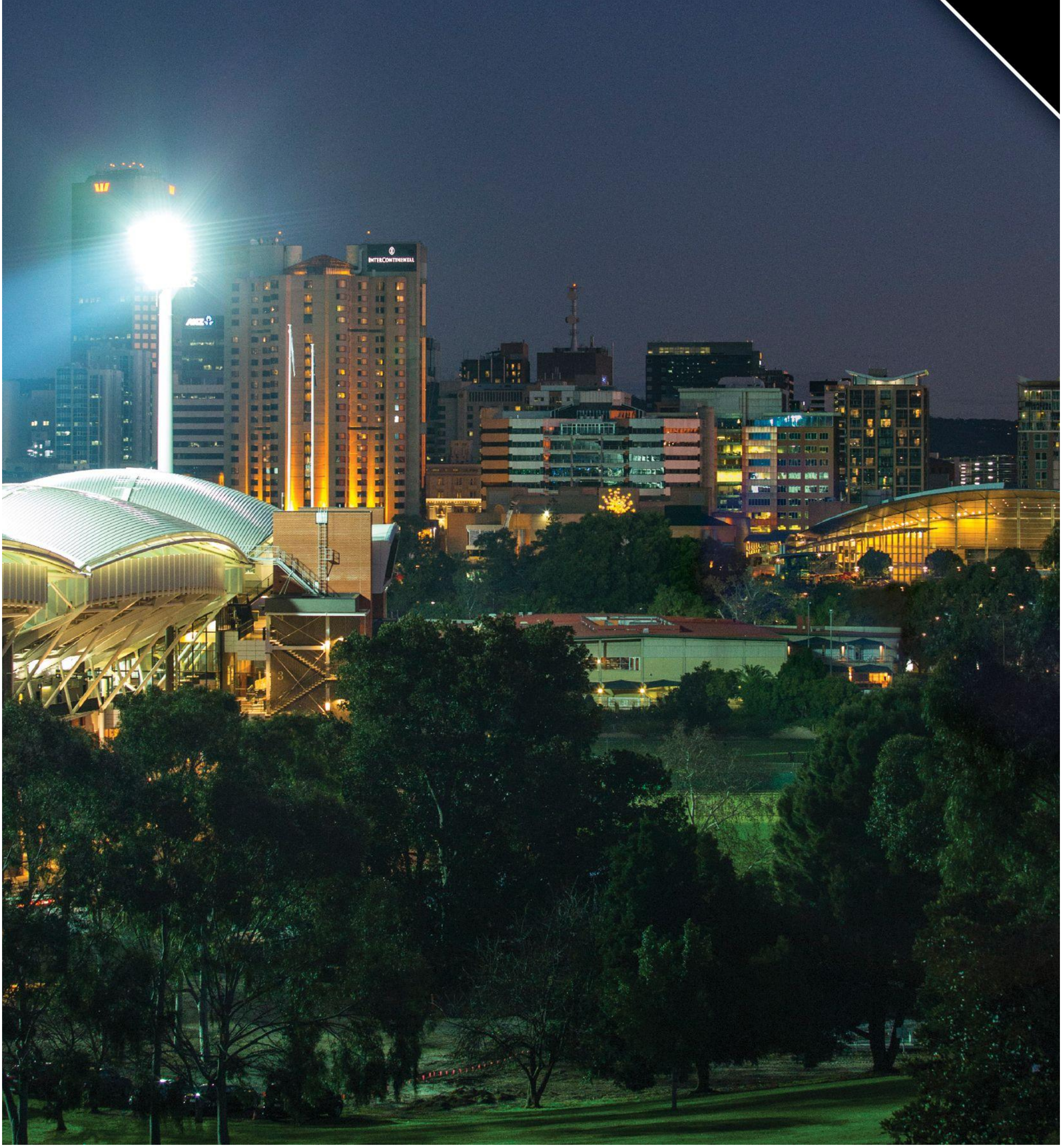
Attachment 20.15

SA Power Networks:
Pole Replacement Expenditure Justification

September 2014



Pole Replacement

Expenditure Justification

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SA Power Networks

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Table of Contents

1. Executive Summary

1.1 Purpose

The figure below shows the profile of pole replacement expenditure, indicating a sharp rise in expenditure over the current regulatory period, which we forecast will continue into the next regulatory period.

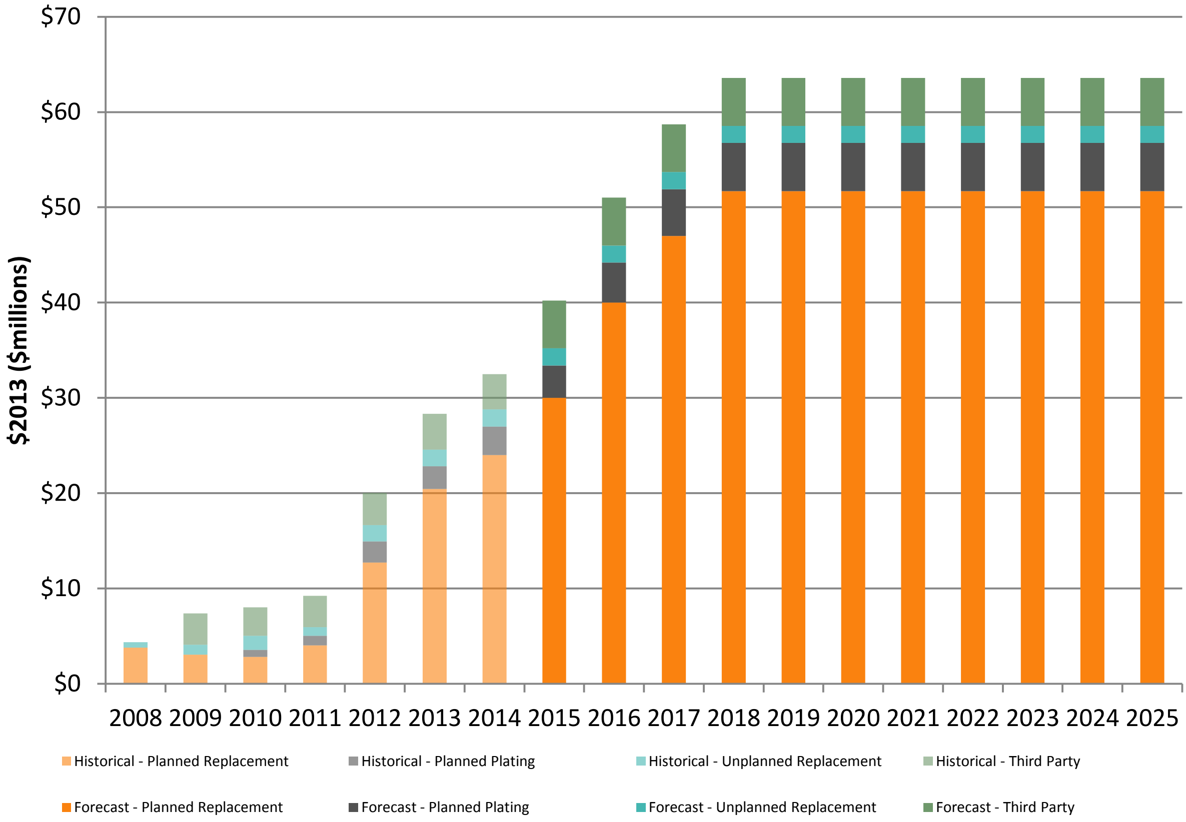

Figure 1: Pole replacement capital expenditure forecast

The purpose of this document is to justify why we believe that the Australian Energy Regulator (AER) should accept that our pole replacement forecast should be allowed for in our building block capital expenditure allowance, which forms part of our regulatory proposal to the AER.

1.2 The main factors behind the increases

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

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

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

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

Therefore, we have a need to increase pole replacements (and life extension through pole plating) in the next two regulatory periods if we are to manage risk back to acceptable levels.

1.3 Legal obligations

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 poles so that our risk is managed back to acceptable levels in accordance with our SRMTMP over the next two regulatory periods.

Our poles expenditure forecast aims to estimate the prudent and efficient level of pole replacement to allow us to comply with the approved SRMTMP.

1.4 Forecasting methodology

We have used two methods that approach the forecasting problem in different ways.

- We have, with the assistance of EA Technologies, developed a condition-based risk management (CBRM) model for our poles population. This type of model is used widely in this country and others, including the UK, to produce forecasts for regulatory purposes. This approach uses asset age and other asset information, such as condition, to make predictions of the state of the assets in the future, and in turn, their risk of failure. This model has been used to determine the volume of replacement activity (pole replacement and pole plating) that will be required to manage the level of risk back to acceptable levels. This has been achieved by assessing the effect on risks for a range of activity volumes.

- We have also prepared another model using a different predictive philosophy. This model uses historical volume and cost data associated with inspections, defect and replacements. This data is used to develop historical trends that are then used to estimate defect and replacement volumes and costs in the future. This model has been used to determine the volume of replacement activity (pole replacement and pole plating) that will maintain the volume of known defects at current level.

- We have found that these two models forecast similar replacement activity levels over the next regulatory period to achieve the assumed outcomes.

This modelling indicates that we will need to replace or extend the life of 1.3% of our pole population each year over the next regulatory period in order to manage our risk back to acceptable levels in accordance with our SRMTMP. Our expenditure forecast incorporates the following assumptions:

- We have set the proportion of pole replacement to our life extension option (pole plating) to be 50:50, which reflects the proportions we currently find feasible[1].

- We have used unit costs that reflect our average historical replacement and plating costs.

- We have profiled the required volume of replacements over the next period to ensure that the step increase from one year to the next is deliverable by us and our contractors at an efficient cost.

1.5 Why the AER should accept our forecast

The National Electricity Rules broadly requires that the capital expenditure forecast in our building block proposal should reflect[2]:

- the prudent and efficient costs

- to comply with our legal obligations, or

- maintain safety, reliability.

We believe that the AER should accept that our capital expenditure forecast associated with pole replacements (and plating) should form part of our capital expenditure forecast in our building block proposal for the following reasons:

- We believe that the forecast activity volumes are a reasonable estimate of the volume required to both:
    - comply with our legal obligations associated with delivering on our approved SRMTMP, and
    - maintain our levels safety.

[1] Pole plating is our preferred options as it is a much lower cost than replacement. However, this option is usually only feasible where the pole corrosion is predominantly at ground level.
[2] NER 6.5.7 (a) - capital expenditure objectives, and 6.5.7 (c) – capital expenditure criteria

- We have used reasonable approaches to forecast the volume of activity to achieve these objectives. One approach uses a type of model that has been accepted as suitable for regulatory purposes. Both models rely upon our asset data and have been calibrated to reflect our circumstances.

- We also consider that the forecast volumes and expenditure are broadly supported by other assessment techniques the AER could apply:

    - Benchmarking, we have commissioned, using RIN data indicates that we have one of the oldest networks and have been replacing at one of the lowest levels, supporting our claim that replacement volumes need to increase.

    - We have also used the AER's repex model to infer the pole lives suggested by our volume forecast. This analysis suggests an average pole life of around 73 years (or an average replacement or refurbishment of 1.4% of the population per annum), which we consider is reasonable given the service life we expect from our Stobie poles.

- It is prudent to manage identified defects in the manner we have proposed. Our forecast allows for the critical (i.e. high risk) defects to be addressed strictly within the documented remediation timeframes. However, our forecast assumes that these timeframe can be relaxed for lower risk defects, facilitating our risk-based approach to addressing defects.

- We have allowed for the prudent and efficient solutions to address the forecast needs. As noted above, we have allowed for the much lower cost life extension option in our forecast. We have used recent history to estimate the proportion of poles where the use of this lower cost solution should be possible.

- We have allowed for the efficient unit cost for the assumed solutions. Our unit costs are based upon our historical costs. A large proportion of these cost are a result of open competitive tender practices. Furthermore, the management and delivery of our services has been found to be good practice. This view is also supported by our own benchmarking and the AER's, which both suggest we are at or near the efficient frontier.

- We have profiled the forecast to reflect a prudent and efficient delivery timeframe.

Taken together, we believe that these points provide a compelling case that the AER should accept our pole replacement expenditure forecast.

2. Introduction

2.1 Background

Our distribution network and poles population

We have one of the oldest distribution networks in the National Electricity Market (NEM) based on data sourced from the AER Category Analysis Regulatory Information Notices (RIN) data published 25 June 2014. A large portion of our poles were installed between the 1950s and 1970s, and so, are now over 50 years old.

