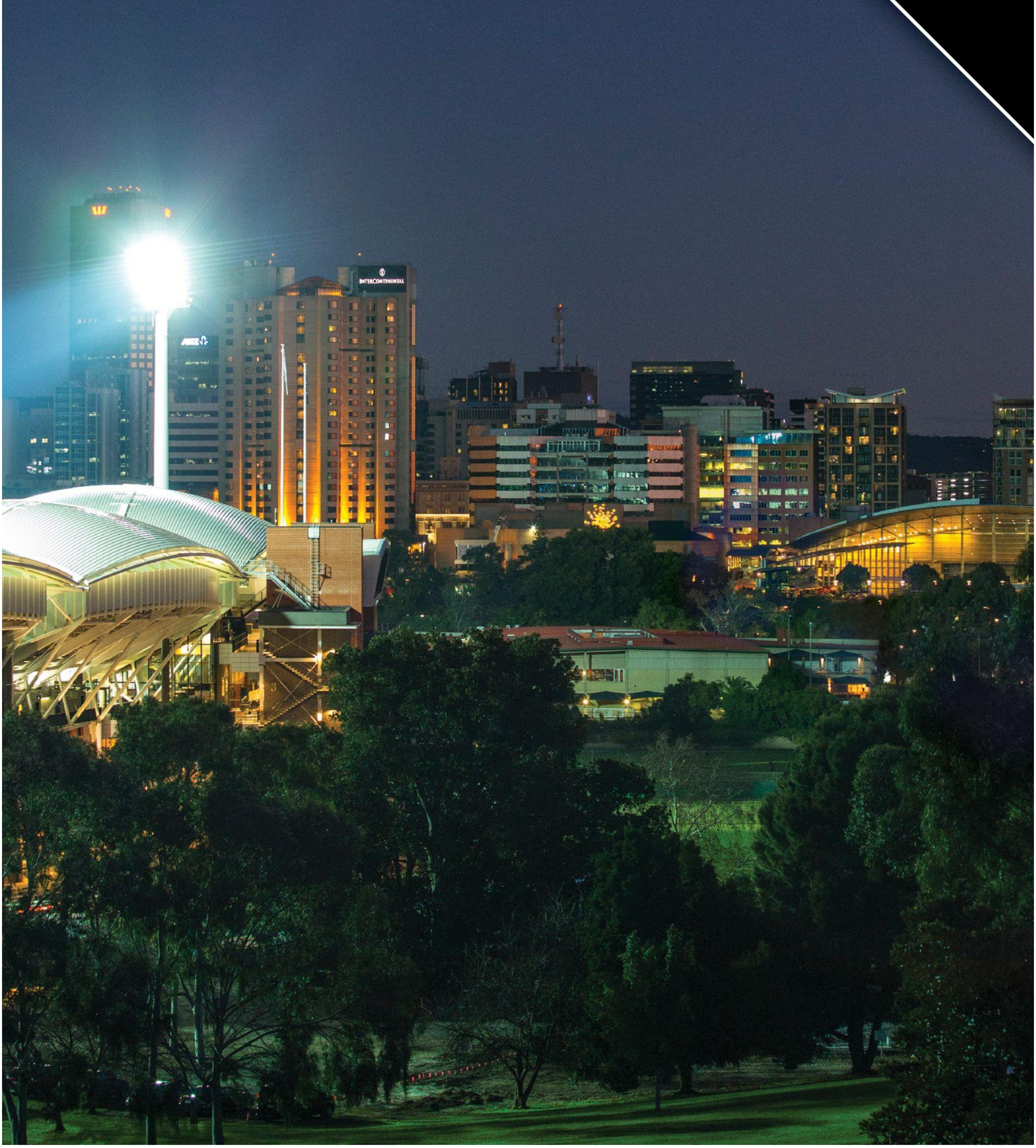
Attachment 20.64

SA Power Networks: Asset Management Plan 3.2.01 Substation Transformers 2014 to 2025



ASSET MANAGEMENT PLAN 3.2.01 SUBSTATION TRANSFORMERS

2014 TO 2025

Published: October 2014

SA Power Networks
www.sapowernetworks.com.au

OWNERSHIP OF STANDARD

Procedure 916 Annex B
Issue 2/13

OWNERSHIP OF STANDARD

Name of Standard / Manual: ***AMP 3.2.01 Substation Transformers***

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

Name: ***S Wachtel***

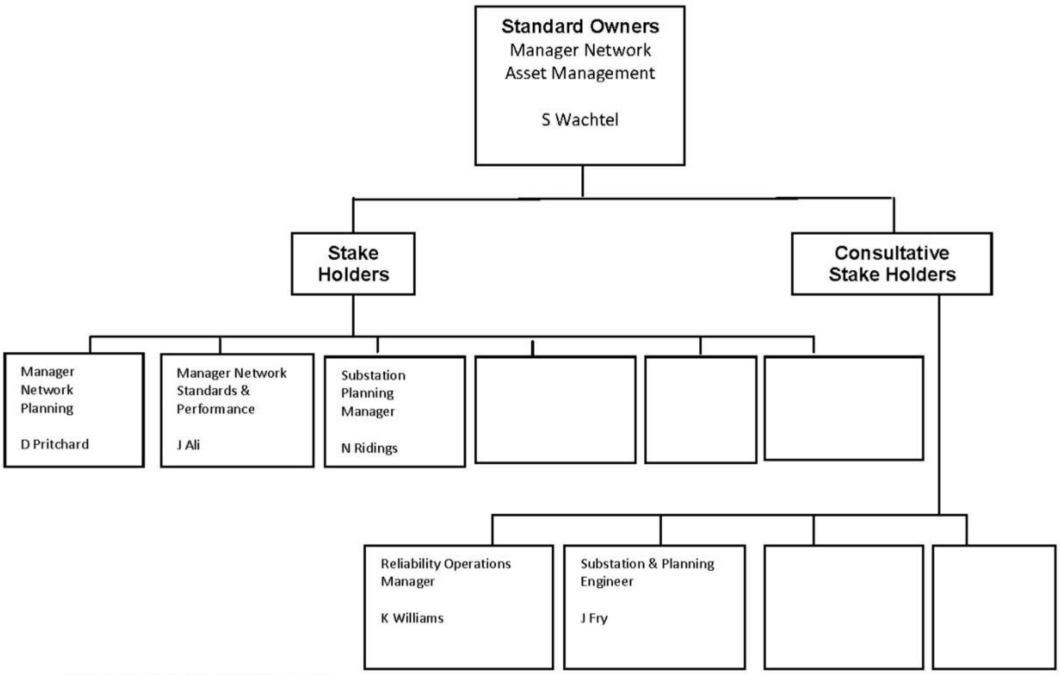
Standard Last Reviewed: September 2014

Standard Last Issued: October 2014

Review Period: 5 Years

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

STANDARD/MANUAL OWNERSHIP STRUCTURE



OTHER RELATED MANUALS

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COMMENTS

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(Asset Management Plan 3.2.01 – Substation Transformers)

DOCUMENT VERSION

Date	Version	Description of Change/Revision
April 2014	0.1	Initial Draft
June 2014	0.2	Draft incorporating some comments and updated CBRM results
August 2014	0.3	Final Draft incorporating reviewers comments
28/10/2014	1.0	Final

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FIGURES

1. EXECUTIVE SUMMARY

1.1 Asset Management Objectives

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

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

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

1.2 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

1.3 Asset Management Strategies

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

The Asset Management Strategy is:

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

The lifecycle management of substation power transformers 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 Substation Power Transformers Asset Management Plan. This will help ensure that the operation of SA Power Networks' distribution network meets the industry and regulatory standards, whilst providing optimal return to shareholders and satisfying customer requirements.

The primary focus of this asset management plan is to manage the substation power transformers 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' distribution network.

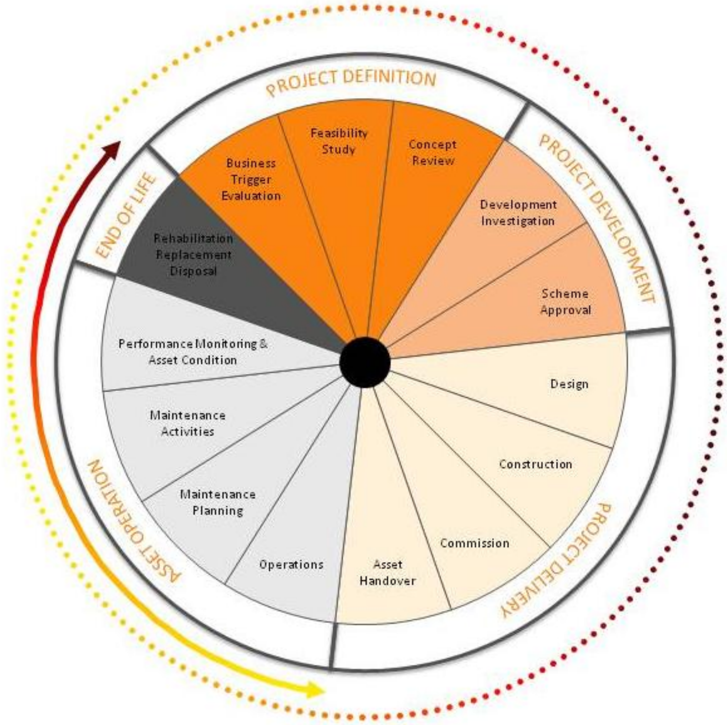


Figure 1 : SA Power Network Asset Life Cycle

1.4 Asset Background

Substation Power Transformers provide transformation of electricity from sub transmission voltages to distribution voltage levels and are located at the bulk electricity supply substations. There are approximately 696 substation power transformers in service with average unit replacement costs ranging from $260,000 to $1,640,000, with the range of actual costs much greater.

SA Power Networks undertakes asset management of the transformers, through condition and performance monitoring with routine inspections and maintenance, overhaul maintenance and refurbishment to extend the asset service life and a long term replacement program. These key roles ensure that SA Power Networks is consistent with sound asset and risk management principles to satisfy customer service needs, meet licence obligations, provide a safe environment for employees and the community, and deliver optimal returns to shareholders.

Substation transformers are generally reliable with historically low failure rates until approaching the end of their service life. The consequences of in-service failures include supply interruption to large numbers of customers (up to 20,000) and catastrophic failure resulting in an explosion, subsequent oil fire and potential environment issues. The response time to replace a large transformer is from 5 to 20 days provided adequate spares are readily available. Failed transformers are replaced utilising an Insurance spare unit held in store. The replacement unit purchased then goes into store as the Insurance spare. A lead time of up to 12 months is the typical duration for the new unit to be purchased, manufactured, and delivered. Over the last five years there has been a rising trend in the number of failures.

The majority of power transformer failures can be predicted by adequate condition monitoring, and the residual risks after implementing this Asset Management Plan are considered as low. A total of 135 substation power transformers are programmed to be replaced during the period of this plan, 2014 through 2025.

1.5 Expenditure

The yearly capital expenditure requirement for replacement of substation power transformers is shown in the figure below.

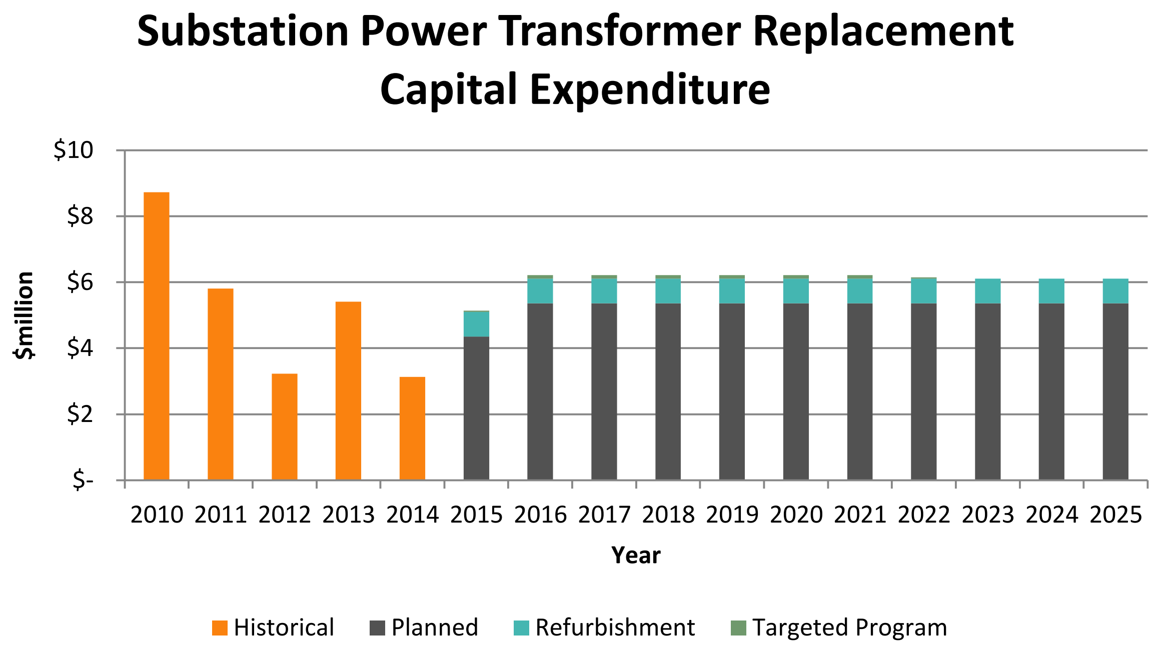


Figure 2 : Substation power transformers Replacement Capital Expenditure - historical and forecast

The forecast expenditure is generally in line with the average annual expenditure over the last 5 years, ±$0.78million or $13%. The majority of the expenditure, around 83%, relates to unplanned replacements following failure based on the past 5 year's expenditure and works undertaken.

1.6 Planned Improvements in Asset Management

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

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

2. INTRODUCTION

2.1 Background

2.1.1 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 nationalisation of Adelaide Electric Supply Company.
- 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 became rebranded to SA Power Networks. The rebranding emphasised the focus on SA Power Networks core business of serving business and residential customers in metropolitan, regional and remote areas of South Australia.

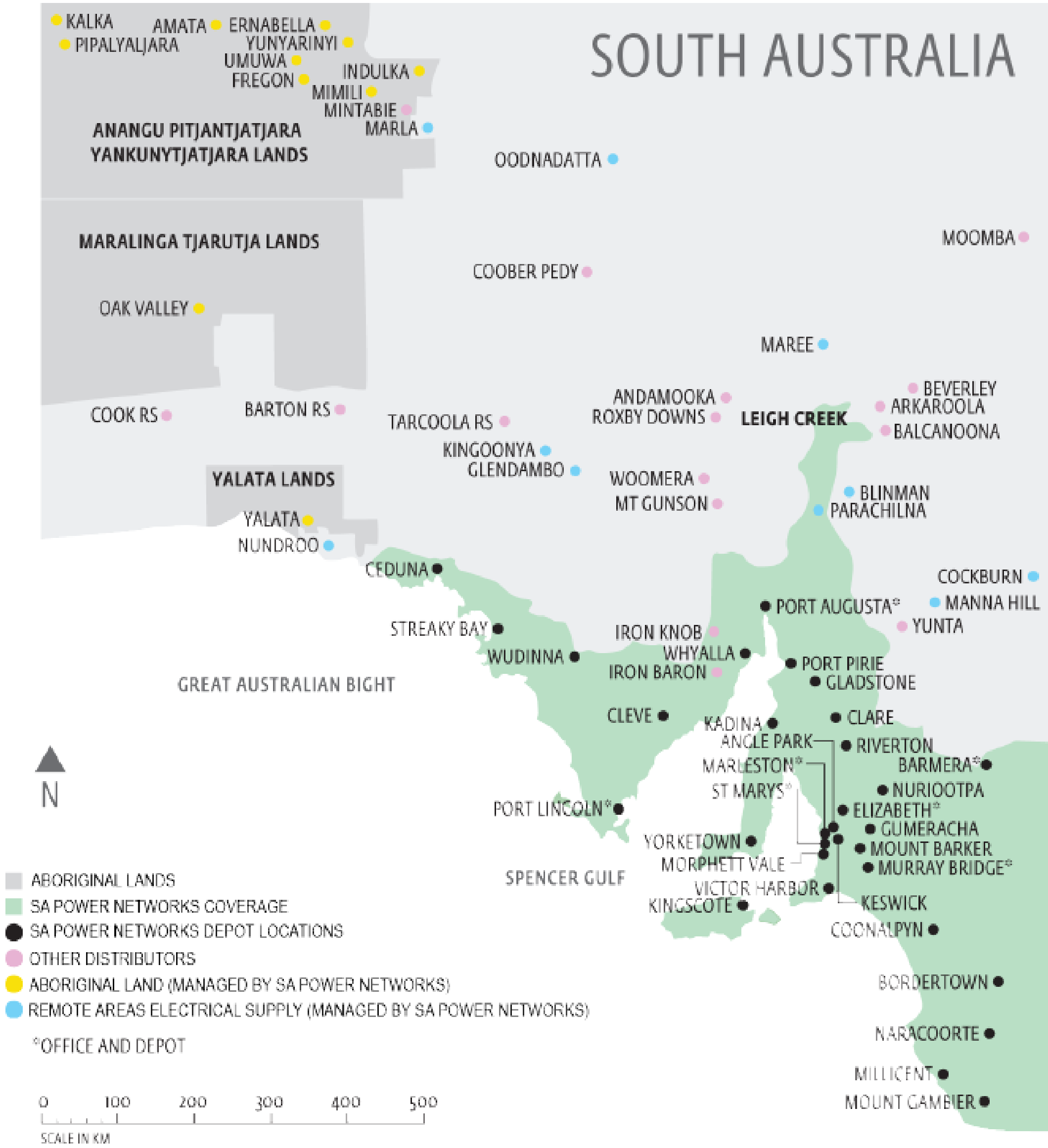


Figure 3 : SA Power Networks network map

2.1.2 Substation Power Transformers

This Asset Management Plan (AMP) covers high voltage substation transformers and ground level voltage regulators at voltages ranging from 11 kV to 66 kV inclusive. Pole top single-phase regulators and station supply transformers are excluded from this AMP and are instead included in AMP3.1.01 Distribution Transformers and AMP5.1.02 Elizabeth Transformer Stations.

