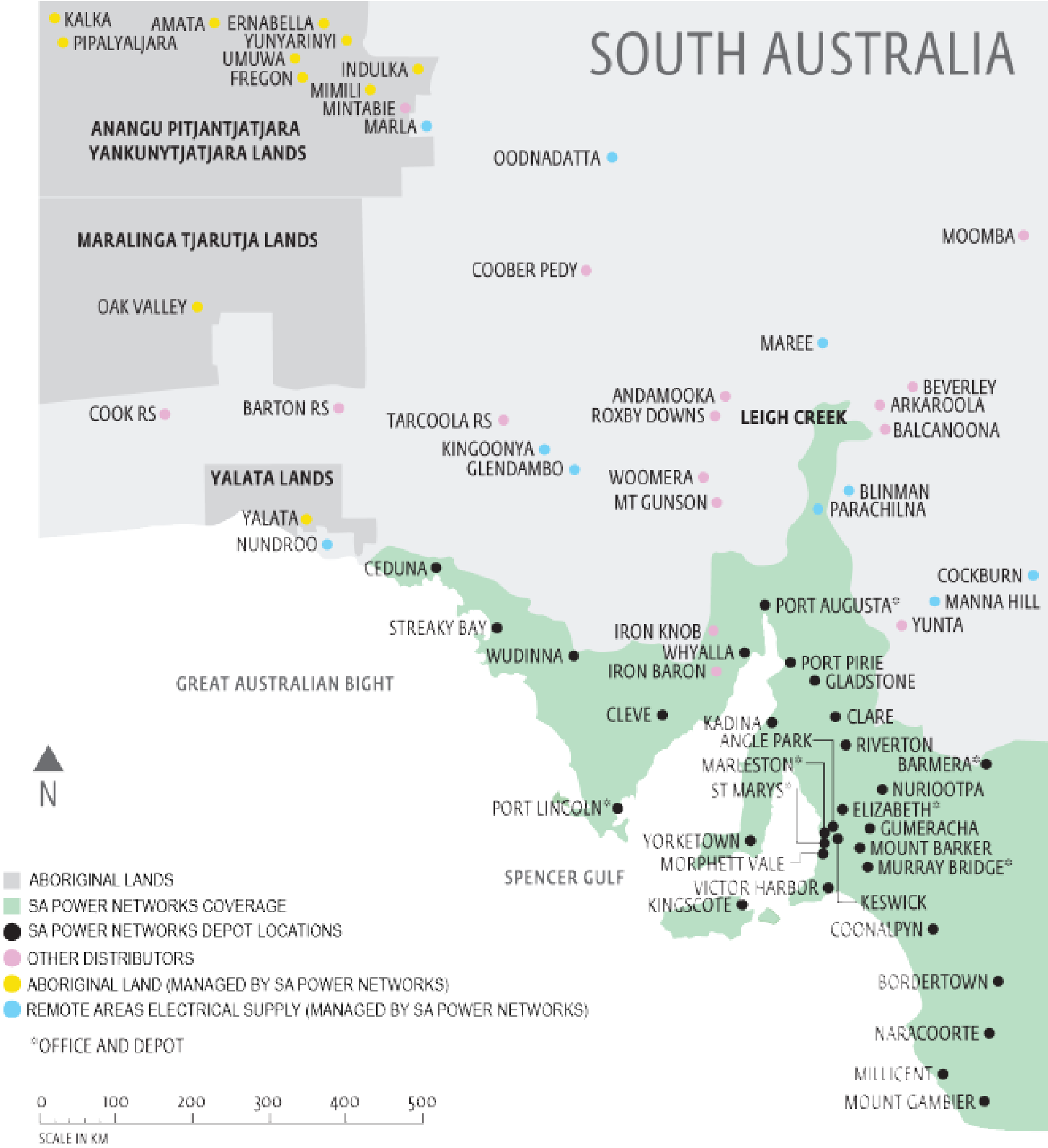

Figure 3 : SA Power Networks network map

2.1.3 South Australian Environment

SA Power Networks' overhead line network is situated along the coast which is constantly exposed to a saline environment. As a consequence, corrosion of conductors in the network is a cause for concern to SA Power Networks. SA Power Networks has acknowledged the impact of corrosion on its overhead network assets by identifying the different corrosion zones within South Australia based on work undertaken both by SA Power Networks and the CSIRO. Figure 4 illustrates the levels and location of the atmospheric corrosion zones in 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.

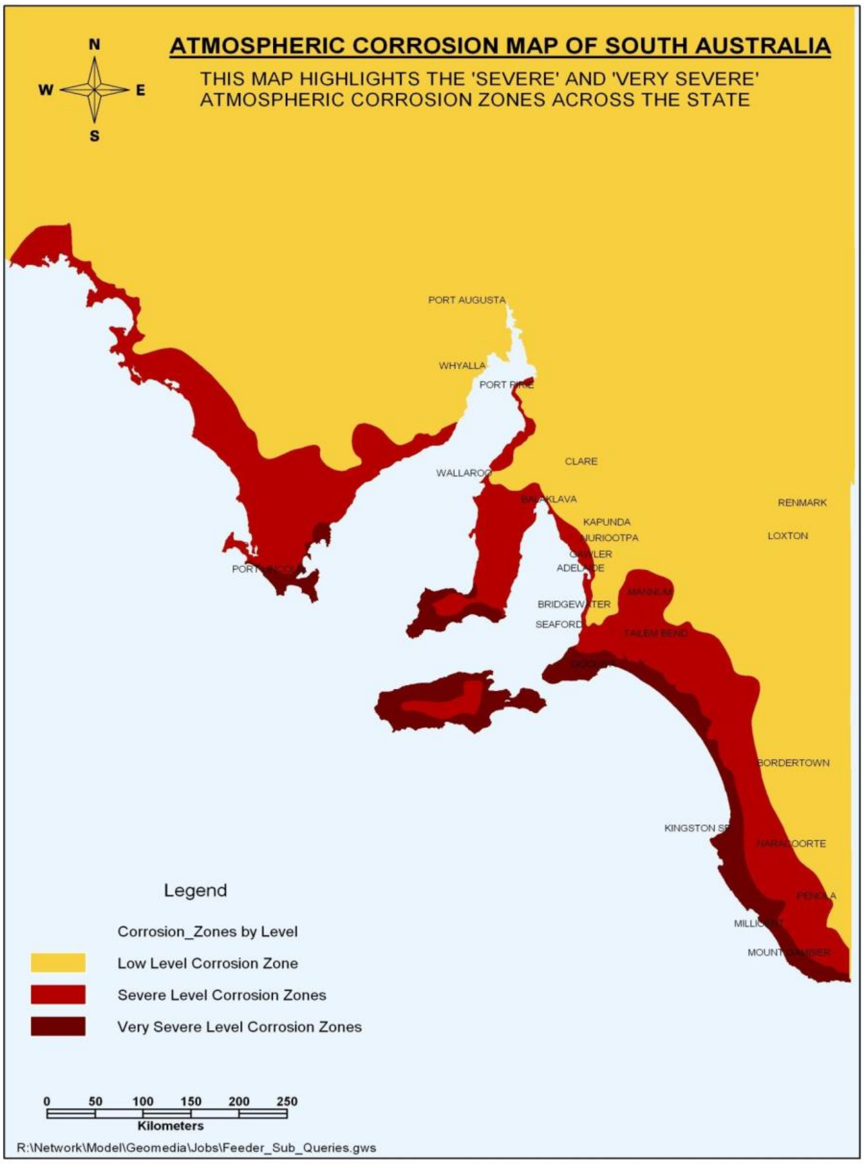

Figure 4 : Atmospheric Corrosion Zone Map of South Australia

South Australia has several natural reserves or conservation parks that are protected, as well as forestry plantations, which SA Power Networks' distribution network intersects. Operating the distribution network in bush land and forests poses risk of bushfire. SA Power Networks has recognised the importance of mitigating 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 areas of bushfire in South Australia.

The areas identified are classed as high, medium and non-bushfire risk areas. High bushfire risk areas include most of the protected natural reserves, conservation parks and forestry planations. Medium bushfire risk area reflects the risk on developments on the fringe of dense bush land. This area consists of some 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.

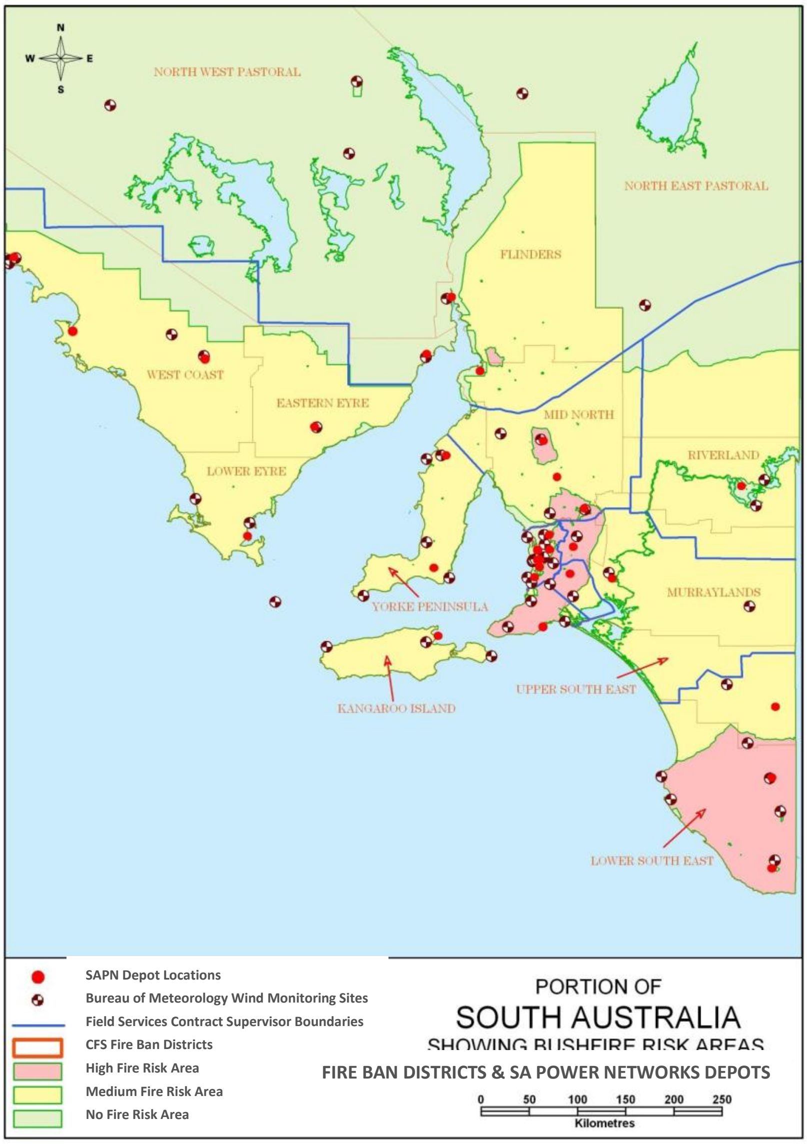

Figure 5 : Bushfire Risk Areas in South Australia

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 the GIS system.

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 as defined in the Regulated Service Standards.

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

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.

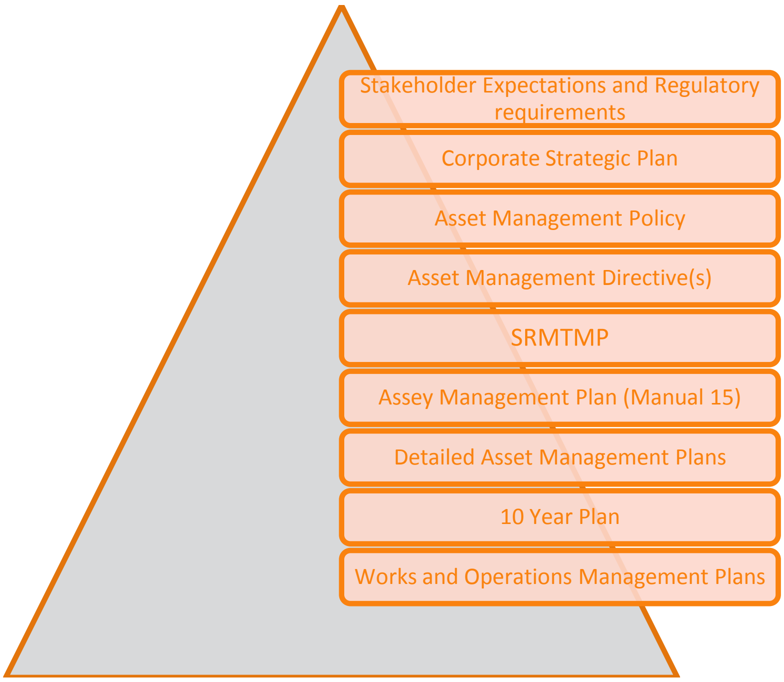

Figure 6 : Asset Management document framework

The Overhead Conductors 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 Overhead Conductor Asset Management Plan is to detail SA Power Networks' plans in managing overhead conductors between 2014 and 2025. Reference will be made to conductor fittings and accessories as they impact on the management of overhead conductors. The plan includes overhead earth wires even though they are not separately identified from the overhead conductors in SAP. Conductors used in the phase conductors are similar to overhead earth wires, thus are included in this asset management plan.

Insulators, structures and other associated equipment will not be discussed in the plan.

2.3.2 Supporting documents and data

The Overhead Conductor 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

Manuals 15, 12 and 11 sit within the ESCOSA approved SRMTMP Framework.

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 overhead conductor.

The Line Inspection Manual No. 11 provides a detailed guide in assessing the condition of overhead conductor, the procedures in recording the data collected during the condition assessment and prioritisation of defects. High resolution photographs of common defects of components in overhead assets (conductors, insulators, supports, fittings and other), 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 the existing reactive approach in managing network assets. The methodology provides a basis for the economic, reliable and safe management of assets, which includes overhead conductors.

2.3.3 Structure of Overhead Conductor AMP

This AMP 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 have of the assets. Stakeholders include asset owners as well as customers. The service levels drive the strategic and operational elements of the asset management plan, as the assets are required to fulfil their designed intention throughout their lifecycle. 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 the Service Level.

3.1 Customer Research and Expectations

3.1.1 SA Power Networks Customer Research

There is no specific customer expectation survey in relation to overhead conductors since they form part the overall Network. It is reasonable to expect that the information derived from the customer research for the network is applicable to the components, therefore can be adapted to overhead conductor.

3.1.2 Network Customer Expectations

SA Power Networks stakeholder engagement program for the 2015-2020 regulatory periods 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 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 drive 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 initiatives 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 almost 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.

The overall finding of the Consumer Survey on reliability performance levels are that 88% of customers who participated in the customer survey advised that they were either very satisfied or somewhat satisfied with their current levels of performance.

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.

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 2015-2020 by 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 2015-2020 in 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 and Electricity Regulations
- 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, 2010–2015, 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 are 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 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

Overhead conductor replacements to meet demand are covered in AMP.1.1.01 – Distribution System Planning Report, and the Distribution Annual Planning Report (DAPR). These replacements are in additional to those detailed within this document.

5. Overhead conductor population and issues

5.1 Background

The graphs and statistics used throughout the Overhead Conductor Asset Management Plan are based on data extracted from SA Power Networks' GIS and SAP systems and other sources within the organisation. The age data used in the profiling of the electricity network reflects the date of installation and the date of restringing an overhead circuit in the network.

5.1.1 Size and age of the network

The total route length of the overhead network captured within the GIS system and SAP is 71,160km (see Box 1 for an explanation of route length).

Box 1 - route length definition The route length of an overhead circuit is calculated as the distance between the first and last tensioned structures supporting the overhead conductor. The detailed design of the conductor is not considered in the route length (ie sag / creep are not allowed for).

The age profile of SA Power Networks' overhead network reflects the history of the company.

A dramatic increase in the route length of overhead conductor occurred during the period between 1955 and 1977, as is shown in Figure 7. This coincided with the formation of ETSA and electrification of the state, an increase in electricity demand, as well as an increase in and dispersion of the population.

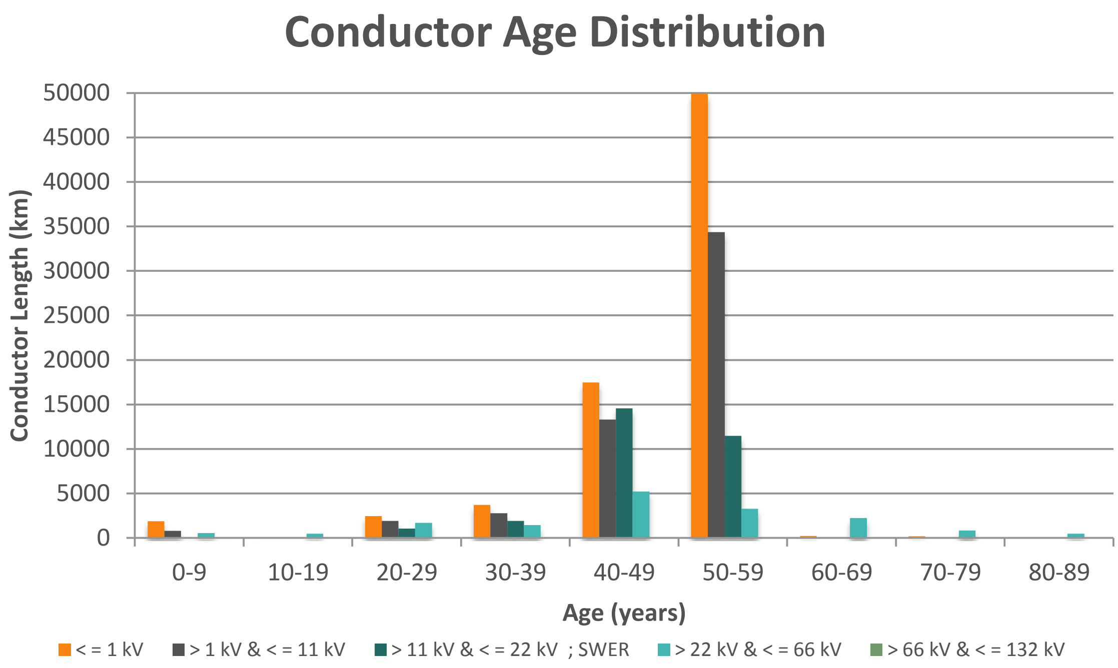

Figure 7: Conductor Age Profile

The average age of SA Power Networks' overhead network is 49 years, with the majority of the conductors installed in the years 1955, 1956, 1958 and 1966. Approximately 59% of SA Power Networks' overhead conductors are greater than 50 years of age with only 2% less than 20 years old.