Our poles are fairly unique in the NEM in that the majority of our poles are of a steel and concrete design, known as a Stobie pole. Stobie poles are more expensive than the wood poles more commonly used in other jurisdictions. Typically, however, they last longer, and so we have found them to have lower life-cycle costs.

Due to this longer life, historically, we were not seeing a significant number of pole failures. Consequently, the planned replacement of poles has not been a significant concern to us. But the aging of the network means we have been transitioning into the replacement cycle and so the need to replace poles has been increasing.

The changing safety environment

Since 2007, we have been improving our asset management practices and systems. A major part of that improvement has involved a transition from a "replace-on-fail" approach to a "replace-before-fail" approach for our more critical assets. This approach makes use of better information that is now available on the condition the assets and improved analysis techniques that allow us to assess the risks of asset failure.

The need for this change in how we managed assets has been brought into sharp focus by recent events such as the 2009 Victorian bushfire and serious incidents in Western Australia. These events have provided a greater realisation across the industry of the significant safety risks posed by defective network assets in sensitive areas.

Consequently, the environment we are now in with regard to developing safety management plans and interacting with our jurisdictional safety regulator, the SA Office of the Technical Regulator (OTR). There is now greater emphasis on ensuring that our network complies with current technical standards.

Implications on pole replacements

As part of these changes, we have reduced inspection cycles in critical regions, improved our overhead line inspection practices and developed an accreditation regime for our Asset Inspectors. This however has resulted in a significant increase in the volume of defects we have been identifying. Consequently, there has been a recent sharp increase in the volume of replacements and life extension activities we have needed to undertake on our poles.

Importantly, the volume of defects and replacement activity is greater than we envisaged when we made our previous proposal to the AER. It is also above what the AER allowed for in its determination.

Furthermore, although this new inspection regime was introduced in 2010, we are still in a transitional phase due to the significant lead-time in sourcing, training and accrediting asset inspectors. We have still to inspect a significant portion of our network and aim to complete this

first cycle by 2018. Consequently, we are predicting that pole replacement activities and associated expenditure will continue to rise during the next regulatory period.
It should noted that despite the above noted changes to our inspection practices our criteria for pole assessment, as explained in Section 4.3, have remained unchanged over the same period, ie we are utilising the same criteria today as we were in 2010 for deciding whether a pole should be replaced, plated, or monitored.

2.2 Purpose

Figure 2 below shows the profile of pole replacement expenditure, indicating the sharp rise in expenditure over the current regulatory period, which we forecast will continue into the next regulatory period.

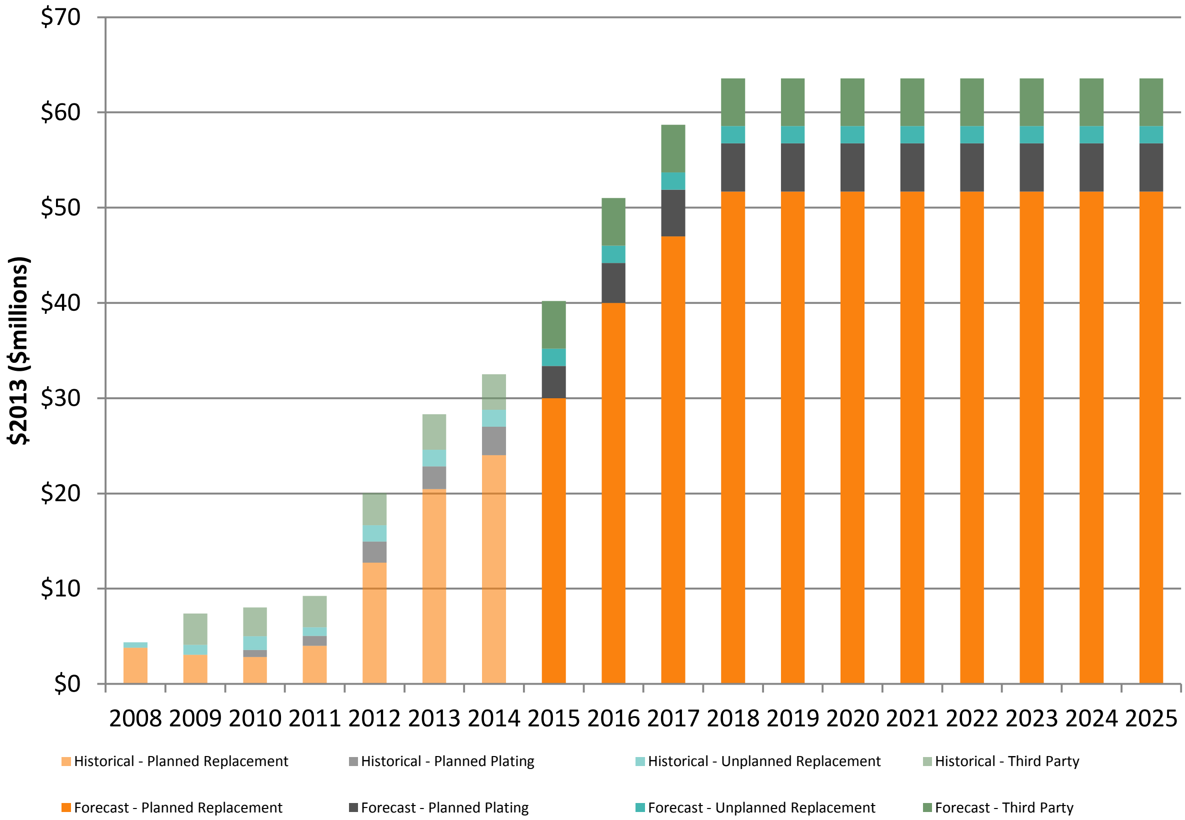

Figure 2: Pole replacement expenditure forecast

The purpose of this document is to justify why we believe that the AER should accept that our pole replacement forecast should be allowed for in our building block capital expenditure allowance, which forms part of our regulatory proposal to the AER.

In this regard, this document aims to justify why we believe that the forecast is in accordance with the NER expenditure objectives and criteria[3].

[3] Ref to NER clauses

2.3 Structure

To achieve this purpose the document is structured as follows:

- In section 3, we discuss the legal obligations that underpin our need to undertake these replacement activities. Importantly, this explains how these should be viewed in the context of the NER expenditure objectives.

- Section 4, provides an overview of the relevant inspection practices and replacement criteria that underpin our actual replacement decisions. This is followed in Section 5 with a more extensive explanation of why expenditure has been recently increasing so sharply. These two sections provide useful background on how we manage our poles in order to prudently comply with the legal obligations and why this has led to an increase in replacement activity. This in turn provides important context on our forecasting methodology that should aid in appreciating why our forecasting methodologies and the resulting expenditure profile reasonably reflect the prudent approach to complying with our legal obligations in the next regulatory period.

- Section 6 then explains the methodologies we have used to prepare the forecast, including the assumptions that underpin this forecast. This section also explains why we believe these methodologies produce a reasonable forecast of the level of expenditure that will enable us to prudently and efficiently comply with our legal obligations.

- In Section 7 we provide other analysis we have undertaken, using some of the assessment techniques we understand the AER may apply to assess our expenditure. We have used the findings from this analysis to validate our forecast.

- In Section 8, we draw all these matters together to summarise why we believe the AER should accept that our pole replacement forecast, in the context of our overall capex forecast set out in our building block proposal, is in accordance with the NER capital expenditure objectives and criteria.

3. Legal obligations

This section explains the legal obligations that underpin replacement forecasts. This understanding is important in appreciating why our expenditure forecast is in accordance with the NER capex objectives and criteria.

3.1 Obligations and requirements

The need for the replacement activities allowed for in our pole forecast largely relate to our legal obligations to operate a safe network.

Part 6 of the South Australia Electricity Act 1996 sets out our obligations in this regard. Of particular note here, Section 60 sets out our responsibilities as an owner or operator of an electricity network covered by this act, stating:

> *"(1) A person who owns or operates electricity infrastructure or an electrical installation must take reasonable steps to ensure that—*
>
> > *(a) the infrastructure or installation complies with, and is operated in accordance with, technical and safety requirements imposed under the regulations; and*
> > *(b) the infrastructure or installation is safe and safely operated.*
> > *Maximum penalty: $250 000."*

Division 1, Part 10 of the South Australia Electricity (General) Regulations 2012 set out the safety requirements related to the operation of our overhead lines, where Section 48 states

> *"(1) Aerial lines (including service lines) must be designed, installed, operated and maintained to be safe for the electrical service conditions and the physical environment in which they will operate.*
>
> *(2) Without limiting the effect of subregulation (1), line construction in a bushfire risk area must be suitable for the levels of hazard in the area.*
>
> *(3) Schedule 1 applies in relation to aerial lines (including service lines) installed after 1 July 1997."*

Section 12, of Schedule 1 of these regulation then provide more specific requirements associated with the maintenance of our overhead lines, stating:

> *"(1) Aerial lines, their structures and components must be maintained to be in a safe operating condition.*
>
> *(2) A system of maintenance must be instituted for aerial lines, their structures and their components, including—*
>
> > *(a) predetermined processes to confirm the safe state of components;*
> > *(b) managed replacement programs for components approaching the end of their serviceable life.*
>
> *(3) Maintenance programs must be carried out in accordance with the listed standards."*

The listed standard in the Regulations covering our poles is ENA C(b)1. However, for management purposes this standard has been superseded by AS/NZ 7000, which is the Australian Standard, released in 2010, that covers similar matters.

Importantly, to provide some oversight on our adherence to our regulations, including our safety obligations, Section 23 of the South Australia Electricity Act 1996 also provides requirements on us to develop management plans, stating:

> *" (1) The Commission must make a licence authorising the operation of a transmission or distribution network subject to conditions determined by the Commission—*
>
> > *(c) requiring the electricity entity—*
> >
> > > *(i) to prepare and periodically revise a safety, reliability, maintenance and technical management plan dealing with matters prescribed by regulation; and*
> > > *(ii) to obtain the approval of the Commission (which may only be given by the Commission on the recommendation of the Technical Regulator) to the plan and any revision; and*
> > > *(iii) to comply with the plan as approved from time to time; and*
> > > *(iv) to audit from time to time the entity's compliance with the plan and report the results of those audits to the Technical Regulator; and"*

Section 72 of Division 5 of the regulations prescribe what we must cover in these plans, stating:

> *"(2) For the purposes of sections 22(1)(c) and 23(1)(c) of the Act, the following are matters that must be dealt with by a safety, reliability, maintenance and technical management plan:*
>
> > *(a) the safe design, installation, commissioning, operation, maintenance and decommissioning of electricity infrastructure owned or operated by the person;*
> > *…"*

These plans are known collectively as our safety, reliability, maintenance and technical management plan or SRMTMP. Importantly, the SRMTMP must be approved by the relevant regulatory body, which is the Essential Services Commission of South Australia (ESCOSA) on the recommendation of the South Australian Office of the Technical Regulator (OTR) and we must comply with the approved plans. In accordance with these obligations, audits are routinely undertaken to assess compliance with these obligations.

In appreciating the significance of these obligations on our replacement needs, the SRMTMP directly references our internal procedures that define how we undertake our line inspection practices, including how we assess and grade pole defects and the criteria associated with the remediation of these defects, including pole replacement and refurbishment activities. As such, we have a legal obligation to comply with these internal procedures, via the approved SRMTMP. We will discuss our specific practices in more detail in Section 4.

Our replacement forecast has been developed to allow for what we consider to be the prudent and efficient level of compliance to our stated practices. Importantly, the level of compliance, and the resulting increases in replacement activity, should be seen in the context of the changing safety environment that we noted in the introduction. We will discuss this changing environment further in Section 5.

4. Asset management practices

In the preceding section, we noted that we have legal obligations to comply with our ESCOSA approved internal procedures that set out how we must safely manage our overhead lines. This section summarises our practices as they relate to poles, covering the physical asset management activities that we apply to determine the need to replace or refurbish poles.

4.1 The SRMTMP and covered SA Power Networks documents

As discussed in Section 3, the SRMTMP links our legal obligations set out in SA legislation to our internal management documentation. The internal documentation covers a suite of manuals, technical standards, guidelines, procedures and processes that are referenced through the SRMTMP. Dependent upon the nature of the document, each is classified under one of four major categories. The diagram below shows the separate categories as well as the hierarchy of the internal categories from the highest to the lowest in descending order.

