Appendix 1.17: Power transformers, bushings and on-load tap changers - FMEA

Regulatory proposal for the ACT electricity distribution network 2019-24
January 2018

Disclaimer: On 1 January 2018, the part of ActewAGL that looks after the electricity network changed its name to Evoenergy. This change has been brought about from a decision by the Australian Energy Regulator. Unless otherwise stated, ActewAGL Distribution branded documents provided with this regulatory proposal are Evoenergy documents.

POWER TRANFORMERS, BUSHINGS & ON-LOAD TAP CHANGERS

FMEA

Version number 1.3 : Effective date: 20 Jul. 2016

Table of Contents

Version Control

Date	Version No.	Author	Description of Change
12/2/2016	0.1	[redacted]	Initial draft for comment
17/2/2016	1.0	[redacted]	Comments by [redacted]
22/2/2016	1.1	[redacted]	Version for approval
25/2/2016	1.2	[redacted]	Comments by [redacted]
20/7/2016	1.3	[redacted]	Further comments by [redacted]

Related Documents

	Title	Reference
A	INITIATIVE AM13 - PILOT PROJECT	Initiative AM13 of Staying Number 1 suite of projects
B		

Document Authorisation

Endorsed		
	Signature	Date
Name	[redacted]	
Position	Strategic Planning Manager	

Endorsed		
	Signature	Date
Name	[redacted]	
Position	Branch Manager Asset Strategy	

Endorsed		
	Signature	Date
Name	[redacted]	
Position	Branch Manager Asset and Network Performance	

Authorised		
	Signature	Date
Name	[redacted]	
Position	General Manager Energy Networks	

Purpose of Report

This is the final report for completion of a project to apply Failure Modes and Effects Analysis (FMEA) to Zone Substation Power Transformers, Bushings and On-load Tap Changers (OLTC). This report:

- provides a summary of the project background and objectives;
- summarises the outcomes of the project, including potential savings;
- provides an assessment of the outcomes against the initial project objectives;
- recommends a revised maintenance program for Power Transformers, Bushings & OLTCs;
- recommends an analysis and investigation into implementation of FMEA on other suitable assets;
- seeks authorisation to implement the recommendations;
- provides comprehensive results of the FMEA in the Appendix; and
- provides a feedback loop on the implementation of the recommended objectives.

Background

FMEA is a systematic, proactive method for evaluating a maintenance process to identify where and how assets might fail, to assess the relative impact of different failures, in order to identify the elements of the maintenance process that require most attention.

The full range of benefits from implementing FMEA are better achieved by completing them on complex and critical assets which are comprised of a number of sub-systems (on-load tap changers and power transformers), where the failure types and their frequencies cannot be easily identified.

Power Transformers, bushings & OLTCs have been chosen as appropriate assets for this project because of their criticality, technical complexity, and the potentially high risk of failure under fault conditions which can cause very high value of damage.

The criticality of these assets in providing a reliable supply to our customers has been considered to formulate an appropriate maintenance strategy to ensure higher levels of supply reliability at the same or reduced cost.

Project Objectives

The objectives of this project are to:

- Develop FMEA as a reliable tool for improving strategic processes and providing more cost effective maintenance.
- Identify and quantify potential savings in the life cycle management of the Power Transformer & OLTC.
- Explore options to improve asset reliability and availability by identifying, analysing, and improving the management of their high-risk components. Reliability and availability are appropriate metrics for maintenance efficiency.
- Estimate potential improvements in reliability and availability of the assets in the study.
- Consider the most appropriate path to develop this FMEA study into a complete Reliability Centred Maintenance (RCM) strategy for potential improvements in extending and sustaining the reliability of the assets.
- Update zone substation Power Transformer Assembly Asset Specific Plan (ASP) and related maintenance procedures with prudent and proactive maintenance, and condition assessment tasks that identify, monitor and address the failure modes earlier in the process when they are less expensive to repair.
- Update Program of Works (PoW) for 2016/17 & onwards.

Project outcomes

Analysis of Maintenance Costs

The following tables summarise costs as detailed in the Asset Specific Plan on power transformer and OLTC maintenance for ActewAGL's fleet of 31 power transformers.

Table 1: Transformer & OLTC Maintenance by Activity Description

Source: ActewAGL Asset Specific Plan

Corrective

ASSET TYPE	TASK	COST BASIS	ANNUAL COST / TRANSFORMER
Online Tap Changers	Refurbish power transformer On-Line Tap Changer	Every 7 yearly manufacturer recommended	$6,500
Online Tap Changers	Replace tap changer counter	3 units every year	$150
Online Tap Changers	Replace tap changer motor drives	24 hours internal effort and $1,000 materials. 1 in 4 years	$30
Power Transformers	Repair power transformer oil leak	2 units per year	$7,700