These ages suggest that, although the network is not within its replacement cycle, it is approaching its replacement cycle. Therefore, the volume of defective conductor is likely to gradually increase over the next 10 to 20 years.

5.1.2 Voltage levels in the network

SA Power Networks overhead line network consists of both sub-transmission and distribution voltages that range from 240V to 66kV. The specific voltages used in the network are listed below:

- Distribution voltages:
  - Overhead low voltage distribution (415V or 240V)
  - Overhead high voltage 7.6[2] and 11kV
  - Overhead Single Wire Earth Return (SWER) (19kV)
  - Overhead other distribution voltages (7.6kV, 6.6kV and 3.3kV)

[2] Being phased out over time, being standardised as 11kV

- Sub-transmission voltages:
  - Overhead sub-transmission 33kV
  - Overhead sub-transmission 66kV

The majority (over 90%) of the route length of overhead conductor belongs to the distribution voltages (including SWER and the low voltage network), which reflects the nature of SA Power Networks' business. Several 66kV lines are present in SA Power Networks' overhead network.

The majority of the conductors installed and restrung between 1930 and 1949 were 33kV lines, while the majority of the conductors installed and restrung in 1955, 1956, 1958 and 1966 were SWER and 11kV lines. This pattern is due to an increase in grid connections associated with inland rural areas between the 1950 and 1970. To a lesser degree, low voltage, 33kV and 66kV lines were frequently installed throughout 1950 to 1979.

Table 1 below shows the make-up of the network in the various voltage levels.

Table 1: Overhead Conductor route length by operating voltage

Operating Voltage	Route Length (km)	% of Total route Length
66kV	1,435	2.0
33kV	3,951	5.6
19kV (SWER)	29,093	40.9
11kv and 7.6kV	17,724	24.9
Low Voltage (including services >10m)	18,957	26.6

5.1.3 Conductor types used in the network

The overhead line network consists of different types of conductors, including bare, insulated unscreened conductors (IUC), and aerial bundled conductors (ABC). The covered conductor population represents only 2.2% of the overhead network.

Based on the available data in SA Power Networks systems, the overhead conductors have been classified, for management purposes, into four groups:

- Aluminium (includes AAC, AAAC/6201 and AAAC/1120 conductors)
- ACSR
- Copper
- Steel.

The conductor types listed in the second column of Table 2 are the identifiers used by SA Power Networks for the four groups. An additional category, 'Unknown', is used to represent overhead conductors that do not have their conductor type identified in GIS or SAP.

The conductor group names in Table 2 will be referred to throughout this asset management plan.

Table 2 : Conductor types and route lengths

Group Name	Conductor Type	Route Length (km)	% of Total route Length
Aluminium	AAC	1,409	6.8
	AAAC	367	
	Aluminium[3]	3,069	
Copper	Copper	7,577	10.6
ACSR	ACSR	18,424	25.9
Steel	SC/AC	7,587	49.7
	SC/GZ	27,769	
Unknown	Unknown	4,958	7.0

Figure 8 below shows the route length of these conductor groups across the voltage levels discussed above. This clearly shows that a large portion of our network (nearly 40%), by its route length, is the portion of the SWER network that was constructed using steel conductor.

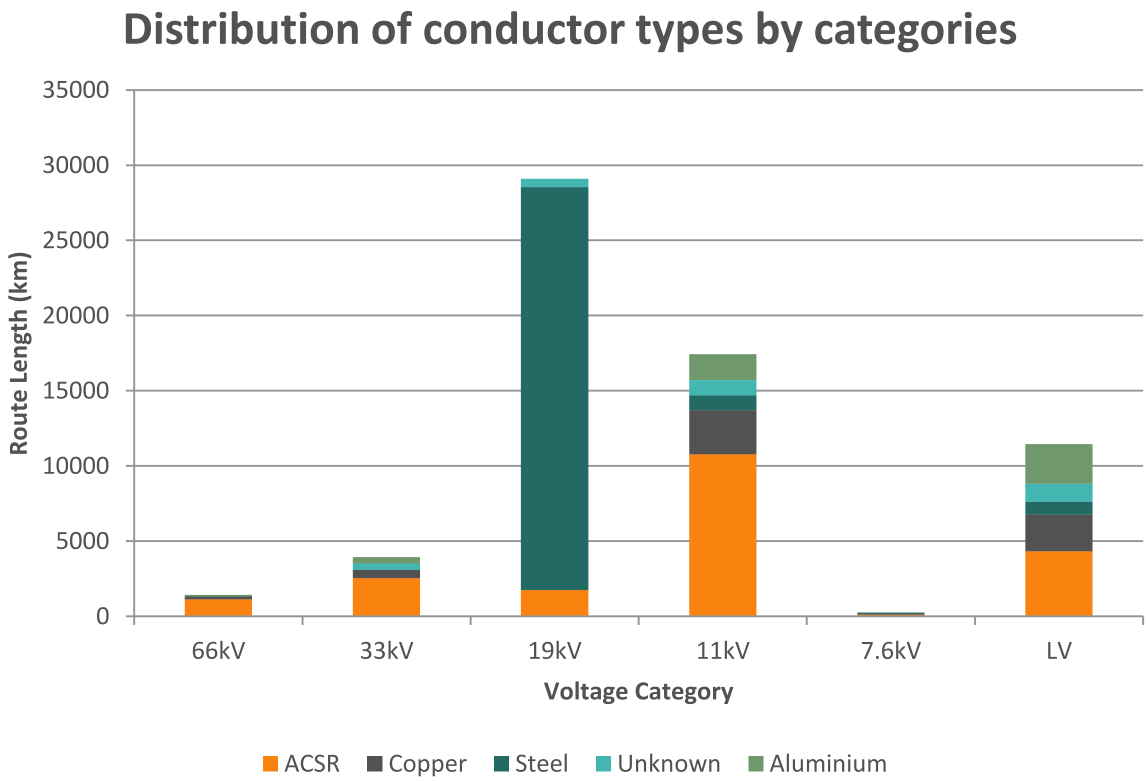

Figure 8 : Distribution of conductor groups across voltage groups

5.2 Assessing conductor failures

5.2.1 Common failure modes

There are a number of failure modes intrinsic to overhead conductors. The failure modes that tend to define the service life of a conductor are as follows:

- corrosion – degradation of the conductor by the environment
- fatigue – degradation of the conductor or fittings by the movement of the conductor (eg by wind induced oscillations)

[3] no further details on type available

- annealing – loss of strength due to heating of the conductor through the electrical current they carry (particularly overheating)
- creep - stretching of the conductor due to the mechanical loading of the conductor (which is most susceptible to aluminium conductors)
- insulation breakdown for ABC and covered conductors

Table 3 shows the typical indicators SA Power Networks uses to identify each of these failure modes. The severity of the indicator signifies the likelihood of imminent failure due to that failure mode.

The overall condition of the conductor is recorded in SAP by assessing these indicators and in turn estimating the significance of each failure mode.

Table 3: Conductor failure modes and indicators

Failure Mode	Indicators/Conditions
Corrosion	Discoloration, which includes loss of galvanising Pits in conductor strands Bulging of conductor
Fatigue	Fretting/ Abrasion Broken strands (at clamp points)
Annealing	Discolouration Melting Reduction in tensile strength
Insulation breakdown (only applicable to ABC and covered conductors)	Surface tracking on insulation near conductor joints Pits in insulation at conductor joints
Creep	Excessive sag, beyond that allowed for in design, leading to inadequate conductor clearances

The design of the overhead conductor and the environment it is located in can influence which one of the failure modes will dominate. The conductor type is an important factor that influences the whether corrosion will be the dominant failure mode. Thus the rate of corrosion is not only influenced by whether the conductor is in corrosive region (eg near the coast), but also the conductor type. For example, in the equivalent corrosive environment, steel conductors will corrode faster than ASCR conductors, and ACSR conductors will corrode quicker than Copper conductors. This appreciation is important because, as we have discussed above, a large proportion of our conductor population is steel conductor.

The identification of one failure mode can also signal other impending or active failure modes. For example, the pitting in conductor strands due to corrosion may increase stress; this in turn magnifies the effect of wind induced vibrations in the remaining conductor strands. Consequently, a conductor exposed to a corrosive environment is prone to fatigue at a higher rate than one that is not in a corrosive environment. On the other hand, annealing and creep are less dependent on corrosion since these primarily depend on the electrical load profile and conductor temperature. Annealing can present as creep in heavily loaded and full tension conductor.

5.2.2 Other factors leading to conductor failure

There are other factors that can be associated with an increasing likelihood of failure. Conductor accessories and joint defects.

Table 4 : Conductor accessories and joint defects detected during 5 year period

Problem Code	Defect Count	% of overall
Alum/Steel Joints	578	19
Armour Rods/Line Guards	282	9
Conductor Grips	416	14
Conductor Joints Inadequate	949	31
Conductor Spacers	4	0.1
Hot Joint (IR Survey)	614	20
Line Hot Joint	182	6
Total	3,024	

Conductor age

It is difficult to assess the condition of conductors and produce a reliable estimate of the likelihood of failure. However, it is know that all the failure modes can be induced through the effect of aging. Therefore, in addition to the indicators stated above, the age of a conductor is considered when assessing the potential for conductor failure.

Lightning severity

Direct lightning strikes on conductors are inevitable[4]. However, a lightning strike on a conductor can impose very high stresses on that conductor. Therefore, if the conductor is near the end of its life (ie one or more of the indicators suggests it may be prone to one of the above failure modes), the conductor is more likely to fail if it is struck by lightning.

Therefore, SA Power Networks can minimise the occurrence of premature failure of conductors by proactively replacing conductors where they have been assessed as having a high probability of failure.

Defects or failure of other components

Defects or failure of other components in the overhead line can lead to the failure of conductors. For example, the severe corrosion of the messenger wire in a vibration damper can reduce its ability to dampen vibrations in the conductors, resulting in increased fatigue of the conductors. Therefore, the condition of other line components is considered when assessing the condition of the conductor.

Vegetation

Vegetation infringement on an overhead line easement can lead to an outage. For example, the contact of vegetation with the lines may result in a high impedance fault. Unchecked the interaction of vegetation with the overhead lines is inevitable, hence proactive mitigation is required to minimise the risk of outages.

SA Power Networks has implemented an annual vegetation patrol program in Bushfire Risk Areas to minimise the impact of vegetation encroachment on the overhead line network.

However, SA Power Networks has experienced issues due to vegetation outside of the clearance zone infringing on the overhead lines. This vegetation can become airborne during severe wind conditions and interfere with the operation of the overhead lines and thus adjacent vegetation must also be proactively

[4] *It is not practical to design overhead lines for zero strikes to the phase conductors. This is due to the statistical nature of lightning, which results in different peak currents, wave shapes, directions etc. Overhead lines are designed for a certain number of lightning strikes per year based on the required security of the line.*

managed. In circumstances such as these categorising the affected line as high risk and increasing the frequency of patrols of the overhead lines, or even modifying the design of the line may be warranted.

5.3 Classifying conductor failure risks and conductor condition

5.3.1 Corrosion zones and the network

As noted above, overhead conductors in different corrosive environments are prone to different rates of conductor degradation. In order to assess overhead conductor degradation in the network, SA Power Networks assigns each line to the highest corrosion zone (see section 2.1.3) that the line passes through. More detailed allocation of sections of feeder to corrosion zones it not possible at present due to limited detailed information being held in SAP and GIS to allow sensible segmentation of feeders. This is an area for improvement over the next 5 years in terms of data held and used for analysis.

Of the 71,160km of route length of overhead conductor, 53% of conductor is in the low corrosion zone, 35% of conductor is in the severe corrosion zone, and the remaining 11% is in the very severe corrosion zone.

Analysis of data on the year of installation or restringing of overhead conductor and corrosion zones has identified the following general relationships between the conductor types and the corrosion zones they are located in:

- ACSR and Copper conductors aged greater than 64 years (ie the old ACSR and copper conductor) are predominantly used in low and severe corrosion zones.
- During the period 1950 to 1979, steel and ACSR conductors are commonly used state-wide and so are more evenly spread through corrosion zones.
- In the past 35 years, significant route length of ACSR overhead conductor and the 'unknown' conductor type were built in the medium and high corrosion zones.

Steel conductors dominate in all three corrosion zones, followed by ACSR conductors. Copper conductors dominate over aluminium conductors and conductors in the 'unknown[5]' group in the low and medium corrosion zones. The route length of overhead conductors using Copper, Aluminium and unknown conductors are approximately the same in high corrosion zones.

[5] Approximately 7.8% of total route length of conductor is of 'unknown' conductor type. This figure is reducing over time as more asset data is collected and data held is improved.