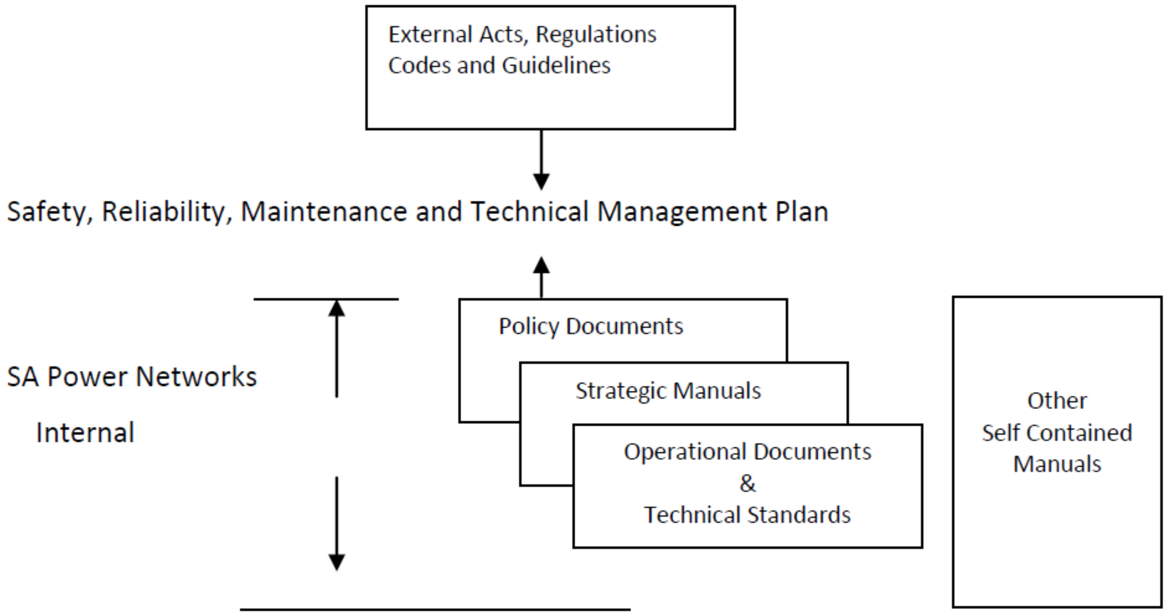

Figure 3: SRMTMP referenced internal document structure

Section 4 of the SRMTMP sets out the relevant documents associated with the safety and technical aspects of the maintenance of our network, including our poles.

The specific referenced documents most relevant to the preparation of the poles forecast are as follows:

- Network Management Asset Management Plan (No. 15), which is a policy document that describes how the electricity distribution network assets of SA Power Networks are managed by the Network Management group on behalf of the asset owners, customers and stake-holders. The Manual provides focus within SA Power Networks Network Management group for the purpose of ensuring that the integrity of the electricity distribution network and associated assets are effectively managed over the life cycle of the various assets.
- The Network Maintenance Manual (No. 12), details the strategies which govern SA Power Networks maintenance practices. The manual is designed for use by SA Power networks

employees, from executives to field personnel involved in the maintenance of network assets. It details SA Power Networks network maintenance strategies and also specified the responsibilities associated with those strategies.

- The Line Inspection Manual (No. 11), provides a detailed guide in assessing the condition of our line assets, including poles. This included definitions of what constitutes a defect, maintenance risks associated with defects, and priorities for rectification of defects. It embodies the knowledge, intent and experience of inspectors, coordinators, and maintenance engineering specialists.

The documents listed above provide a detailed explanation of the maintenance and replacement practices applied to our poles, covering:

- Inspections and inspections cycles - how and how often we inspect the condition of poles.
- Defect identification - how we measure the condition of poles and determine whether they are defective.
- Defect intervention – how we decide whether we need to replace or refurbish a pole and over what time period.

These management practices and the detailed operating and capital plans that result from them are then developed into our Poles Asset Management Plan (Poles AMP 3.1.05).

4.2 Pole inspections and inspection cycles

Like other distributors, we inspect our poles periodically. The period between inspections, known as the inspection cycle, is set to reflect the expected deterioration rate of the asset and the criticality of the location. That is, poles in a higher risk environment have a shorter inspection cycle than those in a lower risk environment.

For defining the appropriate inspection cycle, we classify our poles based upon two parameters that reflect the location of the poles:

- The corrosion zone, which reflects the rate of corrosion we may expect given the environmental conditions. This is graded as either low (CZ1), severe (CZ2) and very severe (CZ3).
- The bushfire risk zone, which is graded as a high bushfire risk, medium bushfire risk, or non bushfire risk.

Maps of these zones are provided in the Poles AMP 3.1.05.

Importantly, we increased the frequency of our inspection cycles in the current regulatory period in the high corrosion zones. This change is one of the factors that has driven the recent increase in replacement volumes. The reason for this change will be discussed further in Section 5.

In response to the realisation of greater risks in areas prone to bushfires, our regulatory proposal allows for some further changes to our inspection cycles in these areas. The reasoning and justification for these further changes is set out in Asset Inspection Strategy Business Case.

However, it is worth noting that we are not expecting these further changes to have a material effect on the volume of replacement activities.

Our historical, current and planned inspection cycles are summarised below:

- Historically (pre 2010)
  - 10 years in all regions

- Currently (2010 – 15)
  - 5 years in severe and very severe corrosion zones
  - 10 years elsewhere

- Planned (beyond July 2015)
  - 5 years in all medium and high bushfire risk areas
  - 5 years in severe and very severe corrosion zones
  - 10 years elsewhere

4.3 Defect identification and grading

Measuring the condition of poles

We perform various investigations on the condition of each pole that we inspect. These investigations are set out in the Line Inspection Manual.

Importantly, an estimate of the structural strength is made for each pole inspected. This measure indicates whether the pole may fail while in service for mechanical loadings that could be normally anticipated.

This testing involves estimating the structure strength of the pole at critical loading points, covering the ground-level and above ground. For our Stobie poles, this testing involves measuring the amount of good steel such that the structural strength can be estimated and compared against the AS/NZ 7000 standard.

Assigning a risk score based upon the condition

To facilitate our risk-based approach to maintaining our network, we calculate a "score" for all assets inspected that reflects the risks associated with the measured condition of the asset and the assets criticality. This score is known as the maintenance risk value, or MRV. The calculated MRV of an inspected asset is a critical parameter that we use to define grade the severity of the defect and define the timeframe for any remediation actions.

The method for determining the MRV is defined in our Network Maintenance Manual and Line Inspection Manual.

For poles, the MRV is calculated based upon the following:

- probability of failure, which is a qualitative measurement;
- defect severity;
- consequence of failure, covering environmental, safety, quality, and reliability impacts;
- consequence of fire start; and
- number of customers affected.

The MRV of a defect is significantly influenced by the probability of failure and severity of defect, but to a lesser degree by the other factors[4]. Defects and their management are graded as followed, based upon their MRV:

- P1 - Defects with a MRV of 190 or greater are classified urgent (P1) as they pose a significant / likely risk to safety or interruption to supply. These defects should be rectified within 28 days.

- P2 - Defects with a MRV of between 90 and 189 are classified non urgent (P2) as no plant failure has occurred but there is possible potential to deteriorate / fail. These defects should be rectified within 180 days.

- P3 - Defects with a MRV of between 50 and 89 are classified unlikely (P3) to fail but degradation may slowly continue. These defects should be rectified within 720 days.

- P4 - Defects with a MRV of between 1 and 49 are classified as ongoing condition monitoring.

The Maintenance Requirements Matrix For All Maintenance provides further details associated with the causes and identification of defects of our assets, including poles.

4.4 Defect and replacement activities

As noted above, the three most severe defect grades (ie P1, P2 and P3) indicate that the pole is beyond its acceptable strength limit or is unlikely to have a sufficient margin to ensure it will reach its next inspection before the residual strength has reduced beyond this limit.

In these instances, we determine what actions we must take. There are two options which are covered by the replacement forecast:

- Pole plating - Our preferred option is to extend the life of the pole. For Stobie poles, which make up the vast majority of our poles, this involves welding additional steel plates to the pole to increase it structural strength. Hence, we call this pole plating[5] and an example is shown in Figure 4. This is our preferred approach as it is a much lower cost solution than replacing the pole and can extend the life of a pole by as much 20 to 30 years.

[4] Further information on calculating the MVR is contained in Section 9.4 and 9.8 of the Line Inspection Manual.
[5] This approach is analogous to pole nailing or staking, which is used on wood poles to extend

Figure 4: Pole Plating being undertaken

- Pole replacement – Where pole plating is not feasible, we replace the pole. Our preferred pole replacement is the Stobie pole. We believe this type of pole provides the lowest life-cycle costs of available pole types in most circumstances. However, due to the greater mechanical loading designed into our network through our existing use of Stobie poles, the like-for-like replacement of a Stobie pole with another Stobie pole is typically the most feasible. Importantly, due to these different loading requirements, the AER should not assume that cost of a wooden pole used in other jurisdictions will be comparable to the wooden pole we would require for similar circumstances, for example all attachments are designed to fit to Stobie poles therefore the cost associated with redesign, sourcing and fitting of replacement of all attachments would need to be considered in addition to the cost of the pole.

As noted above, there are circumstances when our preferred option of pole plating is not considered the prudent or efficient solution. These circumstances cover:

- Poles that have been previously plated – to replace a plated pole, the previous plate needs to be removed, as the amount of steel on the pole under the plate cannot be assessed prior to removing the plate it must be assumed that no steel remains. This results in the pole needing to be secured with a crane to ensure the safety of personnel and the public. This can increase the plating cost to the point where replacement is more efficient.

- Poles with significant above ground damage – plating is designed to restore strength to the region on the pole affected by ground level corrosion (typically from ground level to 150mm below the surface). If there is significant damage, such as corrosion of sections, missing concrete, significant impact damage, then the above ground structural strength will still not meet AS/NZS 7000 requirements.

5. Recent pole replacement increases

This section provides an overview of the factors that have caused expenditure (and replacement volumes) to significantly increase over the current regulatory period.
The aim of this section is to explain the technical matters causing these increases and explain how this has affected our knowledge of risks. This understanding aids in the appreciation of the defect forecasting methodology that follows.

5.1 Our main concern with pole failure

As suggested previously, our main concern with the structural failure of a pole is one of safety. Importantly, improving reliability is not a significant driver of our need to replace Stobie poles[6].

The two main consequences that we seek to avoid through limiting the number of structural failures are bush fires and direct impact damage.

The consequence of structural failure causing bush fires is dependent upon the location of the pole. The network has been categorised according to the perceived level of bushfire risk, with areas of particular risk identified as Non Bushfire Risk Areas, Medium Bushfire Risk Areas and High Bushfire Risk Areas.

Figure 5: Fire Started by pole failure - ST22 Bagley Bridge 11kV Feeder

[6] Historical failure data does not suggest that reliability deterioration due to pole failures is a significant issue.

The consequence of direct impact following structural failure is deemed to be more significant in urban areas, where the possibility of the failure directly injuring the public is much higher than in rural regions.

5.2 Ageing network and other factors driving risk

We expect the service life of Stobie poles typically to be between 45 and 80 years depending upon the inherent corrosiveness of the installed location. As noted in Section 3, we typically expect plating to extend the life of suitable poles by 20 to 30 years.

The first Stobie poles were installed in 1924, and an assessment of the current age profile indicates that the majority of poles have been installed for between 30 and 60 years. As such, the pole population is moving into the period where defects could be expected to increase depending upon location and other factors, and therefore, replacement expenditure can be expected to increase if we are to avoid serious safety incidents in the future.

5.3 Changing perception of risk

5.3.1 Our changing inspection regime

Prior to the current regulatory period a 10 year inspection cycle applied across all powerline assets.

Although there was no significant rise in structural failures, the risk of structural failure could not be stated with confidence as the age of the pole population was moving into the period where the rate of defects is expected to increase. That is, the condition of poles and the resulting risk of structural failure was not fully known.

Therefore, leading into the current regulatory period, we had approved by the OTR an inspection regime with associated defect rectification standards. This change to a 5 year inspection cycle in high corrosion zones was accepted by the AER in its determination for the current period.