Preventative

ASSET TYPE	TASK	COST BASIS	ANNUAL COST / TRANSFORMER
Power Transformers	Maintain power transformer oil and clean if required	3 units per year 1 hours internal effort + new oil drum (1 off)	$160
Power Transformers	Replace cubicle heater	3 units per year	$120
Power Transformers	Replace power transformer temperature indicator - oil/winding	2 units per year	$170
Power Transformers	Replace sight glass on conservator tank or on tap changer unit.	3 units per year	$420
Power Transformers	Replace silica gel bottle	16x silica gel bottle replacement	$180

Condition Monitoring

ASSET TYPE	TASK	COST BASIS	ANNUAL COST / TRANSFORMER
Bushings	Test Power Transformer Bushings for Dielectric Loss	Six power transformer every year (6x 3 bushing unit)	$370
Power Transformers	Test oil used in power transformer	3.5 hours internal effort, twice a year + external consultant cost for analysis	$2,000
Power Transformers	Test power transformer - DP insulating paper test	3 units per year	$3,500

Table 2: Single Transformer & OLTC Maintenance cost per annum by Category

Source: Table 1

Category	Cost
Corrective	$ 14,380
Preventative	$ 1,050
Condition Monitoring	$ 5,870
Total per transformer averaged over fleet	$20,116

The highest individual cost category for the power transformer assembly is corrective maintenance, of which over half is planned for repair of oil leaks (tank and bushings), closely followed by refurbishment of OLTCs. Oil leaks are an inevitable consequence of aging transformers, and gasket technology at the time of the installation of the transformer. The cost and effectiveness of OLTC maintenance can be improved with non-invasive condition monitoring, based on acoustic/vibrational analysis.

The next highest category cost is condition monitoring, which includes insulation paper testing and oil sampling and analysis. This level of condition monitoring is appropriate to manage the risk of failure for a critical, high cost asset. It has become apparent in the FMEA study that annual oil sampling and analysis, coupled with paper insulation testing is critical to managing the transformer reliability and risk of failure.

A major transformer failure could cost in the vicinity of $550k[1] (extra to a scheduled end of economic life replacement cost), depending on the consequential damage caused by the failure. This is a relatively rare event in the life of a single transformer. Given the expected long life of a power transformer, the mean time between major failures, if the asset is not replaced, can be expected to be in the vicinity of 60 years, but with a high level of variability (standard deviation σ), depending on service and maintenance conditions. ActewAGL has a fleet of 31 transformers, so if steps are not taken to replace high risk individual units and/or carry out mid-life refurbishments, as the fleet ages, a major transformer fault can ultimately be expected to approach a frequency of 1 failure in every 2 years.

The maintenance strategy for the Transformer/OLTC combination should be to provide adequate preventative maintenance to preserve the design life of this asset, and to conduct sufficient condition monitoring to ensure an economic transition to replacing the asset before it fails, while preserving N-1 reliability where possible.

[1] Based on a value of $10,000 per MVA of a 55MVA transformer, Bartley W. H. https://www.hsb.com/TheLocomotive/AnAnalysisofInternationalTransformerFailuresPart1.aspx

Planned Maintenance Activity

Tables 3 and 4 below provide an indication of the planned/expected expenditure (capex and opex) on transformer/bushings/OLTC maintenance. There is an expectation that major corrective maintenance will be required, in this case, repairing oil leaks. As expected, condition monitoring figures largely in the overall maintenance expenditure, improving on the earlier practice of testing oil to also include testing the transformer insulating paper. Provision is also made to refurbish approximately 4 on-load tap changers every year (each tap changer in fleet of 31, refurbished every 7 years).

Table 3: Planned and Expected Transformer maintenance by Activity Type

Source: Riva

Maintenance Activity	**Repeats**	**Unit Cost**	**Total Cost**	**Category**
Replace tap changer counter	3	$1,500	$4,500	Corrective
Replace tap changer motor drive	0.25	$3,600	$900	Corrective
Replace power transformer temperature indicator - oil/winding	2	$2,550	$5,100	Preventative
Test power transformer – Degree of Polymerisation (DP) insulating paper test	2*	$36,000	$72,000	Condition Monitoring
Replace sight glass on conservator tank or on tap changer unit.	3	$4,200	$12,600	Preventative
Repair power transformer oil leaks	2	$115,500	$231,000	Corrective
Replace silica gel bottle	16	$ 180	$2,880	Preventative
Maintain power transformer oil and filter if required	3	$1,600	$4,800	Preventative
Test oil used in power transformer	31	$2,000	$60,000	Condition Monitoring
Test Power Transformer Bushings for Dielectric Loss	18	$1,850	$11,100	Condition Monitoring
Refurbish power transformer On-load Tap Changer	31/7	$45,500	$195,000	Corrective
Replace cubicle heater	3	$1,200	$3,600	Preventative

* Originally recommended as 3 per annum by asset management staff however the panel overseeing maintenance expenditure revised this to 2 p.a. as a risk/resources trade-off.

Table 4: Maintenance by Category

Source: Table 3

Category	Cost
Corrective	$ 431,400
Condition Monitoring	$ 143,000
Preventative	$ 28,980
Total for all transformers	$ 603,480

The forward maintenance program in Riva continues the strong emphasis on condition monitoring, and also has an allowance of $431.4k per annum for corrective activities. The FMEA workshops have looked into the effectiveness of these maintenance programs, and provided commentary and recommendations on improvements.