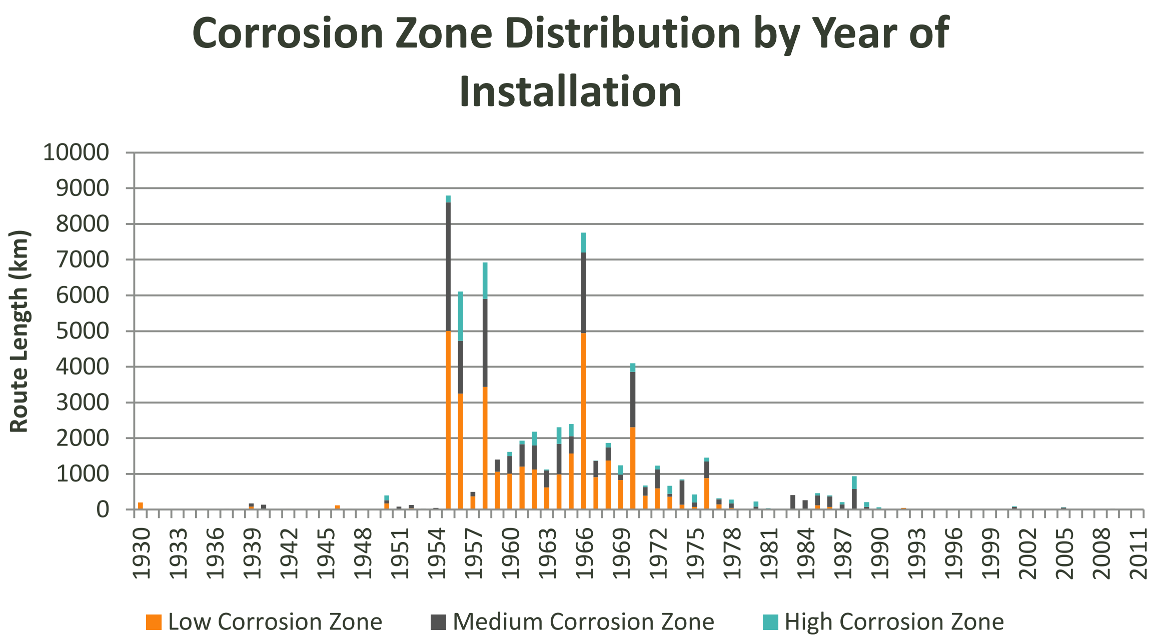

Figure 9 : Distribution of corrosion zone against year of installation

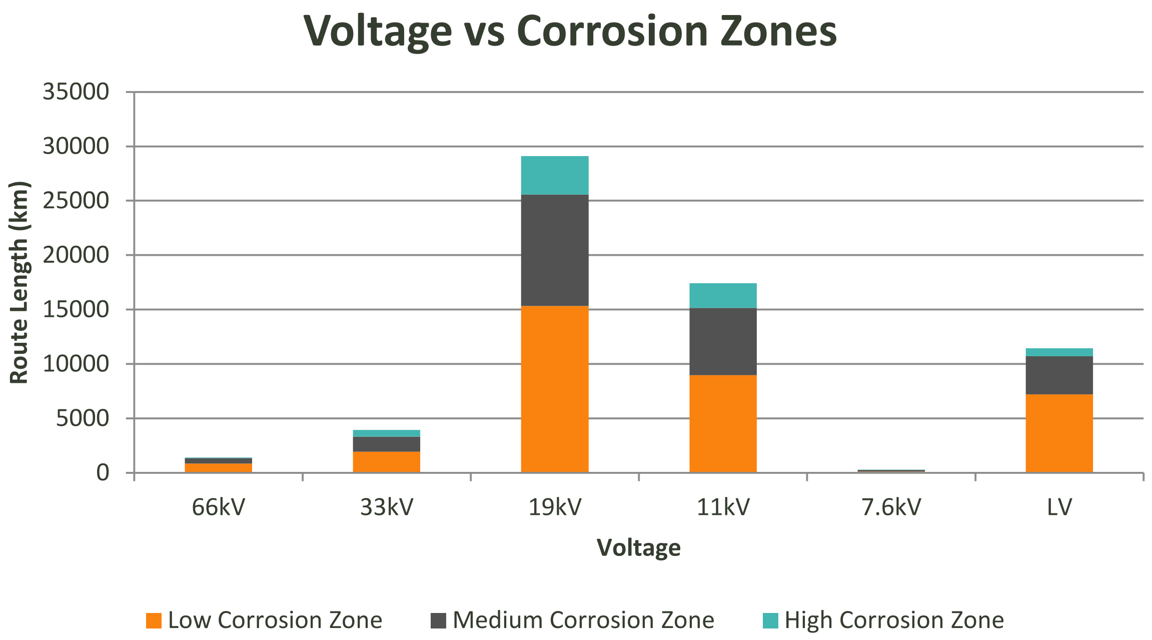

Figure 10 : Distribution of corrosion zones across voltage groups

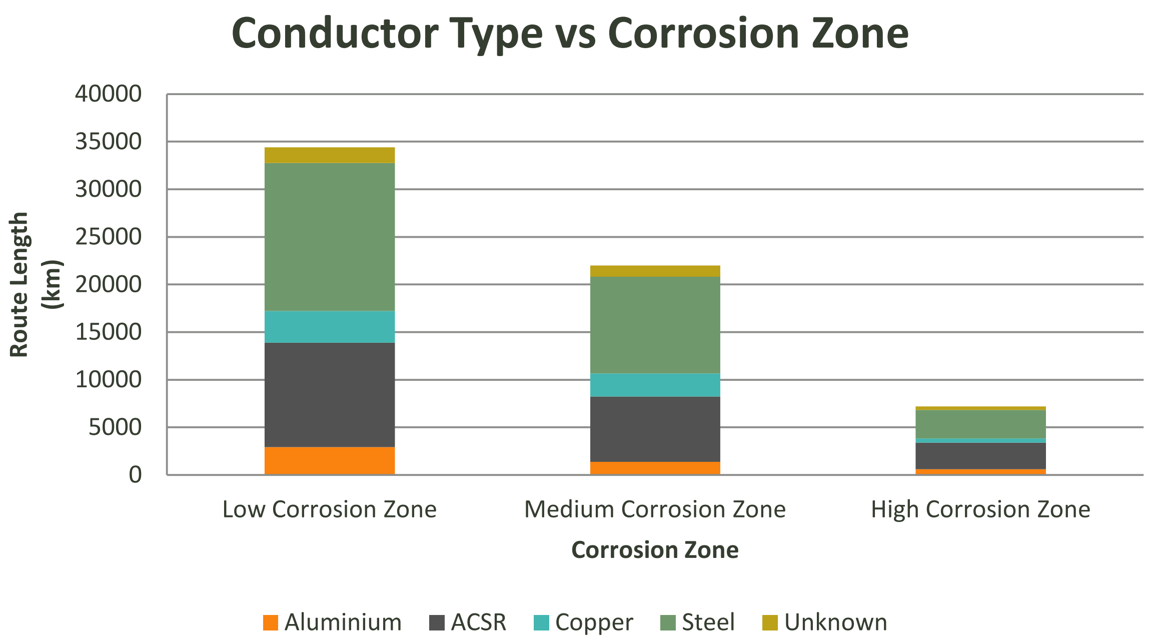

Figure 11 : Distribution of conductor groups across corrosion zones

5.3.2 Bushfire risk areas and the network

In order to minimise the impact of operating the overhead conductor in bush land, SA Power Networks has also assigned a bushfire risk area (see Section 2.1.3) to each overhead line, based on the highest bushfire risk area the line passes through. The three types of bushfire risk area are high bushfire risk area (HBFRA), medium bushfire risk area (MBFRA) and non bushfire risk area (NBFRA).

The following general relationships have been identified from analysis of the distribution of conductor by corrosion zone and bushfire risk area:

- Approximately 89% of the total route length of overhead conductor in the low corrosion zones is more than 41 years of age.
- Approximately 60% of the total route length of overhead conductor in low corrosion zones is more than 41 years of age and in medium bushfire risk areas.
- Steel (44%) and ACSR (27%) are the dominant conductor groups across all the bushfire risk areas and across all age groups.

With respect to distribution of overhead conductor in bushfire risk areas the following can be noted:

- Around 79% of the total route length of overhead conductor in severe corrosion zones is more than 41 years of age.
- Approximately half of all conductors and a third of the total route length of the conductor reside in the 51 to 60 years age group and are located in medium and high risk bushfire areas.
- 70% of the total route length of overhead conductor in the medium bushfire risk areas is in the 41 to 50 years age group.

Importantly, the least corrosion resistant conductor types (ie ACSR and steel) have tended to be used in the severe corrosion zones, which also coincide with the medium and high bushfire risk areas. There are around 5,600km of these conductor types in these very high risk areas. Of this cohort, 2,190km are over 50 years old.

Finally, it is also important to note that there are approximately 3,365km of overhead conductors located in the medium and high bushfire risk areas, which do not have their conductor types identified, with approximately 600km also not having a known age. As such, these conductors represent a small proportion of which the risk of failure is still unclear. These data gaps are being filled over time through the inspection process and other data cleansing activities.

The following graphs show the distribution of conductor by age and material by bushfire risk area.

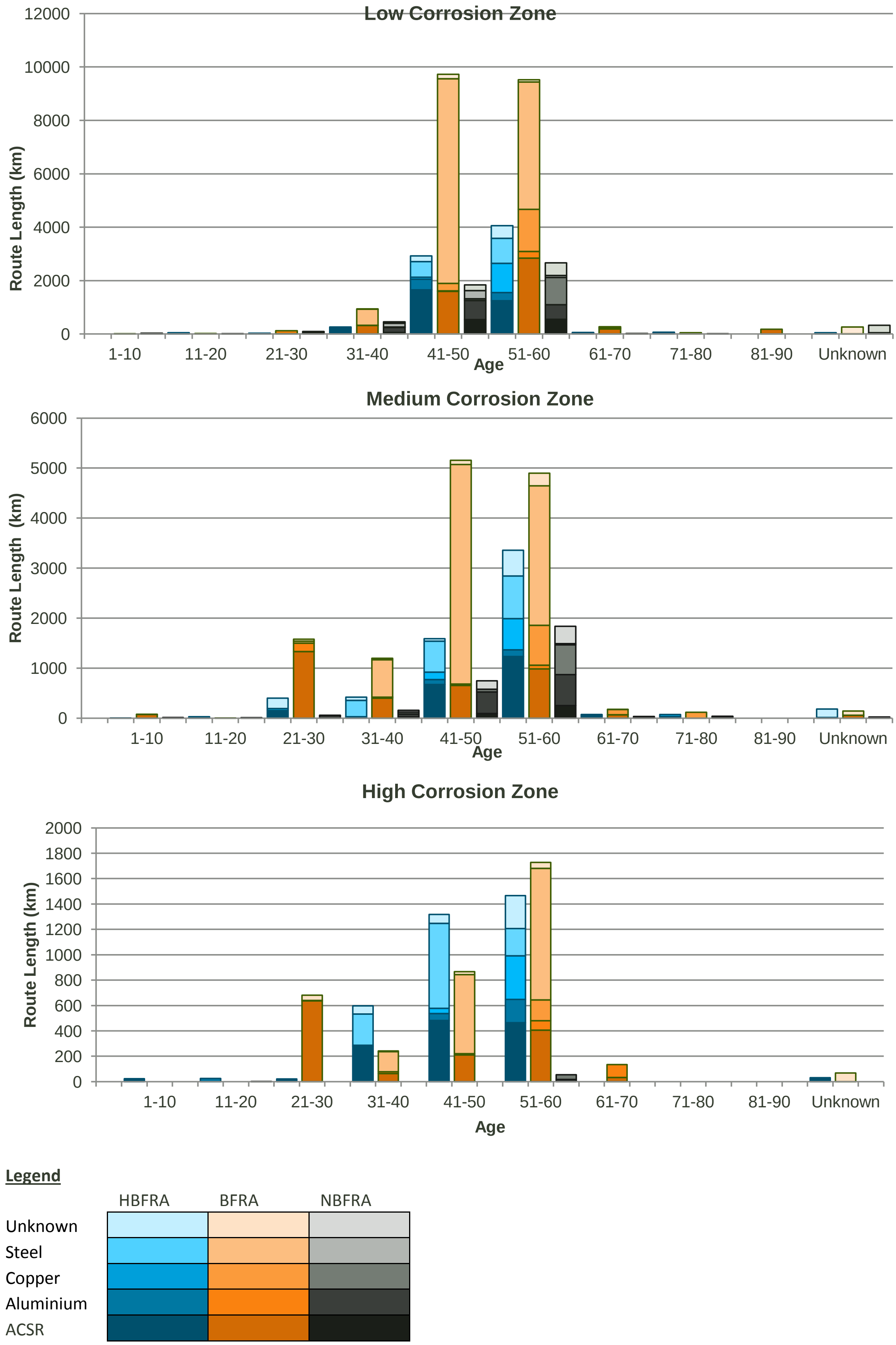

Figure 12 : Age profile as per bushfire risk area boundaries and conductor type in low corrosion zone

5.3.3 Evidence of conductor related defects

The conductor-related defect entries recorded during the past five years were extracted from SAP. Key observations from analysis of this data set are:

- Approximately 47% of the total defects related to overhead lines are conductor specific.
- Majority of the conductor specific defects are broken conductor strands (46%) and corroded conductors (41%).
- Abrasion and wear are the dominating causes for broken conductor strands.
- A total of 12% of defects are related to insulated conductors (8% of covered conductor defects and 4% of ABC defects).
- Fatigue and corrosion are the dominating causes of defects in ABC and covered conductors, respectively.
- Incidence of defects related to creep and insulation breakdown are extremely low.

The breakdown of defects in conductor accessories and joints was also analysed. Key observations are:

- 77% of the total defects in conductor accessories and joints are related to conductor joints.
- Inadequate conductor joint contributed the most (31%) to conductor related defects. Hot joint defects (20%) and aluminium/steel joints defects (19%) are the subsequent dominating types of defects.
- Age is not the dominant factor in inadequate conductor joints; the reliability of a joint is directly determined by the quality of the installation not its age.
- More than 95% of the hot joint and line hot joint defects are attributable to thermal failure of the joint.
- For aluminium/steel joints defects, corrosion is the dominating cause over the thermal failure of a joint. Corrosion typically occurs due to incorrect construction of joints which leads to the oxidation of the conductor in the joint.
- Abrasion and wear of armour guards/line rods is the major cause of defect in such accessories. This could be a result of an inappropriate selection of an accessory for the design of the conductor or the conductor is experiencing high Aeolian vibrations. No information was available on whether this included instances where dampers should have been fitted but weren't.
- Corrosion is the major cause of defects in conductor grips.

From this analysis, it has been determined that the majority of the conductor-related defects are due to the malfunction of accessories and joints - rather than the conductor itself. Abrasion (an indicator of fatigue) is the most likely cause of defects in conductors. However, corrosion is the predominant cause of defects in conductor accessories, particularly Aluminium/steel (ACSR) conductors. The poor quality of joints is the main cause for defects in joints. Thermal failure of joints is primarily caused by incorrect jointing of conductors and is the main type of defect found in joints.

5.3.4 Evidence of overhead line failure

Overhead line failure data obtained from SAP has been grouped into two categories as defined in SAP: Emergency Response (ER) and Asset Restoration (AR).

A failure is classified as Emergency Response[6] if it is resolved through the initial response to an unplanned outage in the network. Failures that have not been completely resolved during this initial response are classified as Asset Restoration failures.

Approximately 20% of the overhead line failures were attributable to conductors needing to be repaired. The breakdown of the causes of conductor failure is presented in Table 5.

Table 5 : Emergency Response conductor failure – SAP (2008 to 2013)

Failure Modes	Causes of conductor failure[7]	Failure Count
Annealing	Annealing	9
	Overheating	15
	Subtotal	***24***
Creep	Clearance inadequate	179
	Electrical clearance compromised	18
	Subtotal	***197***
Fatigue	Broken Strands	3,816
	Cracking	7
	Vibration	38
	Wearing	85
	Subtotal	***3,946***
Corrosion	Corroded	269
	Damage (non specific)	52
	Subtotal	***321***
Insulation Breakdown	Insulation breakdown-overhead	20
	Insulation flashover	4
	Subtotal	***24***
TOTAL		**4,512**

The dominant failure mode indicated by SAP for Emergency Response failures is fatigue followed by corrosion as identified through allocation of cause by those undertaking investigations or recording failures.

A total of 23% of the Emergency Response failures in the overhead conductor required the repair or replacement of joints and the replacement of line hardware. This is significantly greater than the number Emergency Response failures that required the repair or replacement of the conductors.

[6] *Emergency Response can be instigated by SA Power Networks personnel, customer calling the call centre or an outage identified by system control and data acquisition (SCADA).*

[7] Causes as defined in SA Power Networks databases

6. LIFECYCLE MANAGEMENT OF OVERHEAD CONDUCTOR

6.1 Introduction

The lifecycle management of overhead conductors will assist SA Power Networks in the reliable and cost effective operation of the lines network. This requires implementing the Asset Management Strategy (referenced in AMP 3.0.01 Condition Monitoring and Life Assessment Methodology 2009-2020). 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 creation, implementation and monitoring of plans in the lifecycle stages are important for the effective implementation of the Overhead Conductor AMP. 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 AMP is to manage the overhead conductors 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 line network.

The asset management strategies selected are tailored to suit each type of conductor and the inherent consequences of failure. The most common strategy selected is to condition monitor and replace based on condition to provide the best possible asset life and economic risk management strategy.

These strategies will provide a low residual risk to the business.

6.2 Risk Management Plan

As noted in Network AMP - Manual No. 15:

"risk assessment and risk management are used by SA Power Networks in the decision making process for network capital expenditure, and in network operations and maintenance activities"

In the Network AMP - Manual No. 15, SA Power Networks define risk management as:

"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 risk management 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; and*
- *Monitor and review the performance of the risk management system."*

SA Power Networks qualitatively measure the risks exposure caused by overhead conductor failures. The likelihood and consequence of the risks is qualitatively measured. Controls are then proposed to mitigate or minimise the risks to an acceptable level. The types of controls selected to mitigate or minimise the risk is dependent on the level of risk. The effectiveness of the controls is periodically evaluated in order to prompt further revision of the controls in the future. A risk rating of the residual risks is provided in order to help validate the controls that are in place.

The risk owner is made responsible for implementing the tasks associated with the controls and to monitor the effectiveness of the controls. Further detail on the risk management plan can be found in Section 7 Risk Management of Network AMP Manual No. 15.

6.3 Maintenance Plan

6.3.1 Maintenance System

The Network AMP - 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 overhead conductor in SA Power Networks distribution network.

The Network AMP Manual No.15 outlines the key drivers of SA Power Networks maintenance plan, they are:

- CBRM principles
- Regulatory, legislative and company specific standards on maintaining optimum network performance parameters, such as reliability and quality of supply
- External recommendations on the adequacy and effectiveness of SA Power Networks maintenance programs

6.3.2 Maintenance Standards & Schedules

Asset management standards are an integral building block to support asset management decision making and provide the foundation for both asset maintenance and asset replacement. These standards will form a basis of the decision to repair/maintain an asset or to undergo replacement.

Specific standards for conductor will prescribe preventative maintenance requirements and how to treat defects identified either through corrective maintenance or asset renewal processes. The purpose of these standards is to ensure assets operate as designed, safely and achieve their design life.

Key factors to consider in regards to maintenance standards for conductor include:

- Frequency of inspection and reporting requirements per asset class
- Updating maintenance standards and incorporation of new information as required (ie change in maintenance requirements for a certain conductor assets)
- Monitoring of actual maintenance against maintenance schedules
- Recording information about condition of conductor and any defects, which will help give an indication of risk of specific assets to assist in prioritising maintenance activities

6.3.3 Maintenance Categories

Maintenance will generally be defined under the following categories:

- **Preventative Maintenance**, referring to regular inspections, patrols, defect detection activities, condition testing, asset servicing and tasks involved in shutdowns or switching and capture of relevant data.

- **Corrective Maintenance**, referring to activities undertaken when an asset has been identified to be in poor/unserviceable condition and requiring repair. This also includes any additional inspections undertaken outside regular maintenance tasks.
- **Reactive Maintenance** (unplanned), referring to actions undertaken directly following unforeseen circumstances, such as a customer complaint, breakdown, accident, safety response, damage due to environmental factors or third-party interference.

6.3.4 Selection of maintenance strategy

Section 17.1 Asset Management Process – Maintenance and Replacement Process from the Network Asset Management Plan - Manual No. 15 illustrates the process used to select the appropriate maintenance strategy for an overhead line. 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.

6.3.5 Implementation of Maintenance Strategy

SA Power Networks utilises two types of maintenance. The first is visual inspection which is used to monitor the condition of the conductor. Second, infrared thermography is used to investigate the condition of joints in overhead conductor.

The sampling frequency for visual inspection and infrared thermography is dependent on the voltage, electrical loading of the line, 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).

6.4 Creation, Acquisition and Upgrade Plan

Procedure 935 in the Quality Management System (QMS) documents the process that SA Power Networks follows for the acquisition of new line assets. The key stages listed in the process are as follows:

- A business case is prepared which includes a new high level risk assessment.
- The approved specification is issued to Procurement for issue to tender.
- Key stakeholders are updated on the status of tender evaluations once short listing has commenced.
- Samples are installed at the Angle Park Skill Enhancement Centre for field evaluation.
- If a trial is required, it’s approved by the Manager Network Standards and Performance.