Recognising the likely heterogeneous level of risk (driven by both probability and consequence of failure) across the network, we embarked upon a prioritised inspection regime. This program had a number of areas of focus, specifically:

- those poles with the longest time elapsed from previous inspection
- those poles in a high bushfire risk area
- those poles in a high corrosion risk area.

5.3.2 Significant increase in the perceived level of risk

As noted in Section 4, we use the Maintenance Risk Value (MRV) to rank defects. The MRV represents the level of risk associated with known network defects that could, within different timeframes, lead to structural pole failure.

As can be seen in the following figures, the recorded MRV has increased significantly since the introduction of the targeted inspection regime. It should be noted that this does not represent the entire MRV as there are still parts of the networks that are not in the approved inspection cycle.

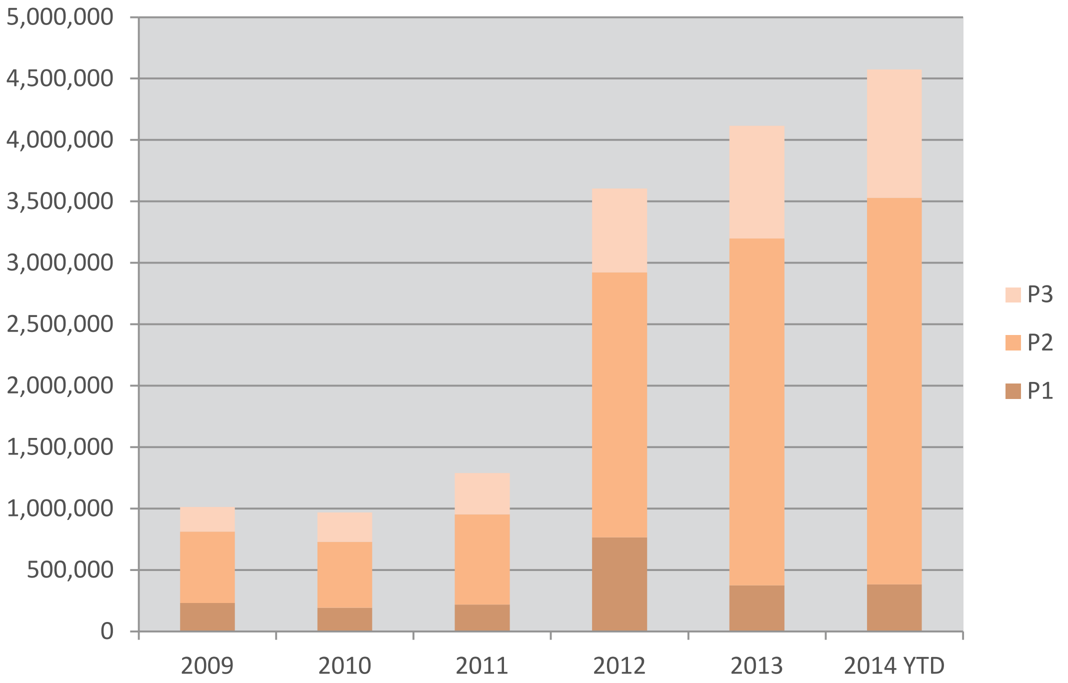

Figure 6: Overall Maintenance Risk Value by defect priority for 2009 to 2014 – all powerline assets (P1 being the highest)

As such, compared with the time at which the preventive maintenance regime was approved, the level of risk (as measured through the MRV) has increased significantly.

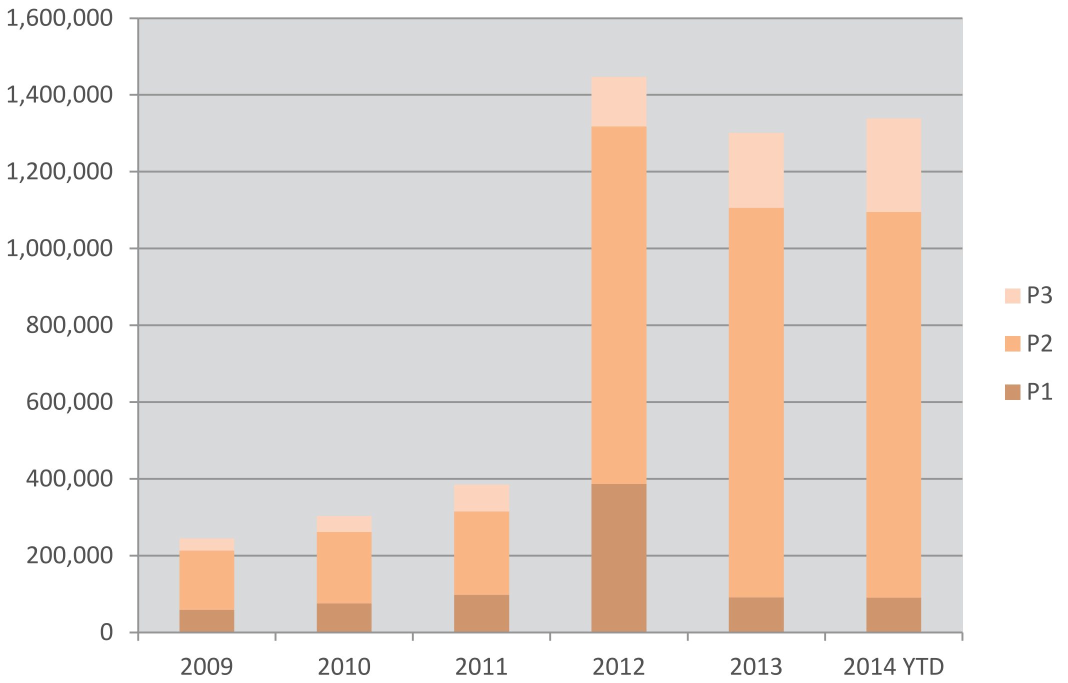

Figure 7:Pole Replacement Maintenance Risk Value by defect priority for 2009 to 2014 (P1 being the highest)

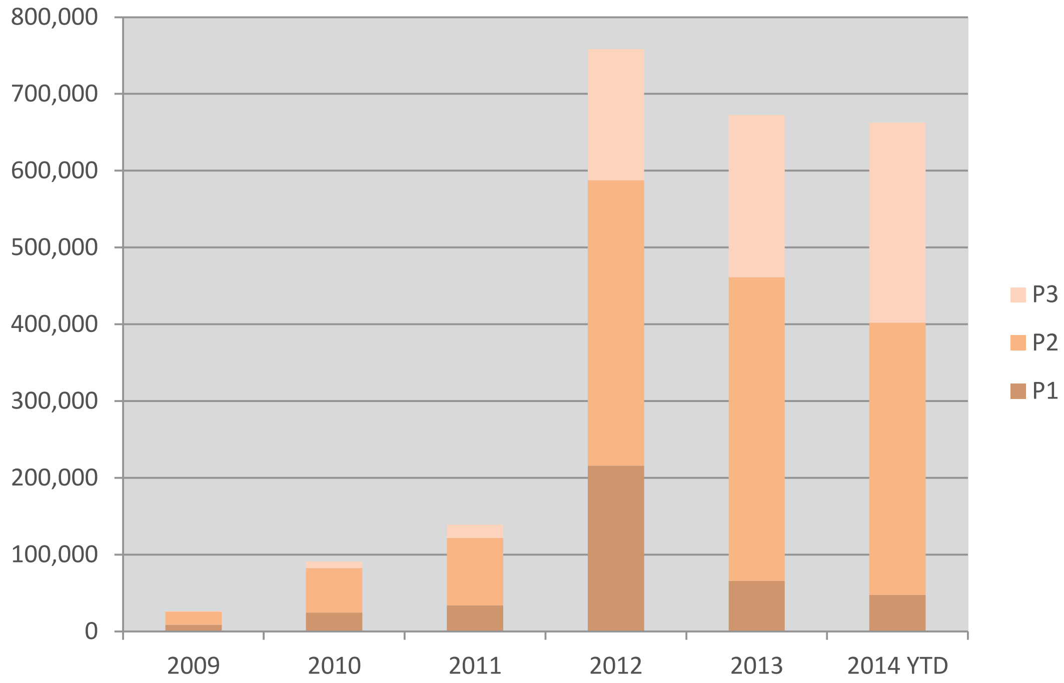

Figure 8: Pole Plating Maintenance Risk Value by defect priority for 2009 to 2014 (P1 being the highest)

The following figures show the number of defects identified over the same period and the rising number of poles requiring replacement or plating.

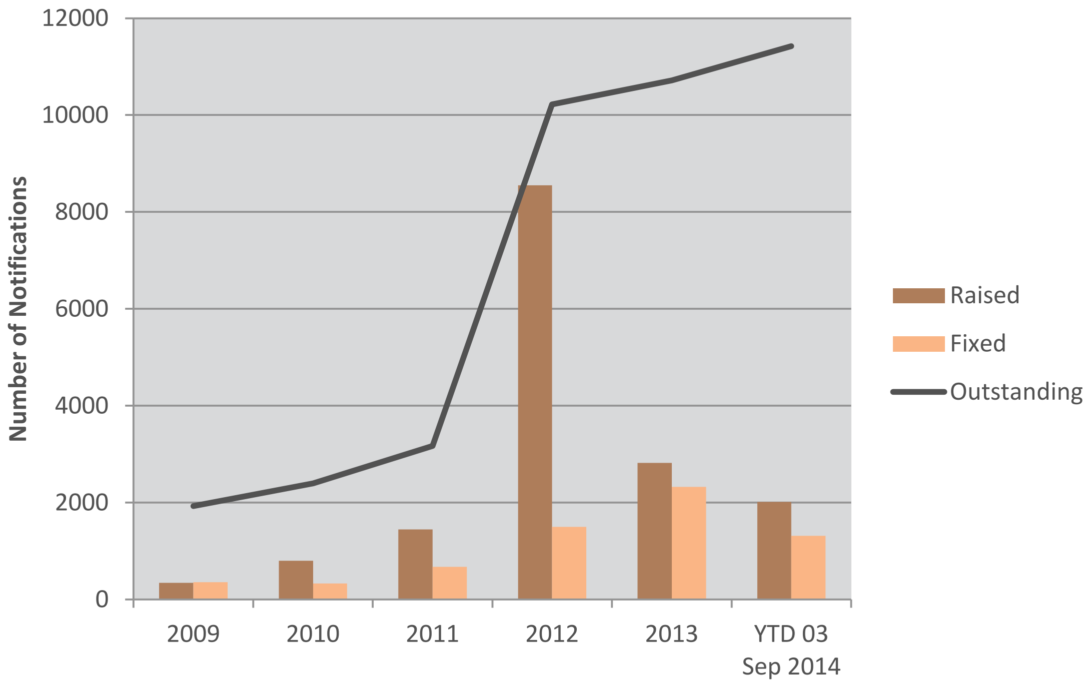

Figure 9:Pole Replacement Notifications for 2009 to 2014 (P1 being the highest)

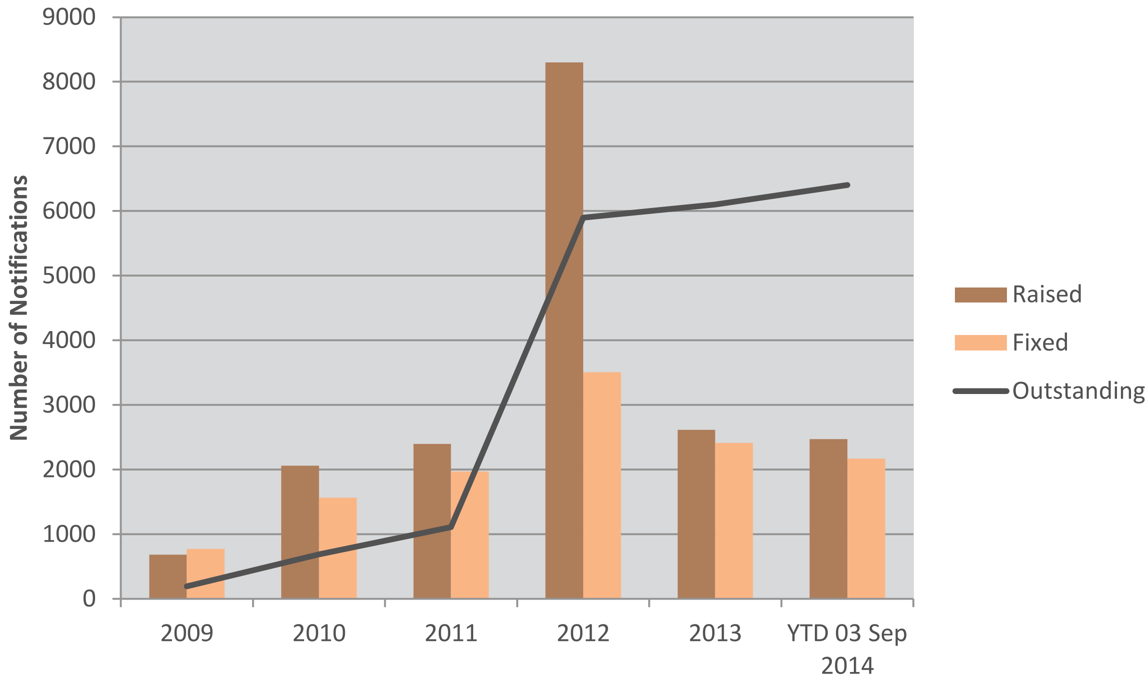

Figure 10: Pole Plating Notifications for 2009 to 2014 (P1 being the highest)

5.4 Increased level of intervention expenditure

As a result of the increased awareness of defects, we needed to increase the number of pole interventions in accordance with the rules applied to level P1, P2 and P3 defects.