Transformers, including voltage regulators, are devices used to transform electrical power from one voltage level to another voltage level within the electricity network.

A transformer must be suitably rated to carry the full load of the circuit it is placed in and also be able to withstand periods of cyclic overloading to meet peak and emergency demands. In general a transformer is moderately loaded for a majority of the time and is called upon to operate at full nameplate load or greater during peak periods of daily seasonal load cycles.

A transformer must also be designed to withstand the abnormal voltage peaks (resulting from lightning strikes and switching surges) and also current peaks due to system faults.

SA Power Network substation transformers range in age from 1 to 72 years, with an average of 34 years. Manufacturers will generally design for a substation power transformer insulation life expectancy of approximately 20 to 30 years for a transformer loaded continuously to its full rating, however, due to the varying operating conditions (load and temperature cycles, frequency of system faults etc), this life is not guaranteed.

The life expectancy of a transformer subject to normal aging is highly dependent on the operating temperature of the transformer. As many substation power transformers are lightly loaded, the expected service life of a substation power transformer is significantly greater than the design life. The Australian utility industry experience for substation transformers ranges from 40 to 60 years with an average of around 50 years of service life. Internationally there is a realisation that life expectancy figures are nominal and that long life of substation power transformers can be achieved within most networks under favourable conditions.

2.2 Goals and Objectives of Asset Management

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

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

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

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 4.

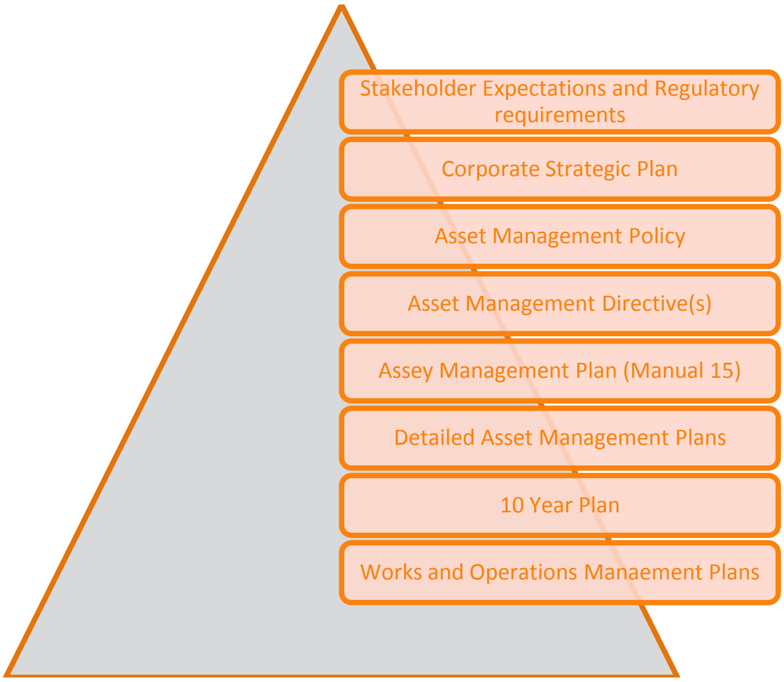


Figure 4 : Asset Management document framework

The substation power transformers Asset Management Plan ensures that the distribution 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 substation power transformers Asset Management Plan is to detail SA Power Networks' plans in managing substation power transformers between 2014 and 2025.

2.3.2 Supporting documents and data

The substation power transformers Asset Management Plan refers to the following SA Power Networks documents:

- Network Asset Management Plan Manual No. 15
- Network Maintenance Manual No. 12
- Substation Inspection Manual No. 19

- Condition Monitoring and Life Assessment Methodology (CM&LA) AMP.3.0.01

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

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

The Substation Inspection Manual No. 19 provides a detailed guide in assessing the condition of substation assets, the procedures in recording the data collected during the condition assessment and prioritisation of defects. High resolution photographs of common defects of components in substations and the codes for capturing the common defects are provided in the manual.

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

2.3.3 Structure of Substation Power Transformers AMP

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

3. LEVELS OF SERVICE

Service levels should represent the expectations that stakeholders 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 life-cycle. Issues such as cyclic or periodic replacement cycles, routine maintenance schedules and asset inspections (often part of the Routine Maintenance Plan) are all integral to 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 substation power transformers 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 substation power transformers.

3.1.2 Network Customer Expectations

SA Power Networks stakeholder engagement program for the 2015/16-2019/20 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 driver reliability, manage risk and support economic growth. Asset management initiatives that have a direct impact on reliability and/or prevent potential safety hazards were rated as most important. Consumer priority areas included assets in high bushfire risk areas and near roads in residential areas. The priority areas for Business and Government consumers included areas that would support economic growth.
- Prioritise preventative maintenance to mitigate risk. All preventative maintenance initiative should consider potential safety hazards and be completed as a priority when risks can be mitigated.
- CFS Bushfire Safer Places should have continuous power. Investment in bushfire management initiatives would ensure that essential services are managed under critical conditions.
- 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 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 2015/16-2019/20 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 2015/16 - 2019/20 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
- 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 published each year by ESCoSA.

4. FUTURE DEMAND

4.1 Demand Drivers

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

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

4.2 Demand Forecast

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

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

4.3 Demand Impact on Assets

When Power Transformers are required to operate outside their design capabilities (current ratings and/or fault ratings) there is a risk of catastrophic failure. Failure of a transformer would require the upstream circuit breaker to operate resulting in loss of supply to large parts of the network. Depending on the extent of the damage to the transformer, restoration could take from several days to two weeks.

4.4 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.

4.5 Key Asset Programmes to Meet Demand

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

5. LIFECYCLE MANAGEMENT

5.1 Background Data.

Substation power transformers serve a vital role in the transformation of electricity from sub transmission voltages to distribution voltage levels and are located at the bulk electricity supply substations. There are approximately 701 substation power transformers in service.

This asset plan covers high voltage substation transformers and ground level voltage regulators at primary voltages ranging from 11 kV to 66 kV inclusive.

HV/LV transformers installed in the distribution network (not in substations), as well as pole top single-phase regulators and station supply transformers, are covered by a separate Asset Management Plan.

Each transformer must be suitably rated to carry the load of the circuit it is placed in and be able to withstand periods of cyclic overloading to meet peak energy and emergency demands. In general, substation power transformers are moderately loaded for the majority of the time and called upon to operate at full nameplate rating or greater during peak periods of seasonal load cycles. Each transformer must also be able to withstand abnormal voltages, resulting from lightning strikes and, switching surges, as well as currents due to network faults. The nameplate rating of a transformer is a basic guide to its use and operation above a transformer's nameplate rating is a common engineering requirement.

As the substation power transformers age and deteriorate, they become more prone to failure. At the least a failure of a transformer may result in unplanned supply interruptions to customers. As substation transformers contain insulating oil and faults can result in significant energy being released within the transformer, there is a commensurate risk of explosive failures which can result in a subsequent oil fires, damage to co-located or adjacent assets, and potential environmental pollution from release of oil. In the SA Power Networks power distribution system, substation transformer failures resulting in a transformer fire are very rare with the last event occurring 10 January 2002.

The ages of substation transformers in SA Power Networks range up to 72 years, averaging 35 years. Manufacturers generally design transformer insulation to an international standard that aims to achieve a nominal insulation life of approximately 20 to 30 years for continuous full load applications. This design criterion is typically well away from the normal operating conditions of a substation transformer and thus transformers are able to attain service lives ranging approximately 40-60 years in practice.

For asset management purposes SA Power Networks categorises substation power transformers in use in the sub-transmission and distribution networks as:

- Large – Capacity ≥ 20 MVA
- Medium – Capacity ≥ 5MVA and < 20 MVA
- Small – Capacity < 5MVA

These are proportioned to approximately 51.6% small, 29.5% medium and 18.8% large. The population summary distribution of the substation power transformers is shown in Figure 5 and is based on the data collected for the CBRM exercise. The oldest transformer currently in service is 72 years old.

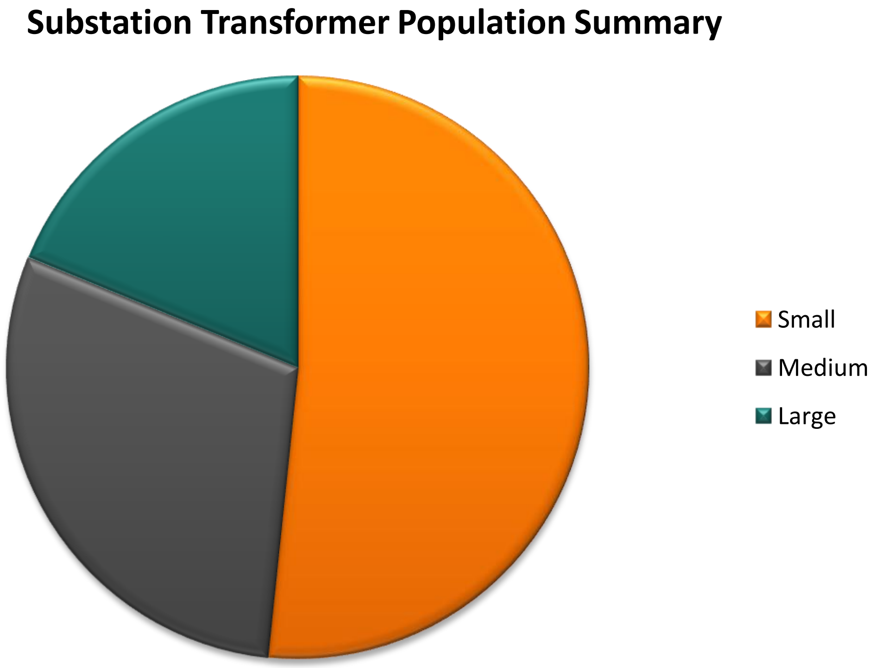


Figure 5: Substation Transformer Population Summary

Whilst transformers are prone to be less robust with age, this is only one of many factors affecting the transformers insulation service life. It is prudent though to consider age related issues such as mechanical deterioration, corrosion and loss of robustness in evaluating the likely risks to the network. The age of the transformer types is shown in Figures 6-8.

For Power Transformers failures are classed as condition, ie directly related to equipment condition, and non-condition, ie failure influenced by external event such as animals, vegetation or lightning. The failure types for Power Transformers are set out in Table 1 below.

Table 1: Power Transformer Failure Types

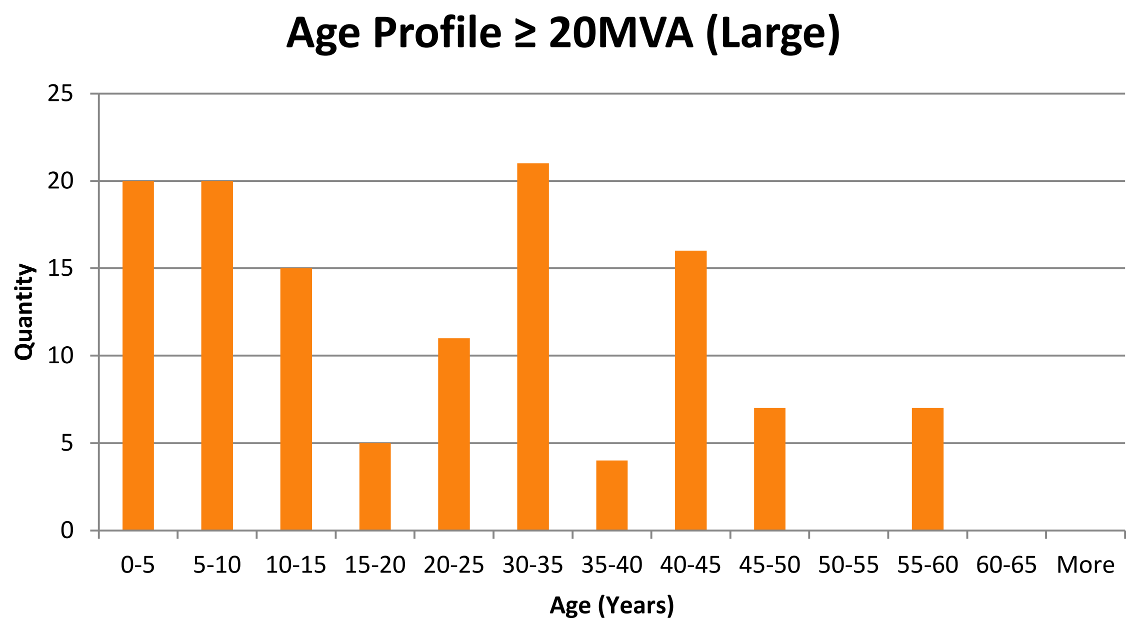
Failure Scenario	Description
Minor	Failures (typically defects) that do not result in a service interruption.
Significant	Disruptive failures (unplanned or forced interruptions) that are repairable on site.
Major	Disruptive failures (unplanned or forced interruptions) that require emergency asset replacement
Condition replacement	Equipment discovered through condition monitoring (without disruptive failure) in a state that is not economically repairable and in need of replacement.

The record of failures over the period 1 July 2008 to 30 June 2013 as a per annum figure is outlined in Table 2.