Findings from FMEA workshops

The FMEA process disclosed a number of potential failure modes, root causes and subsequent remedial activities to reduce the risk of failure to acceptable levels. Power transformers are usually long-life, reliable assets, however because they are critical to the successful operation of the distribution network, high value assets, and the cost of failure is so high, it is an unacceptable strategy to run these assets to failure. A successful maintenance strategy for these assets demands effective condition monitoring and this is the area that provides opportunity for improvement.

The main findings from the workshop are listed below:

1. **Poor sampling techniques (transformer oil), inadequate observation/condition monitoring:** This has a high risk score because of frequent occurrence of unreliable results combined with the criticality of reliable results and analysis. The recommendation is to provide high quality training on oil sampling, storage and analysis of results and scheduling sampling times. This process should be periodically audited to maintain standards.
2. **Suspected sludge formation over transformer core and windings**: Oxidation forms acid in the oil when it reacts with oxygen. This acid will form sludge which will settle on the windings of the transformer reducing the heat dissipation from the transformer. The heat transfer from the windings to the oil is limited, causing the windings to operate at higher temperatures. Sludge formation on the windings has a cumulative effect on the transformer with more sludge creating more heat,

in turn creating more sludge. The high acid content together with the excessive temperatures will cause the deterioration of the transformer insulation to be accelerated and if left untreated the transformer will fail.

Transformer oil should be specifically tested for the presence of sludge, however a regular maintenance program allows the transformer oil to be upgraded before sludge created by oxidization occurs. This results in a cost saving to the business. Once sludge occurs, the internal parts of the transformer require flushing with hot oil to remove the sediment. If not rinsed down, the core and coil assembly will hold the acids which will leach back into the oil over time. This will cause the re-deterioration of the oil to be accelerated. If reclamation is done in the early stages of the acid build up before sludge formation occurs, the oil will retain its properties for a longer period under normal operating conditions.

For the reasons outlined above, aging transformers should have their insulating paper tested for the presence of furans.

3. **Oil leaks, ruptures, corrosion, gasket failure, weld failures, connection point failure, taps which are inadvertently left on:** The key to prevent such failures from escalating into major problems is to develop a comprehensive inspection process and ensure it is followed. Periodically, inspections should be audited to ensure quality. Allow sufficient time for the duration of inspections, to be determined in consultation with Zone Substation maintenance staff. If resources are constrained, consider reducing the frequency of inspections to ensure accurate and high quality reports.

4. **Temperature sensing transducer failure, Wiring / contact failure, Relay failure, Switch failure:** Thermo-scan the control circuitry to ensure that there are no hot spots in the control cabinet. Conduct a close visual inspection of control wiring to ensure no burn marks, or discoloured wiring. Check for burnt odour. Install self-diagnostic protection relays.

5. **Tap changer failure:**

   - **AC supply failure**
   - **Shear pin failure**
   - **Motor failure**
   - **Mechanism jam due to wear and tear**
   - **Contact seizure**

   Record and analyse the results of current tap changer maintenance, service and range tap tests. Measure, record and analyse dynamic contact resistance on load breaking switches. Investigate the potential to use a Vibro-Acoustic measurement instrument on OLTCs. This instrument allows the maintenance crew to detect most of the common OLTC malfunctions such as contact wear, arcing in diverter, arcing in selector, synchronism problem, drive mechanism problem, brake failure. Successful application of this instrument can detect potential failures, and prolong time between overhauls.

Specify a separate chamber for the tap changer to reduce cross contamination of transformer oil.

6. **Radiator fans, or oil pump failure. Potential failures:**
   - **AC supply failure**
   - **Burnout of motors**
   - **Bearing failure**
   - **Temperature sensing transducer failure**
   - **Fans, pumps rotate wrong way**

   Install fan, pump failure alarm and provide monitoring via SCADA.

7. **Transformer core clamps become loose or distorted:** Introduce the Sweep Frequency Response Analysis Test (SFRA Test). The SFRA test can detect efficiently, displacement of transformer core, deformation and displacement of winding, faulty core grounds, collapse of partial winding, broken or loose clamp connections, short circuited turns, open winding conditions etc.

Maintenance Implications

The maintenance strategy should emphasise regular inspections, testing, logging and analysis to carefully assess the condition of power transformers.

Physical Inspections

Power transformers are periodically inspected to detect physical defects. To ensure the maximum benefit is derived from these inspections, develop a comprehensive inspection procedure and checklist and follow up with training, and periodic audit. Ensure there is sufficient time to complete a thorough inspection. Where resources are constrained, consider inspecting less frequently, but more thoroughly to ensure an accurate comprehensive report. A photographic record should be kept to assist monitoring of external corrosion, minor oil leaks etc.