- Relevant stakeholders approve the new equipment and Risk Assessment.
- E-Drawings, work methods, asset management and training programs are finalised.
- Formal supply contract is considered.
- Logistics for the new equipment is arranged.

6.5 Repair and Replacement Plans

The repair and replacement plans proposed in this section are independent of each other.

The repair plan will indicate the most economical and effective preventative maintenance activities to mitigate existing risks. This includes the replacement of those conductors where the risk associated with operating the conductor based on its current condition is classified as high. Thus, the replacement of the conductor in the repair plan is the last step taken after the actions to prolong the life of the conductor have been implemented.

The replacement plan contained within this AMP is a proactive plan aimed at targeting those conductor failures primarily due to corrosion. Corrosion is one of the primary factors in conductor failure since severely corroded conductors can unpredictably fail. Corrosion can also be considered a dominant failure mode due to the significant financial impact on SA Power Networks. Also, corrosion can act as a catalyst for other failure modes; such as fatigue at vulnerable locations along the conductor, under attachments and fittings. Hence, it is important to replace those conductors that show evidence of severe corrosion or fatigue along the conductor and the potential of severe corrosion at conductor attachment and fittings.

6.6 Disposal Plan

Assets that reach the disposal stage usually do not have any economic value beyond their scrap metal value. 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.

7. DEVELOPMENT OF THE REPLACEMENT CAPEX FORECAST

7.1 Introduction

Section 5 discussed the major issues that affect the SA Power Networks conductor population. It also detailed the specific issues driving the need to replace overhead conductor.

This section explains how the replacement capex forecast out to 2025 has been prepared, given the current population and the known issues that must be managed. This section also provides the regulatory context and justification for this forecast.

To achieve these aims, the section is structured as follows:

- To provide context on the need for future capex, the historical profile of capex is discussed. This explains why capex has been increasing so significantly since around 2011 and how this relates to future requirements.
- Following this, we discuss the approach we have used to forecast overhead conductor replacement capex. We explain the salient points to be considered when developing a forecast for overhead conductor, set out the overall approach we have used, and explain the specific forecasting methods.
- Finally, we discuss the forecast that has been prepared from this approach, including why we believe it to be appropriate given our circumstances, and its regulatory treatment.

7.2 Historical expenditure profile

The figure below shows capex associated with replacing overhead conductor since 2008. This figure shows a significant increase in expenditure occurred in 2012.

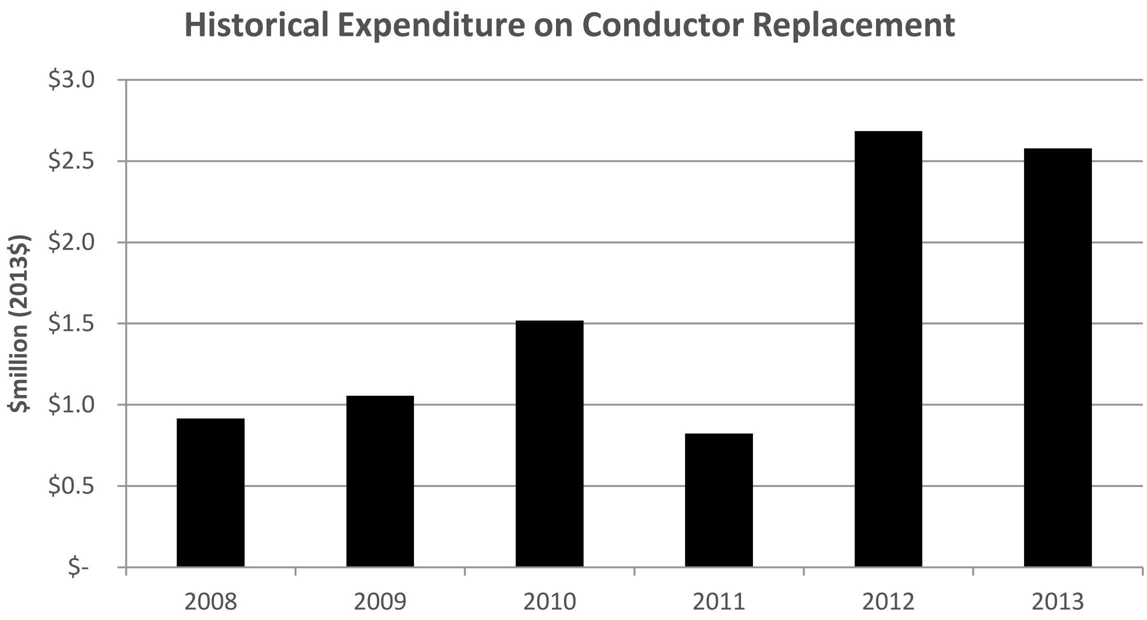

Figure 13: Conductor replacement profile

This increase was in response to a review of the condition and failure risks associated with conductors. This review commenced near the beginning of the current period, and was instigated by concerns over the increasing trend in conductor failure. Critically, this review found that the conductor population was neither in as good condition, nor performing as well, as previously thought.

Significantly, it was found that SA Power Networks' record keeping with regard to low voltage conductors had been inadequate. Recognising the potential issues associated with the increasing trend in low voltage failures, SA Power Networks began to investigate the nature of these failures through interviewing field personnel.

As a result of these investigations it was ascertained that approximately 50% of low voltage conductor failures resulted in conductors falling to the ground. Conductors falling to the ground represent a significant personnel safety and fire risk. Furthermore, the findings of the Victorian Royal Bushfire Commission suggested that these risks could be extremely high in bushfire risk areas.

We have a legal obligation through our state legislation to operate a safe network. As part of these legal obligations, we must prepare, and comply with, a safety, reliability, maintenance and technical 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).

That is, OTR and ESCOSA have the role of setting safety, reliability, maintenance and technical standards in the South Australian jurisdiction.

The SRMTMP sets out how we will maintain our network, including our poles, covering how we will inspect them, identify defects, and address these defects. This plan directly references our internal policies, procedures and practices where these matters are set out.

We have developed this plan and had it approved by the ESCOSA. As such, we are now obliged to follow this plan. An aim of this plan is to address the growing risk associated with defective assets, including overhead conductor, so that our risk is managed back to acceptable levels in accordance with our SRMTMP over the next two regulatory periods.

During the current period, after becoming aware of the actual level of risk associated with overhead conductor, the rate of replacement was increased, with an accompanying increase in expenditure.

Figure 14 below shows the trend in conductor failures. This shows the increasing trend in LV failure between 2007 and 2010 that lead to our review of the management of conductors. However, more importantly for the replacement forecast, it also shows that conductor failures have continued to increase since 2011 – even in the face of the increase in replacement volumes we have undertaken.

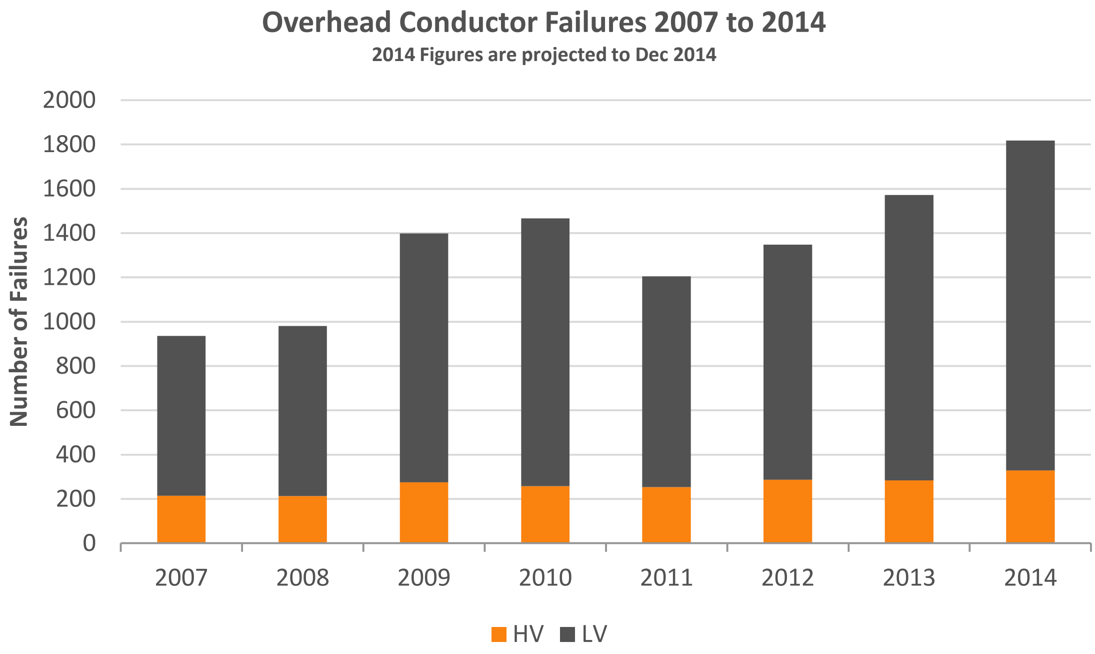

Figure 14: Conductor failures

MRV represents the level of risk associated with defects that could, within different timeframes, lead to conductor failure. While Figure 15 indicates the recorded MRV for conductors has only marginally increased during the period between 2009 and 2014, it is important to highlight the MRV forecast is based on historical defect data. Given it is difficult to assess the condition of conductors; the MRV forecast is not, in this instance, a reliable risk level indicator.

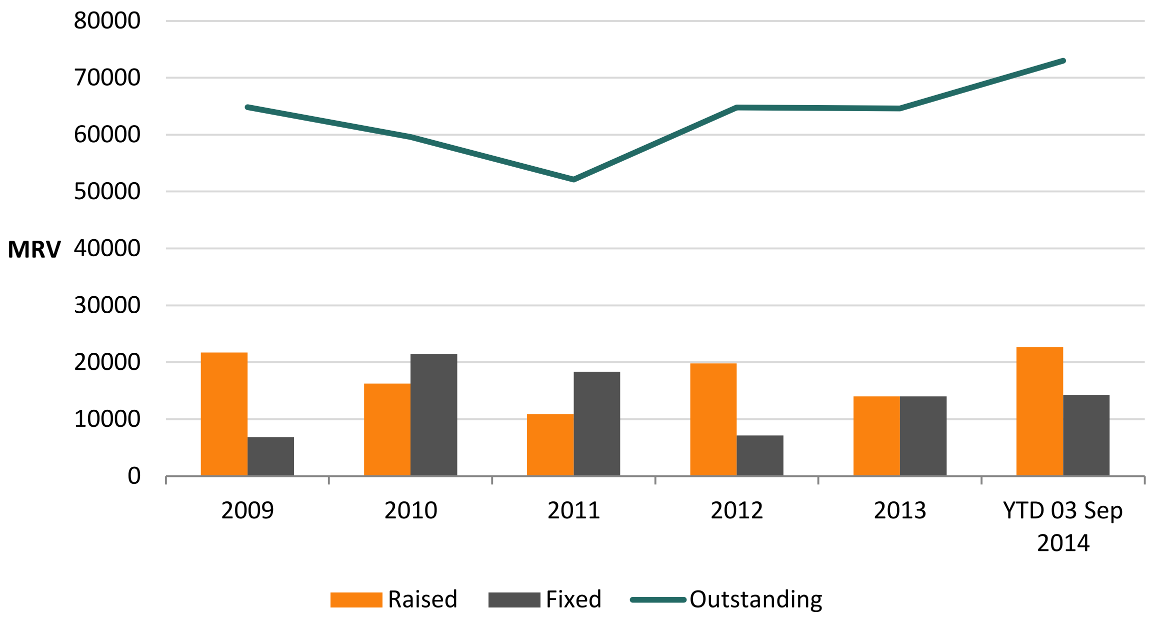

Figure 15: Maintenance Risk Value for Conductor (2009 to 2014)

7.3 The Forecasting Approach

7.3.1 Background to the preferred approach

Conductors, as an asset class, could be characterised as a high volumes / low cost replacement category. Therefore, it is more appropriate to develop a forecast that is aimed at making predictions at a more aggregate level. These models tend to average out the uncertainty that may apply at a specific asset-level in order to produce an aggregate forecast of volumes and expenditure.

In considering what type of forecasting approach may be appropriate, it is important to note that we do have a good understanding of the conductor asset base in general terms. This understanding includes:

- historical data and trends on inspections and defects by conductor types, voltage levels, and locations
- historical failure data by feeder and therefore conductor type, location and voltage
- the age profile and location of different conductor types
- the key factors that drive the degradation and failure of different conductors types and their location (eg conductor types and corrosions zones)
- the risks associated with failure of conductors based upon their location (eg bushfire zones)

Therefore, we have a range of forecasting methods that could be suitable. These methods range from:

- historical trend models, which make a projection into the future using these trends
- more sophisticated approaches that use the existing status of the assets and simulate their aging in order to predict the future condition of assets and the risks associated with their failure

Given the good data we have available for conductors, we have elected to use a more sophisticated approach as our preferred method for preparing the replacement forecast for conductors. In this regard, we have commissioned EA Technologies to develop a forecasting model for conductors, using their condition-based risk management methodology (CBRM). This type of methodology and model has been used successfully elsewhere for both asset management and regulatory forecasting purposes. As such, we consider it a suitable approach for our circumstances. A further discussion of our rationale for the CBRM approach is contained in Box 2 below.

Box 2 - CBRM rationale

CBRM is a decision support tool developed to assist asset managers in quantifying, communicating and managing asset-related risk. The model has particular emphasis on predicting matters that can be associated with the end of life of an asset. In this regard, the CBRM process produces computer models that provide a quantitative representation of current and projected future asset condition, performance and risk. The models are used to evaluate possible asset renewal strategies and investment scenarios to arrive at a forecast that best meets the objectives of the organisation.

CBRM seeks to overcome the common problem associated with optimising asset management decisions. This problem concerns the lack of reliable and consistent data, which is necessary to construct 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 an asset cohort within a general asset class to behave differently.

Examples of such cohorts in conductors would include conductor type, voltage level, and corrosion zone, changing equipment specifications and installation practices, operating environment and usage history.

Rather than use a purely statistical representation of the asset population at an aggregate level CBRM models seek to make the best possible use of available information by combining asset register information, operating context, operating history and condition information using rules that are consistent with engineering principles and the operating experience of local asset Subject Matter Experts (SMEs). The resulting models are adjusted and calibrated so that the output and behaviour of the model is consistent with historical observations and SME expectations. While CBRM models incorporate some subjective SME judgment, this judgment is codified by rules and is applied consistently. The rules are transparent and may be subjected to scrutiny, review and tested for sensitivity as required. [8]

CBRM offers a tactical advantage to asset managers 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 that inform asset management strategy and tactics, as well as providing higher quality forecasts necessary for budget and regulatory purposes.

Considering the recent changes in our understanding of the risks presented by our conductors, we have also used other approaches to produce alternative forecasts that the CBRM model output can be compared against.

[8] Additional information on the CBRM model construction and calibration, and justification of the data and factors used in the models can be found in 'EA Technology, Application of CBRM to SA Power Network's Conductors, Poles, Circuit Breakers and Transformers, March 2013' and 'SA Power Networks, CBRM Justification, September 2014'

These alternative approaches include:

- the Australian Energy Regulator's replacement model (the AER's repex model)
- a 'top-down' population method, developed by an independent party (the Aurecon conductor model)
- an internally developed model, which uses historical inspection and defect trends to make defect and replacement projections into the future (the multi-variable defect forecasting model or MVD model).

These alternative approaches make less use than the CBRM method of all the data we have available on conductors. Consequently, they provide us with less visibility of the factors underlying and driving our specific maintenance and replacement needs across our network. As such, they are less suited to our asset management tasks.

Furthermore, we have found the MVD model to be a good estimator of maintenance needs and defect volumes. For assets, such as poles, we expect a strong correlation between the defects and the need to replace – in fact, for poles, they are directly related. Therefore, for these asset types, this model can be considered a good estimator of the future replacement needs.

However, for conductors, the relationship between defects and the need to replace is not as strong. Historical failure rates can be as strong a driver of the need to replace conductor. Therefore, this model is less suited as an approach to forecast replacement needs for conductors.

For these reasons, these alternative methods are not our preferred approach for forecasting conductor replacement volumes and capex. However, we have still applied them for comparison and validation purposes.

7.3.2 Our Preferred Approach

Our preferred approach can be considered in terms of two parts

- The forecasting approach
- The validation approach

7.3.2.1 The Forecasting Approach

The forecast method can be characterised as a 'delivery-adjusted CBRM model'. In this regard, a CBRM model has been used to prepare a base volume and expenditure forecast to 2025. However, the CBRM model develop by EA Technology does not allow for delivery constraints that can occurs if expenditure steps up too fast from one year to the next.

Therefore, where the CBRM model predicts a significant step up in replacement levels, we have profiled the CBRM model output to represent what we believe would be the prudent and efficient delivery profile.

The following provide a summary of the conductor CBRM model. A more detailed discussion of this conductor CBRM model and its resulting forecast is provided in appendix C.

CBRM is a process that transforms diverse sources of previously disconnected engineering knowledge, experience and data into a 'what if' management tool that can be used to support asset renewal decision making. The CBRM process is illustrated in Figure 16 below.