Table 2: Power Transformer Failures per annum

Failure Scenario		Number of Transformers
Minor	Condition	346
Minor	Non Condition	39
Significant	Condition	4.4
Significant	Non Condition	2.0
Major	Condition	2.4
Major	Non Condition	0.4
Condition Replacement		3.4

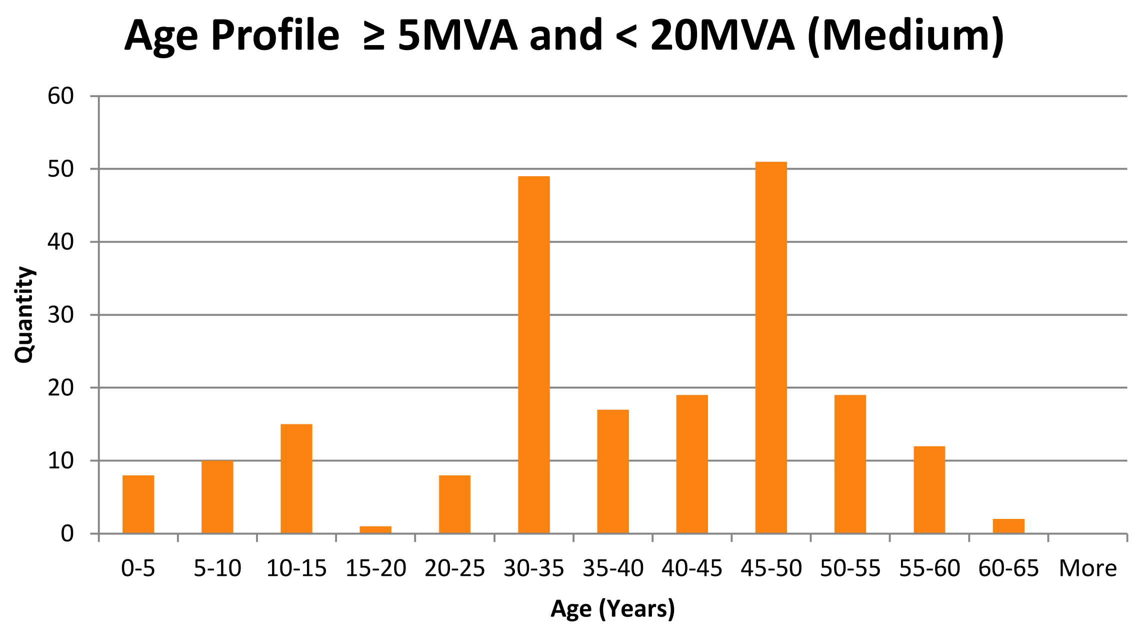
5.1.1 Large Transformers



Large Transformers	2013	2008
Average Age	24.1	23.0
Median Age	24.0	23.0
Maximum Age	59.0	53.0

Figure 6: Age profile for Large transformers (30 June 2014)

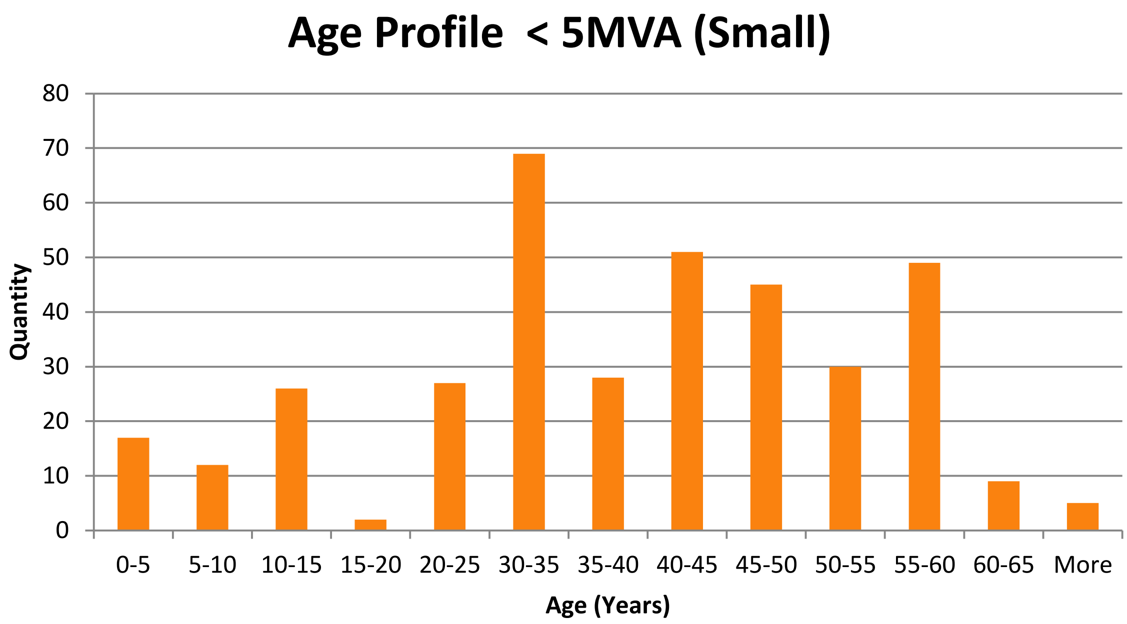
5.1.2 Medium Transformers



Medium Transformers	2013	2008
Average Age	35.9	34.7
Median Age	39.0	39.0
Maximum Age	63.0	58.0

Figure 7: Age profile for Medium transformers (30 June 2014)

5.1.3 Small Transformers



Small Transformers	2013	2008
Average Age	37.3	37.1
Median Age	41.5	40.0
Maximum Age	72.0	67.0

Figure 8: Age profile for Small transformers (30 June 2014)

5.1.4 Asset Summary

The following tables list the transformer quantities by capacity category and primary nominal voltage as at 30 June 2013.

Table 3: Transformers by Capacity

Capacity	Installation Type	Numbers	Total
Large: ≥ 20MVA	Fixed tap Regulator OLTC	1 6 116	123
Medium: ≥ 5MVA & < 20 MVA	Fixed tap Regulator OLTC	10 18 179	207
Small: < 5MVA	Fixed tap Regulator OLTC	302 27 37	366
Total		**696**	

Table 4: Transformers by Voltage

Capacity	Installation Type	Numbers	Total
66kV	Fixed tap Regulator OLTC	32 2 247	281
33kV	Fixed tap Regulator OLTC	224 11 84	319
11kV or less	Fixed tap Regulator OLTC	57 38 1	96
Total		**696**	

5.2 Risk Management Plan

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

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

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

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

As probably the most important asset within a substation, the continued reliable operation of power transformers is vital to SA Power Networks business. It is generally accepted that operational management and an on-going maintenance regime is imperative for transformers. Without these in place transformers will be more likely to fail prematurely.

Transformers are generally very reliable and the risk of in service failure is considered to be low with appropriate management regimes in place. However should a transformer fail, the consequences can be very significant.

The consequence of a transformer fault can include the following:

- external flashover and damage to HV bushings
- oil fire
- distortion of tank, winding, lead supports
- short circuit between turns
- winding collapse

Typical causes of transformer faults are:

- mechanical failure - usually due to a through fault on the MV distribution network
- insulation failure - due to lightning, over-voltages during switching, internal short circuit and water ingress, insulating paper deterioration, poor oil condition
- thermal failure - due to high resistance connections or overloading or cooling equipment failure

A comprehensive condition monitoring and maintenance regime can substantially reduce the incidence of failures through the early detection of incipient degradation and damage to transformers and thus allow for a strategic response to developing issues. The value of such practices though needs to be balanced against the costs of enhanced monitoring and maintenance regimes for the assets. In performing such a review the following considerations are inputs.

- Asset values - They represent about 40% of the zone substation asset value. If a transformer is not monitored and maintained, the risk of failure increases which can result in explosions and fires causing substantial damage to the neighbouring equipment and possibly the entire station.
- A transformer failure can result in significant other costs such as upgrade works and costs of temporary measures. For example, the failure of a 66kV bushing on a transformer can result in a major fire and cause the complete destruction of the transformer costing in the order of $1.5m.
- Increasing failure risk due to ageing – The design life of a fully loaded transformer is approximately 20 to 30 years. Most of the transformers on the network however have supplied loads well below their continuous ratings for the majority of their service life and thus their service lives have been extended to well beyond the design life. The extended service life has been achieved with an accompanying high level of reliability and availability. During this time however, various forms of degradation and agents that result in accelerated aging accumulate; such as moisture in the transformer's cellulose based (paper) insulating system, insulating oil degrades and increases aging rates and through faults weaken the solid insulating and mechanical structures within the transformers.
- Reliability of supply - Although many zone substations design and transformer ratings are based on an 'N-1' planning policy in high risk areas such as the CBD, the loss of a transformer may place limitations on the transfer capacity and the ability to manage load at a zone substation. This also causes the load on the remaining in service transformers to be significantly increased and may mean that they are operated at their maximum cyclic ratings for some period leading to a higher risk of supply reliability problems. Transformers with elevated moisture levels that operate at high loading may be subject to the risk of water bubble formation from moisture ejected from their solid insulation in response to sharp increases in internal operating temperature. This can result in a reduced ability to withstand operating voltage and can lead to unexpected failures. All transformers should be maintained in sufficient condition to avoid the risks associated with operation at maximum overload capability.
- In addition the loss of one transformer in a zone substation that is not equipped with 66kV line breakers exposes the station to loss of supply (possibly complete loss of supply in a two transformer station) in the event of a 66kV line fault. This represents a significant reduction in supply security.
- Cost of loss of supply – A loss of supply due to a transformer failure can potentially result in severe penalties associated with the regulatory incentive scheme (SAIFI, CAIDI, SAIDI, and MAIFI). Large compensation claims from customers may also result.

- Tap-changer failure – if oil immersed tap-changers are not maintained, there is a risk that failure will occur due to contact degradation or insulation failure possibly resulting in arcing. Transformers and their associated tap changers (TC) are strategic assets and must be managed in a manner that ensures their ongoing reliability, availability and capacity is maintained.

Inspection and condition monitoring tasks are normally scheduled at standard intervals as detailed in the Maintenance Plan. Monitoring condition trends over time is a primary strategic asset management tool which tracks deterioration over time. As areas of concern are identified, condition monitoring frequencies may need to be shortened as the risk of an impending failure becomes apparent. Such deterioration can develop slowly over time, or in some cases, quickly and then requiring urgent operational actions to reduce the risk of in-service failure. To improve the ability of SA Power Networks to better manage these contingencies, plans are in place to acquire a number of semi-portable on-line Dissolved Gas Analysis (DGA) systems capable of being installed on transformers showing indications of significant deterioration in condition (see AMP 3.0.01 Condition Monitoring and Life Assessment Methodology).

5.3 Maintenance Strategy

The maintenance strategy for High Voltage substation power transformers comprises periodic routine inspections, overhauls, maintenance and condition monitoring, supplemented by additional specific inspections as determined by asset condition.

The scope and frequency of tasks of this maintenance strategy are contained in the Network Maintenance Manual 12 plus reference to the Substation Inspection Manual 19 and Substation Maintenance Manual 30.

5.3.1 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 substation power transformers will prescribe preventative maintenance requirements and how to treat defects identified either through corrective maintenance or asset inspection processes. The purpose of these standards is to ensure assets operate as designed, safely and achieve their optimal life.

Key factors to consider which are guided by standards include:

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

5.3.2 Maintenance Categories

Maintenance will generally be defined under the following categories:

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

- **Corrective** - 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** - referring to actions undertaken directly following unforeseen circumstances, such as a customer complaint, accident, safety response, damage due to environmental factors or third-party interference.

5.3.3 Maintenance Plan for Substation Power Transformers

The maintenance strategy for substation power transformers comprises of periodic routine inspections, overhaul maintenance and condition monitoring, supplemented with targeted inspections and testing based on asset performance and condition. The maintenance requirements are detailed within the Network Maintenance Manual.

Inspection and maintenance frequencies have been timed to balance the requirements of appropriate Australian and International Standards, good industry practice, manufacturer's recommendations and the body of experience gained from SA Power Networks' own operating experience.

The routine maintenance and inspection intervals for substation power transformers are defined in Table 5.

Table 5: Substation Power Transformer Maintenance Intervals

Maintenance Type		Asset Type	Maintenance Interval
Inspection	Visual Inspection	TF, Regulator or Oil-filled reactor	6 months
	Thermographic Inspection	TF, Regulator or Oil-filled reactor	6 months
Diagnostic	TF Protection Devices	OLTC TF or Regulator	6 years
		Fixed Tap <5MVA	By defect
		Fixed Tap ≥5MVA	6 years
	Oil Quality	TF or Regulator ≥ 40 years old	3 years
		TF or Regulator < 40 years old	3 years
	DGA	TF or Regulator ≥ 40 years old	1 year
		TF or Regulator < 40 years old – Small (<5MVA)	3 years
		TF or Regulator < 40 years old – Medium or Large (>20MVA)	1 year
Maintenance	OLTC TF or Regulator	With Reinhausen 'V type' tap changer	6 years
		Reinhausen 'C Type' – spring change	Every 50,000 operations
		Others	6 years nominal**
	Fixed tap TF or oil filled reactor	<5MVA	By defect
		>5MVA	12 years
	Station/Auxiliary transformer		By defect

** NOTE: Routine maintenance may be deferred for up to 12 months subject to suitable results from comprehensive oil diagnostic testing and approval from Asset Manager. Maximum deferral permitted is 2 years beyond normal cycle.

5.3.3.1 Routine Inspections

Periodic routine inspections are carried out on substation power transformers (approximately every 6 months) by Asset Inspectors or Asset Management Officers. These consist of a visual inspection, specifically focusing on OLTC readings, oil levels, bushings, oil leaks, silica gel breathers, earth connectors, winding temperature readings, and general condition of tank, pipe work and cooling equipment.

In addition thermographic checks are also carried out of tanks (main, OLTC and conservator), cooling equipment, bushings, bolted electrical connections and cable boxes if fitted.

5.3.3.2 Diagnostic and Condition Monitoring

Diagnostic and condition monitoring may be carried out either on-line or off-line. Testing is undertaken on transformer protective devices, oil quality tests are performed on the main tank and switch tank, and dissolved gas analysis (DGA) testing is undertaken on oil samples from the main tank only as set out in the Maintenance Strategy for Substation Power Transformers in the Network Maintenance Manual.

5.3.3.3 Routine Maintenance

Routine maintenance incorporates a detailed inspection, test and overhaul program that requires the asset to be taken out of service and thoroughly examined for wear and tear. During this maintenance cycle, replacement parts are installed as required. On completion, assets are subject to a range of pre-energisation checks to ensure the asset is safe to be placed back in service.

5.3.3.4 Defect Maintenance

Defect maintenance addresses correction of an observed defect or fault which may impact the asset performance or cause a potential failure. Defect maintenance is initiated either through preventative maintenance programs, inspection or the fault management process.

5.3.4 Insurance Spares

The spares holdings are based on experience gained in maintaining the range of power transformers and regulators currently installed across the network. The strategic spares held are detailed in the Network Maintenance Manual (Manual 12).

SA Power Networks spares strategy requires that in the event of a failure of any transformer or regulator a replacement spare unit of similar rating will be available where the loss of the transformer or regulator would result in an on-going loss of supply to customers. The strategy is described in detail in the Network Maintenance Manual (manual 12).

The strategic spares holdings generally will enable, subject to the extent of damage, the failed equipment to be repaired and placed back into service within 2 to 20 days, subject to location and transformer size. If the unit has catastrophically failed, a replacement insurance spare unit will be procures, which can take upwards of 12 months.

Further details of transformer strategic spare parts and units can be found in Section 10.1 of Network Maintenance Manual No. 12.

5.3.5 Mobile Substations

In addition to the spares detailed above, SA Power Networks possesses the following mobile substations which can be deployed for rapid emergency supply restoration:

- 2 x 10MVA 66/11kV or 33/11kV
- 2 x 3.8MVA 33/11-7.6kV and 1 x 3MVA 33/11kV

5.3.6 Repair or Scrapping of Spare Transformers

When a unit is removed from service, either for capacity upgrade or following failure, it is assessed as to whether it should be kept as a spare or whether it should be scrapped.

The repair/refurbish or disposal decision takes into account the following factors:

- Cost of repair/refurbishment
- Cost of a new unit
- Number of same units in service
- On-going availability of spares
- Is the asset still technically/operationally acceptable (eg may have high noise level)

In any case, any power transformer over 45 years of age removed from service should not be re-installed except for a like-for-like replacement under emergency conditions.

5.4 Failure Modes and Response Strategies

Due to the complex nature of transformers, multiple failure modes can apply to individual units. These failures can be categorised into signal impending and hidden modes.

'Signal Impending': This type of potential fault within a transformer can be detected by appropriate condition monitoring testing and analysis. For SA Power Networks oil quality and DGA are the main techniques used for detecting the on-set of potential problems/failures within power transformers. This type of fault, can in most instances, be detected sufficiently early, providing adequate time to plan the replacement of the transformer in a timely manner without unduly impacting on customer service and performance.

'Hidden': This covers those faults within the transformer that cannot be detected by condition monitoring process. The fault will generally result in the loss of the transformer without evidence of early warning signs. These faults will result in the interruption of supply with the loss of the transformer. This type of fault will require the transformer to be repaired or replaced possibly under emergency conditions, generally impacting on customer service and performance.