Instrument Condition Monitoring

Instruments are now available to evaluate the mechanical integrity of core, windings and clamping structures within power transformers by measuring their electrical response to injecting an AC signal over a wide frequency range. The instrument most commonly used to conduct these measurements is the Sweep Frequency Response Analyser (SFRA).

Transformers are effectively a complex network of capacitors and resistors that can generate a unique signature when tested at discreet frequencies and plotted as a curve. The distance between conductors of the transformer forms a capacitance. Any movement of the conductors or windings will change this capacitance which in turn will be reflected in the plotted curve or signature.

An initial SFRA test is carried out to obtain the signature of the transformer frequency response by injecting various discreet frequencies. This reference is then used for future comparisons. A change in winding position, degradation in the insulation, or other internal changes will result in change in capacitance or inductance thereby affecting the measured curves.

Tests should be carried out annually or following major external events like short circuits and results compared with the initial signature to test for any problems.

SFRA analysis can detect problems in transformers such as:

- winding deformation
- displacements between high and low voltage windings
- partial winding collapse
- shorted or open turns
- faulty earthing of core or screens
- core movement
- broken clamping structures
- problematic internal connections

The technology is now quite mature with a number of reputable suppliers:

- Venable Instruments: Model 350c Frequency Response Analyzer
- Newtons4th: SFRA45 Sweep Frequency Response Analyzer
- Doble: M5200/M5400 Sweep Frequency Response Analyzer
- Megger: FRAX99/101/150 Sweep Frequency Response Analyzer
- Omicron: VE000660 SFRA Analyzer complete set
- SIVA Instrument: Sweep Frequency Response Analyzer
- Core Technology: Sweep Frequency Response Analyzer

Oil Tests

Transformer insulating oil testing is an important diagnostic tool for assessing the internal condition of the transformer. Oil sampling and testing is carried out yearly on all power transformers.

Oil samples are tested in a laboratory to assess oil quality as well as perform dissolved gas analysis (DGA). Oil quality testing measures key parameters such as conductivity, acidity (for sludge build up), moisture, dielectric strength, and breakdown insulation voltage. DGA is performed to measure the amount of critical gasses dissolved in the oil and is used to detect and interpret the condition of the transformer.

Cityworks should contain the historical trending of the oil and DGA test results as this is valuable for determining the condition and expected remaining life of a power transformer. In addition to the oil and DGA test results other factors such as load conditions, recent faults, and dissolved gas ratios should be recorded as they may also need to be considered when making maintenance decisions.

Insulating Paper Tests

New kraft (transformer insulating) paper has an average cellulose polymer chain that is 1,000 glucose molecules to 1,200 glucose molecules long. The manufacturing and transformer drying process breaks down the cellulose. New paper in a new transformer, therefore, has shorter polymer chains—from 800 glucose molecules to 1,000 glucose molecules long. Over time, there is a natural and steady breakdown of the polymer chains. As the polymer chains get shorter, the mechanical strength of the paper is reduced. The degree of polymerization (DP) of paper insulation has a direct correlation to the paper's tensile strength. When the degree of polymerization has fallen to around 200, the paper is so weak that any stress will lead to failure. When the cellulose chain splits and two shorter chains are formed, the breakdown process forces out one or more of the glucose molecules. The breakdown also creates water, carbon monoxide and carbon dioxide. The glucose molecule chemically changes during this event and creates a compound containing a furan ring. Furans are measured in parts per billion. The life of the paper insulation is typically the life of the transformer. As a test case[2], a 40-year-old transformer showed a degree of polymerization of 260, with estimated remaining life at 19 percent. The transformer was immediately taken offline and internally inspected to identify any problems. When personnel investigated the interior of the tank, there was significant degradation of the paper insulation. The paper insulation actually disintegrated when touched. The transformer winding also appeared burned to the naked eye.

Results from the dissolved gas analysis sample, however, did not reveal any irregularities with the transformer. There was no significant increase in any of the gases that would typically confirm a problem. Without the furan analysis, therefore, the problem may have gone undetected until there was a catastrophic in-service failure. This transformer problem was discovered, fortunately, and the transformer was replaced before the next summer maximum demand period.

A potential problem arising from furan measurement in oil is that furan levels are significantly reduced through oil regeneration, and will not be a true indication for estimating the DP. Paper sampling provides a true indication of DP.

---

[2] Predicting Failure: Furan Testing of Transformers
http://www.utilityproducts.com/articles/print/volume-16/issue-01/product-focus/transmission-distribution/predicting-failure-furan-testing-of-transformers.html

Finding and mitigating the problem before an in-service failure helped prevent extensive damage to surrounding equipment, unplanned customer outages or an explosion. Testing for furans has shown to be a valuable tool when trying to predict the end of a transformer's life.

Aging transformers should have their insulating paper tested for the presence of furans. This is an expensive process, which should be restricted to the expected half-life of the transformer, say at 25 years, then 10 years after that, and finally 8 years after that. The results of this test provide a good estimate of the expected remaining life of the transformer, and an indicator as to whether the transformer is worth refurbishing.