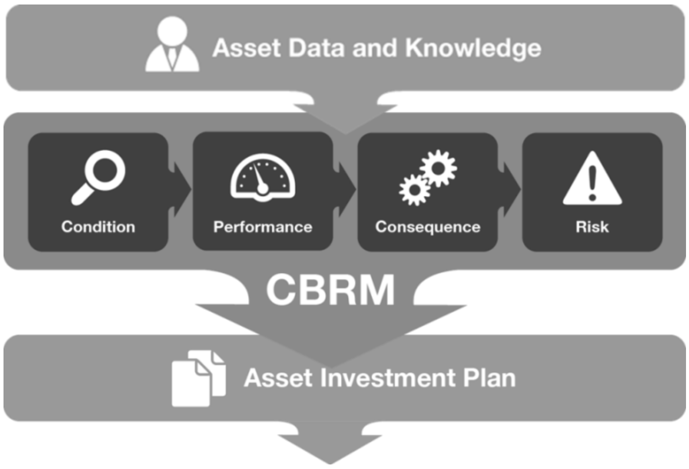

Figure 16: Overview of the CBRM Process

The CBRM process is implemented as follows:

1. **Define asset condition**. 'Heath indices' are constructed for individual assets on a scale of 0-10, 0 indicating the best condition, 10 the worst. The health index incorporates information such as asset age, design features that affect life, operating environment, operating duty and observed condition. The health index is calibrated using SME experience so that health index rankings for individual assets and the overall health index profile are consistent with available evidence and SME experience.
2. **Link current condition to performance**. Identify the shape of the relationship between the health index and Probability of Failure (POF) by relating the POF for high health indices against those of a new asset. Calculate the scale of the health index POF relationship by adjusting the POF curve so that the output of the model is consistent with historical observations.
3. **Estimate future condition and performance.** Use knowledge of degradation processes to 'age' health indices. Ageing rates are dependent on initial health index, operating environment and duty. Calculate future failure rates from aged health index profiles and previously defined health index/POF relationship.
4. **Evaluate potential interventions in terms of POF and failure rates**. Model the effect of replacement, refurbishment or changes to maintenance regimes on future health index profiles and future failure rates.
5. **Define and weight consequences of failure (COF)**. Construct and populate a framework to evaluate consequences of failure in the dimensions of safety, network performance, environmental and financial, all on a consistent financial base. Consequences are calculated by firstly evaluating an average failure cost and then scaling using asset specific criticality factors.
6. **Build a risk model**. Combine probability and consequences of failure to quantify risk. Total risk can be separated into previously defined categories such as safety, environmental, network performance and cost. Total risk and risk within each category can be related to tangible quantities such as cost, Customer Minutes Lost (CML), frequency of fatalities or serious injuries.
7. **Evaluate potential interventions in terms of risk.** Evaluate the effect of proposed replacement or refurbishment programs or changes to maintenance regimes on future asset health indices. Recalculate POF and COF and quantify changes to risk as measured against a base 'do nothing' case.

8. **Review and refine information and process**. Learn from applying the process, identify opportunities to improve asset information and refine models and algorithms. Define and progressively build an improved asset information framework.

This CBRM model output has been determined by setting the replacement forecast to represent a 'maintain and reduce to acceptable level' risk position.

This risk position has been set by setting an average intervention rate over the period 2014 to 2025 such that risk, as calculated by the model, is at an acceptable level by 2025.

7.3.2.2 The validation approach

As noted above, we have used a number of approaches to produce alternative forecasts for our conductor replacements. These approaches are summarised below.

The AER repex model

The AER has developed the model (the repex model) to assess the replacement forecasts that form part of building block proposal, provided by electricity network service providers (NSPs). The repex model is a series of Microsoft Excel spreadsheets and was first used by the AER in the Victorian electricity distribution determination for the 2011-2015 regulatory control period.

We have used this repex model as our primary approach to validating our forecast. In order to develop the forecast in the repex model, we have calibrated the model parameters in the manner we understand the AER will apply. This model has been prepared based upon the asset information we reported in our category analysis RIN. However, expenditure reported here includes overheads in order to be consistent with our forecasts.

Further information on the Repex model and our modelling for conductors can be found in appendix F.

The Aurecon conductor model

We commissioned an independent expert, Aurecon, to develop an alternative 'top-down' model to forecast conductor replacements.

Similar to the AERs repex model, this approach models conductor as aggregate populations, its primary asset inputs are age profiles and unit costs, and it uses asset lives[9] to predict failures (or replacement needs).

However, this model uses an alternative asset classification (to the AERs repex model) that makes use of some of the factors that are known to distinguish asset lives in our network. In particular, these factors include:

- The conductor type (ie ACSR, aluminium, steel and copper)
- The corrosion zone (ie low, medium, high).

The model produces an annual profile of replacement volumes for these classifications over a 10 year period using the asset age and asset life. This annual profile is then averaged to produce the main output volume forecast[10].

The expected lives used in the analysis undertaken by Aurecon were based on SA Power Networks and also industry experience.

[9] Unlike the AER's repex model, the Aurecon model uses a 'deterministic' life model (ie assets are replaced when they exceed this life).

[10] This averaging is consider appropriate because of the deterministic life model, which can produce quite variable replacement result year-on- year, reflective of the shape of the age profile.

The volume forecast is transformed into a capex forecast by applying replacement unit costs. These costs have been derived from historical data.

A more detailed discussion of this Aurecon conductor model and its resulting forecast is provided in appendix B.

The multi-variable defect model (MVD model)

The MVD model has been developed internally by SA Power Networks. 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 at the individual feeder 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.

- Defect calculation:

  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.
- Cost per defect calculation:

  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 sufficiently large data set) using adjustment factors for the other locations and voltages for which there is insufficient data.

  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.

A more detailed discussion of MVD model and its resulting forecast is provided in appendix D.

7.4 The Capex Forecast

CBRM model results

The amount of conductor replacement (route length - km) forecast directly through the CBRM model is shown in Figure 17. This indicates the replacement volume would be around 250 km in 2015 rising to around 350 km by the end of the next regulatory period.

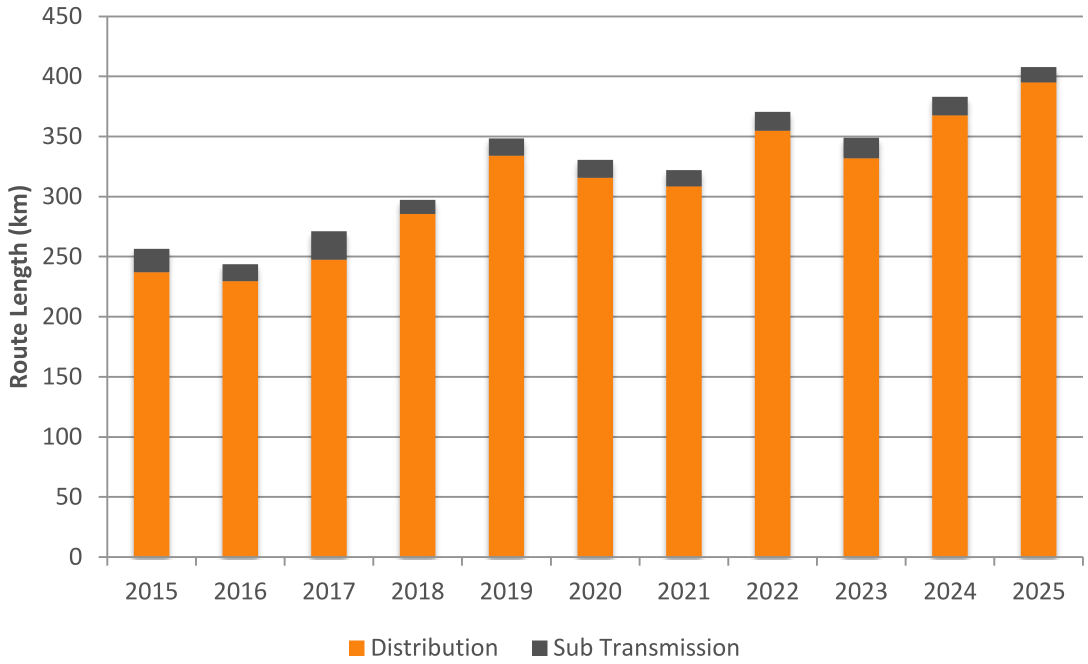

Figure 17: Conductor CBRM model replacement volume forecast

The CBRM model applies the appropriate unit rates for these volumes to calculate the replacement capex over the same 10-year period. This CBRM forecast is shown in Figure 18 below. This indicates a replacement capex of $14 million in 2015 rising to around $16 million by the end of the next period.

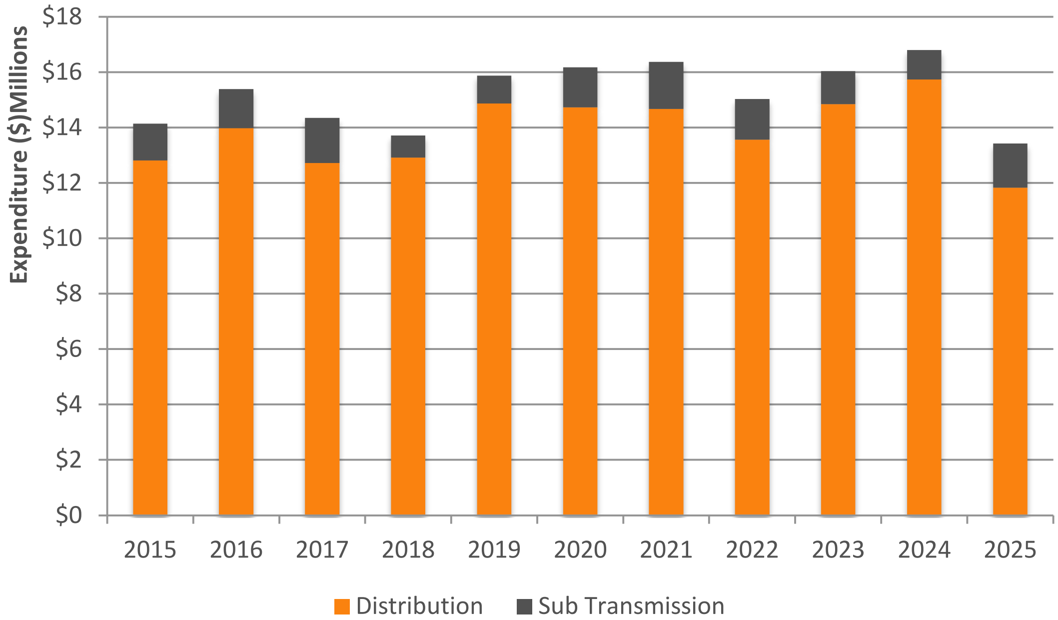

Figure 18: Conductor CBRM model replacement capex forecast

Importantly, the 250 km requirement in the first year of the forecast is significantly above what we have completed in any year in the current period as a result of, probably as demonstrated by the Repex model, not having not replaced enough conductor over the last five years, resulting in a 'catch-up' in the first year of the model results. That is, the rate of increase suggested by the models has not been matched by history.

We do not believe it will be feasible to deliver such a significant increase. Therefore, we have profiled the capex to reflect recent increases we have been able to achieve. We believe that this annual rate of increase reflects a prudent and efficient approach to delivering the increased need. For reference, the historical replacement capex has been shown with the delivery-adjusted forecast in Figure 19 below.

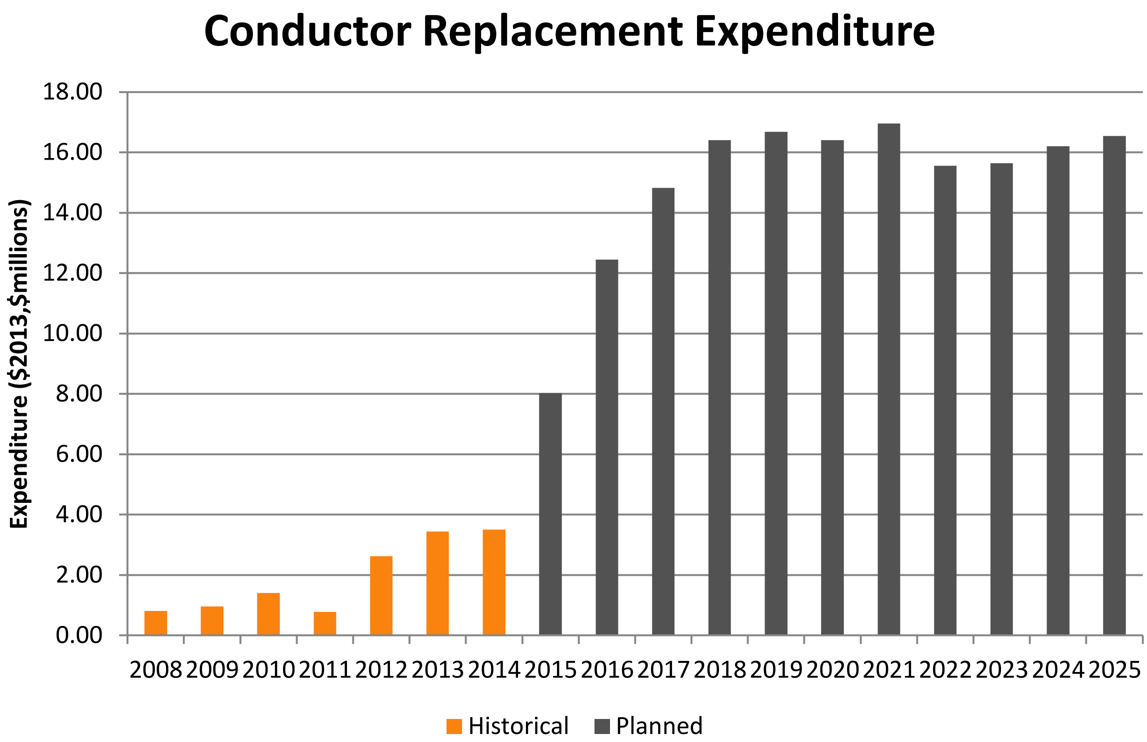

Figure 19: Conductor delivery-adjusted CBRM model replacement forecast

7.5 Forecast validation

7.5.1 The repex model

The AER Repex model has been used as the main method to verify the results derived using our preferred approach.

As noted above, for this analysis, we calibrated the repex model's planning parameters (ie asset lives[11] and unit costs[12]) using the approach we understand the AER will use. In this regard, we have set these parameters to reflect the average of the five years (2008/09 to 2012/13) that we have reported in our category analysis RIN.

Figure 20 below shows replacement volumes forecast by this repex model. For comparison purpose, the figure also shows the actual volumes report in our RIN for the years from 2008/09 to 2012/13. The figure also shows the total volumes forecast by the CBRM model.

[11] We have calibrated the mean life and assumed the standard deviation of this life to be the square root of the mean, in accordance with the assumption we understand the AER will use.

[12] In order to be comparable with expenditure reported in this AMP, the unit costs have be adjusted to reflect 2013 real dollars and have had overheads added.

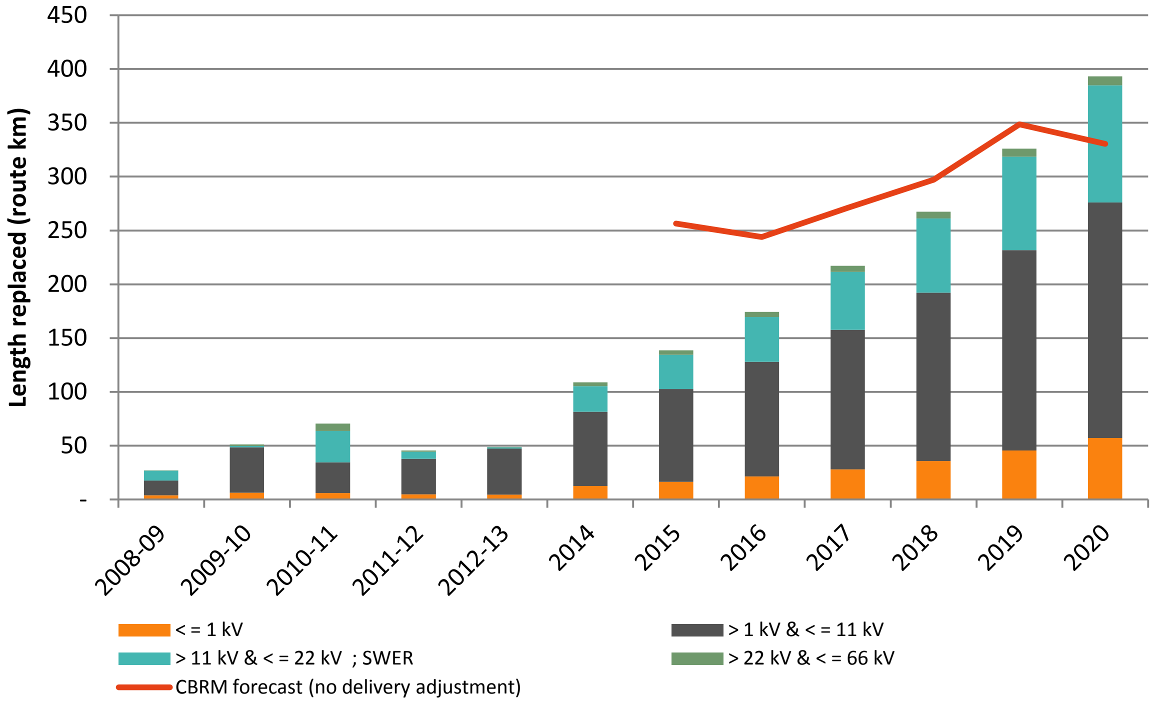

Figure 20: Conductor repex model volume analysis

This repex model suggests that our replacement expenditure is set to increases fairly significantly from now through to the end of the next regulatory period and beyond. The model predicts an annual growth rate in the volume of replacement of 24% (compounded). However, the level is below the CBRM model's forecast, at least up to 2020 when it will exceed the CBRM model.