Failure of transformers will involve at least one of the following areas:

- Core and windings
- Insulating medium (oil)
- Bushings or cable box
- Tap changing mechanism

Refer to Table 5 for further analysis of failure modes.

Table 6: Power Transformer Failure Mode Analysis

Failure Mechanism	Cause	Failure Mode - Response
Degradation of internal paper and oil insulating system	Operating condition and time	Signal Impending – condition monitor
Application of severe overvoltage	Lightning strike	Random/Hidden – fix on failure
	Design weakness revealed over time	Hidden – targeted replacement based on performance
Severe or prolonged overloading	Operating condition and time	Signal Impending - condition monitor
Degradation of internal winding mechanical withstand strength and inability to cope with large forces generated under system faults	Accumulation of operation events over time	Wear and tear, generally Hidden – replace on age or fix on failure for 'pre-mature' failures
	Design weakness revealed over time	Hidden – targeted replacement based on performance
External flashover	initiated by foreign object including birds or vermin	Random/Hidden – fix on failure

Generally for metropolitan and large country town substations, the substation design permits some redundancy so that most customer load can be restored, either via being transferred to another unit or substation, within four hours whenever there is a failure. The 66-33/11kV, 10 MVA mobile substations are a significant asset in the ability to restore supply to customers. The response time for installing the mobile substations is typically up to 12 hours in metro locations.

Small substations (ie < 5MVA capacity) may have no redundancy and will either require mobile generation or the mobile substations to be installed to restore supply; typical response time is 12-24 hours in country locations.

Replacement of a failed unit can take several days for a small unit but up to 20 days or longer for a large unit and during that time supply to customers being supplied from that substation will be at risk of interruption for any further substation fault or protection operation.

The bypass or alternative supply options to reinstate supply to affected customers will result in the system being configured abnormally and hence potentially for any additional minor fault within the substation and/or network may result in an interruption of supply to a significantly larger number of customers.

5.5 Disposal Plan

The disposal of a transformer must be approved by the Manager Network Planning. If disposal is approved, the Network Planning Department will assess the unit and decide if parts can be salvaged for spares in other units, which are still in service.

Salvaging is arranged by the Logistics Group within Field Services, and is completed by undertaking Work Instruction MLS/WD.09.003.WO1. This involves testing an oil sample for PCB levels. If the test results show that PCB levels are less than 50ppm, the oil is moved into bulk storage for reuse following re-refining or disposal in accordance with approved manner, and the remaining tank is sold off as scrap metal. If the test results show that PCB levels are over 50ppm the transformer is placed in the PCB holding compound immediately, and the disposal of the unit is arranged to be undertaken by an approved company.

6. REFURBISHMENT and REPLACEMENT PLAN

6.1 Refurbishment and Replacement Plans

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

Over the life of an asset it suffers from the cumulative deterioration resulting from normal electrical, thermal and environmental stresses experienced on a day-to-day basis plus the abnormal (severe) stresses due to lightning and switching over-voltages and system faults. Due to this, failure is inevitable, and therefore it is prudent to establish a set of condition criteria, including age, by which to assess a unit's condition and therefore probability of failure. Once beyond the set condition limits, the assets are programmed to be retired.

The maintenance strategy which is translated into the annual opex work plan will indicate the most economical and effective preventative maintenance activities to mitigate existing risks. This will include the refurbishment or replacement of the transformer if the risk of operating the transformer based on its current condition becomes unacceptable. The replacement of the transformer is the last step taken after the actions to prolong the life of the transformer are implemented.

6.2 Refurbishment Plan

SA Power Networks manages a large population of substation power transformer assets across the various stages of the Asset Life Cycle, with many assets nearing the end of useful life through a number of technical or economic reasons.

Network refurbishment programs are developed to identify and direct appropriate intervention to assets approaching the end of useful life but whose upgrade/replacement is not considered prudent on the basis of condition, reliability or performance.

The scope of network refurbishment program are driven by a number of technical and economic reasons and include both targeted works to recondition specific asset subpopulations and sustained investment to manage ongoing condition risks identified across the general population.

6.2.1 Installation of oil filters to Reinhausen 'V' type On Load Tap Changers

In 2011 SA Power Networks experienced two separate failures of transformers, caused by a failure within the Reinhausen 'V' Type OLTC. One of these failures was a result of carbon build up within the tap changer, resulting in a flashover and complete failure of the transformer.

To carry out maintenance on the OLTC a mobile crane, transformer edge fall protection and switching to offload the transformer are required. In some cases use of the mobile substation may be required. This being a labour intensive maintenance operation, each maintenance incurs significant expense, especially if the OLTC insert assembly is heavily carbonised. For this reason the retrofit of Reinhausen 'V' type tap changers with an oil filtration system to reduce carbon and moisture within the oil has been proposed as a solution.

Following a trial of a filter unit on one of the Seacombe Substation transformers over 2012-13 a business case has been produced to examine the benefits and cost of fitting oil filters to some or all (82) transformers fitted with the Reinhausen V type tap changer.

In summary, the business case recommends fitting the oil filters to high cost maintenance sites (20) based on an NPV evaluation.

Benefits of fitting the oil filter include:

- risk of another V type OLTC failure due to carbon build up is essentially removed
- Lower operating costs are expected as OLTCs will be in better condition at the end of their maintenance cycle resulting in fewer repairs
- Extended maintenance cycles; able to increase from six to nine years. This has significant advantage at single transformer sites where there are few ties to offload the substation, a mobile substation is required which adds significant expense to any work carried out. By reducing maintenance, this can lead to quite significant operational savings.
- Improved OLTC performance/reliability as units run cleaner
- Reduced maintenance results in increased transformer availability and reliability for the network

Further information on all targeted programs of work can be found in Appendix D.

Table 7: Expenditure on installation of oil filters to Reinhausen 'V' Type On Load Tap Changers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	-	1	3	3	3	3	3	3	1	-	-	-	**20**
$ ('000)	$-	$ 35	$ 105	$ 105	$ 105	$ 105	$ 105	$ 105	$ 35	$-	$-	$-	**$ 700**

6.2.2 Ongoing Refurbishment of Substation Power Transformer

Sustained refurbishment programs address ongoing capital requirements of SA Power Networks' Power Transformer assets to meet required levels of safety and performance. Expenditure requirements within this area are varied and driven primarily by specific asset needs identified through condition, reliability, operational performance data and economic assessments.

Capital refurbishment of substation power transformers incorporates a range of transformer specific works that include OLTC overhaul and replacements, cable box retrofits, oil treatment/replacement and overhaul of transformer cooling equipment and main tank oil seals and gaskets.

Proposed refurbishment expenditures are intended to maintain current performance of this asset class and address expected requirements when managed in conjunction with targeted replacement works. Forecast requirements are summarised below.

Table 8: Expenditure on Ongoing Refurbishment of Substation Power Transformers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
$ ('000)	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	**$9000**

6.3 Replacement Plan

Several different methodologies have been utilised to develop the forecast replacement quantum of works over the period 2014–2025 and associated capital expenditure. Methodologies utilised were:

- Top down:
  - Work undertaken by consultants Aurecon
  - Developed Asset Health Index Based Model

- Failure rate modelling – linear and Weibull methodologies
- Condition Based Risk Management (CBRM) model:
  - Bottom-up detailed assessment
  - Takes into account specific asset, specific asset condition data, specific asset consequences and likelihood of failure
  - Can give several possible outputs; predicted replacements based on likelihood of failure, ie the health Index; Predicted replacement based on maintaining a certain level of risk; or predicted replacements based on NPV.
- Targeted programs of work:
  - Where there is a problem with a specific asset model or specific asset
  - Where the assets are non-compliant with a required standard
- Historical trend – extrapolation of historical trends in numbers of replacements and spend
- AER repex model:
  - Top-down benchmarking mode
  - Uses age-based replacement modelling
  - Limited high level information required – asset age profile; expected life and standard deviation of expected life; historical expenditure; and average asset replacement cost
  - Simplistic approach which has limitations.

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

6.3.1 Top-down methodology

Aurecon were employed to develop a top-down power transformer replacement strategy for SA Power Networks. The full report produced is included in Appendix B and is summarised below.

6.3.1.1 Replacement Unit Costs

Aurecon developed until costs for use in their analysis based on a typical scope of works. It should be noted that these costs differ for most groups of transformers from those developed by SA Power Networks based on actual projects and works undertaken and completed, but have been retained in this section to match the final strategy report delivered to SA Power Networks by Aurecon (Appendix B).

6.3.1.2 Outputs of Analysis

The forecasts from the Weibull derived failure rates analysis undertaken by Aurecon appear to be on the high side of the SA Power Networks expectation. The alternative budget based on pure historical failure rate projects for the different categories of transformers has produced numbers that are more in line with SA Power Networks experience based on approximately 13 years of data. It does though not allow for the units that were removed from service for other reasons but were likely to fail if left in service nor any increase in failure rates due to changes in transformer demographics. Being based on simple linear modelling of failure rate, these approaches are not in line with the industry understanding on the long term performance of populations of assets such as transformers.

Thus a possible alternate budget is a median between these approaches, which is aimed at hedging the weakness of the linear approach with the likely over estimate of the Weibull approach. Given the life of the budget is realistically only 5 years and the assets are very long lived relative to the budget cycle this represents a rational compromise.

Table 9: Median based Transformer Replacements

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Small	5.0	5.0	4.6	5.6	4.6	5.2	5.2	5.7	5.3	5.8	5.3	5.4	62.7
Medium	1.9	2.5	3.0	3.1	2.6	3.2	3.7	4.3	4.8	3.3	4.9	3.9	41.2
Large	0.8	0.4	0.9	0.4	0.9	0.4	0.9	0.5	1.0	0.5	1.0	0.5	8.1
TOTAL	**7.8**	**7.9**	**8.5**	**9.1**	**8.2**	**8.8**	**9.8**	**10.4**	**11.0**	**9.6**	**11.2**	**9.8**	**112.1**
Per Year	***9.3***												

Table 10: Expenditures Based on Median Projections)

$millions	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	*Total*
Small	$2.53	$2.55	$2.32	$2.84	$2.35	$2.62	$2.64	$2.91	$2.67	$2.94	$2.70	$2.72	***$31.79***
Medium	$1.64	$2.10	$2.56	$2.60	$2.21	$2.67	$3.13	$3.60	$4.06	$2.83	$4.13	$3.33	***$34.85***
Large	$1.10	$0.47	$1.14	$0.51	$1.18	$0.55	$1.22	$0.59	$1.26	$0.63	$1.30	$0.67	***$10.62***
TOTAL	**$5.27**	**$5.12**	**$6.02**	**$5.95**	**$5.74**	**$5.84**	**$6.99**	**$7.09**	**$7.99**	**$6.40**	**$8.14**	**$6.72**	**$77.26**

NOTE: Utilised Aurecon Unit Rates (see Appendix B) not SA Power Networks generated unit costs

6.3.2 CBRM methodology

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

CBRM is a decision support tool developed to assist asset managers in quantifying, communicating and managing asset related risk, with particular emphasis on issues associated with end of life. 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 proposal that best meets the objectives of the organisation.

CBRM seeks to overcome the common asset management decision optimisation problem of non-availability of reliable and consistent data that 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 asset sub populations within a general asset class to behave differently. Examples of different sub populations would include manufacturer make and model with varying design and quality characteristics, changing equipment specifications and installation practices, operating environment and usage history.

Rather than use a purely statistical representation of the asset population, CBRM models seek to make the best possible use of available information by combining asset register information, operating context, operating history and condition information using rules that are consistent with engineering principles and the operating experience of 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.

CBRM offers a tactical advantage 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 quantity level forecasts necessary for budget and regulatory purposes.

A full description of the CBRM methodology, as applied to Power Transformers, can be found in Appendix 0.

SA Power Networks does not currently have sufficient economic data that an equal dollar for dollar value can be obtained between Network Investment and Risk, this means that the financially optimum replacement year cannot reliably be identified.

SA Power Networks has identified that the level of risk exposed by transformers can be maintained if a fixed percentage of the overall population is replaced per annum. The, required annual expenditure resulting from application of this methodology is summarised below.

This methodology produces results targeted at maintaining risk exposure after allowing for capacity related replacements, the targeted works program detailed below in Section 6.3.3 and expected failures (detailed as unplanned replacements based on historical experience below in Section 6.3.4).

This methodology was selected on the recommendation of EA Technology as it is sensitive to absolute values of risk and more reliant on condition and failure rates information, which SA Power Networks holds good data on, than the other methodologies available within CBRM.

Table 11: Substation power transformers to be replaced from CBRM

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Planned (Number of transformers)													
Small	-	-	-	-	-	-	-	-	-	-	-	-	-
Medium	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	3
Large	-	-	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	4
Sub-Total	***0***	***0***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***7***
Unplanned (Number of transformers)													
Small	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	43.2
Medium	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	21.6
Large	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	9.6
Sub-Total	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***74.4***
TOTAL	**6.2**	**6.2**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**81.4**
Expenditure ($2013, $millions)													
Small	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	**$11.23**
Medium	$2.11	$2.11	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	$2.46	**$28.78**
Large	$1.31	$1.31	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	**$22.30**
TOTAL	***$4.35***	***$4.35***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	***$5.36***	**$62.32**

6.3.3 Targeted programs of work

6.3.3.1 Rusty radiators

Over the last several years a number (>4) of small fixed tapped 33/11kV transformers have needed to be replaced due to severe corrosion, in particular affecting the radiator cooling fins. This problem has been limited to a particular design/construction style where the cooling fins are fabricated from a corrugated metal plate which then forms part of the main tank. To date those which have been replaced have generally been in coastal areas, ie subject to high corrosion atmosphere.

Based on SA Power Networks experience it is expected that other similarly constructed units will suffer the same problem. We expect all the units of this construction type to have shorter than normal lives and those installed in coastal areas are expected to have a life of 20 years approx.

There are another 36 transformers currently identified as having the same construction of radiator cooling fin. The youngest of these units are two years old (approx). Further, 10 units are installed in high atmospheric corrosion areas.

It is likely that over the next 10 years that there will be the need to replace more of these units. Three possibilities exist:

1. Failure rate will significantly reduce (ie basically no more failures) - unlikely
2. Failures will continue at historical rate (approx) – most likely
3. Failure rate will increase significantly – possible

No specific allowance is sought in relation to this issue based on:

- our most likely expectation is (2) above,
- past failures associated with this failure mode are included in our historical unplanned failure rate submission above.

Further information on all targeted programs of work can be found in Appendix D.

6.3.4 Historical trend

The historical spend on substation transformer replacement – planned, unplanned and targeted - is shown in Figure 19 below. This figure is similar to that predicted by some of the other methodologies discussed below. Historically over the period 2008 to 2014 an average of four small, two medium and one large substation power transformers has been replaced per annum, at an average cost of around $5.26 million per annum over the 5 years.