Table 5 below provides a link between the degree of polymerisation (DP) and the condition of the insulating paper. Since the condition of the paper is a critical indicator of the health of the transformer, the DP test results are valuable in assessing the remaining life of the transformer.

Table 5 DP Range (furan test) as an Indicator of Insulating Paper Condition[3]

DP Range	Remark
<200	Test indicates extensive paper degradation exceeding the critical point. Strongly recommend that the transformer be taken out of service immediately and visually inspected.
200-250	The paper is near or at the critical condition. Recommend that the transformer be taken out of service as soon as possible and thoroughly inspected. Paper samples can be taken for direct DP testing.
260-350	The paper is approaching the critical condition. Suggest inspection be scheduled and/or re-sample within 1 year to reassess condition.
360-450	The paper is starting to approach the critical condition. Suggest a re-sample in 1-2 years time.
460-600	Significant paper deterioration but still well away from the critical point.
610-900	Mild to minimal paper ageing.
>900	No detectable paper degradation

OLTC Maintenance

The maintenance program for each OLTC is listed below:

- Monthly inspections to record tap-change count.
- 6 monthly full tap range test.
- 4 yearly ratio test by protection technicians.
- 7 year/100,000 ops Reinhausen - refurbishment depending on condition.
- 6 year/120,000 ops ABB - refurbishment depending on condition.

[3] Gray I.A.R. Evaluation of Transformer Solid Insulation http://www.satcs.co.za/Evaluation_of_Transformer_Solid_Insulation-rev2.pdf

This maintenance program can be made more effective and potentially save costs by applying the following tests:

- Annual dynamic resistance test to assess the condition and performance of the contacts.
- Annual vibro-acoustic test to assess the condition and performance of the tap change mechanisms.

The results of these tests can be used to extend the period between refurbishment to when they indicate the service is required. The may also provide an early warning indictor and suggest a service, preventing an expensive failure.
The above 2 tests can replace the full tap range test on an annual basis.

Financial Implications

Power Transformers: The annual planned maintenance cost for ActewAGL's 31 power transformers is $624k, (exclusive of any overhead loading). This figure does not include the costs incurred in the event of an unexpected transformer failure (cost of risk). The risk, and therefore the cost of this risk will change over the life of the transformer, beginning at almost zero when new, and growing as the transformer ages. For the ActewAGL fleet of transformers with distributed ages, the total cost of the risk is calculated at $244k[4], and is growing every year.

It can readily be seen that investments in technology up to $244k, that substantially remove the risk of an unexpected failure will have a payback period of less than 1 year.

Economic power transformer operation is driven by two important factors:

1. Effective preventative maintenance to preserve the design life of the transformer.
2. Effective condition monitoring to determine the transformer condition. This will ensure that preventative maintenance is applied as required, ensuring the transformer is not over-serviced, which is a waste of money, or underserviced, resulting in a shortened life for this valuable asset. Condition monitoring will also determine the optimum time to refurbish or replace the transformer. An orderly planned replacement is far preferable and less expensive than an unplanned emergency replacement.

[4]Calculated from the PoF derived from transformer mortality tables multiplied by the cost of loss of $10,000/MVA

Intangible Benefits

Aside from immediate financial benefits, improvements in the quality of transformer and OLTC maintenance will result in a number of intangible benefits, which will in turn lead to improved corporate performance. These benefits are listed as follows:

1. Higher quality maintenance has the potential to initiate a virtuous circle by freeing up time and resources to further improve maintenance quality and resulting reliability.
2. Improved maintenance will result in reduced unplanned failures and improved reliability (lower SAIDI & SAIFI).
3. The demand imposed by insisting on higher quality maintenance will result in staff skills improvement.
4. Emphasis on quality and alignment of activities with corporate objectives will result in an improvement in staff morale and encourage self-motivation.
5. Evidence based superior maintenance derived from reliable information from experienced staff will provide management with assurance on the quality of the outcomes.
6. Transparency of maintenance program design and scheduling will result in better acceptance and understanding of the maintenance regime.

Recommendations

The following recommendations have been made as a consequence this FMEA:

Zone Substation Power Transformers, Bushings and OLTCs

1. Provide high quality training and accreditation for oil sampling, storage and analysis of results and scheduling sampling times. Audit periodically to maintain standards.
2. Include testing for the presence of sludge in the transformer oil. Develop a long term schedule to test for the level of furans and other signs of deterioration in transformer insulating paper to estimate the expected remaining life of the transformer.
3. Develop a comprehensive site inspection procedure and checklist and follow up with training. Periodically, inspections should be audited to ensure quality. Allow sufficient time for the duration of inspections, to be determined in consultation with Zone Substation maintenance staff. If resources are constrained, consider reducing the frequency of inspections to ensure accurate and high quality reports.

4. Thermo-scan the control circuitry to ensure that there are no hot spots in the control cabinet. Conduct a close visual inspection of control wiring to ensure no burn marks, or discoloured wiring. Check for burnt odour. Install self-diagnosing protection relays to indicate that the control circuitry has failed.
5. Continue current tap changer maintenance, service and range tap tests. Measure, record and analyse dynamic contact resistance on load breaking switches. This can be accomplished using the circuit breaker analyser. Investigate the potential to use a Vibro-Acoustic measurement instrument on OLTCs.