Conductors at distribution voltages is by far the most dominant type in the repex model, with predicted replacement volumes rising from 105 route km in 2014 to 384 route km by 2020. This is well above the average historical level of around 46 km.

Conductor volumes at sub-transmission voltages are less significant, but are still forecast to increase at a significant rate (16% per annum compounded).

Our analysis suggests that the significant growth in replacement volumes is driven by the shape of our conductor age profile. As we have discussed in Section 5, we have a large portion of conductors that were installed over a very short period, between 1955 and 1960. The calibrated lives in the model are over 80 years. Therefore, the sharp peak in the age profile is entering the leading edge of the asset life model (ie we are beginning to enter the replacement cycle for these conductors), and so replacement volumes are increasing fairly rapidly.

Possible more importantly, the repex model results (shown above) suggest that we have probably not replaced enough conductor over the last five years. That is, the rate of increase suggested by the model has not been matched by history. This finding is in line with our own view, which we discussed above, in that failure and risks have been rising, and consequently, we have not been replacing at a sufficient rate. Given the calibrated life of conductor was found to be 80 years, it seems reasonable to draw this conclusion.

The AER calibration process assumes that the average 5-year history reflected the prudent and efficient expenditure to maintain the performance. As performance was not maintained, but worsened, this calibration assumption is not valid. In effect, we would have needed to replace more conductor to achieve this outcome. Although we have not attempted to estimate how much more conductor we should have replaced to ensure performance was maintained, this does suggest that such an assessment would start to move the repex model forecast closer to the CBRM model.

Therefore, this repex modelling and analysis does provide some support to the validity of the CBRM model.

All that said, the CBRM model replacement capex forecast has been adjusted to allow for the prudent and efficient delivery of replacement. Figure 21 below shows the equivalent chart to that above, using the capex forecast. However, this figure shows the delivery-adjusted CBRM model results for comparison purposes.

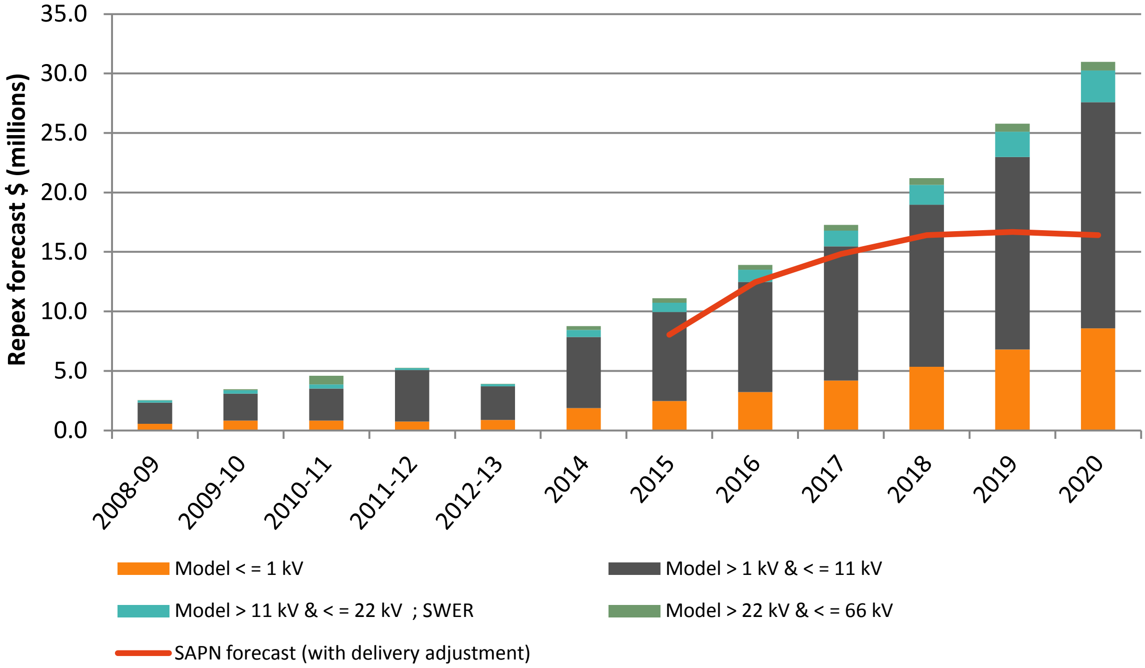

Figure 21: Conductor repex model capex analysis

This figure shows that the AER repex model forecast is above our forecast, once our forecast is adjusted for delivery. Therefore, this supports a view that our forecast is not overstating the replacement need required to maintain the performance of our network over the next regulatory period. In fact, if anything, the repex model results suggests our forecast may not be sufficient for this purpose.

Therefore, we believe that the AER repex model provides a useful validation of our preferred forecast. Furthermore, we are reasonably confident that through the targeting of high risk conductors, we will be able to maintain performance and avoid significant further degradation.

7.5.2 Other Approaches

Table 6 below provides a comparison of the various approaches we have used to produce a forecast for conductor replacement. Due to the averaging used to produce the final forecast output in the Aurecon conductor model and Multi-Variable Defect Forecasting model, this table shows the average annual volumes and capex over the next period (2015 to 2020).

Table 6: Comparison of approaches

Forecast Methodology	Annual Capex ($000s)	Annual Volume (route km)
CBRM (Preferred Methodology)	$15,355	307.0
AER Repex model	$21,833	275.6
Aurecon model	$6,000	233.2
Multi-Variable Defect Forecasting Model	$3,472	49.4
History	$3,956	48.5

This table shows that the MVP approach essentially reflects the continuation of historical levels. As we have argued above, historical levels have not been sufficient to arrest the degradation in performance. Furthermore, the CBRM and repex modelling have both shown how the aging of network is likely to significantly increase this degradation further, if replacement volumes are not increased. Therefore, the MVD model is likely to be a very unreliable estimate of the future replacement needs to maintain performance.

The three approaches that simulate the effects of aging (ie the delivery-adjusted CBRM, repex and the Aurecon model) all produce similar (at the magnitude level) volumes of replacement. Given their different approaches, these differences may be expected.

There are different patterns between the volumes and capex. Most notably, the Aurecon approach suggest $6 million per annum to replace a similar level to the repex model, whereas the delivery-adjusted CBRM needs less capex than the repex to replace a greater volume of conductor. This is mainly due to differences in the classification of conductors in these models, and so which conductor type is being forecast for replacement by each model over the period.

On balance, the similarity between these three methods appears sufficient as a negative assurance on the validity of our preferred forecast ie there is no clear evidence that our forecast is overstating the replacement capex necessary to maintain performance.

7.6 Regulatory Treatment

Given the bottom-up method we have used to prepare the overall replacement capex forecast, we believe the conductor capex forecast discussed here should be fully allowed for in the capex forecast that will be included in SA Power Networks building block proposal to the AER.

The National Electricity Rules broadly requires that the capital expenditure forecast in the building block proposal should reflect[13:]

- the prudent and efficient costs
- to comply with our legal obligations, and/or
- maintain safety, security and reliability

We believe that the conductor replacement capex forecast, discussed here, meets these requirements for the following reasons:

- The need to replace the conductors reflects a prudent approach to meet our legal obligations associated with operating a safe network as outlines in the Electricity Act, Regulations and the ESCOSA approved SRMTMP, and the

[13] NER 6.5.7 (a) - capital expenditure objectives, and 6.5.7 (c) – capital expenditure criteria

requirement to maintain the performance of our network in the face of its continued aging.

- We have used a reasonable approach, given our circumstances and the available data, to determine the volume of replacements to meet these requirements. This approach (the CBRM model) has been used elsewhere for preparing forecasts for regulatory purposes. The approach has made use of a wide range of available data, and key assumptions have been calibrated to reflect our historical circumstances.
- We have used various alternative approaches to validate the magnitude of replacement in this forecast, and verify that it reasonably reflects a 'maintain and reduce to acceptable level' risk position. Most notably, we have used the AER repex model and found that such a model, calibrated as we understand the AER will apply, forecasts a higher capex than we are proposing here.
- Given our forecasting approach is calibrated to reflect history, it inherently allows for the prudent and efficient solutions to address conductor in poor condition (eg continuing to maintain the conductor or replace it), which allows for the prudent and efficient trade-off between capex, opex and reliability.
- We have allowed for the efficient unit cost for the replacements. Our unit costs have been determined directly from recent historical replacement costs. The management and delivery of our services has been found to be good practice; and hence it is reasonable to accept that these historical unit costs reasonably represent efficient costs. This view is also supported by the AER's benchmarking, which suggests we are at or near the efficient frontier.
- The annual profile of the forecast has been adjusted (downwards) to reflect a prudent and efficient delivery timeframe. In this regard, the rate of increase has been reduced to align with increases we have achieved recently.

8. FINANCIAL SUMMARY

8.1 Introduction

This section contains the capital expenditure forecast for overhead conductor replacement.

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.

8.2 Unit Rates

Based on analysis undertaken by SA Power Network in completion of the Category Analysis Regulatory Information Notice (RIN) the following unit rates for replacement of overhead conductor have been developed based on historical spend from 2009 to 2013.

Table 7: Unit Costs

Description	Cost ($000s) / route km
< ≈ 1 kV	$37.7
> 1 kV & < ≈ 11 kV	$31.25
> 11 kV & < ≈ 22 kV; SWER	$24.125
> 22 kV & < ≈ 66 kV	$27.348

There are many variables that contribute to the cost of replacements and upgrades, including installation type (restring or reconstruction), environmental conditions, and accessories, with some of these contributing significantly to costs. As the extent of any such variables cannot be accurately predicted except on a specific project basis; an average unit cost has been derived and used based on actual works undertaken.

8.3 Financial Statement and Projections

The anticipated total cost required per annum for the period 2015 to 2025 associated with overhead conductor replacement, including the targeted program of works summarised in Appendix E, is shown in Table 8.

Table 8 : CAPEX to replace overhead conductor

	$millions												
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	*TOTAL*
Planned Works	$3.50	$7.94	$12.27	$14.65	$16.23	$16.50	$16.32	$16.95	$15.56	$15.64	$16.21	$16.54	$168.30
Targeted Program	-	$0.09	$0.18	$0.18	$0.18	$0.18	$0.09	-	-	-	-	-	$0.90
TOTAL	**$3.50**	**$8.03**	**$12.45**	**$14.82**	**$16.40**	**$16.68**	**$16.41**	**$16.95**	**$15.56**	**$15.64**	**$16.21**	**$16.54**	**$169.20**

9. PLAN IMPROVEMENT AND MONITORING

9.1 Data Management System

9.1.1 Improvements to Data Management System

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

- The determination of risk for an overhead conductor
- The appropriate maintenance, renewal and replacement program for the overhead conductor 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 the SAP and GIS systems are listed below:

1. The objectives of the database needs to be clearly defined and documented
2. Record sources of data to be used in populating database
3. Increase awareness of importance of quality data
4. Start to record data on overhead earth wires and insulated conductors

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.

Another example would be the high proportion of route length of overhead conductor installed in particular years, such as 1955. It is known that in some cases, the age of conductors is based on the date of installation of the poles supporting the conductor or the date of the project. The use of multiple sources reduces the reliability of the age data as the data from both sources may not match.

It is important that data in the database 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 entries in SAP that are classified as unknown. Personnel throughout SA Power Networks are to be made aware of the significance of providing quality data.

It was previously acknowledged that overhead earth wires are implicitly included in this asset management plan. Whilst earth wires are relevant to 33kV and above conductor, explicit inclusion of overhead earth wires in the asset management plan can assist in maintaining the operation of phase conductors during lightning events.

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

9.1.2 Data Management System Improvement Plan

The objectives of SAP and the data stored therein 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 a well-structured database which will provide a solid foundation for optimally managing the data and consequently the overhead assets.

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

SA Power Networks plans to identify and validate the data sources used for overhead conductor data held within SAP. This will improve the traceability of data and reduce the occurrence of redundant data in the database.

Data related to overhead earth wires and insulated conductors (covered conductor, covered conductor thick and ABC) will be identified in SAP. Network Maintenance Manual No. 12, Line Inspection Manual No. 11 and other documentation will include information on overhead earth wires and OPGW.

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 Asset Management Database in the form of SAP will greatly assist in developing efficient maintenance plans. Identifying the key attributes of the overhead conductor is part of satisfying the objectives of the database. An example of the key attributes necessary to determine the capital cost of conductor replacement is indicated in the framework outlined in Figure 22. Collection of this data will greatly assist with improving the calibration of the CBRM models and therefore the results produced.

For each feeder, and each identified segment, the following attributes are needed:
- Unique Identifier
- Bushfire Risk Area
- Fire Ban District
- Corrosion zones -Atmospheric and Ground Level
- Installation date
- Conductor Length
- Number of phases
- Voltage
- Conductor Type
- Phase designation
- Design Temperature
- Maintenance strategy
- failure rate of combined failure modes
- Ranking of failure modes (an identifier can be used)
- Number of defects since first installation

List all unplanned conductor replacement with the following attributes for each event:
- Job or Work Order Number
- Date of replacement
- Cost of replacement
- Conductor length
- Conductor type
- Cause of failure (an identifier can be used)
- Number of customers impacted
- Switch Zone (in OMS)
- SAIDI cost
- SAIFI cost

List all planned conductor replacements with the following attributes for each event:
- Date of replacement
- Cost of replacement
- Conductor length
- Conductor type
- Operating Voltage
- Phasing (for non-3 phase sections)
- Stranding
- Design Temperature
- Material
- 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 22: Key Conductor Data to be collected and stored

9.2 Risk Management Plan

9.2.1 Improvements to the current plan

The present risk management plan evaluates the risks qualitatively: the improvements in Section 9.1 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 conductor 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 a quantitative risk register to assist with decision making; this can be in CBRM or within SAP.

Assuming that quality data is available to create a register, the level of risk in the SA Power Networks' conductor network is based on the failure rate of each overhead conductor /segment 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 combined failure rate can be used to determine the impact of all failure modes and other factors on conductor failures. The failure rate of all failure modes can assist in adopting the appropriate maintenance strategy for the overhead conductor/segments.

SA Power Networks 'geo-codes[14]' its network defects to determine the locality of defects on an overhead conductor's segments. The data collected from geo-coding of defects on a conductor segment provides a significant advantage in determining the likelihood of failure of a given conductor segment. Tagging an identifier to the data enables categorisation of the defects according to failure mode and/or severity and can help indicate the likelihood of future conductor failure. Thus, SA Power Networks can efficiently monitor the changes in risk of an overhead conductor or segment thereof before it fails.

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

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

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

[14] Geocoding is the process of associating geographic co-ordinates, often latitude or longitude, to allow the features to be mapped and entered in the corporate Geographic Information System (GIS)

The current risk management plan does not identify the criticality of all overhead conductor. Furthermore, the current definition of criticality qualitatively captures some of the risks stated above. The criticality of conductor is currently based on the information provided in Network Maintenance Manual No. 12. Overhead conductors are divided into three groups- sub-transmission lines, distribution feeders and LV mains.

The likelihood of defects/faults on of sub-transmission conductor is indicated by the visual inspection and infrared thermography inspection frequencies of overhead conductor. Corrosion zones influence the frequency of visual inspection as a result of this.

The conductor's nominal operating voltage influences the thermography inspection frequency. The sampling frequency indicates that 66kV are 1.5 times more critical than 33kV conductor. Further prioritisation within the two voltage groups is not performed.

For distribution feeders, two groups are created - SWER and other voltages (customer connections, 11kV, 7.6kV and 240V). Similar to the sub-transmission conductor, prioritisation of distribution feeders is indicated by the visual and infrared thermography inspection frequencies. In each group, conductor that are in severe and very severe corrosion zones and high GSL Risk feeders[15] are two times as critical compared to feeders in low corrosion zone and non-GSL Risk feeders.

Thermographic inspection is not conducted on SWER conductor. The thermographic inspection frequency in the other groups, indicates that greater metropolitan conductor are 2.5 times more critical than country conductor. Similar to sub-transmission conductor, further prioritisation of conductors within the various groups formed from the visual inspection and thermographic inspection frequencies is not indicated.

9.2.2 Improvement plan

Criticality is one of the traits along with the magnitude of safety risk, environmental risk, performance risk, operational risk and financial risk exposure to SA Power Networks by a feeder or line in determining the overall risk presented by that feeder or line.

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

For the purposes of the integrity of the database, segments of conductor (pole to pole, or transformer to transformer, or brace pole to brace pole – to be determined) should be identified as having high risk rather than the high risk being attributed to the whole feeder or line. This makes for the most accurate budgeting and maintenance program. All other interpretations for reporting purposes should just build on the identified high risk segments of a line through the application of simple rules.

The current allocation of corrosion zone and bushfire risk area to overhead conductor is not as reliable as it could be. The current approach does not identify

[15] *a high GSL Risk feeder is determined by the SA Power Network's reliability group on an annual basis. The reliability group reviews the customer interruptions monthly (over 12 month cycle) and then determines which feeder is put onto the GSL risk list based on the number of outages. Any feeders on the GSL risk list are reviewed by the reliability group prior to allowing planned outages and after an unplanned outage to decide the prioritisation of feeders to be restored.*

the corrosion zone of the weakest segments[16] and the highest risk of corrosion of other segments of an overhead line. In order to produce a more reliable database, the high risk of corrosion in the weakest[17] segment and other segments of an overhead line has to be identified.

Instead of allocating the highest bushfire risk area encompassed by an overhead line, the bushfire risk of the weakest segments and the highest bushfire risk of other segments of an overhead line are to be identified. This will contribute the reliability and accuracy of the data held in SAP.