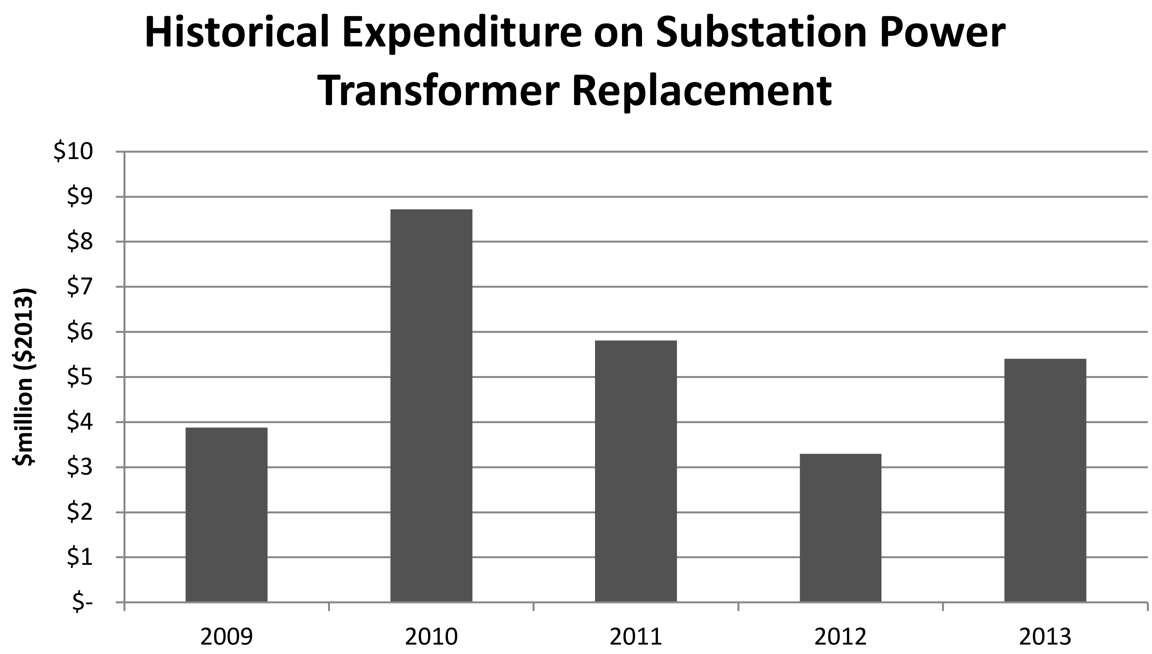


Figure 9 : Historical expenditure on substation power transformers replacement

6.3.5 AER Repex model

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

An initial version of the RepEx model has been prepared as part of the completion of the Category Analysis RIN. The results of this initial RepEx modelling are shown in Figure 10 and Table 9 below.

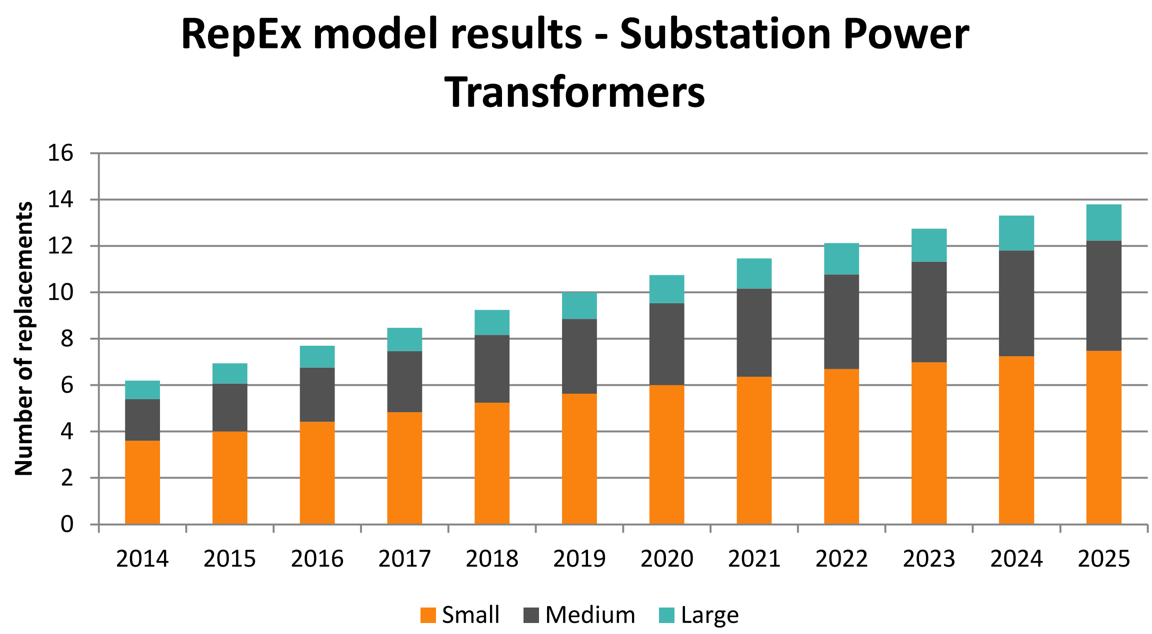


Figure 10 : RepEx model results

Table 12: RepEx Results for Substation Power Transformers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number of Transformers													
Small (≤5MVA)	3.6	4.0	4.4	4.8	5.2	5.6	6.0	6.4	6.7	7.0	7.2	7.5	68.5
Medium (≥5MVA and ≤20MVA)	1.8	2.1	2.3	2.6	2.9	3.2	3.5	3.8	4.1	4.3	4.6	4.8	40
Large (≥20MVA)	0.8	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.4	1.4	1.5	1.6	14.2
TOTAL	**6.2**	**6.9**	**7.7**	**8.5**	**9.2**	**10.0**	**10.7**	**11.5**	**12.1**	**12.7**	**13.3**	**13.8**	**122.7**
Expenditure ($millions)													
Small (≤5MVA)	$0.94	$1.04	$1.15	$1.26	$1.36	$1.47	$1.56	$1.65	$1.74	$1.82	$1.88	$1.94	$17.81
Medium (≥5MVA and ≤20MVA)	$2.11	$2.41	$2.74	$3.07	$3.42	$3.77	$4.12	$4.46	$4.78	$5.07	$5.34	$5.57	$46.86
Large (≥20MVA)	$1.31	$1.42	$1.54	$1.65	$1.76	$1.88	$2.00	$2.11	$2.23	$2.35	$2.46	$2.56	$23.28
TOTAL	**$4.35**	**$4.88**	**$5.42**	**$5.98**	**$6.55**	**$7.12**	**$7.68**	**$8.23**	**$8.75**	**$9.24**	**$9.68**	**$10.08**	**$87.94**

6.3.6 Results Comparison

Table 10 and Figure 11 below illustrate the average number of replacements per year of substation power transformers predicted utilising each of the above detailed methodologies.

Table 13 : Comparison of average number of replacements per annum

	Aurecon - Median	CBRM			Historical	RepEx*
		Maintain Risk (Planned)	Failures (Unplanned)	TOTAL		
Small	5	0	3.6	3.6	3.6	0.8
Medium	2.8	0.3	1.8	2.1	1.8	8.3
Large	0.7	0.4	0.8	1.2	0.8	0.6
TOTAL	**8.5**	**0.7**	**6.2**	**6.9**	**6.2**	**9.7**

NOTE: RepEx data not exactly comparable, for purposes of comparison the following criteria have been used: Small = <5MVA for methodologies other than RepEx for RepEx <600kVa, Medium = 5-20MVA for RepEx = 600kVa – 15MVA, Large = >20MVA for RePex = >15MVA

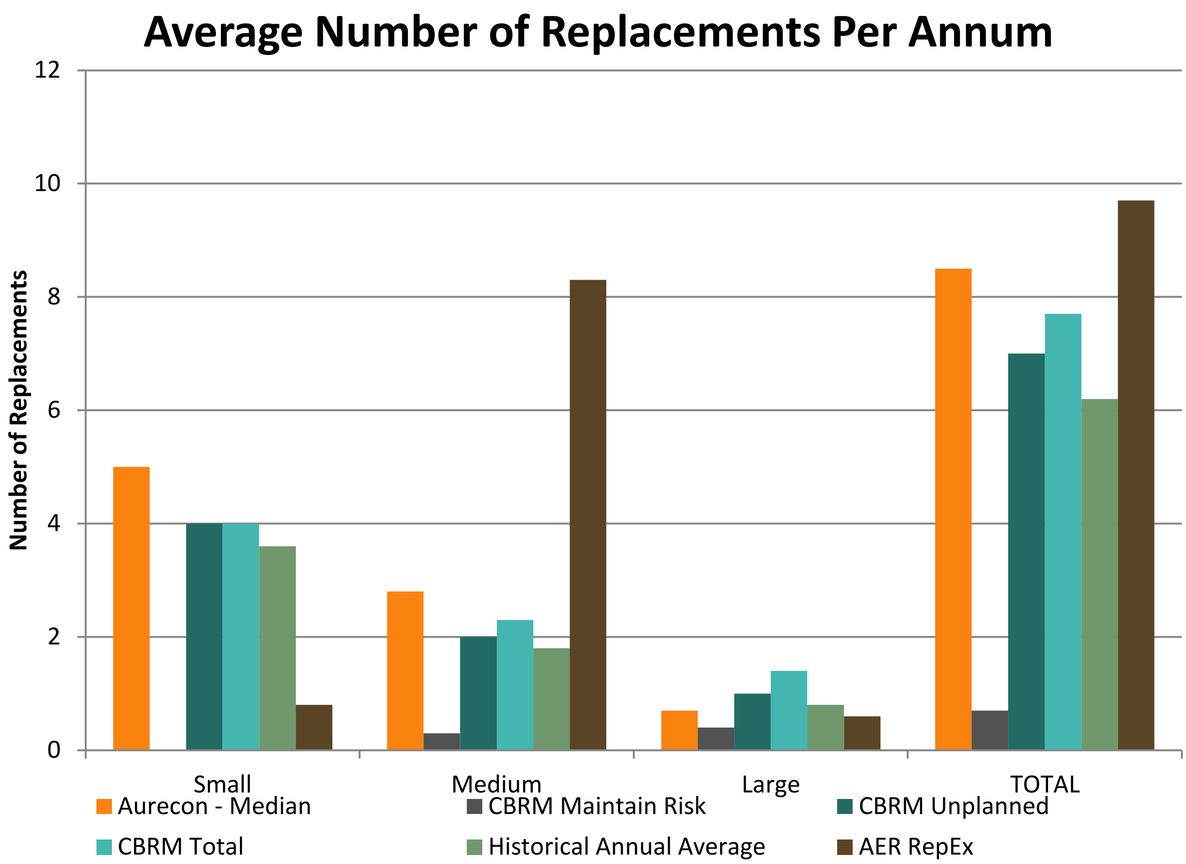


Figure 11 : Comparison of average number of replacements per annum (2015 to 2025)

Figure 12 illustrates the replacement expenditure predicted each year utilising the top down, CBRM maintain risk plus unplanned failures (based on historic rates) plus targeted replacement programs, and RepEx methodologies. As can be seen both the top down and CBRM plus methodologies show the replacement per annum remaining at around the same sustainable level of replacement per annum whereas the RepEx model shows an increasing volume of replacements year on year.

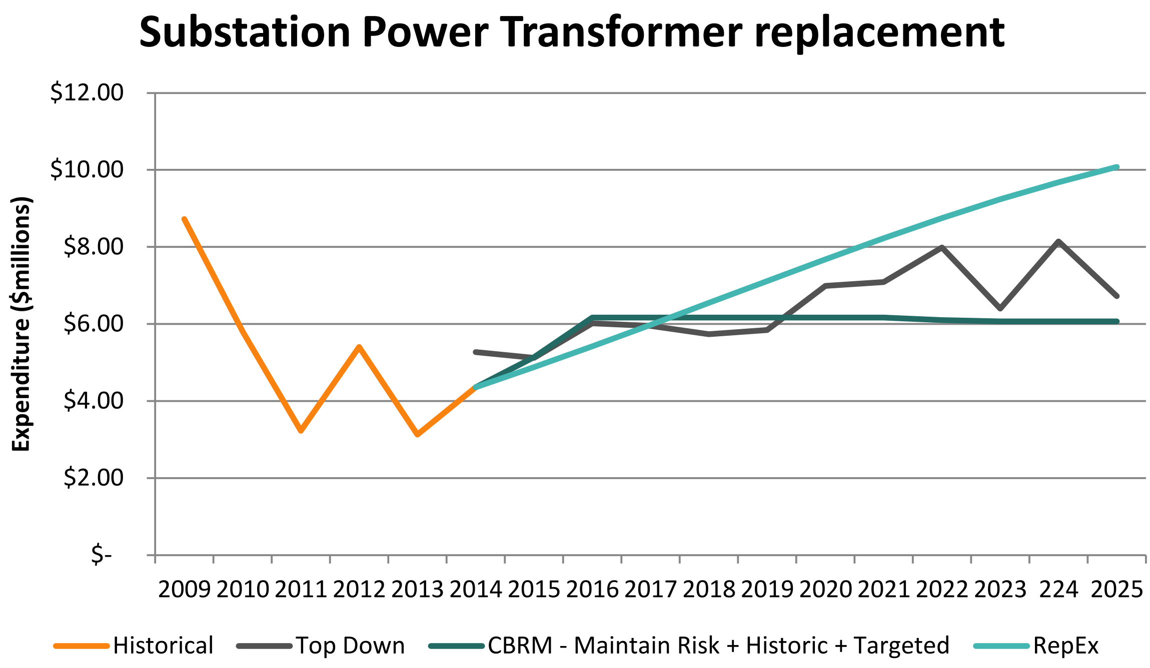


Figure 12 : Comparison of replacement expenditure per annum ($2013)

6.4 Forecast and Discussion

There are significant differences in the average annual number of substation power transformers replacement required in the 2014–2015 period depending on the model and methodology used.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- Maintains the current level of risk associated with substation power transformers
- Maintains existing levels of service and reliability needs necessary to meet customer expectations of network performance. Forecasts levels of expenditure at or below historical levels, considered prudent and efficient by its targeted, optimal replacement of high risk units

- Is based on qualified, asset specific assessments of condition and criticality from high confidence level engineering data
- Has been developed utilising a well proven and well recognised methodology

7. FINANCIAL SUMMARY

7.1 Introduction

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

7.2 Basis of Unit Costs

Costs associated with substation power transformer replacement/refurbishment works have been developed for the categories shown in Table 14 from historical project expenditure over the period 2008 to present.

The scope for individual replacement works will vary to meet site specific needs and any subsequent requirement for upgrade of associated infrastructure (ie Station auxiliaries, protection and control schemes, expansion of control building) to meet equipment needs, regulatory requirements and modern safe operating standards.

Unit costs in Table 14 are derived based on an average allowance for all historical costs typically required to complete a circuit breaker replacement project.

Table 14: Unit Costs for Replacement Works

Substation Transformer Group	Unit rate ($2013)
Large transformers ≥ 20 MVA	$1.64M
Medium transformers ≥ 5 to <2 0 MVA	$1.17M
Small HV/HV transformers < 5 MVA	$0.26M

7.3 Financial Statement and Projections

The total cost required per annum for the period 2014 to 2025 associated with substation power transformer replacement and refurbishment is shown in Table 15.

Table 15 : CAPEX – Replacement and Refurbishment

	$million ($2013)											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	*TOTAL*
Replacement	$4.35	$5.36	$5.36	$5.36	$5.36	$5.36	$5.36	$5.36	$5.36	$5.36	$5.36	**$57.96**
Refurbishment	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	**$9.00**
Target Program	$0.035	$0.105	$0.105	$0.105	$0.105	$0.105	$0.105	$0.035	-	-	-	**$0.70**
CAPEX	**$5.14**	**$6.22**	**$6.22**	**$6.22**	**$6.22**	**$6.22**	**$6.22**	**$6.15**	**$6.11**	**$6.11**	**$6.11**	**$66.91**

8. PLAN IMPROVEMENT AND MONITORING

This section is a summary only of proposed changes and improvements with regard to asset management for substation power transformers. Further details are contained in AMP 3.0.01 Condition Monitoring and Life Assessment Methodology.

8.1 A summary of the desired state of Asset Management

The maintenance of substation power transformers in SA Power Networks system is presently a mix of time and condition based maintenance management. Planned routine and overhaul maintenance, including the critical tap changer maintenance, are principally performed on a time based regime. Remedial works (ie repair of defects) are performed on a prioritised condition basis. For substation power transformers the main source of condition information is obtained from routine plant inspection, oil sampling and analysis (oil quality and DGA) and results from electrical testing.

The low relative cost of many SAPN power transformers and their distribution through a geographically large network makes some condition based approaches such as ubiquitous online monitoring cost prohibitive on a general basis. For some critical or high impact assets, investment in on-line systems may be warranted for risk mitigation purposes. This is discussed in more detail in the Condition Monitoring & Life Assessment Methodology (AMP 3.0.01).

8.2 Improvement Plan – improving what we are doing

SA Power Networks acknowledges the need for continual improvement in its asset management processes. One initiative in that area is the proposal to acquire a number of semi-portable continuous online insulating oil dissolved gas monitoring systems. These will be able to be applied to critical and/or at risk substation power transformers to provide early warning of impending failure. The use of such systems will extend the operating life of these transformers thorough control of their risk by having continuous condition information. This will therefore result in more timely and cost effective management of critical plant and less likelihood of loss of supply and reduced overall capital and maintenance costs. This is discussed in more detail in the Condition Monitoring & Life Assessment Methodology (AMP 3.0.01).