As can be seen in Figure 11 there has, during this regulatory period, been an increase in replacement expenditure. Replacement expenditure covers both replacement and plating.

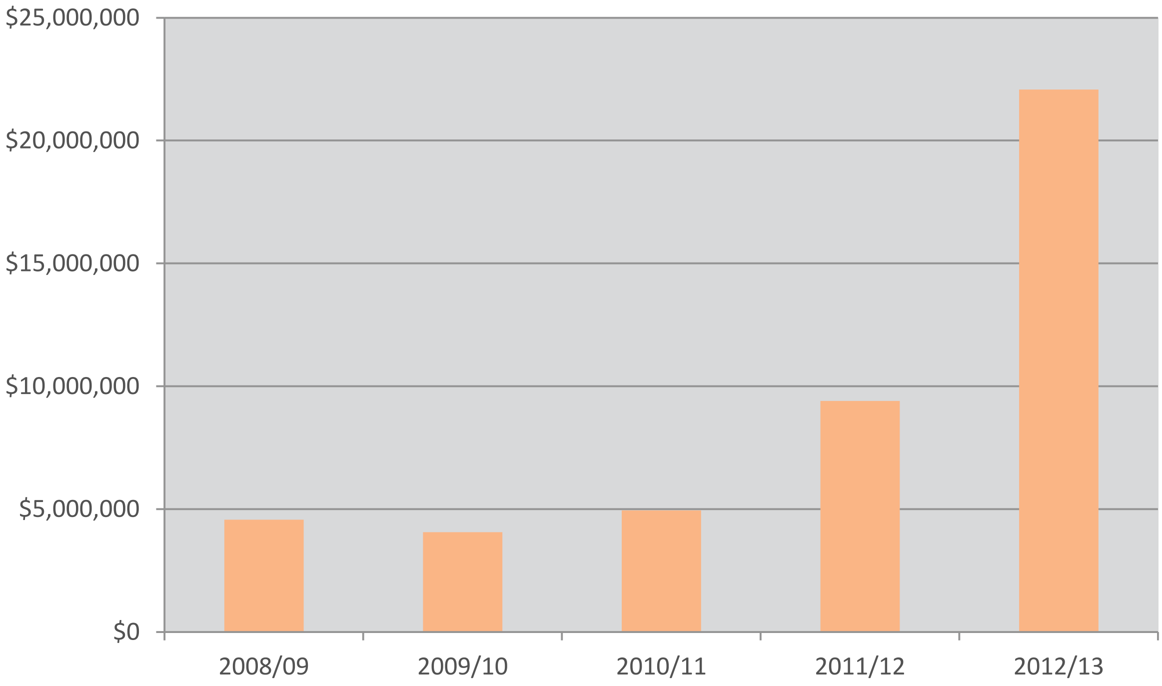

Figure 11: Total pole replacement expenditure for the financial years 2008/09 to 2012/13 (Source: Category RIN data)

6. Forecasting required and intervention on our network

6.1 Forecasting methodologies

Due to the unique nature of our pole population, specifically the extensive use of Stobie poles, two independent methods were used when considering the forecast for intervention expenditure.

Stobie poles were originally designed for use in South Australia, and this is the only place they have achieved widespread use. Further, given the age profile of our poles, we have limited experience with poles that reach the end-of-life, except in the more corrosion-prone areas.

As a result, there is no significant population against which the performance our poles can be compared, and historical data sets are limited. As such, when forecasting the level of intervention required it was deemed prudent to use two independent models that use fundamentally different forecasting approaches.

Consistent with the shift toward a more risk-based approach, the two chosen methodologies, whilst being different, are both based on the level of risk being borne by the network. The two approaches are the Condition Based Risk Management (CBRM) approach from EA Technologies and an internally developed model.

In brief:

- the SA Power Networks Multi-Variable Defect forecasting Model produces forecast of the cost of remedying predicted defects using trends developed from historical defect information
- the CBRM approach forecasts failure risks with and without intervention by simulating the further degradation of the condition of poles, using the current pole age, condition and other data.

6.1.1 Internal forecasting method explained

The internal forecast is based on historical defect data. The model produces forecasts of the expected number of defects and expected rectification cost per defect for each location, corrosion zone and voltage level. These factors combined give a forecast of the total replacement expenditure.

6.1.1.1 Calculating the expected number of defects

The expected number of defects is calculated for each location (rural or urban), voltage [7](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

[7] LV defects, including poles, are allocated to the associated feeder, rather than to an LV classification. For example a defect on a pole on an LV line connected to an 11kV feeder would be allocated to the 11kV feeder in the modelling.

length of feeders in that location and corrosion zone. This assumes that the data sets are sufficiently large for each combination of location and corrosion zone.

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

6.1.1.2 Calculating the cost per defect

The cost per defect is calculated for each location and voltage using historical data for both pole plating and pole replacement, with the defects and resulting interventions modelled separately..

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 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 feeders for which the cost is zero or negative, or the user status code contains "DERR" (flagging duplicate or incorrect records) or "DLFL" (flagging records to be deleted) or the system status does not contain "NOCO" (flagging notification complete, i.e. the defect has been closed through repair or removal).

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.

6.1.1.3 Calculating the cost of replacement

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

The final value of the cost of replacement per year is the five-year total multiplied by 0.28, and then multiplied by (1.135/1.25). The factor 0.28 is to convert five years to a single year and add an additional 40% to account for defects that occur outside the inspection year, based on an assumed rate of 10% per year for the four years not in the inspection period which is derived from actual SA Power Networks data and expereince. The factor (1.135/1.25) is to remove all overheads and add back network and business overheads, assuming that overheads add 25% to the base cost and network and business overheads add 13.5%.

6.1.2 Internal forecasting methodology by example

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

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

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

The expected number of defects over five years for urban CZ2 7.6kV is 533.27. The expected number of defects over five years for urban 7.6kV is 533.80, and the total expected number of defects over five years is 10,851.

For rural 11kV feeders, there are a total of 1019 defects included in the sample at a total cost of $9,680,045 and therefore the cost per rural 11kV defect is estimated at $9,499.55.

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

Therefore the total cost of defects over five years for urban CZ2 7.6kV is estimated at $7,219,908, and the total cost of defects over five years for urban 7.6kV is estimated at $7,227,005.

The total cost over five years for all locations, voltages and corrosion zones is estimated at $142,545,459, and therefore the adjusted annual cost is estimated at $39,912,729 (after including defects outside the inspection year) or $36,240,758 (after adjusting for overheads) per year for ten years.

6.1.3 CBRM model explained

The CBRM model (developed by EA Technologies) bases its expenditure forecast on the Health Index rating which is a score assigned to each pole based on the age, condition and other factors affecting its working life. The Health Index is calculated in several stages (initial HI1, intermediate HI2 and final HIY0) and then used to calculate the probability of failure under various scenarios. Together with measures of the consequence of failure and criticality, this gives a measure of the inherent risk in the network. The replacement expenditure is typically set to a level that maintains and reduces the current level of risk over the next regulatory period to an acceptable level.

6.1.3.1 Calculating the Health Index

The Health Index is defined so that a score of 0.5 represents a new asset and a score of 5.5 represents an asset at the end of its life where the rate of failure begins to increase significantly. The CBRM model computes the Health Index in several stages.

The initial health index HI1 is calculated based on the following factors:

- age;
- expected service life as defined in the model (60 to 90 years);
- duty (mechanical loading); and
- environment (ground corrosion, air corrosion and pollution).

The initial health index is calculated using the formula

$$HI_1 = 0.5e^{B \cdot age}$$

where the ageing constant is defined by

$$B = \ln\left(\frac{5.5}{0.5}\right) \cdot \frac{\text{env} \cdot \text{duty}}{\text{life}}.$$

This formula assumes that the Health Index increases exponentially with age, and uses assumed values for each of the duty factors and environment ratings.

An interim health index HI2 is created by multiplying the initial health index HI1 by a factor determined by the score of any detected defects, using a table of assumed values for each of the defect ratings; for example, if an asset were assigned a defect rating between 3 and 4 based on its last inspection, then its health index would be multiplied by a factor of 1.2.

The final health index HIY0 is determined by comparing the interim health index to either the condition score, corrosion value or problem code (whichever is available first); if the latter score is greater then it becomes the final Health Index, otherwise the value takes the average of the two scores. The scores are determined using a table of assumed values for each of the ratings.

6.1.3.2 Calculating Risk

The CBRM model measures risk by adding up the risk for each scenario measured as the criticality multiplied by the probability of failure multiplied by the consequence of failure. This assumes that failures are not heavy-tailed events; i.e. the largest consequences are not significantly bigger than average and thus the risk can be measured in terms of the expected loss.

The failure scenarios are as follows:

- Replacement
- pole break
- fire start

- bush fire
- plating

The consequences are in the following categories:

- network performance
- safety
- environment
- Opex
- Capex

The model assumes that the Probability of Failure is a cubic function of Health Index:

$$PoF = k\left(1 + HI \cdot c + \frac{(HI \cdot c)^2}{2} + \frac{(HI \cdot c)^3}{6}\right)$$

The constant k is calibrated to historical failure rates and the constant c is assumed to be 1.35 in order that the ratio of PoF for HI=10 to HI=3.5 is approximately 15.

The consequence of failure is calculated by lookup of a table of assumed values for each of the consequence categories based on the voltage, location and average load (MVA).

The criticality is calculated by lookup of a table of assumed values based on the whether the asset supports major customers or customers on life support, the number of circuits, the overall amount of equipment and the environmental sensitivity.

6.1.3.3 Examining alternative forecasting options

The CBRM model allows for several different replacement forecasts:

- Fixed percentage of replacement
- Optimised Net Present Value (NPV)
- Maintain and/or reduce risk

The fixed percentage approach is used to assess forecast risk against a preselected, prudent level of intervention (plating and replacement).

The optimised NPV approach works by selecting the investment year to optimise the net present value of the total cost of remediation and change in risk. This method assumes that the price of defect remediation stays constant over time, so that the net present value of the remediation cost reduces if the remediation is performed in later years. This method is usually not recommended as the preferred approach as it is quite sensitive to the accuracy of the risk profile and financial parameters.

The maintain risk approach selects a level of replacement that maintains and reduces future risk to levels consistent with the SRMTMP. This forecast is based on the assumption that risk changes with time due to ageing of the assets, which increases the Health Indexes and consequently the probability of failure. This approach is the one recommended by EA Technology for application to SA Power Networks.

6.1.4 Comparison of the two different forecasting approaches

While the internal forecast and the CBRM may both be considered risk-based models to forecasting the pole replacement expenditure, in essence they use two very different approaches. The table below lists the six primary differences between the two models.