SA Power Networks have begun to geo-code defects in conductor, which will provide great assistance in identifying the weakest points in a line or segment.

9.3 Maintenance Plan

9.3.1 Improvements to the plan

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

1. Re-organise the defect codes used for recording defects on overhead line components
2. Recognise the impact of other components on conductors
3. Link conductor defects to conductor failure
4. Identify defects on LV conductor separate to HV conductor
5. Identify corrosion zone and bushfire risk area during defect and fault management

The data analysis performed in Section 5 identified issues with incorrect defect codes being used to record the condition of overhead components. This could lead to inappropriate asset management decisions relating to risk, maintenance, repair and replacement of the components. Thus, re-organising codes specific to components is expected to prevent the misrepresentation of the condition of components.

The maintenance plan for conductors does not identify the impact the condition of other components has on the conductors (eg vibration dampers, armour rods, clamps etc). As seen in Section 5, the defects or failures of other components have contributed to the ultimate failure of conductors. Thus, conductor maintenance plans are to include consideration of the condition of other components to ensure labour resources are used effectively.

SAP does not currently link identified conductor defects and conductor failures. Linking of these defects to the conductor's failure is beneficial when estimating the remaining operational life of a conductor, as well as, deciding on the action necessary for the management of overhead conductor.

An improvement in how defects on low voltage overhead conductors are recorded within SAP is needed. At present, defects on low voltage conductors are raised against the upstream high voltage feeder. Identification of the defect on low voltage conductor is only made via the selection of the voltage in the voltage field or inputting the voltage in the text field. The defects registered by inputting the voltage level in the text field will mask the defect as a high voltage defect. As

[16] *The weakest segment or point of a line is determined by the identifying the segment that poses the most risk. Inputs into this determination would be, but not limited to, the highest density of defects and historic failures along the line and electrical loading of the line.*

[17] *The weakest segment or point of a line is determined by the identifying the segment that poses the most risk. Inputs into this determination would be, but not limited to, the highest density of defects and historic failures along the line and electrical loading of the line.*

a consequence, an inflated number of defects would be indicated for high voltage conductor, which may lead to unnecessary maintenance of the HV conductors or their components. It is recommended that the identification of LV defects be made using the 'voltage' field only as this will reduce the data discrepancies.

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

9.3.2 Improvement plan

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

The effective management of other components that affect the performance of conductors is essential in order to minimise the penalties incurred for overhead line or conductor failures. In Section 5.3.3, the majority of unplanned conductor failures are attributable to failure of other components. SA Power Networks has the potential to reduce penalties incurred by revising the system in place for managing the interaction of various components in overhead conductor, with particular emphasis on conductors. This should, if all defects identified are rectified within the required timeframes, greatly improve the effective and economical implementation of maintenance strategies.

9.3.3 Selection of Maintenance Strategy

The strategies available to SA Power Networks are condition monitoring and fix on failure.

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

9.3.4 Implementation of Maintenance Plan

SA Power Networks' 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 across the conductor between joints, also at and under (where possible), conductor attachments and accessories by the use of visual inspection and infrared thermography as stated in the Line Inspection Manual (Manual No. 11) and the Condition Monitoring and Life Assessment Methodology AMP. The visual inspection checklists and the thermography inspection 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 overhead conductor.

Documentation on 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 condition of the conductor. Tracking the age when a defect has occurred may help determine the likely cause of the defect. For example, the primary cause of defects within the first five years of installation of the conductor may be due to incorrect conductor and clamp combination, or the failure to fit other components, for example vibration dampers. This may be a result of incorrect design or incorrect selection of the fitting during 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 line. Identifying such an issue on new and existing conductor and rectifying it in a timely manner will lead to an improvement in the lifespan of the overhead conductor.

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

9.4 Repair and Replacement Plans

9.4.1 Improvements to the plan

1. Developing frameworks/criteria for repair and replacement of conductors
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 conductors in the maintenance plan.

At present, the replacement of conductors is targeting conductors that are highly likely to fail due to corrosion. The criteria are based on the limited data provided, which is conductor type, corrosion zone and year of installation or replacement of the overhead line. As a result, the budgeted route length of overhead line that needs 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 route length of conductors to be replaced.

SA Power Networks plan to prepare documents that detail the criteria and framework used to repair and replace conductors. 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 produce effective and relevant plans.

SA Power Networks will analyse the available data to determine the failure rate according to all failure modes and other factors for overhead conductors.

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

9.5 Disposal Plan

9.5.1 Improvement plan

Testing of conductors that have failed will improve the lifecycle management of conductors. Taking advantage of the opportunity arising from the replacement of conductors or re-tensioning of conductor to inspect failure modes will greatly improve the management of conductors. Testing of conductors for fatigue and checking for corrosion can reduce the unpredictability of conductor failures.

Investigating corrosion in a failed conductor of particular conductor type can assist in the maintenance of other conductors of a similar type and environments that are in operation. Investigation into the corrosion under attachments and fittings, such as armour rods, can provide information on how severe corrosion is at these locations.

If conductors have failed relatively early in the expected life of the conductor, nominally within the first five years after installation, then testing the failed conductor 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 conductors to remove the future occurrence of similar failures.

A disposal plan that incorporates the investigation of fatigue and corrosion failures in conductors and early life failures, on a cost/criticality basis, will contribute to the improvement in the lifecycle management of overhead conductors.

9.6 Monitoring Plan

9.6.1 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 ensure that the risks are minimised as far as reasonably practicable and economical.

9.6.2 Maintenance Plan

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

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

A significant number of unplanned conductor failures are an indication that the maintenance plan is primarily ineffective, followed by the repair and replacement plans if a proactive replacement program is implemented.

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 could have a cascading effect on other defects and lead to more failures. As a result, the inspection frequencies of conductor 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 conductor since the inspection frequency will influence the likelihood of detecting future defects and failures in overhead conductor.

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.

9.6.3 Repair 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 repair and replacement of conductors.

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

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

9.6.4 Auditing of Plans

An independent group within 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 the data recorded in SAP is as per the requirements of the business, including accuracy and completeness.

10. APPENDICES

A. Maintenance strategy – Overhead Conductor

The maintenance strategy for overhead conductor is outlined in Network Maintenance Manual – Manual No. 12. The specific sections applicable for Overhead Conductor are:

- Section 6.2 : Overhead Sub-transmission Conductor; and
- Section 6.3 : Overhead Distribution Assets

B. Aurecon Replacement Strategy Report

AMP 3.1.10
Overhead Conductor

C. CBRM Modelling

In 2011, EA Technology was engaged by SA Power Networks 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, 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 23.

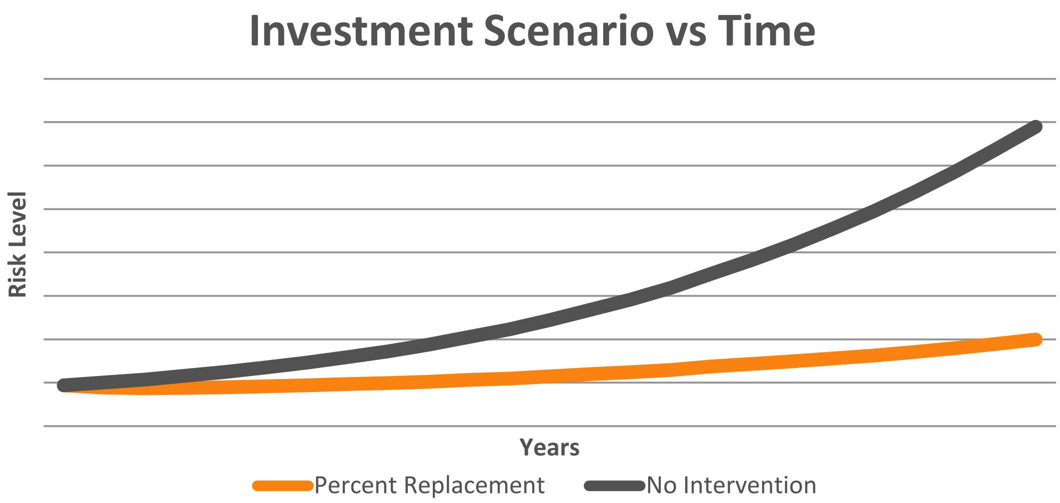

Figure 23 : Example of risk profile over time output graph

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 24.

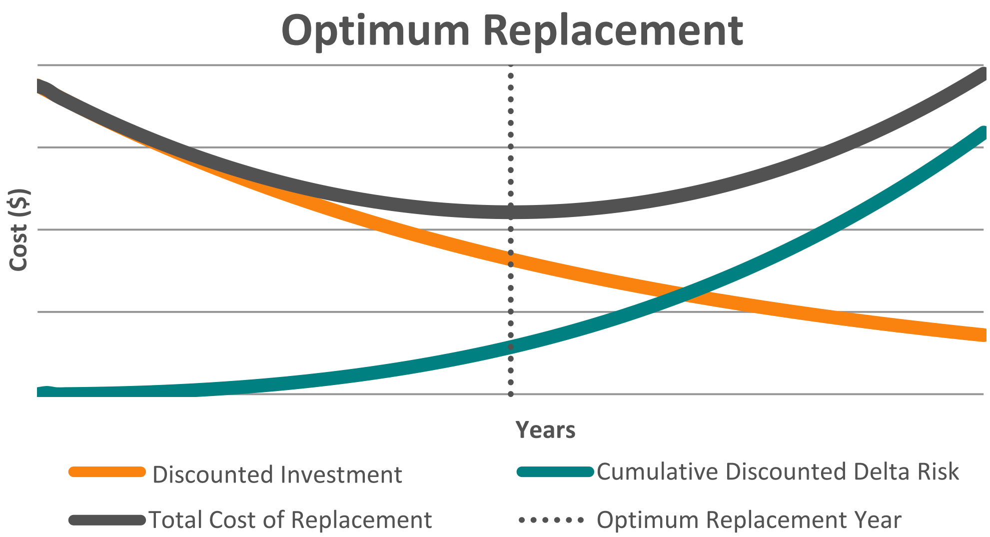

Figure 24 : Example of outputs used to determine optimum replacement year

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 borne 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 optimal replacement year for an asset.

In order to accurately determine the financially optimal replacement year, an even balance between risk and unit costs needs to be achieved.

10.1.1.1 *Conductor Methodology*

CBRM uses two conductor models for conductors supplying sub-transmission lines and distribution feeders. This was deemed appropriate because distribution and sub-transmission assets have different reliability consequence models and expose SA Power Networks to risk levels with an inherently different order of magnitude.

Determination of Health Index

CBRM determines conductor HI1 – Age Related Health Index (HI) by calculating an ageing constant β, which is combined with the conductor's age. The information used and dependencies are shown above in Figure 25.

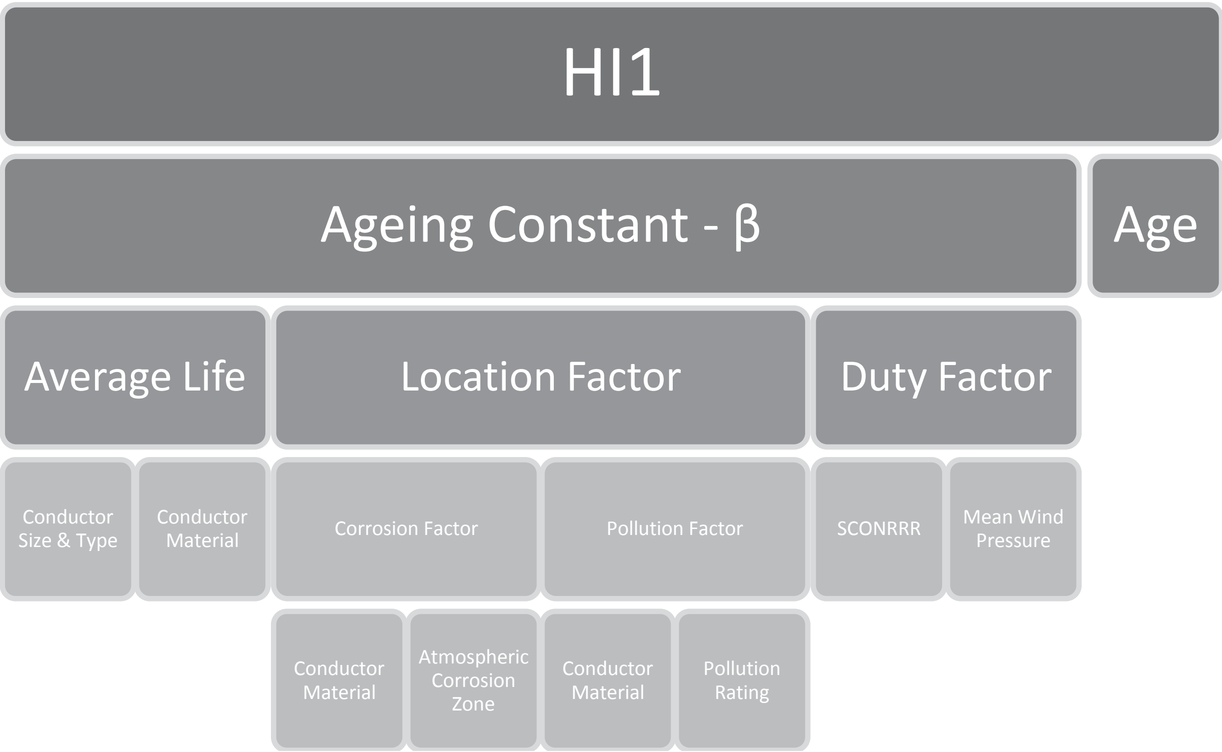

Figure 25: CBRM methodology for determining HI1

The value of β is determined by combining the following information:

- **Average life:** The average life of a conductor 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 depends on the feeder's SCONRRR rating, and the mean wind pressure. The SCONRRR depends on load per km, which means it's a good indicator of the amount of load carried by the conductor. Mean wind pressure is an indicator of mechanical stress experienced by the conductor.

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

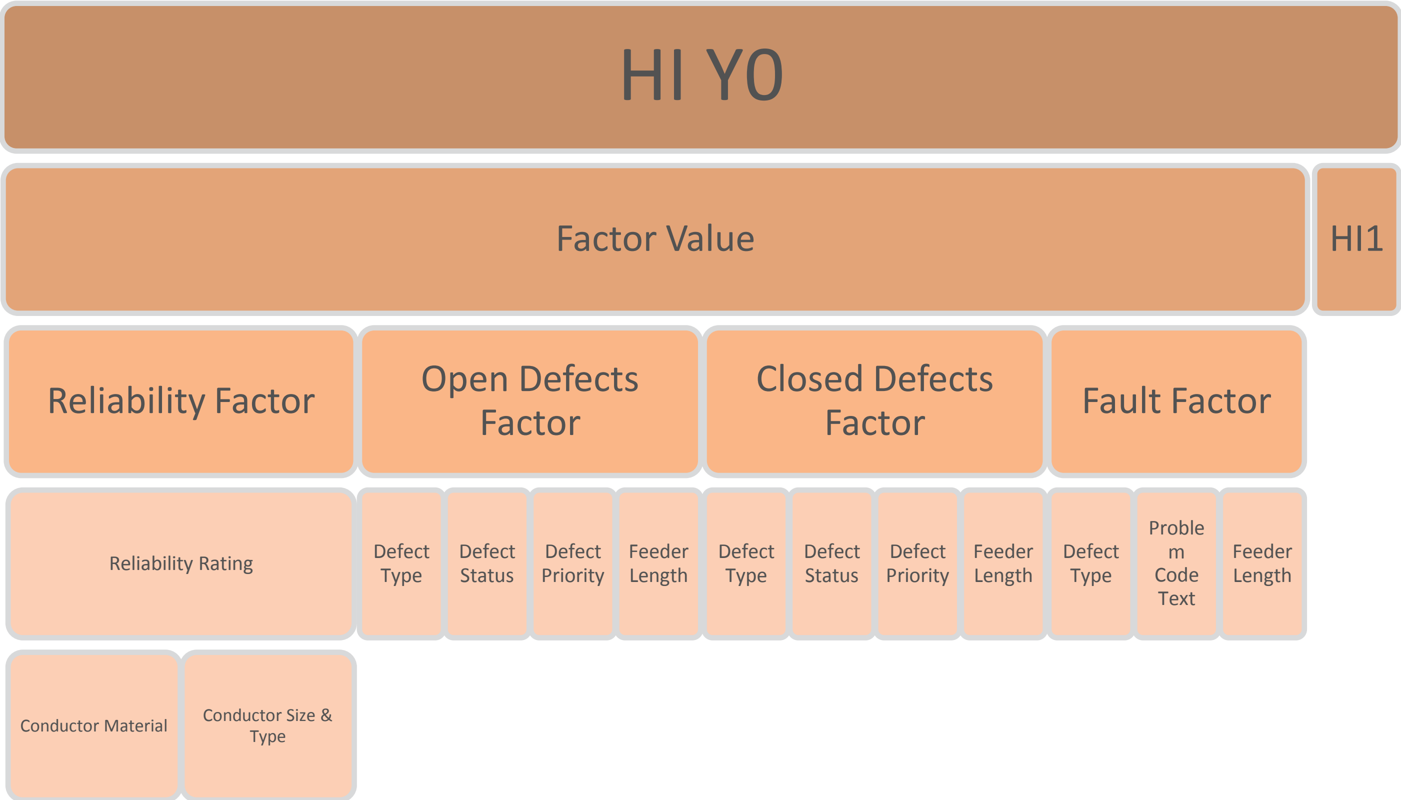

Figure 26: CBRM methodology for determining HI Y0

HI Y0 is the conductor's HI as it stands today; it's determined by combining condition based measurements together and multiplying the results with HI1.