8.3 Monitoring and Review Procedures

A minor review of the AMP, particularly budgets and forecast work to be undertaken, will be undertaken as part of annual budget preparation. A full review will be undertaken, at least every five years or as required to recognise any changes in service levels and / or resources available to provide those services, or as a result of other obligations being placed on the business.

The Plan has a life of 11 years (2014–2025) and is due for revision and updating within one year of each AER price ruling.

9. APPENDICES

A. Maintenance strategy – Substation transformers

The maintenance strategy for substation power transformers is outlined in the Network Maintenance Manual – Manual No. 12. Section 5 describes maintenance strategies for substations, with the specific sections applicable for Substation Power Transformers being:

- Section 5.4: Substation Power Transformer

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

B. Aurecon Replacement Strategy Report

Adobe Acrobat
Document

C. CBRM Modelling

CBRM Overview

CBRM is a decision support tool developed to assist asset managers in quantifying, communicating and managing asset related risk, with particular emphasis on issues associated with end of life. 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 proposal that best meets the objectives of the organisation.

CBRM seeks to overcome the common asset management decision optimisation problem of non-availability of reliable and consistent data that 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 asset sub populations within a general asset class to behave differently. Examples of different sub populations would include manufacturer make and model with varying design and quality characteristics, changing equipment specifications and installation practices, operating environment and usage history.

Rather than use a purely statistical representation of the asset population, CBRM models seek to make the best possible use of available information by combining asset 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.

CBRM offers a tactical advantage 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 quantity level forecasts necessary for budget and regulatory purposes.

Relationship with Actuarial or Statistical based approaches

CBRM may be thought of as a ‘bottom up’ engineering model, whereas statistical approaches such as for example REPEX may be thought of as ‘top down’. Each type of model is subject to error from approximations associated with input assumptions and limitations related to the quality of input data. Both types of model will have application in a mature asset management process as they provide complimentary information from with to base a considered view of replacement requirements. While it would not be expected that a bottom up, and top down model will agree precisely, any differences should be subject to rationalization and explanation and in doing so better inform the decision process.

How CBRM Works

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 13 below.

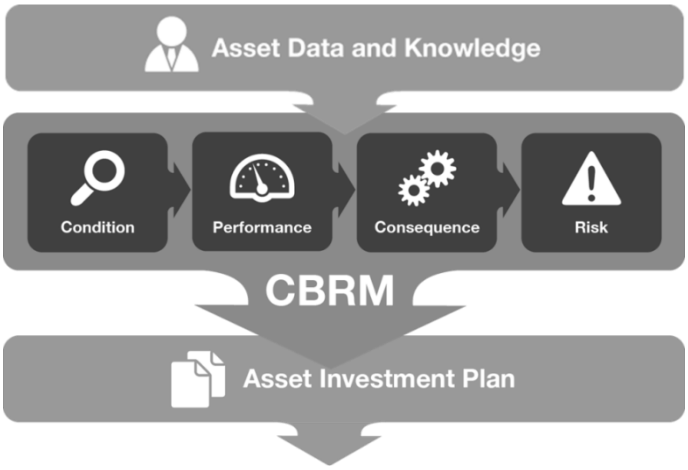


Figure 13: Overview of the CBRM process

Implementation of CBRM process

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

- **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.
- **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.
- **Determine the Consequence of Failure:** The consequence of failure is divided into the following categories:
  - CAPEX: The Capital Expenditure required to remediate an event
  - OPEX: The Operational Expenditure required to remediate an event
  - Safety: The cost incurred due to death/injury to individual(s) as a result of an event
  - Environment: The cost of environmental cleanup/penalties as a result of an event
  - Reliability: Financial penalties imposed if an event causes an outage

  The consequences are individually determined for all of the events associated with the asset using criteria such as location, number of customers, load profiles, SCONRRR category, and type/model.
- **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 14.

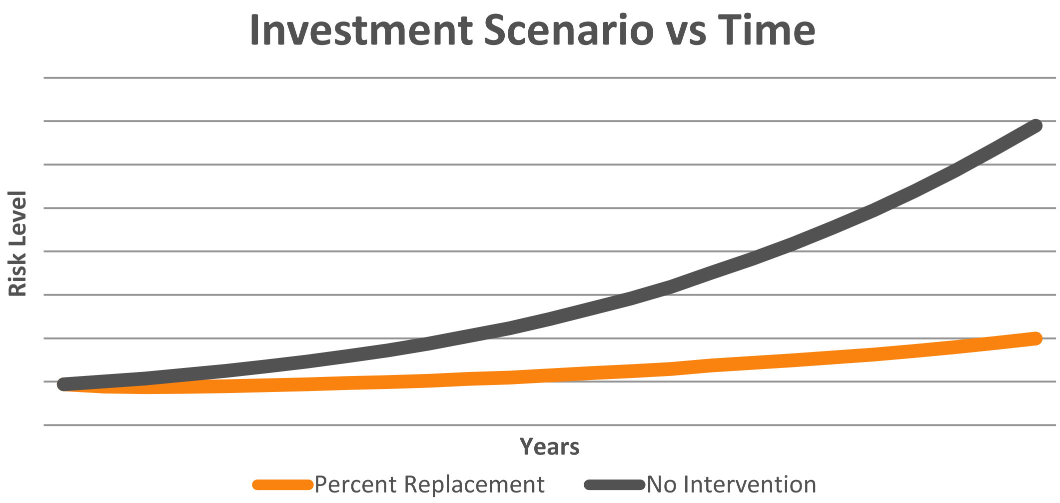


Figure 14 : Example of risk profile over time output graph

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 15.

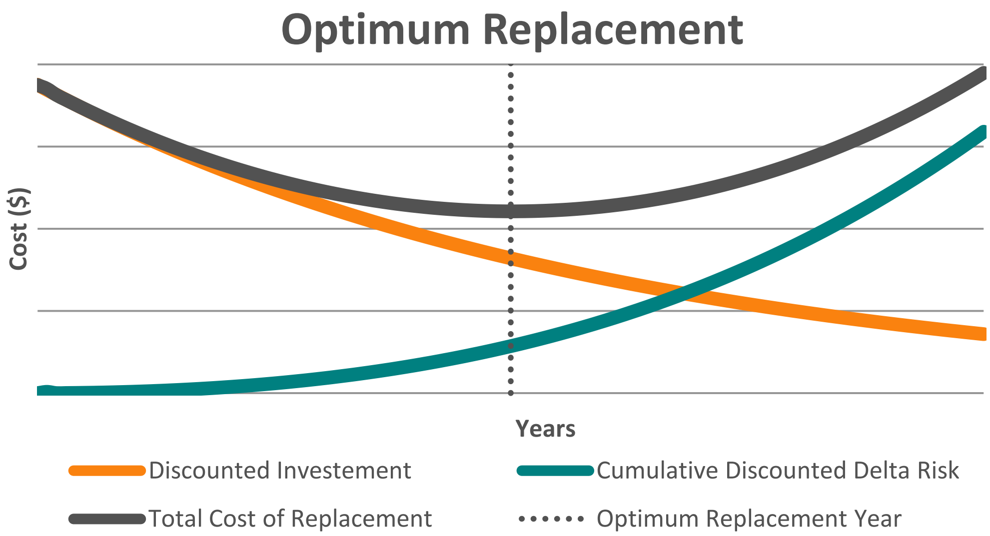


Figure 15 : Example of outputs used to determine optimum replacement year

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

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

Power Transformers Methodology

Determination of Health Index

CBRM formulates a HI representing the transformer unit (TX,) and a HI representing the transformer's OLTC. These two HIs are combined to determine HI Y0, which is the transformer's HI as it stands today.

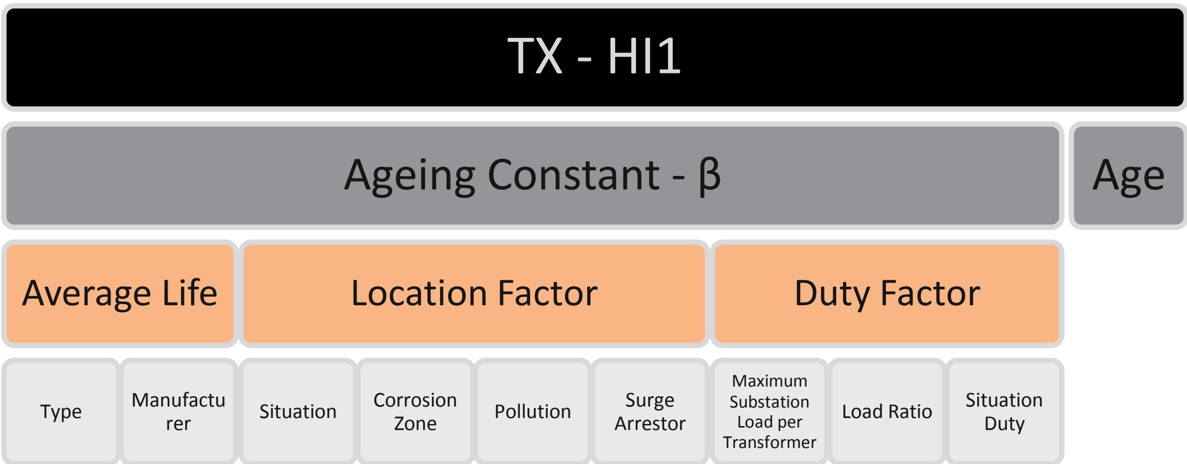


Figure 16 : CBRM methodology for determining TXHI1

CBRM determines TX HI1 – Age Related HI by calculating an ageing constant β, which is combined with the TX age. The information used and dependencies are shown above in Figure 16.

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

Average life: The average life of a TX is determined based on its type, and manufacturer.

Location Factor: The location factor depends on the following information:

1. Situation – An indoor TX has a mild operating environment when compared to an outdoor TX
2. Corrosion Zone – Represents the level of atmospheric corrosion a TX experiences during its operating life
3. Pollution – Localised pollution may affect the condition of a TX
4. Surge Arrestors – The presence of a surge arrestor at the TX location reduces wear experienced during a fault

Duty Factor: The duty factor is determined using the following information:

1. Maximum Substation Load per Transformer – Identifies the load the transformer experiences during peak summer season, CBRM expresses this as a percentage of the transformer's manufacturer specified rating.
2. Load Ratio – Used as a scaling factor for Item 1, and is essentially the ratio of *substation load : maximum substation load*.
3. Situation Duty – Accounts for effects of TX location on how hard it has worked.

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

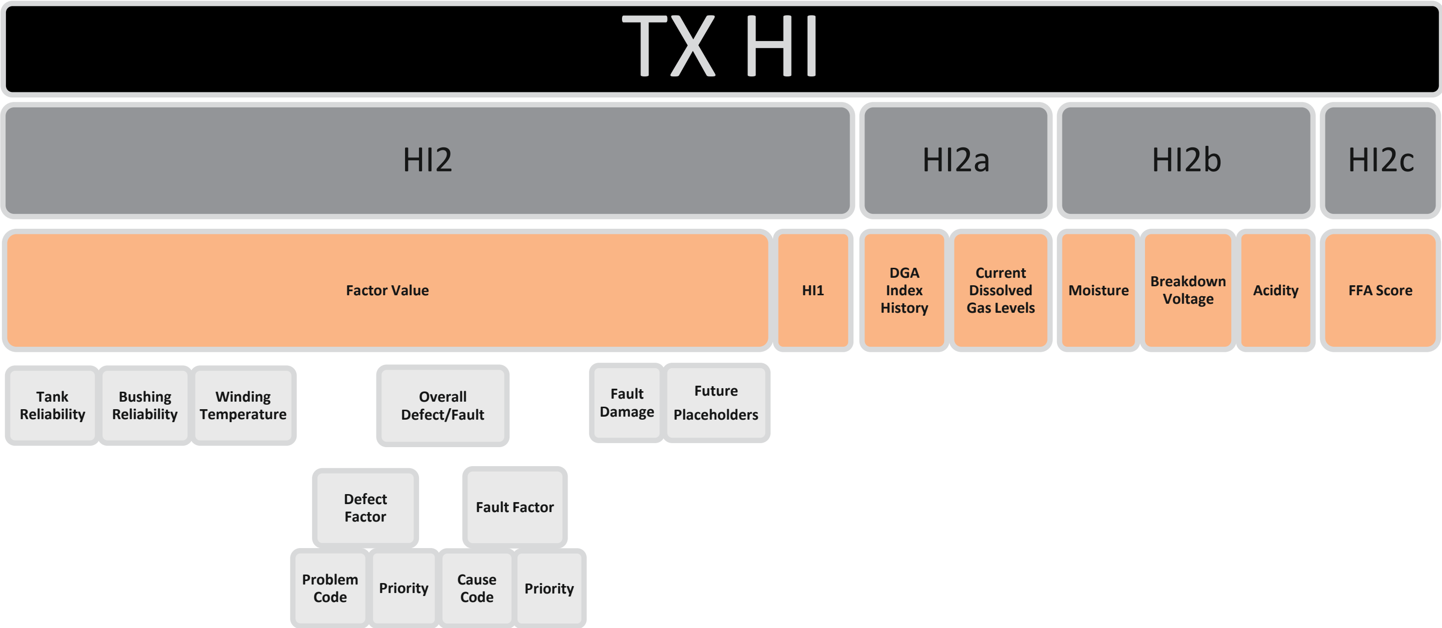


Figure 17: TX HI

TX HI represents the TX condition as it stands today, it's established by determining the following interim HI:

- HI2 – Determined by combining HI1 with the following condition based measurements:
  - Tank Reliability: Captures operator knowledge with respect to TX reliability
  - Bushing Reliability: Captures operator knowledge with respect to bushing types
  - Overall Defect Fault Factor: Captures operational history of the TX by combining separate weighted sums of the defects and faults recorded against the TX in SAP where scores are assigned by priority and notification coding
  - Fault Damage: Allows for the TX to be tagged as having experienced above average fault events, and is only used when no other fault data is available
  - Future Maintenance/Visual Inspection Placeholders: These are empty placeholders to be used when more condition information is available in the future
- HI2a – Determined from Dissolved Gas Analysis (DGA) test results. CBRM finds the most recent result, and combines this with a history factor representing the trend from previous results. The trend is used to estimate if DGA is accelerating, stable or falling. CBRM also uses a flag to indicate likely contamination between the TX and TC so that HI2a is capped to six if the flag is set.

- HI2b – Determined using oil condition information. Ideal information used to determine this HI is the moisture content, acidity and breakdown strength. Serious oil degradation is represented by a maximum value of three, indicating a significant issue but not end of life.
- HI2c – Determined from the Furfuraldehyde (FFA) value. FFA represents the mechanical strength of the paper used to insulate the windings within the transformer. CBRM uses an empirical mathematical relationship to determine this HI, which is calibrated to give a value of seven for a FFA value of 5ppm indicating that the paper has very little remaining strength and is at risk of failure during operation.

CBRM determines TC HI1 – Age Related HI by calculating an ageing constant β, which is combined with the TC age. The information used and dependencies are shown above in Figure 18.

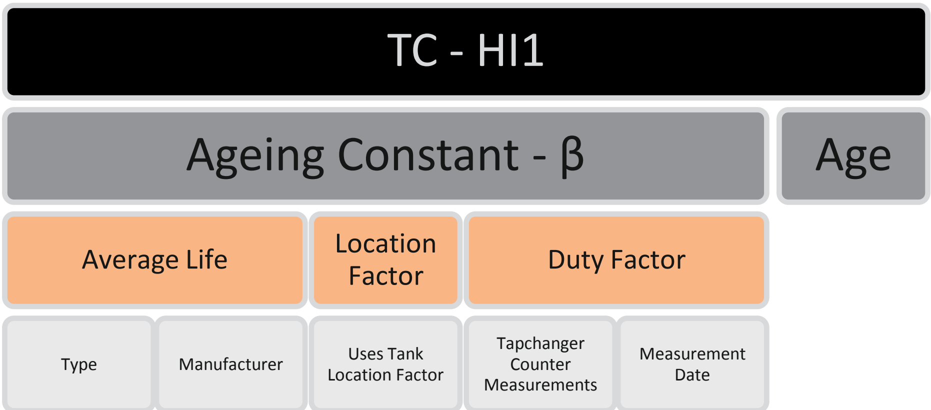


Figure 18: Tap Changer-HI1

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

- **Average life:** The average life of a TC is determined based on its type, and manufacturer.
- **Location Factor:** This the same location factor used for TX HI1.
- **Duty Factor:** The duty factor is determined using the last two counter measurements, and the dates they were measured. CBRM calculates the daily tapping rate, and extrapolates this to estimate how many taps the TC will undertake annually.