Table 1: comparison of the models

Internal forecast	CBRM
The forecast is primarily based on the historical defect rate.	The forecast considers historical defects as one of many inputs
The forecast does not use age or condition, and only uses location and corrosion zone to define subpopulations for estimating defect rates.	The forecast considers age and condition, and also takes into account location factors.
The forecast is a bottom-up approach, calculated from the individual feeder defect data.	The forecast is a top-down approach, calculated from pole population characteristics (e.g. age, condition, location).
The risk is measured (implicitly) by the number of defects; the consequence of failure is not considered other than the cost of replacement or plating.	The risk is measured in terms of criticality, probability of failure and consequence of failure in several different failure scenarios and consequence categories.
Risk changes over time only implicitly and at a constant rate, as an accumulation of unaddressed defects.	Risk changes over time, due to an increase in the probability of failure as the assets deteriorate with age.
The alternative forecast calculates the number of defects based on the number of years since the last inspection, rather than a constant five year period.	The alternative forecasts based on this method consider different replacement rates by fixed replacement, risk level maintenance and financial optimisation.

6.2 Forecasting results

6.2.1 Internal forecast results detailed and explained

The internal forecasting methodology has forecast a total of 12,109 defects over the next five years including P1, P2 and P3. Based on the defect remediation costs, this represents a five year forecast of $142,545,459 before adjustments. The forecast replacement expenditure is $39,912,729 (after including defects outside the inspection year) or $36,240,758 (after excluding overheads other than business and network) per year for ten years totalling $181,203,788 over the regulatory period. This is explained further in the following sub paragraphs.

6.2.1.1 *Volume of defects*

The internal model has forecast a total of 10,851 defects over the next five years (prior to inclusion of defects detected outside the inspection year, 12,109 once these are included). The breakdown by voltage and location is given in Table 2 below.

Voltage	Rural number of defects	Urban number of defects
7.6kV	33	534
11kV	1598	5089
19kV	2663	46
33kV	373	42
66kV	63	410

Table 2: internal forecast of the number of defects during the regulatory period

6.2.1.2 *Cost per defects*

The internal model has estimated the cost per defect for each voltage and location as given in Table 3 below, based on historical data.

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

Table 3: internal forecast of the cost per defect

6.2.1.3 *Cost of replacement*

The internal model has forecast the total replacement cost (before adjustment) at $142,545,459 during the regulatory period, which represents $36,240,758 per year (totalling $181,203,788 during the regulatory period) after adjustment for defects detected outside the inspection year and business and network overheads. The unadjusted totals for each voltage and location are given in Table 4 below.

Voltage	Rural cost (unadjusted)	Urban cost (unadjusted)
7.6kV	$341,590	$7,227,005
11kV	$15,178,153	$62,350,217
19kV	$29,297,109	$651,792
33kV	$7,270,265	$1,055,354
66kV	$2,048,297	$17,125,677

Table 4: internal forecast of the total cost during the regulatory period (before adjustment)

6.2.2 CBRM results detailed and explained

The CBRM was used in the mode where a level of intervention expenditure is nominated in order to keep the risk level steady over the next regulatory period.

As can be seen in Figure 12 below, we examined a number of potential intervention scenarios ranging from 1% through to 1.5%. The chart shows the risk level over ten years associated with the different levels of intervention.

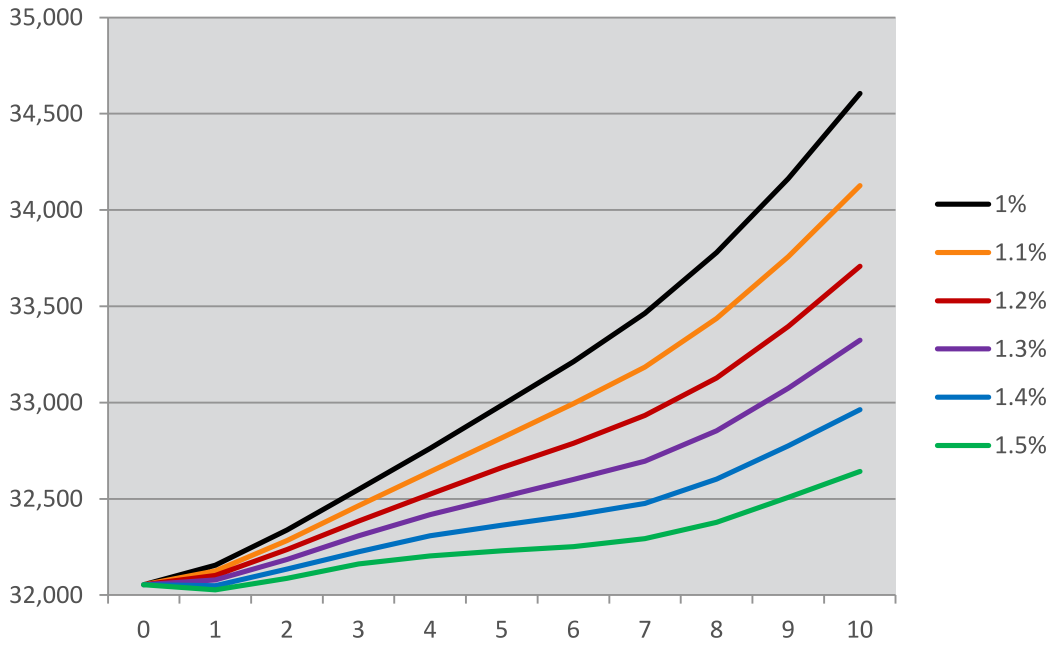

Figure 12: Risk level ($'000) forecast by the CBRM over ten years for intervention scenarios ranging from 1% through to 1.5%

The forecast five and ten year compound annual growth rates (CAGR) for risk for each of the intervention scenarios is given in Table 5 below.

Intervention rate	Five year CAGR	Ten year CAGR
1%	0.575%	0.769%
1.1%	0.472%	0.629%
1.2%	0.377%	0.504%
1.3%	0.282%	0.389%
1.4%	0.192%	0.28%
1.5%	0.11%	0.182%

Table 5: Compound annual growth rate for risk over five and ten years for each of the intervention scenarios

6.3 Comparison of results

Whereas the two forecasting methods use very different approaches, they have both been applied in a way that forecasts the required level of expenditure to ensure that an acceptable level of risk in accordance with the approved SRMTMP is maintained. The internal model addresses defects as they arise, whereas the CBRM approach aims to intervene to reduce the probability of failure.

When applied using the same approach to risk management, the internal model predicts that intervention (in the way of replacement or plating) will be required on approximately 0.82% of poles to maintain the current level of risk as denoted by MRV. The CBRM model indicates that an intervention rate of 1.3% will result in a reduction in risk over the next two regulatory periods to an acceptable level, in accordance with our SRMTMP over the next two regulatory periods.

Based on a 1.3% intervention rate, the CBRM forecasts a compound annual growth rate in risk of 0.282% over five years and 0.389% over ten years. Assuming a pole population of 740,000 poles, a 50% rate of plating and a cost per replacement estimated at $11,928.56 after adjusting for overheads, this leads to a forecast of $52.91million per year for planned pole replacement and plating.

6.4 Choosing the preferred forecast

6.4.1 Driven by principles of prudence

We believe that it is prudent to attempt to arrest the increasing risk, and reduce the level of risk of pole structural failure over the next and following regulatory periods to an acceptable level, in accordance with our approved SRMTMP.

Each of the chosen models has been used on this basis:

- the CBRM model has been used to constrain the level of financial risk
- the internally developed model has been used to constrain the level of defects

6.4.2 The CBRM methodology is our preferred methodology and toolset for forecasting

Our preferred forecast method for the replacement spend on the pole population is the CBRM approach. As well as using a risk based approach, the CBRM model has a number of advantages as a forecasting tool:

- it forecasts risk as the monetised value of potential loss
- it is in use with numerous DNSPs
- it has been specifically calibrated and tested by EA Technology for the SA Power Networks pole population.

The forecast intervention expenditure is on average $52.91million per year or $249.67million for the upcoming regulatory period.

6.4.3 An intervention rate of 1.3 percent meets our prudence criteria

Based upon the results of the CBRM forecast, and checking against the internally generated forecasting tool, we have forecast a required intervention rate of 1.3 percent will be necessary to enable us to meet our approved SRMTMP.

Based upon our known intervention costs, this translates to a forecast replacement expenditure of $249.67million over the upcoming regulatory period. This level of intervention maintains and reduces the level of risk over the upcoming regulatory period (with a compound annual growth rate of 0.282%) and constrains the level of growth in expenditure over the following period to a sustainable level at a rate of 0.389% over ten years with the aim of managing risk associated with defective poles back to acceptable levels in accordance with our SRMTMP.

6.5 Deliverability of forecast

We have profiled the required volume of replacements over the next period to ensure that the step increase from one year to the next is deliverable by us and our contractors at an efficient cost.

More detail on deliverability of our capital works program is provided in the supporting Network Program Deliverability strategy document.

7. Validation using other AER assessment techniques

We have used other techniques that the AER may apply to further verify our pole forecasts. These verification techniques include:

- intercompany benchmarking using the category analysis RINs
- analysis using the AER repex model.

Our findings from these two techniques are discussed in turn below.

7.1 Intercompany benchmarking

We have commissioned an independent expert, Huegin Consulting, to undertake the types of intercompany benchmarking foreshadowed by the AER in its expenditure assessment guidelines. This benchmarking covered analysis of various metrics using the economic benchmarking and category analysis RIN data.

The findings of this analysis support a position that we perform very well against our peers, and most likely can be viewed as on the efficient frontier.

With regard to our poles forecast, we believe there are a number of measures that support our position that our current level of replacement of poles is not sustainable and needs to increase. The measures and the findings are as following:

- SA Power Networks replaces poles at a lower rate (as a proportion of the population) than all DNSPs other than Jemena – Figure 13.
- Even when adjusted for differences in mean economic lives of poles, SA Power Networks is still replacing poles (in FY13) at a lower rate than the industry average – Figure 14.
- SA Power Networks have more pole failures per 100,000 poles in the population than all other networks other than the rural networks of Essential Energy and Ergon Energy, as illustrated by Figure 15.
- SA Power Networks, along with Ergon Energy, spend less on pole replacement per number of installed poles than any other network – Figure 16.
- SA Power Networks have almost twice as many poles in the current population that were installed over 50 years ago than the industry average for this measure – Figure 17.

The following graphs demonstrate each of the above observations.

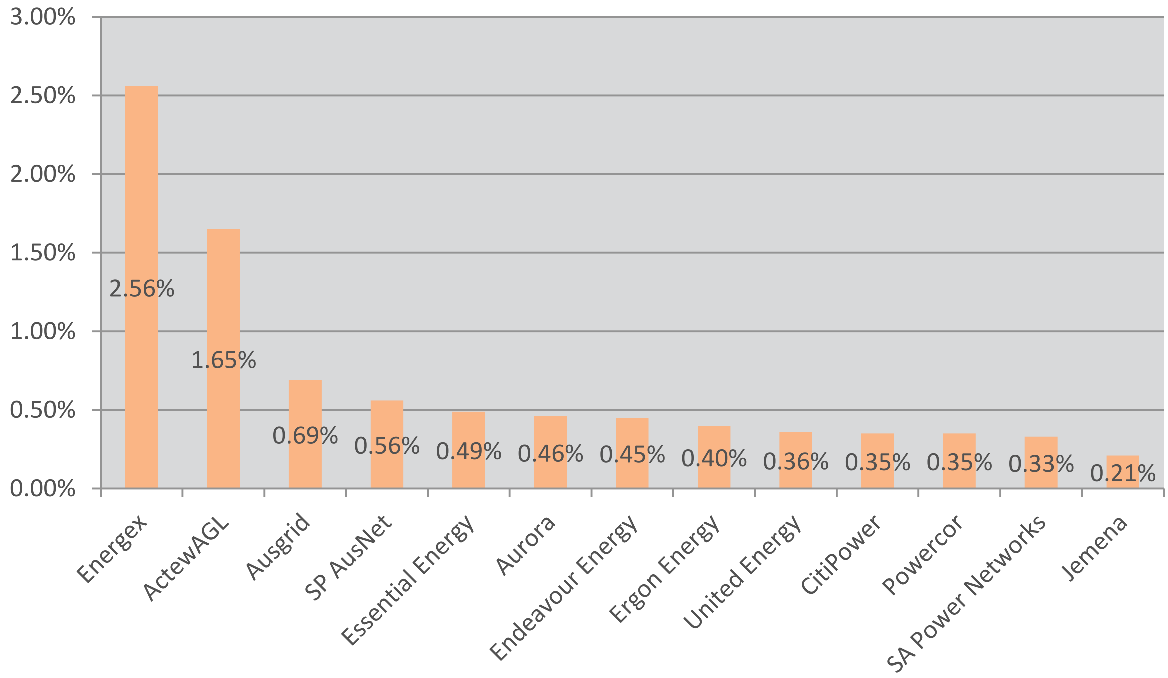

Figure 13: Proportion of pole population replaced in FY13 (Source: Category Analysis Regulatory Information Notices (RINs)).