The following condition based measurements are used to determine HI Y0:

- **Reliability Factor:** The Reliability Factor is determined using the conductor's reliability rating and is dependent on conductor material, size and type.
- **Closed and Open Defects:** CBRM uses the Defect Type and Status to determine if the SAP notifications represent a defect and if they have been assigned with either a closed or open status. The defect factor is determined by summing the number of identified defects for the conductor, with weighting determined by priority score and status. The closed and open defect factors are then determined by dividing the results by the square root of the conductor's length.
- **Faults:** CBRM uses the Defect Type and Problem Code Text to determine if the notifications stored in SAP are conductor faults and assigns each fault a weighting. The fault factor is determined by summing the weightings, and dividing the sum by the square root of the conductor's length.
- **Determination of Risk Consequences:**
  - CBRM uses the following events to define conductor risk consequences:
  - Fault – The conductor causes an unplanned outage
  - Replacement – A section of the conductor is replaced based due to poor condition
  - Repair – Repairs are undertaken, this is generally completed on a span or overhead line components
  - Fire Start – The conductor starts a small bushfire
  - Bushfire – The conductor 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 9 below.

Table 9: Financial Consequence categories

Event	CAPEX	OPEX	Safety	Environment	Reliability
Fault: Condition Non Condition	Investment in line hardware to remediate a fault	Cost of labour to remediate a fault	For each event, CBRM splits safety into three incidents: • Minor • Major • Fatality Each incident 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 incidents: • Loss of Oil/Litre • SF6 Emission/kg • Fire • Bushfire • Waste/tonne • Disturbance Each incident 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 feeders, CBRM values reliability consequence by estimating the SPS penalty incurred as a consequence of an outage. 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 feeder's SCONRRR For Subtransmission feeders, 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*
Replacement: Condition	Investment in new conductor	Cost of labour to install new conductor			There are no Reliability Consequences associated with this event
Repair: Condition	Investment in line hardware to repair a section	Cost of labour to repair a section			There are no Reliability Consequences associated with this event
Fire Start (by SA Power Networks): 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
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 conductor is located in a fire risk area. Essentially the modifier pushes the fire/bushfire risk towards conductor located in fire risk areas, and ensures there's no fire/bushfire risk associated with conductor located in non fire risk areas.

Because conductor is a linear asset, CBRM defines the PoF unit as failures per unit of length (ie per km), so that the longer the section the greater the overall PoF.

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 Phases: The number of phases the conductor supplies on the feeder – not used for Subtransmission conductor
  - Customer Type: SCONRRR of the feeder supplied by the conductor if applicable
- OPEX
  - Number of Phases: The number of phases the conductor supplies on the feeder – not used for Subtransmission conductor
  - Customer Type: SCONRRR of the feeder supplied by the conductor if applicable
- *S*AFETY
  - Customer Type: SCONRRR of the feeder supplied by the conductor
- ENVIRONMENT
  - Environmentally Sensitive Area: Subjective risk assessment of the vulnerability of the environment to conductor damage
  - Number of Phases: The number of phases the conductor supplies on the feeder – not used for Subtransmission conductor
- RELIABILITY
  - Major Customers: If major customers exist on the feeder, a fault exposes more risk
  - Customer Type: SCONRRR of the feeder supplied by the conductor – not used for Distribution conductor
  - Number of Life Support Customers: Feeders supplying life support customers expose the network to more risk
  - Number of Customers: Conductors supplying high customer feeders expose more risk – not used for Distribution conductor
  - Number of Reclosers: The installation of reclosers on a feeder reduces the amount of risk that the conductor supplying that feeder exposes – not used for Subtransmission conductor
  - Number of Phases: The number of phases the conductor supplies on the feeder – not used for Subtransmission conductor

The varying asset replacement maturity levels and their relationship to CBRM are discussed in Table 10 below.

Table 10: 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 as 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 index. 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; are 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; are 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

Model results for Overhead Conductor

Model results to date have been generated for the target risk based approach, the approach recommended for SA Power Networks by EA Technology. The lengths of conductor to replaced per annum based on the target risk basis methodology are shown in Table 11 and are summarised in 7.3.

Table 11: Total route length of overhead conductor to be replaced per annum from CBRM

	Route length(km)												
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Distribution	334	333	375	362	449	407	475	466	403	513	551	457	5,125
Subtransmission	42	33	37	38	26	44	34	42	30	34	42	36	438
TOTAL	**376**	**366**	**412**	**400**	**475**	**451**	**509**	**508**	**433**	**547**	**593**	**493**	**5,563**

D. Multi-Variable Defect Forecasting Methodology

The internal forecast Multi-Variable Defect Forecasting Methodology 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.

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. As most of the categories have insufficient data for an average defect rate, the average defect rate is calculated based on rural corrosion zone 2 rate (which is assumed to have a majority and a sufficiently large data set) using adjustment factors for the other locations and corrosion zones for which there is insufficient data.

The historical feeder defect rate per year is the number of defects (P1(+PZ), P2 or P3, in cycle in 2012 or 2013) 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.

For other rural corrosion zones, the defect rate is the rural corrosion zone 2 defect rate multiplied by an adjustment factor. The corrosion zone adjustment factor is the weighted average of the ratio of average defect rate corrosion zone 2 (both rural and urban) across a selection of asset categories, weighted by the number of defects. This assumes that the ratio of defect rates for other corrosion zones to corrosion zone 2 is approximately equal for most asset categories.

For urban corrosion zones, the defect rate is the rural corrosion zone defect rate multiplied by an adjustment factor. The urban adjustment factor is the weighted average of the ratio of average defect rates for urban vs rural (all corrosion zones) across a selection of asset categories, weighted by the number of defects. This assumes that the ratio of defect rates for urban to rural is approximately equal for most asset categories.

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.

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.

Illustration

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

Rural feeder CN25 operates at 19kV, is located in corrosion zone CZ3, has 87.9km of overhead lines, has experienced, thirteen P2 defects and one P3 defect in 2012 and 2013 and was last inspected six years ago.

Rural CZ3 has 1677.72km of overhead line and total defect rate 6.37 per year, and therefore the defect rate per year per km for rural CZ3 is estimated at 0.0038 and the expected number of defects over five years for CN25 is estimated at 1.67.

The expected number of defects over five years for rural CZ2 19kV is 66.36. The expected number of defects over five years for rural 19kV is 177.72, and the total expected number of defects over five years is 706.26.

For rural 11kV feeders, there are a total of 142 defects included in the sample at a total cost of $1,859,059.74 and therefore the cost per rural 11kV defect is estimated at $13091.97.

The ratio of 11kV to 19kV defect costs averages 1.158, and therefore the cost per rural 19kV defect is estimated at $15163.09.

Therefore the total cost of defects over five years for rural CZ2 19kV is estimated at $868,783.13, and the total cost of defects over five years for rural 19kV is estimated at $2,694,779.

The total cost over five years is estimated at $12,400,064, and therefore the adjusted annual cost is estimated at $3,472,018 (after including defects outside the inspection year).

Internal forecast results detailed and explained

The internal forecasting methodology has forecast a total of 706 defects over the next five years including P1, P2 and P3. Based on the defect remediation costs, this represents a five year forecast of $12,400,064 before adjustments. The forecast replacement expenditure is $3,472,018 (after including defects outside the inspection year) per year for five years totalling $17,360,089 over the regulatory period. This is explained further in the following sub paragraphs.

Volume of defects

The internal model has forecast a total of 706 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 12 below.

Table 12: Internal forecast of the number of defects during the regulatory period

Voltage	Rural number of defects	Urban number of defects
7.6kV	2	17
11kV	111	344
19kV	178	5
33kV	25	2
66kV	4	18

Cost per defect

The internal model has estimated the cost per defect for each voltage and location as given in Table 13 below.

Table 13: Internal forecast of the cost per defect

Voltage	Rural cost per defect	Urban cost per defect
7.6kV	$14,467	$18,659
11kV	$13,092	$16,885
19kV	$15,163	$19557
33kV	$26,856	$34,637
66kV	$44,598	$57520

Cost of replacement

The internal model has forecast the total replacement cost (before adjustment) at $12,400,064 during the regulatory period, which represents $3,472,018 per year (totalling $17,360,089 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 14 below.

Table 14: Internal forecast of the total cost during the regulatory period (before adjustment)

Voltage	Rural cost (unadjusted)	Urban cost (unadjusted)
7.6kV	$28,071	$316,729
11kV	$1,458,186	$5,801,878.97
19kV	$2,694,779	$90,360
33kV	$659,394	$87,160
66kV	$196,549	$1,003,623

E. Targeted Programs

A single targeted program of works relating to overhead conductor has been identified for completion between 2015 and 202, in addition to the planned replacement program described above. This project is to address a known issue with Wraploc on SWER feeders on the Eyre Peninsula.

PROPOSAL

It is recommended that 820 Wraplocs on 19kV SWER high voltage overhead conductor on various Eyre Peninsula feeders be replaced.

BACKGROUND

A strategy for long term management of failure needs to be considered as deterioration of conductor and Wraplocs will continue over time plus often underlying damage is not always evident until dismantled. This Wraploc construction appears to most prevalent on all SWERs in Ceduna, Streaky Bay and to a lesser degree on some Wudinna and Cleve feeders.

Table 15: Feeders with Wraploc to be replaced

Feeder	Wraploc	Last inspected	No of customers
CV22	10	2005	40
PA22	1	2001	25
SB23	3	2004	63
SD54300	1	2012	
W23	17	1998	51
W24	14	2006	75
CD17	36	2003	84
SB17	48	2009	147
SB18	223	1996	42
SB19	271	1996	72
W20	136	2003	55
W27	26	2010	61
W29	34	2011	99

OPTIONS ANALYSIS

A desk top review of the location of wraplocs has been undertaken and feedback from the field has been sought on the replacement of Wraplocs. Five options have been developed and considered to address the identified issue.

OPTION 1 – 'do nothing'

This option is unacceptable as the Wraploc condition has been assessed as poor and repeated failures are certain to continue.

- Advantages:

- Little or no capital expenditure in 2012

- Disadvantages:
  - Wraplocs have failed on numerous occasions and the likelihood of further failures is 'almost certain'

OPTION 2 – Whenever there is an outage near Wraplocs they will be replaced at the same time where possible.

- Advantages:
  - Improved reliability performance through reduced outages
  - Reduced operating costs by eliminating future failures
  - Opportunity maintenance undertaken with replacement of Wraplocs with other outages
- Disadvantages:
  - Capital cost in future years increased at a unknown value
  - Will take an unknown number of years to complete, and some will fail before replacement

OPTION 3 – Raise notifications and issue for replacement of Wraplocs with a map showing how the work can be grouped to reduce outages.

- Advantages:
  - Improved reliability performance through reduced outages
  - Reduced operating costs by eliminating future failures
- Disadvantages:
  - Capital cost
  - Will take an unknown number of months to complete, and some may fail before replacement

OPTION 4 – Raise small projects and replace Wraplocs on the first half on the feeder. When small projects are completed, use option 3 for the remainder of the replacements.

- Advantages:
  - Improved reliability performance through reduced outages to the whole of the feeder.
  - Reduced operating costs by eliminating whole of feeder failures
- Disadvantages:
  - Capital cost
  - Will only work where there is a large number of Wraplocs on the feeder

OPTION 5 – Raise projects to replace all Wraplocs on the feeders

- Advantages:
  - Improved reliability performance through reduced outages for Wraploc failures.
  - Reduced operating costs by eliminating future failures
- Disadvantages:
  - High Capital cost and requires a task force or similar.

RECOMMENDATION

It is recommended that a different option be used for different feeders depending on the number and position of Wraplocs on each feeder, with the following to be applied:

- Option 3 to be adopted for feeders with 50 or less Wraplocs on them. Individual notifications to be raised for each Wraploc and issued with a map of the feeder showing the position of Wraplocs to be replaced so that they can be grouped to reduce outages.
- Option 4 to be adopted for feeders with a large number of Wraplocs on them. Raise projects and replace Wraplocs on the first half of the feeder. This will reduce the chance of a whole of feeder outage due to a Wraploc failure. In the long term, use option 3 to complete the total removal of Wraplocs.

Figure 27: Examples of issues identified

F. 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.

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.

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 Overhead Conductor. The following steps were undertaken in development and calibration of the model.

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 year of the age profile does not contain a significant number fo assets.

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 8.2 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.

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 using

asset 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.

Model results

The results of the Repex modelling are shown in Table 16 and Figure 28 below.

Table 16: Total route length of overhead conductor to be replaced per annum from RepEx

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Route Length (km)													
< ≈ 1 kV	5.1	6.9	9.2	12.2	16.0	20.9	26.9	34.4	43.6	54.7	67.9	83.5	**381.4**
> 1 kV & < ≈ 11 kV	32.0	41.3	52.8	66.5	82.9	102.0	124.0	149.0	177.0	207.7	241.0	276.3	**1,552.5**
> 11 kV & < ≈ 22 kV ; SWER	10.0	13.6	18.3	24.4	32.0	41.7	53.6	68.2	85.8	106.9	131.6	160.3	**746.4**
> 22 kV & < ≈ 66 kV	2.0	2.4	2.9	3.4	4.0	4.7	5.4	6.3	7.2	8.2	9.3	10.4	**661.1**
TOTAL	**49.1**	**64.3**	**83.2**	**106.5**	**134.9**	**169.2**	**210.0**	**257.9**	**313.6**	**377.4**	**449.7**	**530.6**	**2,746.4**
Expenditure ($000s)													
< ≈ 1 kV	$0.19	$0.26	$0.35	$0.46	$0.60	$0.79	$1.01	$1.30	$1.64	$2.06	$2.56	$3.15	**$14.38**
> 1 kV & < ≈ 11 kV	$1.00	$1.29	$1.65	$2.08	$2.59	$3.19	$3.88	$4.66	$5.53	$6.49	$ 7.53	$8.64	**$48.52**
> 11 kV & < ≈ 22 kV ; SWER	$0.24	$0.33	$0.44	$0.59	$0.77	$1.01	$1.29	$1.65	$2.07	$2.58	$3.17	$3.87	**$18.01**
> 22 kV & < ≈ 66 kV	$0.05	$0.07	$0.08	$0.09	$0.11	$0.13	$0.15	$0.17	$0.20	$0.22	$ 0.25	$0.29	**$1.81**
TOTAL	**$1.49**	**$1.95**	**$2.52**	**$3.22**	**$4.08**	**$5.11**	**$6.33**	**$7.77**	**$9.44**	**$11.35**	**$13.52**	**$15.94**	**$82.71**

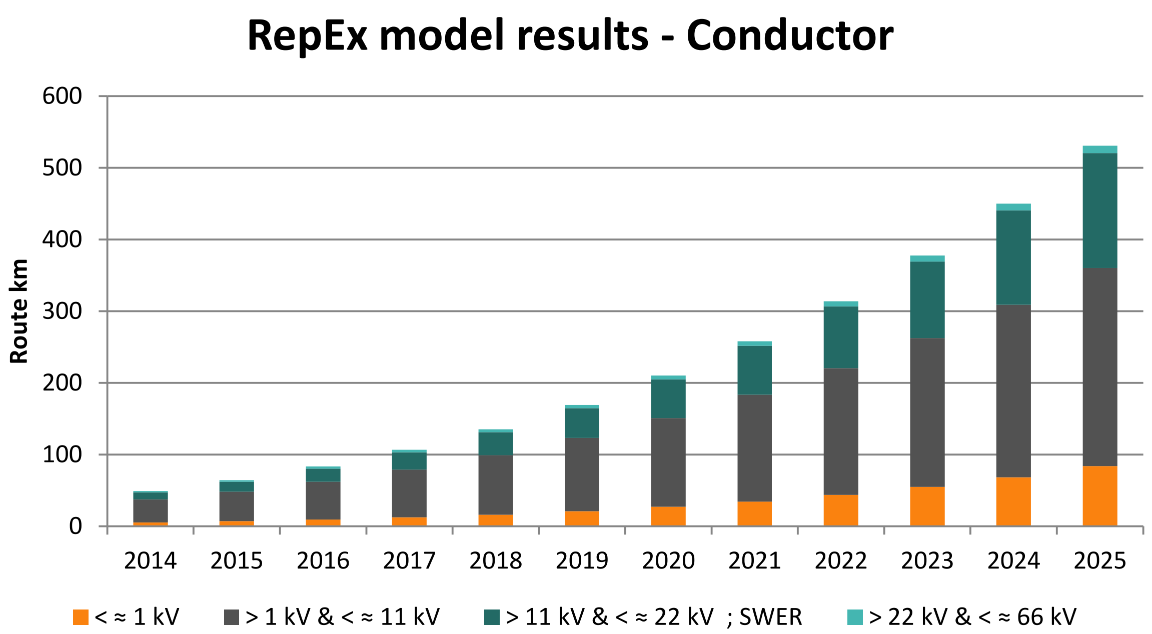

Figure 28: RepEx model results

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.

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 AER's 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 DNSP's 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.

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 AERs 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.

G. Definitions

ABC	Aerial Bundled Conductor
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).
DERR	SAP User Status Flag – Incorrect, duplicate, test or similar entry
Detailed Asset Management Plans	A set of AMP's which sit under the high level Asset Management Plan (Manual 15).
Disposal	Removal of assets from the asset base.
DLFL	SAP System Status Flag - Deletion
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.
IR	Infra-Red
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.
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.
NOCO	SAP System Status Flag – Notification Completed
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.
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
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.

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