It's important to note that HI1 is capped to 5.5, as this indicates the TC is beginning to experience significant degradation. CBRM applies this cap because further degradation cannot be justified without condition based measurements.

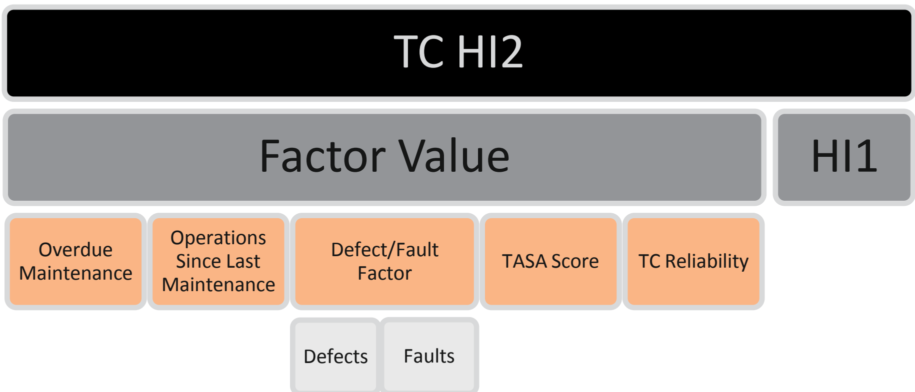


Figure 19: Tap Changer HI2

TC HI2 represents the TC condition as it stands today. This HI is determined by combining HI1 with an overall factor value, which is established by combining factors derived from condition based measurements. The overall factor value is a combination of the following condition based measurements:

- **Overdue Maintenance -** This takes into account if the TC is overdue for maintenance by looking at the last maintenance date and the date the model was most recently run.
- **Operations Since Last Maintenance –** This takes into account overdue maintenance based on the number of operations since the last maintenance. Each make and model of TC has different criteria for the overall score assigned.
- **Defect/Fault Factor -** Captures operational history of the TC by combining independent totals of the defects and faults recorded against it in SAP.
- **TASA Score –** The TC Activity Signature Analysis (TASA) score is supplied from TjH2B oil test results.
- **TC Reliability –** Captures operator knowledge with respect to TC reliability.

Final Determination of Overall Transformer Health Index:

The overall HI for a given transformer is established by combining TX HI and TC HI2. The ratio of *TX HI : TC HI2* is determined, and converted to a HI modifier based on its magnitude. HI Y0 is finally determined by choosing *MAX(TX HI, TC HI2)* and multiplying it by the HI modifier.

Determination of Risk Consequences

CBRM uses the following events to define transformer risk consequences:

- Major Failure – Failure that results in an unplanned outage requiring major repairs
- Significant Failure – Failure that results in an unplanned outage
- Minor Failure – Defect that does not result in an unplanned outage
- Replacement – The transformer is replaced due to unacceptable condition during a planned outage

CBRM assumes that each event incurs financial consequences on SA Power Networks, these are separated into the five consequence categories listed in item 3 of section 6.1.1, and an explanation on how CBRM determines the financial consequences for each of the categories is detailed in Table 16.

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**
  - Situation: Accounts for the difference in capital cost for an indoor transformer.
- **OPEX**
  - Customer Type: Allows different relative costs based on customer type, for example CBD failures require additional road management costs
  - Obsolescence: Obsolete assets have increased repair costs as their support and parts are not readily available

- **SAFETY**
  - Situation: An outdoor transformer can pose a much greater safety risk due to lack of containment
  - Customer Type: Reflects the proximity of a transformer to people
  - Medium: Takes into account the insulation medium, and therefore accounts for the increased safety risks of oil
- **ENVIRONMENT**
  - Size of Transformer: Scales the average environmental consequences according to the transformer's size
  - Oil Containment: Recognises sites without oil containment
  - Risk Assessment: Scales average environmental consequences to an overall subjective site risk assessment rating
- **RELIABILITY**
  - Obsolescence: An obsolescence rating is assigned to both the TX and TC. CBRM takes the highest of the two ratings
  - Customer Type: Scales the consequences based on the substation's SCONRRR
  - Situation: Accounts For differences between an indoor and outdoor transformer
  - Secondary Voltage: Assigns transformers with less common voltages to have higher risk
  - No. Transformers: Scales the consequences for the number of transformers at the site

The varying asset replacement maturity levels and their relationship to CBRM are discussed in Table 17 below.

Table 16: Financial Consequence categories

Event	CAPEX	OPEX	Safety	Environment	Reliability
Event: Major Failure Condition Non Condition	Investment in a new transformer Categorised as small, medium and large	No OPEX	For each event, CBRM splits safety into three accidents: • Minor • Major • Fatality Each accident is assigned an overall consequence representing financial investment to prevent it from occurring. Each event is assigned an average consequence factor for each subcategory. 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 safety into five subcategories: • Loss of Oil/Litre • SF6 Emission/kg • Fire • Waste/tonne • Disturbance Each subcategory is assigned an overall consequence. Each event is assigned an average consequence factor for each subcategory. CBRM multiplies the average consequence factor by the overall consequence for each subcategory, and the sum of the results is the overall environmental consequence for the specific event.	CBRM values the consequence as load put at additional risk. This is determined by multiplying the average load lost, VCR, and a LAFF factor. For redundant transformers, the LAFF is a cubic relationship of the ratio of *Load Above Firm Capacity : Maximum Demand* For non redundant transformers, CBRM uses a preset LAFF
Event: Significant Failure Condition Non Condition	Investment in spare parts Categorised as small, medium and large	Cost of repairs Divided into small, medium and large			
Event: Minor Failure Condition Non Condition	No CAPEX	Cost of repairs Divided into small, medium and large			There are no Reliability Consequences associated with this event
Event: Replacement Condition	Investment in a new transformer, including design costs Categorised as small, medium and large	No OPEX			There are no Reliability Consequences associated with this event

Table 17: 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	Decisions and forecasts made from asset age profiles. This approach corresponds to the 'deterministic' option available within the repex model and is rarely if ever used in distribution utility practice
Asset Health based	Assets are replaced when they reach a pre-determined condition or health. Commonly used and often based on quantitative condition monitoring or subjective inspection criteria	Replacement at a pre-defined health index. The replacement health index selected will define the probability of failure. This is the basis of many existing asset management strategies where a global standard defines common 'pass' and 'fail' criteria for all assets regardless of their criticality to business objectives
Target failure rate based	The volume of asset replacements 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 >> risk to business
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. Analysis is very sensitive to risk and WACC

CBRM Model Calibration

The objective of CBRM is to produce a decision support model that consistently combines both objective data, and subjective engineering knowledge to produce more representative projections than would be achieved than other methods, particularly in situations where data is sparse or incomplete. It is not intended that CBRM predictions compete with those of other approaches such as REPEX, rather each method produces a 'data point' that should be considered in totality. In a regulatory discussion, CBRM projections would represent the best available estimates of forward renewal requirements that incorporate available engineering data and engineering opinion. An actuarial model such as REPEX would represent a future projection based on high level historical data and statistics with an accuracy level commensurate with data quality and validity of model assumptions. While it is unlikely that the output of both approaches will agree precisely, any differences should be explainable, and inform the outcome of the regulatory discussion.

The intent of CBRM is to embrace and use subjective knowledge to improve model predictions. Subjectivity is however minimised by referencing the output of the model to observable calibration features. The rationale for calibrating each component of the model is as follows:

Health Index

The intent of the asset Health Index is to produce an estimate of asset health that incorporates both observable data including condition observations, with subjective SME knowledge. The health index and health index forecasts are produced by rules, many of which are calibrated using subjectively determined weighting factors. Weighting factors are progressively adjusted so that the model produces health indices that are reflective of the conclusions that subject matter experts would reach if independently evaluating the same input information. In finalising calibrations for health indices, the process firstly ensures that health indices are correctly ranked, and secondly that the spread or distribution is reflective of evidence and expectations. The absolute value of health indices is less critical for most applications as final predictions are normalised through the Probability of Failure estimation process.

Probability of Failure

The relationship between Health Index and Probability of Failure is calibrated using an objective approach that essentially fits the HI/PoF curve (k) to physical observations of failures. Adjustment is primarily by the scale parameter of the PoF curve. Where data is available, relative rates of failure at different points in the asset lifecycle may be used to further adjust the HI/PoF curve to accommodate relative failure rates at various health index points by adjustment of the shape factor (c). Where such data is not available, a standard HI/POF shape is used that has been found to produce representative forecasts in other models.

Risk

The total value of risk is calculated as the product of the average cost per failure multiplied by the total number of failures. Both quantities can be objectively determined from historical data. The total risk is then spread out over the model population using combinations of POF (discussed above) and criticality factors. The calibration of criticality factors is achieved from a combination of objective measures (for example number of customers affected) and subjective subject matter expert driven measures. It should be noted that the allocation of criticality affects only the relative criticality ranking within the model, and does not affect the overall risk quantum predicted by the model.

Aging Function in CBRM

The relationship between age and condition is complex and dependent upon many factors. Furthermore the form of relationship is variable depending upon the failure mode and its associated degradation mechanism with different forms being applicable for corrosion, thermal deterioration of insulation and fatigue for example. Given the scope and intent of CBRM, it is not practicable to attempt to replicate an engineering evaluation of deterioration curves based on specific degradation mechanisms. Nevertheless it is often the case that rate of deterioration increases as condition decreases due to for example loss of protective coatings, accelerative effects of degradation products, and mechanical impact loading caused by increased tolerances in mechanisms.

The exponential ageing function has been chosen to predict future asset health indices in CBRM models for pragmatic modelling reasons. Firstly experience has shown that the exponential function performs well for short range predictions (<=5 years) matching operational experience. Secondly the exponential form used has the mathematical property that allows a future health index to be projected from an initial health index without reference to the asset age eg $H_f = H_i e^{B(T_f - T_i)}$ which is a useful property in the construction of a condition based model. It should also be noted that a fundamental aspect of CBRM is validation of output against historical data, and when this is not available SME experience. To accommodate tuning of the ageing function a range of additional parameters termed the ageing reduction index is included in each model. These parameters allow ageing rates to be adjusted should it be found that the unadjusted exponential function does not produce representative predictions. Further explanation of the rationale can be found in ‘Using modelling to understand and improve CBRM’, EA Technology Report No. 5947, 2006.

Model Selection

CBRM derived model output can support a range of asset renewal strategies. These are in order of increasing complexity, as described above:

- Age based
- Condition based
- Performance (failure rate) based
- Risk based
- Economic optimisation (NPV based)

The chosen approach is a matter of asset management strategy, however EA Technology would normally encourage clients to use either Performance, Risk or Economic (NPV) approaches over Age and Condition based approaches. The key differences between a performance (failure rate) and condition (health index) driven strategy are as follows:

1. Modern asset management theory, and asset management system standards (PAS-55 and ISO 55000), require that asset management strategy be directly linked to the corporate objectives of the organisation. While corporate objectives can vary from company to company, it is fair to say that most if not all electricity infrastructure organisations objectives, as they relate to renewal decisions would be framed in terms of measures such as customer service levels, public risk and cost. Developing renewal strategies to meet a specified level of performance in terms of number failures or level of risk will be more directly related to corporate objectives than achieving or maintaining a minimum condition level.
2. The future replacement and failure rates of an asset population would be related to the shape of the current health index profile. Under a maximum health index or condition drive strategy it would be theoretically possible for a population to have a low future

replacement requirement, yet have an increasing failure rate. This may be undesirable in terms of impact on public safety outcomes, customer service levels, and repair costs, particularly where these are the performance measures upon which an organization is being managed and judged.

3. Where resources are limited, the target performance approach will assist with prioritisation of replacements based on their contribution to failures (worst assets first) by allowing the threshold replacement level to flex. A fixed condition threshold based approach may result in a less efficient utilisation of resources under constraints should the 'quota' of replacements be spent before all assets have been evaluated.

NPV optimisation balances the future stream of costs, including intangibles against the cost of asset renewal. As such NPV analysis is sensitive to the absolute value of risk calculations. This sensitivity is greatly reduced with other approaches such as constant risk or percentage change in risk. For these reasons NPV optimisation should only be used for models where there is a high degree of confidence in the source data and model calibration.

NPV predictions that don't match reasonable expectations and seem incorrect are an area of concern and possibly suggest an opportunity to improve model calibration and should be further investigated.

CBRM is theoretically capable of producing retrospective to present predictions. To do so however requires a CBRM data set representative of the past starting period. It is however unlikely that this is readily available to SA Power Networks at this time. CBRM can of course make present to future predictions and these may be found in the future year predictions of the model. For future comparison, CBRM data sets may be saved and locked which will readily allow such past to present comparisons to made in the future.

CBRM Model results for Substation transformers

SA Power Networks has identified that the level of risk exposed by transformers can be maintained if a fixed percentage of the overall population is replaced per annum. The, required annual expenditure is summarised below.

This methodology produces results targeted at maintaining risk exposure after allowing for capacity related replacements, the targeted works program detailed below and expected failures (detailed as unplanned replacements below.

This methodology was selected on the recommendation of EA Technology as it is sensitive to absolute values of risk and more reliant on condition and failure rates information, which SA Power Networks holds good data on, than the other methodologies available within CBRM.

Table 18: Substation Transformers planned to be replaced from CBRM

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Planned													
Small	-	-	-	-	-	-	-	-	-	-	-	-	-
Medium	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	3
Large	-	-	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	4
Sub-Total	***0***	***0***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***0.7***	***7***
Unplanned													
Small	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	43.2
Medium	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	21.6
Large	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	9.6
Sub-Total	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***6.2***	***74.4***
TOTAL	**6.2**	**6.2**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**6.9**	**81.4**

D. Targeted Programs

Rusty radiators

Background

Over the last several years a number (>4) of small fixed tapped 33/11kV transformers have needed to be replaced due to severe corrosion, in particular affecting the radiator cooling fins. This problem has been limited to a particular design/construction style where the cooling fins are fabricated from a corrugated metal plate which is then forms part of the main tank. To date those which have been replaced have generally been in coastal areas, ie subject to high corrosion atmosphere.

Several examples are given below of units that have been replaced due to this issue.

Beachport Substation

Beachport Substation 2011:
33/11kV 2.5MVA
ST43023 YOM 2004 Installed 2005
Wilson QT670

Campbell Park Substation

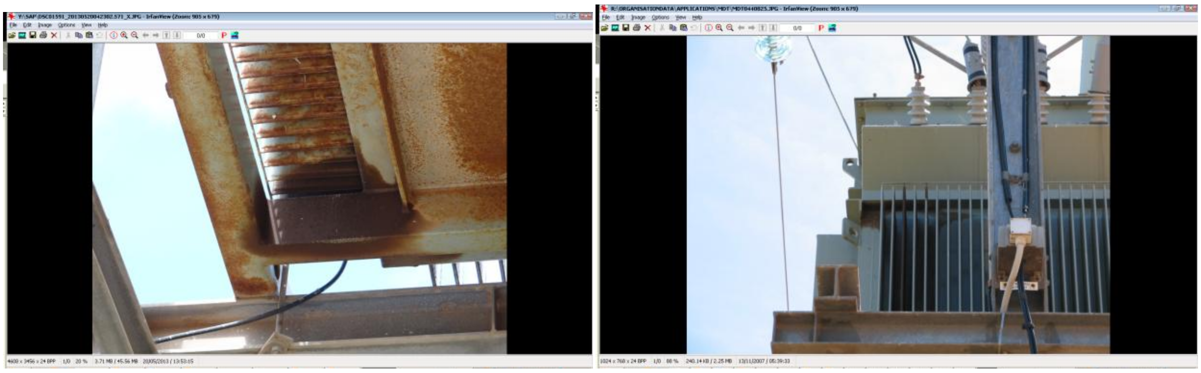
Campbell Park Substation 2013
33/11kV 500kVA
ST23509 YOM 1997 Installed 2006
ABB E1164

Narrung Substation

Narrung Substation 2013
33/11kV 1500kVA
ST24017 YOM 1999 Installed 1999
ABB QT299

Narrung unit ST24017 initially installed in 1999 but was replaced in 2006 due to severe corrosion of the radiator fins. Unit was subsequently repaired and returned to service in 2007 at Narrung to replace ST24016 (also suffering severe corrosion of the radiator fins).