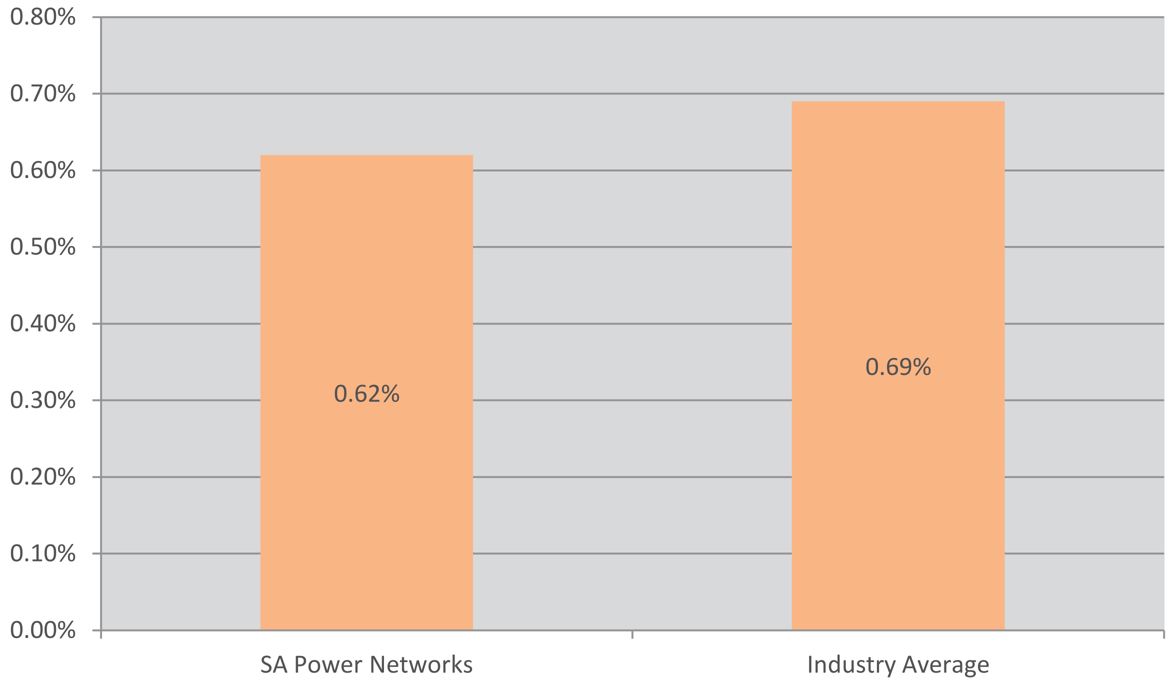

Figure 14: Replacement rate in FY13 adjusted for variation in pole economic lives (Source: Category Analysis Regulatory Information Notices (RINs)).

Figure 14 shows the pole replacement rate adjusted for the differences in the reported standard economic lives. That is, the reported replacement rate for each business has been adjusted based on the ratio of the standard economic life of poles for an individual business compared to the industry average economic life (which is 47 years).

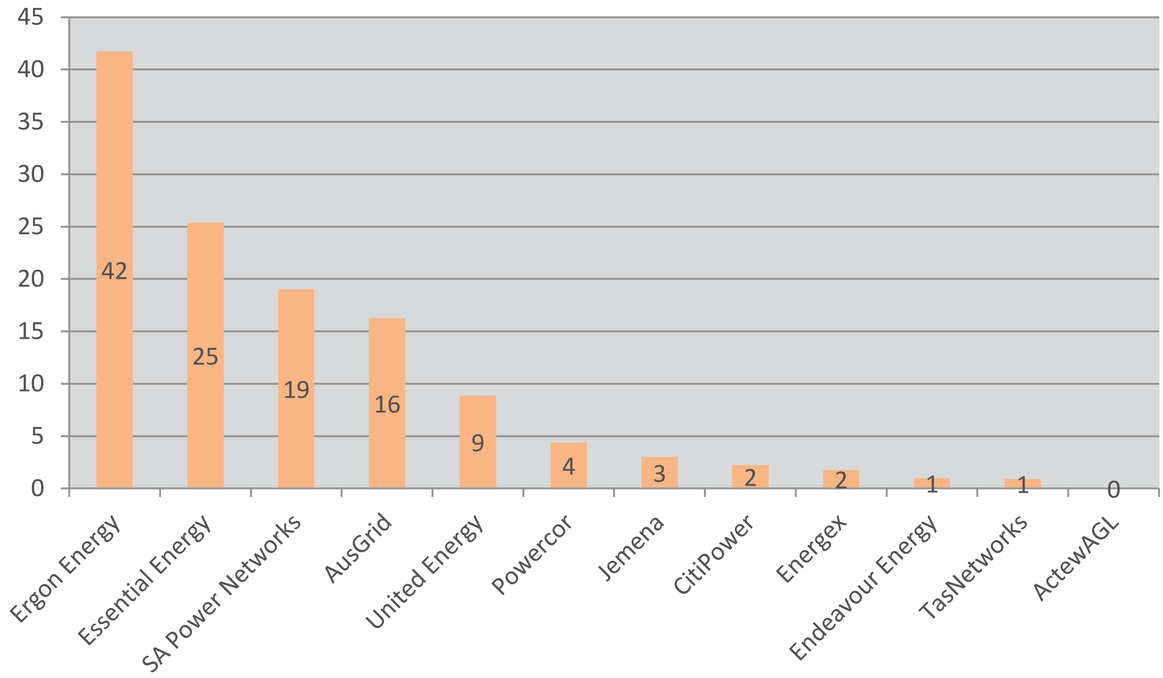

Figure 15: Pole functional failures per 100,000 poles in FY13 (Source: Category Analysis Regulatory Information Notices (RINs)).

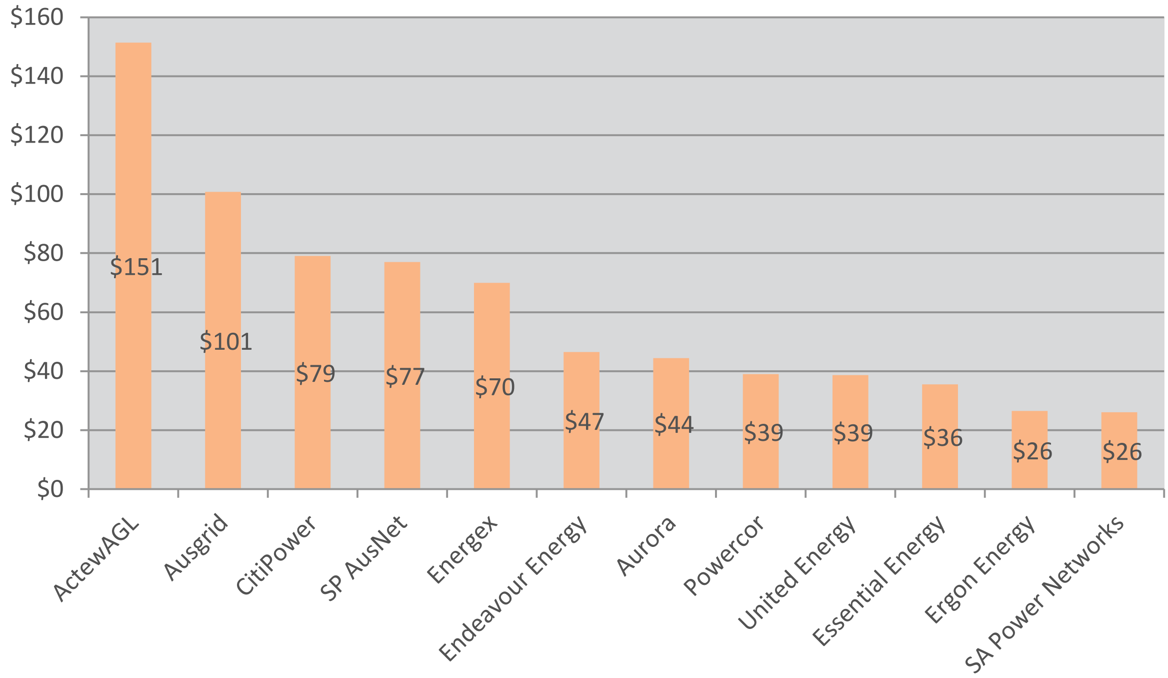

Figure 16: Pole replacement expenditure per installed number of poles in FY13 (Source: Category Analysis Regulatory Information Notices (RINs)).

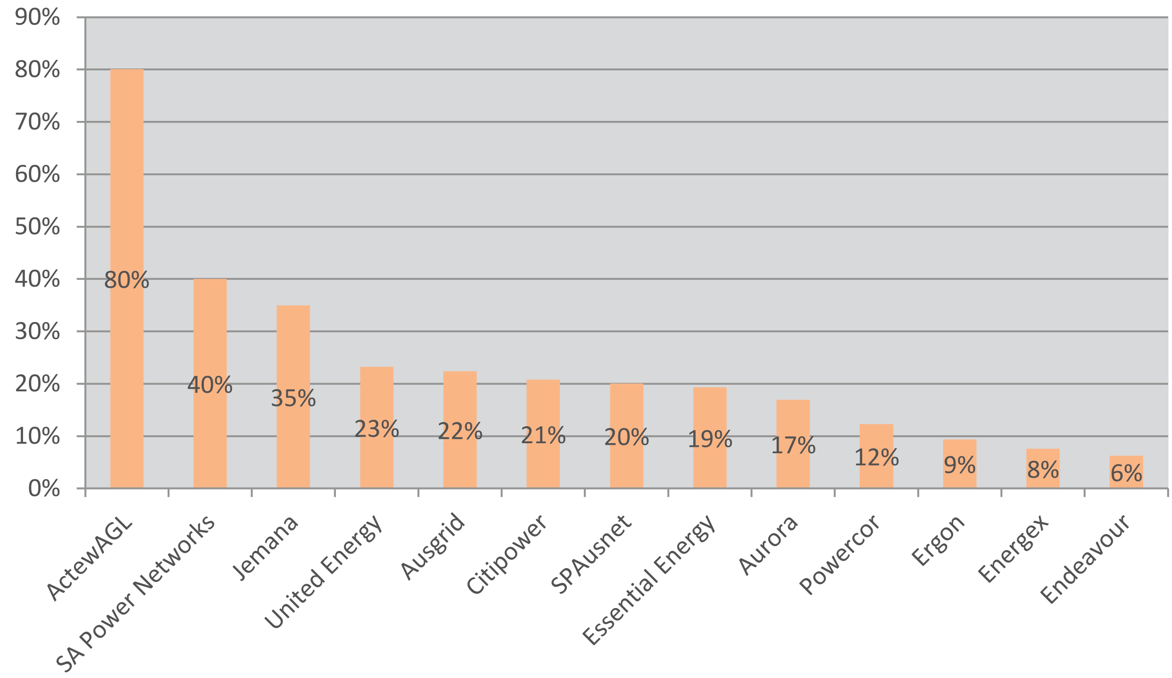

Figure 17: Percentage of currently installed poles that are over 50 years old (Source: Category Analysis Regulatory Information Notices (RINs)).

While we accept that this analysis does not, on its own, directly show that our forecast is the appropriate amount, we believe, taken together, these measures support the position that our pole replacement expenditure should continue to increase into the next regulatory period.

The broader benchmarking report has been included as a supporting document to our regulatory proposal.

7.2 The AER Repex model

We have used the AER's repex model to validate our pole replacement forecast. For this analysis, we used the age profiles advised to the AER in our category analysis RIN.

As part of this analysis, we calibrated the model lives using various starting assumptions, covering:

- the method we understand the AER will use, which assumes that the future intervention rate will match the 5-year historical intervention rate, using the replacement volumes in the category analysis RIN
- the intervention rate assuming the replacement volumes given in the last year of the category analysis RIN data (i.e. 2012/13)
- the assumed average intervention rates over the 12-year period to 2025, covering rates of 1.0%, 1.1%, 1.2% and 1.3%.

The average lives and the intervention rates given in the first year of the model (2014) for these various scenarios are shown in the table below[8].