   Specify completely sealed tap changer oil tank in such a manner to restrict generated gases in insulating oil from travelling from tap changer tank to main tank and vice versa.

6. Install air and oil flow detectors to provide fan and pump failure alarms and provide monitoring via SCADA.
7. Introduce the Sweep Frequency Response Analysis Test (SFRA Test).

FMEA on other Critical Assets

Asset managers were asked to nominate a selection of Asset Types for further FMEA based on the following criteria:

- Asset criticality – based on potential effects of failure: Financial, Operations (loss of supply), Reputation, Health/ safety, Environment, Legal/ compliance, Program/ project
- Current asset reliability
- Current effort to support reliability, efficiency of that effort, and potential for improvement (for example programmed fault finding for hidden failures)
- Risk of obsolescence and potential for technological step change in performance
- Current OPEX expenditure
- Asset replacement value and proximity to end of economic life
- Probability of successful application of FMEA to the asset
- History of previous analysis (or lack of) on that asset class

Subsequent to the nomination process and a combined workshop with the asset managers, the following asset classes were determined to be suitable for analysis:

Completed:

1. 132kV, 66kV and 11kV Circuit Breakers
2. Power Transformers, Bushings and On-Load-Tap-Changers

Future Studies:

1. Zone Substation and Distribution Substation Batteries
2. Distribution Hazemeyer Switchgear & its cable terminations
3. Distribution Air break switches
4. Distribution Surge diverters
5. Secondary Systems 11kV zone feeder protection – includes all components in protection system
6. Secondary Systems 132kV line distance protection – includes all components in protection system
7. Secondary Systems 132/11kV Transformer protection – includes all components in protection system

Assessment against Objectives

1. Implement FMEA as a reliability tool: This objective has been met. Further assets have now been selected for FMEA with a view to optimising the maintenance schedule.
2. Identify and quantify potential savings: This objective has been met. The savings are documented in this report.
3. Potential improvements in reliability and availability: This objective has been met. A number of improvements in maintenance procedures have been identified which should lead to potential improvements in reliability and availability.
4. Update Power Transformer (including OLTC) Asset Specific Plan (ASP) and related maintenance procedures: This objective is currently in progress.
5. Update PoW for 2016/17 & onwards: This objective is currently in progress.

Appendix A: Risk Tables (Severity, Occurrence & Detection)

SEVERITY of Effect	Ranking
Hazardous-without warning: Very high severity ranking, potential failure mode affects safety, noncompliance with policy and without warning.	10
Hazardous-with warning: Very high severity ranking, potential failure mode affects safety, noncompliance with policy with warning.	9
Item inoperable, with loss of primary function.	8
Item operable, but primary function at reduced level of performance.	7
Equipment operable, but with some functions inhibited	6
Operable at reduced level of performance.	5
Does not conform. Defect obvious.	4
Defect noticed by routine inspection.	3
Defect noticed by close inspection.	2
No effect	1

PROBABILITY of Failure	Failure Rates	Ranking
Very High: Failure is almost inevitable	**Very High:** Failure is almost inevitable Possible Failure Rate >=1 every week	**10**
	Very High: Failure is almost inevitable Possible Failure Rate 1 every month	**9**
High: Repeated failures	**High:** Repeated failures Possible Failure Rate 1 every 3 months	**8**
	High: Repeated failures Possible Failure Rate 1 every 6 months	**7**
Moderate: Occasional failures	**Moderate:** Occasional failures Possible Failure Rate 1 every year	**6**
	Moderate: Occasional failures Possible Failure Rate 1 every 3 year	**5**
	Moderate: Occasional failures Possible Failure Rate 1 every 5 years	**4**
Low: Relatively few failures	**Low:** Relatively few failures Possible Failure Rate 1 every 8 years	**3**
	Low: Relatively few failures Possible Failure Rate 1 every 15 years	**2**
Remote: Failure is unlikely	**Remote:** Failure is unlikely Possible Failure Rate <=1 every 20 years	**1**

Detection	Likelihood of DETECTION	Ranking
Absolute Uncertainty	Control **cannot** prevent / detect potential cause/mechanism and subsequent failure mode	**10**
Very Remote	**Very remote** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**9**
Remote	**Remote** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**8**
Very Low	**Very low** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**7**
Low	**Low** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**6**
Moderate	**Moderate** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**5**
Moderately High	**Moderately High** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**4**
High	**High** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**3**
Very High	**Very high** chance the control will prevent / detect potential cause/mechanism and subsequent failure mode	**2**
Almost Certain	Control **will** prevent / detect potential cause/mechanism and subsequent failure mode	**1**

Appendix B: Transformer and OLTC Data

132 kV zone substation transformers

Zone substation transformers have rated voltages 132 kV / 11 kV (1 pu) and are of three limb core type construction, with neutral connected directly to earth. Rated voltages are obtained on Tap 6 (for 27 tap transformers) or Tap 5 (for 19 tap transformers).