Poonindie Substation



Poonindie – Replacement planned early 2014
33/11kV 1.5MVA
ST23504 YOM 1997 Installed 2001
ABB E1164

Change to Transformer Specification

Decision made 2011 (approx) to only allow bolt-on galvanised radiators on new transformers as per below.

Future Replacements

It can therefore be reasonably concluded that other similarly constructed units will suffer the same problem. We expect all the units of this construction type to have shorter than normal lives and those installed in coastal areas expected to have an expected life of 20 years approx.

There are another 36 transformers currently identified as having the same construction of radiator cooling fin. The youngest of these units are two years old (approx). Further, 10 units are installed in high atmospheric corrosion areas.

It is likely that over the next 10 years that there will be the need to replace more of these units. Three possibilities exist:

1. Failure rate will significantly reduce (ie basically no more failures) - unlikely
2. Failures will continue at historical rate (approx) – most likely
3. Failure rate will increase significantly – possible

No specific allowance is sought in the next Reset submission based on:

- our most likely expectation is (2) above,
- past failures associated with this failure mode are included in our historical unplanned failure rate submission of the transformer AMP

Risk: The next Reset determination includes a significant reduction in the allowance for unplanned transformer failures.

Installation of oil filters to Reinhausen 'V' type OLTC

It is proposed that oil filters be retro-fitted to 20 existing substation power transformers fitted with Reinhausen V type tap changers at a cost of $700,000 by 2022.

Reason

In 2011 SA Power Networks experienced two separate failures of transformers, caused by a failure within the Reinhausen 'V' Type OLTC. One of these failures was a result of carbon build up within the tap changer, resulting in a flashover and complete failure of the transformer.

To carry out maintenance on the OLTC a mobile crane, transformer edge fall protection and switching to offload the transformer are required. In some cases use of the mobile substation may be required. This being a labour intensive maintenance operation, each maintenance incurs significant expense, especially if the OLTC insert assembly is heavily carbonised. For this reason the retrofit of Reinhausen 'V' type tap changers with an oil filtration system to reduce carbon and moisture within the oil has been proposed as a solution.

Project Justification

Following a trial of a filter unit on one of the Seacombe Substation transformers over 2012-13 a business case has been produced to examine the benefits and cost of fitting oil filters to some or all (82) transformers fitted with the Reinhausen V type tap changer.

In summary, the business case recommends fitting the oil filters to high cost maintenance sites (20) based on an NPV evaluation.

Benefits of fitting the oil filter include:

- risk of another V type OLTC failure due to carbon build up is essentially removed
- Lower operating costs are expected as OLTCs will be in better condition at the end of their maintenance cycle resulting in fewer repairs
- Extended maintenance cycles; able to increase from 6 to 9 years. This has significant advantage at single transformer sites where there are few ties to offload the substation, a mobile substation is required which adds significant expense to any work carried out. By reducing maintenance, this can lead to quite significant operational savings.
- Improved OLTC performance/reliability as units run cleaner
- Reduced maintenance results in increased transformer availability and reliability for the network

Time Frame & Costs

To minimise installation costs it is proposed to install the oil filter coincident with the transformers next OLTC maintenance cycle. Consequently the program would run over a period of six years as the various OLTCs selected for a filter installation become due for maintenance.

The average estimated cost for each oil filter installation, excluding costs of coincident planned maintenance, is $35,000 ($2013).

Costs $,000 (2013)											
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	**Total**
$35	$105	$105	$105	$105	$105	$105	$35	$0	$0	$0	**$700**

E. 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 Transformers. 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 represents 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 1st 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 7.2 above. The unit costs from the Category Analysis RIN were not utilised for the reasons described below.

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

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

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

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 five 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 19 and **Error! Reference source not ound.** below.

Table 19: RepEx Results for Substation Power Transformers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number of Transformers													
< 22 kV ; > 60 kVa and < ≈ 600 kVa ; SINGLE PHASE (SUB)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
< 22 kV ; > 60 kVa and < ≈ 600 kVa ; MULTIPLE PHASE (SUB)	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
< 22 kV ; > 600 kVa ; MULTIPLE PHASE (SUB)	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.9	1.0	1.1	1.3	1.4	9.2
> ≈ 22 kV & < ≈ 33 kV ; < ≈ 15 MVA (SUB)	3.3	3.6	4.0	4.3	4.6	4.9	5.1	5.3	5.5	5.7	5.8	5.9	58.0
> ≈ 22 kV & < ≈ 33 kV ; > 15 MVA and < ≈ 40 MVA (SUB)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
> 33 kV & < ≈ 66 kV ; < ≈ 15 MVA (SUB)	2.0	2.3	2.5	2.8	3.1	3.3	3.6	3.9	4.1	4.3	4.5	4.7	41.0
> 33 kV & < ≈ 66 kV ; > 15 MVA and < ≈ 40 MVA (SUB)	0.3	0.4	0.4	0.5	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1.0	7.6
TOTAL	**6.0**	**6.7**	**7.4**	**8.1**	**8.8**	**9.5**	**10.2**	**10.8**	**11.5**	**12.0**	**12.6**	**13.1**	**116.5**
Expenditure ($millions)													
< 22 kV ; > 60 kVa and < ≈ 600 kVa ; SINGLE PHASE (SUB)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
< 22 kV ; > 60 kVa and < ≈ 600 kVa ; MULTIPLE PHASE (SUB)	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.25
< 22 kV ; > 600 kVa ; MULTIPLE PHASE (SUB)	$0.12	$0.13	$0.15	$0.18	$0.21	$0.24	$0.28	$0.32	$0.37	$0.42	$0.47	$0.53	$3.43
> ≈ 22 kV & < ≈ 33 kV ; < ≈ 15 MVA (SUB)	$4.97	$5.47	$5.96	$6.43	$6.88	$7.29	$7.67	$8.00	$8.28	$8.52	$8.71	$8.86	$87.03
> ≈ 22 kV & < ≈ 33 kV ; > 15 MVA and < ≈ 40 MVA (SUB)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01
> 33 kV & < ≈ 66 kV ; < ≈ 15 MVA (SUB)	$3.86	$4.31	$4.80	$5.30	$5.81	$6.32	$6.83	$7.32	$7.78	$8.20	$8.57	$8.87	$77.96
> 33 kV & < ≈ 66 kV ; > 15 MVA and < ≈ 40 MVA (SUB)	$0.61	$0.70	$0.79	$0.89	$1.00	$1.12	$1.24	$1.36	$1.49	$1.62	$1.76	$1.91	$14.49
TOTAL	**$9.56**	**$10.63**	**$11.72**	**$12.82**	**$13.91**	**$14.99**	**$16.03**	**$17.02**	**$17.95**	**$18.79**	**$19.55**	**$20.20**	**$183.17**

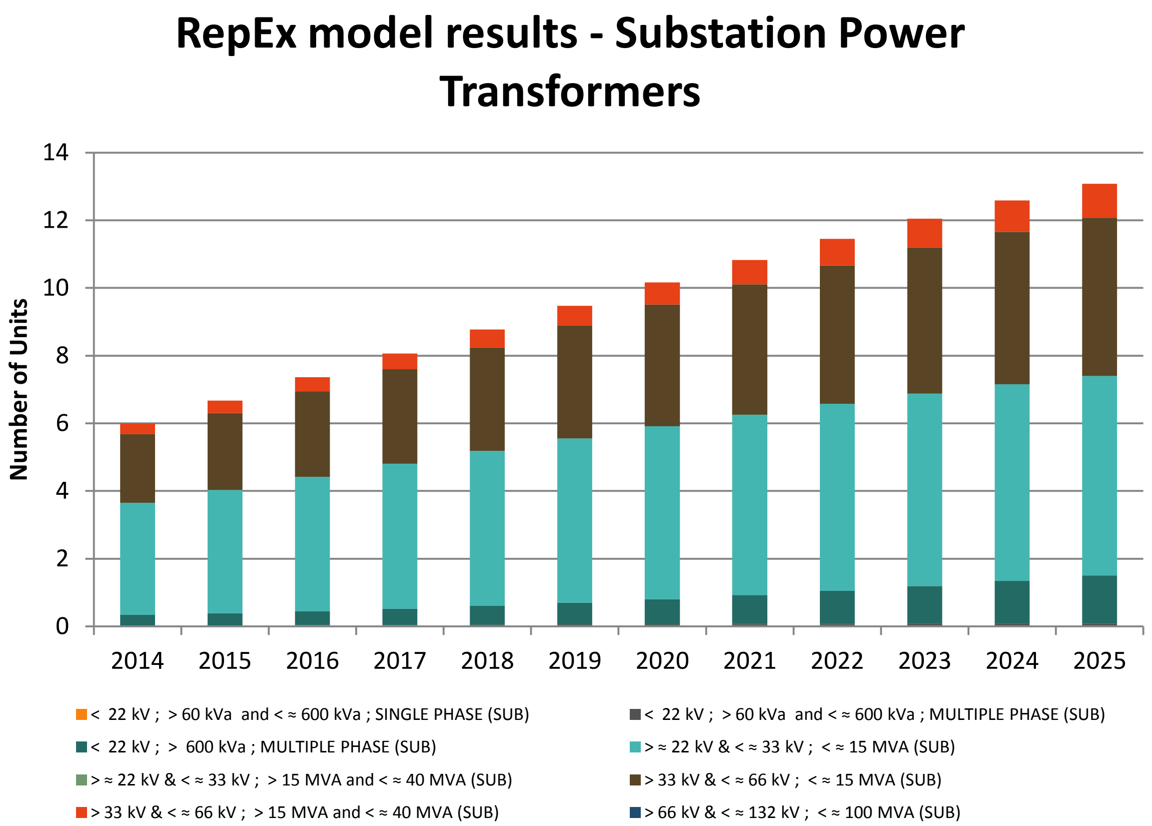


Figure 20 : RepEx model results

When compared to the other forecasts developed the repex model results were significantly higher. This was thought to be due to the AERs classifications for transformers, the model was therefore repopulated but using the SA Power Networks classifications, as described earlier in this document, and produced the results shown in Table 20 and Figure 21 below. These results are more in line with the expectations of the business and the other forecasts developed and have been used for all reported repex results in this document. The RIN data as submitted to the AER remains in accordance with the AERs classifications.

Table 20: Amended RepEx Results for Substation Power Transformers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number of Transformers													
Small (≤5MVA)	3.6	4.0	4.4	4.8	5.2	5.6	6.0	6.4	6.7	7.0	7.2	7.5	68.5
Medium (≥5MVA and ≤20MVA)	1.8	2.1	2.3	2.6	2.9	3.2	3.5	3.8	4.1	4.3	4.6	4.8	40
Large (≥20MVA)	0.8	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.4	1.4	1.5	1.6	14.2
TOTAL	**6.2**	**6.9**	**7.7**	**8.5**	**9.2**	**10.0**	**10.7**	**11.5**	**12.1**	**12.7**	**13.3**	**13.8**	**122.7**
Expenditure ($millions)													
Small (≤5MVA)	$0.94	$1.04	$1.15	$1.26	$1.36	$1.47	$1.56	$1.65	$1.74	$1.82	$1.88	$1.94	$17.81
Medium (≥5MVA and ≤20MVA)	$2.11	$2.41	$2.74	$3.07	$3.42	$3.77	$4.12	$4.46	$4.78	$5.07	$5.34	$5.57	$46.86
Large (≥20MVA)	$1.31	$1.42	$1.54	$1.65	$1.76	$1.88	$2.00	$2.11	$2.23	$2.35	$2.46	$2.56	$23.28
TOTAL	**$4.35**	**$4.88**	**$5.42**	**$5.98**	**$6.55**	**$7.12**	**$7.68**	**$8.23**	**$8.75**	**$9.24**	**$9.68**	**$10.08**	**$87.94**

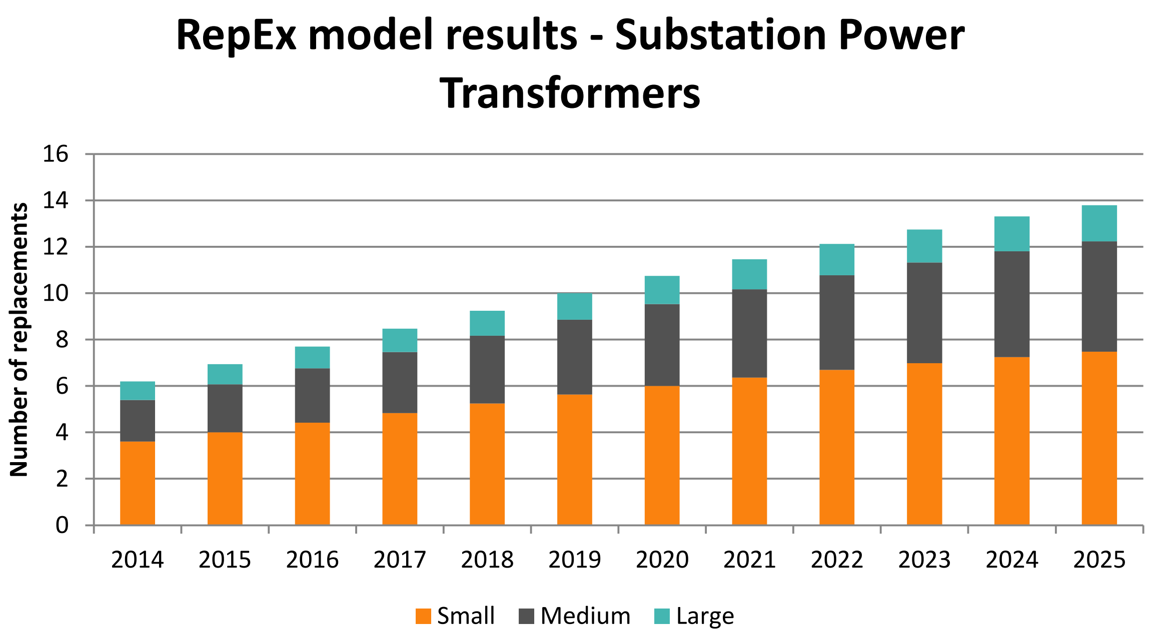


Figure 21 : Amended RepEx model results

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 AERs major categories of assets. For example, a DNSP can provide data on feeder by voltage and/ or technology type so as to group assets with common failure modes and likely similar replacement ages.

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

Average unit costs do not provide a realistic estimate of costs

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

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

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

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

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.

F. Strategic Spares Asset Pools

Transformer Capacity	Pool Population	Minimum Spare Holding
< 5MVA (small)	< 18	1
	< 48	2
	≥ 48	3*
< 20MVA (medium)	< 24	1
	< 72	2
	≥ 72	3*
< 30MVA (large)	< 24	1
	< 72	2
	≥ 72	3*
≥ 30MVA (large)	< 12	1
	< 36	2
	≥ 36	3*

NOTES: * Subject to Asset Manager's written confirmation.

G. Abbreviations

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

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

Acronym/Abbreviation	Definition
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.
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	Photovoltaic
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.

Acronym/Abbreviation	Definition
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.
Services	Services Department. This group manages core services dealing directly with individual residential or business customers.
SNC	Senior Network Controller.
SOC	Senior Operations Controller.
SOP	Safe Operating Procedure – Document that describes safe operating work procedure.
SPS	Service Performance Scheme – see STPIS.
SSF	Service Standard Framework.
STPIS	Service Target Performance Incentive Scheme.
TF	Transformer.
UFLS	Under-frequency load shedding.
UID	Underground industrial development.
URD	Underground residential development.
WARL	Weighted Average Remaining Life.

H. References

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