Scenario	Life	2014 intervention rate
Poles - AER calibration	79.0	0.42%
Poles - 2013 calibration	74.3	0.76%
Poles - 1.0% intervention	75.3	0.68%
Poles - 1.1% intervention	74.3	0.76%
Poles - 1.2% intervention	73.5	0.85%
Poles - 1.3% intervention	72.6	0.94%

Table 6 AER repex model results

These results indicate the following:

- Our preferred intervention rate of 1.3% (over a 12 year period) reflects a level in 2014 that is approximately double the average intervention rate we have be able to achieve over the previous 5 years.
- However, our preferred intervention rate (over a 12-year period) reflects a level in 2014 that is just above the intervention rate we achieved in 2013.

Importantly, we do not believe that the AER calibration method is valid for our particular circumstances. As we have discussed in the introduction and Section 5, we are in a transition period with regard to pole inspections and replacements. Therefore, it is not valid to use the average volume of interventions over this 5-year period as we do not consider that this reflects the true prudent and efficient volume of replacements.

As we have noted, we found a significantly greater number of defects that we anticipated, and therefore, we have been ramping up our replacements over the 5-year period to deal with these defects. However, as shown by the MRV risk profile provided in Section 5 (Figure 6), this increase has not arrested the pole risk; the pole risk has continued to increase over this period.

Consequently, it seems reasonable to consider that using a similar average intervention rate over the next period would still not arrest this risk. Furthermore, given that this historical risk profile has not flattened off over this period, it also seems reasonable to consider that further increases in replacement volumes, above the 2013 level, will be required to arrest the increases in risk – given our network is aging and we are moving into (not out of) a pole replacement cycle.

With regard to our preferred intervention rate, our repex modelling suggest that this would require an average pole life of approximately 72.6 years prior to intervention through either replacement or plating. We consider that this life appears entirely reasonable. This life is around what we consider to be a typical service life for our Stobie poles. This life is still 10 to 15 years longer than may be expected for the typical (unstaked) wood poles used in other jurisdictions.

[8] It is important to note that the intervention rate is not fixed in the repex model, but varies over time based upon the assumed life and the age profile.

Furthermore, given this is the mean life across our poles population then this allows for the longer lives we expect in regions of low corrosion, where may expect lives above 90 years, and the shorter lives in more corrosive regions, where may expected lives less than 50 years.

It is also important to note that we currently only have approximately 2.5% of our poles plated. Therefore, this average life derived through the model does not reflect the life extension of 20 to 30 years that we anticipate we will achieve through pole plating. Our poles forecast allows for approximately 50% of interventions being addressed through plating, and therefore, we anticipate that in the future the average life of our poles will increase as the plated pole population increases.

Based upon this reasoning, we consider that our analysis through the AER repex model supports our preferred poles forecast.

8. Regulatory Treatment

In this section, we explain why we believe that the AER should accept that our pole replacement forecast should be allowed for in our capital expenditure (capex) forecast, which forms part of our building block proposal to the AER.

8.1 The NER requirements

Chapter 6 of the NER defines what should be allowed for in the capex forecast in the building block proposal. This is prescribed through the NER capex objectives and criteria.

The capital expenditure objectives define what outcome the expenditure forecast is permitted to achieve, covering four objectives :

> *"(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> > *(i) the quality, reliability or security of supply of standard control services; or*
> > *(ii) the reliability or security of the distribution system through the supply of standard control services,*
> > *to the relevant extent:*
> > *(iii) maintain the quality, reliability and security of supply of standard control services; and*
> > *(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services."*

The capital expenditure criteria define what the expenditure forecast must reflect in achieving these objectives. This covers three criteria:

> *"(1) the efficient costs of achieving the capital expenditure objectives;*
>
> *(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*
>
> *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives."*

Although these requirements apply to our total capex forecast (not specific projects), given the bottom-up approach we have used to prepare our capex forecast, we believe the pole replacement forecast can be discussed with direct reference to these requirements.

8.2 Why the AER should accept our forecast

The capital expenditure objectives

We have a legal obligation to identify and address defective assets on our network

With regard to the capital expenditure objectives, we believe that the second clause (to comply with applicable regulatory obligations) is the primary objective that that this forecast is required to achieve. That is, we believe that the level of pole defect intervention that is allowed for by this forecast is necessary to comply with applicable South Australian legislation over the next period.

As discussed in Section 3, we have a legal obligation to operate a safe network. As part of these 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). This plan sets out how we will maintain our network, including our poles. This plan covers how we will inspect them, identify defects, and address these defects. We have developed this plan and had it approved by ESCOSA on the recommendation of the Office of Technical Regulator (OTR). As such, we are now obliged to follow this plan.

We have included references to this legislation, our approved SRMTMP, and our procedures covered by the SRMTMP in this document. We have also provided in our supporting documentation the communications from the OTR endorsing the SRMTMP.

We have used a reasonable approach to forecast the scale of the need to comply with these obligations

We believe that the forecasting methodologies we have used provide a reasonable estimate of the volume of replacement activity that is likely to be required to comply with the approved SRMTMP.

We have used two methods that approach the forecasting problem in different ways.

One approach uses a type of model (a CBRM model) that has been used widely in this country and others, including the UK, to produce forecast for regulatory purposes. This approach uses asset age and other asset information, such as condition, to make predictions of the state of the assets in the future, and in turn, their risk of failure.

As the CBRM model can be sensitive to input assumptions, which could be contentious, we have also prepared another model using a different predictive philosophy. This model uses historical volume and cost data associated with inspections, defect and replacements. This data is used to develop historical trends that are then used to estimate defect and replacement volumes in the future.

These two models are discussed in Section 6, where have shown that they provide similar results using similar assumptions that reflect the intent of our approved SRMTMP.

Our forecast is also aimed at maintaining risks

We also consider that the fourth clause (to maintain safety) is a valid objective of our forecast, given the assumptions we have used to prepare the forecast. In this regard, the forecast volume of defect intervention was set to:

- maintain and reduce the risk to an acceptable level, in the CBRM model
- maintain the defect level, in the historical trend model.

Our forecast volume is supported by benchmarking of other DNSP replacement levels and analysis we have performed using the AER's repex model

Analysis we have undertaken of the category analysis RINs of the NEM DNSPs suggest we have one of the oldest networks and one of the lowest replacement rates. We believe that this analysis provides support to a view that our replacement volumes need to increase above historical levels.

We have included references to this analysis.

In additional, we also believe that our forecast volume is supported by analysis we have performed using the AER's repex model.

Importantly, we believe that the calibration process suggested by the AER is not valid for the circumstances discussed here. In this regard, we do not consider that calibration of the model to our 5-year average historical position is valid as it does not reflect the risk position that we are transitioning to that is reflected by our approved SRMTMP.

We have recalibrated the model to reflect this position. This re-calibrated model has asset lives that we consider reflect our Stobie poles, and provides a replacement volume and profile that is in broadly accordance with our forecast.

We have provided this analysis in our supporting documentation.

The capital expenditure criteria

It is prudent to manage identified defects in the manner we have proposed

Like other jurisdictions, we adopt a risk-based approach to decide when we will replace a defective asset. Our approved SRMTMP and associated forecast allows for this approach. In this regard, we have used *prudence principles* that underpin our forecast. These principles guide the timeframes we assume we will apply to address the different grades of defect, depending on their risks.

This broadly means that the most severe defects will be addressed strictly within our documented standards. However, this requirement is relaxed as the grade of the defect and associated structural failure risk reduces. The overall aim of the approved SRMTMP (and forecast) is to manage risk associated with defective poles to an acceptable level.

This intention is in accordance with commitments we have made to the OTR. Furthermore, we believe this reflects a prudent approach to managing defects, which we consider is in accordance with industry best practice, and the recent industry move to be more risk averse to carrying defects on a network that pose a significant safety risk.

We have allowed for the prudent and efficiency solutions to address the forecast need

As noted above, our forecast allows for the deferral of a replacement activity where we consider the risks would not warrant the action i.e. there is an inherent assumption that there is a prudent and efficient level of "do-nothing" occurring in our forecast.

Additionally, our forecast also allows for a significant proportion of pole life extensions occurring, rather than pole replacements. Where feasible, extending the life of poles through plating is a significantly lower capital cost solution than pole replacement. Our forecast assumes that pole life extensions will be possible at similar proportions to we have recently achieved. This covers approximately 50% of the forecast activity volume.

Taken together, we believe that this reasonably reflects prudent and efficiency solutions to address the forecast needs.

We have allowed for the efficient unit cost for the assumed solutions

The unit costs we have assumed in our models have been derived from our average historical costs for undertaking equivalent replacement activities (i.e. replacements and life extensions).

Importantly, a significant portion of these historical costs reflect outsourced services that have resulted from competitive tender processes. Furthermore, we have been found to have good practices with regard to the management and delivery of these services.

Consequently, we believe that it is reasonable to accept that our unit costs assumptions reflect the efficient unit costs.

This view is supported by our own unit cost benchmarking, which found our unit costs to be in line with our peers. We also believe that this view is supported by the AER's own benchmarking (top down and unit costing), which has found SA Power Networks' historical expenditure to be at or near the efficient frontier.

We have profiled the forecast to reflect the prudent and efficient delivery timeframe

Our models predict a level of replacement that is significantly above current recent levels. We are concerned that we may not be able to deliver this increase over a short timeframe. We are also concerned that too large an increase over a short period may increase the costs of our suppliers and service providers.

Therefore, we have profiled the increase in replacement volumes to ensure that there is a gradual transition in volumes from historical levels. We believe that this profile reflects a plan that we are confident can be delivered prudently and efficiently.

More detail is provided in the supporting Network Program Deliverability strategy document.

Why no opex (or STPIS target) adjustments

Although we are forecasting the need for a significant increase in the volume of pole replacements, we do not believe that this will result in any material change to the operating expenditure (associating with managing the pole population). In this regard, it is important to restate that our forecast is only aimed at addressing the growing risk associated with pole defects that we uncover through our inspection program, i.e. it is aimed at managing risk to acceptable levels in accordance with our approved SRMTMP.

We do anticipate that this program will reduce the volume of the highest risk defects that we are currently carrying on our network. However, this will be at the expense of increasing volumes of the lower risk defects. Importantly, these higher risks are primarily associated with safety hazards that are largely borne by our customers, and as such, although we believe there will be a net benefit in reducing these volumes, there is little financial benefit to us. In addition and as discussed in Section 3, we are obliged through our SRMTMP to undertake these activities to ensure that the risks will be managed back to acceptable levels. It could be argued that there will be some localised reduction in our costs associated with managing these risks (e.g. reduced insurance premiums), however, we do not believe that, at the network level, any reductions will be material as any of these localised reductions will be offset by increases elsewhere due to the increased aging and loading we anticipate will occur across our network.

Document Authorisation and History

Revision History

Date	Version	Author	Description of Change/Revision
	0.1		Initial Draft

Approvals

Name and Title	Role	Signature and Date

Distribution

Date	Version	Name and Title	Purpose

References

The following documents were referenced in completion of this document:

Ref	Document Name	Date	Version	Author

Acronyms and Abbreviations

Acronym / Abbreviation	Definition

Appendix A REFERENCES

References

Relevant legislation

1 South Australia Electricity Act 1996

2 South Australia Electricity (General) Regulations 2012

SRMTMP and relevant covered SA Power Networks documents

3 Safety, Reliability and Technical Management Plan

4 ESCOSA approval of 2014 SRMTMP, dated 5 September 2014

5 Network Asset Management Plan (No. 15)

6 Network Maintenance Manual (No. 12)

7 Line Inspection Manual (No. 11),

Technical standards

8 AS/NZ 7000

9 ENA Cb1 (superseded by AS/NZ 7000)

Forecast

10 EA Technology, Application of CBRM to SA Power Network's Conductors, Poles, Circuit Breakers and Transformers, March 2013

11 SA Power Networks, CBRM Justification, September 2014

12 SA Power Networks Multi-Variable Defect Forecasting Model

13 CBRM model - poles

14 AER repex model analysis

Other supporting information

15 Poles Asset Management Plan 3.1.05

16 Maintenance Requirement Matrix for all Maintenance July 2014.docx

17 Asset Inspection Strategy Business Case

18 SAPN benchmarking using the category analysis RINs

19 Network Program Deliverability strategy document

20 SA Power Networks Category Analysis RIN response 2014 http://www.aer.gov.au/node/24388