Transformers have tappings on 132 kV star side.

Maximum tap voltage is either:

- 1.06 pu = 139.92 kV (19 tap) or
- 1.05 pu=138.6 kV (27 tap)

Minimum tap voltage is:

- 0.79 pu=104.28 kV

Delta side volts at minimum tap:

- 11.0 kV

Tap steps are either:

- 0.010 pu (1.32 kV) for 27 tap transformers or
- 0.015 pu (1.98 kV) for 19 tap transformers.

The Tap No. is as per nameplate, with Tap No. 1 corresponding to the minimum secondary voltage and tap 27 (or tap 19) to the maximum secondary voltage boost.

66 kV Zone Substation Transformers

Zone substation transformers have rated voltages of 66 kV / 11 kV with 11 kV star side neutral connected directly to earth. All transformers have on load tap changers with 22 taps on 66 kV delta side, to maintain 11 kV on star side.

Tap range is from:

- Tap 1 (72930 V = 1.105 pu) to
- Tap 22 (52140 V = 0.79 pu)

Tap steps are:

- 990 V (=0.015 pu).

Tap 8 is rated voltage of

- 66/11 kV (1pu/1pu).

These transformers have only fans for additional cooling and do not have pumps. TX2 has pumps and no fans.

OLTC Data matched to Transformers

Power Transformer				OLTC	
Substation	**Name**	**Manufactured Date**	**Oil Type**	**Manufacturer**	**Model**
Belconnen Zone Substation	Transformer #2	1/01/1988	INHIBITED	ASEA	UZEDN380/500
Belconnen Zone Substation	Transformer #1	1/01/1988	INHIBITED	ASEA	UZEDN380/500
Telopea Park Zone Substation	Transformer #1	1/01/1984	INHIBITED	ASEA	UZEDN380/500
Telopea Park Zone Substation	Transformer #3	1/01/1983	INHIBITED	REINHAUSEN	MIIIY500/60C
Telopea Park Zone Substation	Transformer #2	1/01/1984	INHIBITED	ASEA	UZEDN380/500
City East Zone Substation	Transformer #1	1/01/1978	INHIBITED	REINHAUSEN	MIIIY500/60C
City East Zone Substation	Transformer #3	1/01/1978	INHIBITED	ASEA	UZEDN380/500
City East Zone Substation	Transformer #2	1/01/1986	INHIBITED	REINHAUSEN	MIIIY500/60C
Fyshwick Zone Substation	Transformer #3	1/01/2000	INHIBITED	ABB	UZEDT380/300
Fyshwick Zone Substation	Transformer #1	1/01/2005	INHIBITED	ABB	UZFRT380/300
Fyshwick Zone Substation	Transformer #2	1/01/2007	INHIBITED	ABB	UZFRT380/300
Civic Zone Substation	Transformer #3	1/01/2011	INHIBITED	ABB	UZEDN380/600
Civic Zone Substation	Transformer #2	1/01/1986	INHIBITED	ASEA	UZEDN380/500
Civic Zone Substation	Transformer #1	1/01/1986	INHIBITED	ASEA	UZEDN380/500
Gilmore Zone Substation	Transformer #1	1/01/1966	INHIBITED	REINHAUSEN	DIIIY400-150/60
Gilmore Zone Substation	Transformer #3	1/01/1966	INHIBITED	REINHAUSEN	DIIIY400-150/60
Gold Creek Zone Substation	Transformer #1	1/01/1994	INHIBITED	ABB	UZFDN380/500
Gold Creek Zone Substation	Transformer #3	1/01/1993	INHIBITED	ABB	UZFDN380/500
Latham Zone Substation	Transformer #3	1/01/1970	INHIBITED	REINHAUSEN	DIIIY400-60/110
Latham Zone Substation	Transformer #2	1/01/1970	INHIBITED	REINHAUSEN	DIIIY400-60/110
Latham Zone Substation	Transformer #1	1/01/1981	INHIBITED	REINHAUSEN	MIIIY500/60C
Theodore Zone Substation	Transformer #1	1/01/1966	INHIBITED	REINHAUSEN	DIIIY400-150/60

Theodore Zone Substation	Transformer #3	1/01/1966	INHIBITED	REINHAUSEN	DIIIY400-150/60
MoSS Zone Substation	Transformer #1	1/01/2009	INHIBITED	UNKNOWN	UNKNOWN
Wanniassa Zone Substation	Transformer #1	1/01/1979	INHIBITED	REINHAUSEN	MIIIY500/60C
Wanniassa Zone Substation	Transformer #2	1/01/1974	INHIBITED	REINHAUSEN	DIIIY400-60/110
Wanniassa Zone Substation	Transformer #3	1/01/1975	INHIBITED	REINHAUSEN	DIIIY400-60/110
Woden Zone Substation	Transformer #3	1/01/1982	INHIBITED	REINHAUSEN	MIIIY500/60C
Woden Zone Substation	Transformer #2	1/01/1977	INHIBITED	REINHAUSEN	MIIIY500/60C
Woden Zone Substation	Transformer #1	1/01/1977	INHIBITED	REINHAUSEN	MIIIY500/60C

Appendix C: Implementation of Recommendations - Status

1. Provide high quality training and accreditation for oil sampling, storage and analysis of results and scheduling sampling times. Audit periodically to maintain standards.

Comments & Progress

2. Include testing for the presence of sludge in the transformer oil. Develop a long term schedule to test for the level of furans and other signs of deterioration in transformer insulating paper to estimate the expected remaining life of the transformer.

Comments & Progress

3. Develop a comprehensive site inspection procedure and checklist and follow up with training. Periodically, inspections should be audited to ensure quality. Allow sufficient time for the duration of inspections, to be determined in consultation

with Zone Substation maintenance staff. If resources are constrained, consider reducing the frequency of inspections to ensure accurate and high quality reports.

Comments & Progress

4. Thermo-scan the control circuitry to ensure that there are no hot spots in the control cabinet. Conduct a close visual inspection of control wiring to ensure no burn marks, or discoloured wiring. Check for burnt odour. Install self-diagnosing protection relays.

Comments & Progress

5. Continue current tap changer maintenance, service and range tap tests. Measure, record and analyse dynamic contact resistance on load breaking switches. This can be accomplished using the circuit breaker analyser. Investigate the potential to use a Vibro-Acoustic measurement instrument on OLTCs.

   Specify a separate chamber for the tap changer to reduce cross contamination of transformer oil.

Comments & Progress

6. Install air and oil flow detectors to provide fan and pump failure alarms and provide monitoring via SCADA.

Comments & Progress

7. Introduce the Sweep Frequency Response Analysis Test (SFRA Test).

Comments & Progress

Appendix D: Derivation of Cost of Risk of Power Transformer Failure

Transformer	ID	Manufacture Date	Age Yrs	PoF Next Year	Estimated Cost of Risk $
East Lake Zone Substation	Transformer #1	1/01/2014	2	0	$ -
Civic Zone Substation	Transformer #3	1/01/2011	5	0.001	$ 550
MoSS Zone Substation	Transformer #1	1/01/2009	7	0.001	$ 120
Fyshwick Zone Substation	Transformer #2	1/01/2007	9	0.001	$ 250
Fyshwick Zone Substation	Transformer #1	1/01/2005	11	0.001	$ 250
Fyshwick Zone Substation	Transformer #3	1/01/2000	16	0.004	$ 1,000
Gold Creek Zone Substation	Transformer #1	1/01/1994	22	0.007	$ 3,850
Gold Creek Zone Substation	Transformer #3	1/01/1993	23	0.007	$ 3,850
Belconnen Zone Substation	Transformer #2	1/01/1988	28	0.011	$ 6,050
Belconnen Zone Substation	Transformer #1	1/01/1988	28	0.011	$ 6,050
City East Zone Substation	Transformer #2	1/01/1986	30	0.012	$ 6,600
Civic Zone Substation	Transformer #2	1/01/1986	30	0.012	$ 6,600
Civic Zone Substation	Transformer #1	1/01/1986	30	0.012	$ 6,600
Telopea Park Zone Substation	Transformer #1	1/01/1984	32	0.013	$ 7,150
Telopea Park Zone Substation	Transformer #2	1/01/1984	32	0.013	$ 7,150
Telopea Park Zone Substation	Transformer #3	1/01/1983	33	0.014	$ 7,700
Woden Zone Substation	Transformer #3	1/01/1982	34	0.014	$ 7,700
Latham Zone Substation	Transformer #1	1/01/1981	35	0.015	$ 8,250
Wanniassa Zone Substation	Transformer #1	1/01/1979	37	0.016	$ 8,800
City East Zone Substation	Transformer #1	1/01/1978	38	0.017	$ 9,350
City East Zone Substation	Transformer #3	1/01/1978	38	0.017	$ 9,350

Woden Zone Substation	Transformer #2	1/01/1977	39	0.017	$ 9,350
Woden Zone Substation	Transformer #1	1/01/1977	39	0.017	$ 9,350
Wanniassa Zone Substation	Transformer #3	1/01/1975	41	0.018	$ 9,900
Wanniassa Zone Substation	Transformer #2	1/01/1974	42	0.018	$ 9,900
Latham Zone Substation	Transformer #3	1/01/1970	46	0.023	$ 12,650
Latham Zone Substation	Transformer #2	1/01/1970	46	0.023	$ 12,650
Gilmore Zone Substation	Transformer #1	1/01/1966	50	0.033	$ 18,150
Gilmore Zone Substation	Transformer #3	1/01/1966	50	0.033	$ 18,150
Theodore Zone Substation	Transformer #1	1/01/1966	50	0.033	$ 18,150
Theodore Zone Substation	Transformer #3	1/01/1966	50	0.033	$ 18,150
Total Estimated cost of risk					**$ 243,620**

Appendix E: FMEA Data sheets