AMS – Victorian Electricity Transmission Network

Power Transformers and Oil-Filled Reactors (PUBLIC VERSION)

Document number	AMS 10-67
Issue number	10
Status	Approved
Approver	J. Dyer
Date of approval	28/08/2015

ISSUE/AMENDMENT STATUS

Issue Number	Date	Description	Author	Approved by
5	06/11/06	Editorial review	G. Lukies D. Postlethwaite	G. Towns
6	15/02/07	Review and Update	G. Lukies D. Postlethwaite	G. Towns
7	17/03/07	Editorial Review	G. Lukies D. Postlethwaite	G. Towns
8	17/04/07	Update of failure rates	D. Postlethwaite	G. Towns
8.1	01/08/11	Revised Structure & General Update	L. Clough	
9	07/01/13	Review, Update and Revised Structure	D. De Silva D. Meade	D. Postlethwaite
10	28/08/15	Review and Update (Regulated Assets Only)	P. Seneviratne T. Gowland M. Cotton	J. Dyer

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1 Executive Summary

Power transformers and oil filled reactors are an essential component of the Victorian electricity transmission network. These specialised assets are required to transfer power between circuits to maintain quality and security of supply in a safe manner. AusNet Services' power transformer and oil filled reactor fleet includes a total of 142 transformer banks with ratings from 35 MVA to 1000 MVA. These transformer banks include 45 single-phase and 127 three-phase transformers, operating at 22 kV, 66 kV, 220 kV, 330 kV and 500 kV. Energy losses in the Victorian electricity transmission network have been reduced by progressively replacing single-phase 220 kV transformers with more efficient three-phase units. Importantly, replacement of deteriorated transformers with units incorporating modern technology extends maintenance cycles and rationalisation reduces the probability of transformer failures.

Transformers in Victoria are operated at high utilisation levels as a result of the probabilistic planning criteria that are used to plan the transmission network in Victoria. Cyclic ratings rather than continuous ratings are also used in the economic assessment, which results in higher load levels. The high ambient temperatures, during the extended 2002 – 2009 drought, coupled with high utilisation and poor cooling designs of the [C.I.C] transformer have negatively impacted the maintenance, reliability and the condition of power transformers.

The long term targeted replacement and component refurbishment programs are demonstrating positive outcomes in effective management of the fleet's reliability as shown in the volume of unplanned maintenance on power transformers over the period 2000 to 2014 peaking in the 2006-10 period. Also in the similar period the major failure rates peaked with six major failures of power transformers, driving the Victorian failure rate above the CIGRE Australia average of 0.4% per annum. As the current condition of the overall fleet indicates above-average deterioration for 32 % of the power transformer fleet with 25% of the above average deteriorated units in the 'extremely advance' condition that should be addressed by the appropriately identified economical solution of either asset replacement or refurbishment.

Reliability centred maintenance models show that a reactive management approach; such as "Do Nothing" or "Replace on Failure" is neither prudent nor economic with an associated increase in failure risk over the next ten years. Continuing investment in power transformer refurbishment and replacement is necessary to economically manage failure risks which are being driven by the value of unserved energy, declining reliability and measurable deterioration.

Key strategies for the Power Transformers and Oil Filled Reactors include:

1.1 New Assets

- Continue to improve the tender specification for power transformers by making use of experience gained by maintenance, refurbishment and emerging and tested new technologies.
- Continue to evaluate suppliers for their ability to provide transformers that meet the requirements of the AusNet Services transformer tender specification.
- Continue to conduct Design reviews to ensure that suppliers understand the requirements contained in the AusNet Services transformer tender specification.
- Continue to inspect and monitor transformers during each stage of manufacture to ensure compliance with the requirements of the transformer contract.
- Perform transformer tests to confirm that the transformer meets design expectations and operational performance before the end of manufacturer's warranty period.

1.2 Monitoring, Maintenance and Refurbishment

- Continue to carry out routine monitoring and testing of transformer on a periodic basis to detect incipient failure behaviour and assess general condition.
- Undertake mid-life refurbishment of selected transformers to extend asset life where economic.
- Monitor closely transformers with deteriorating individual components i.e. core and winding, bushings, oil condition, OLTC or external components, which typically being assessed at C4 or C5 condition. Implement necessary repair or refurbishment to manage the risk of unexpected transformer outage.
- Continue replacement program for SRBP and Oil impregnated paper bushings identified as being in poor condition.
- Continue the program to repair significant oil leaks and oil damaged wiring on transformers.
- Continue to paint and treat corrosion on transformers which exhibit poor external condition.
- Continue to hold appropriate contingency spare transformers and components in order to provide a satisfactory network contingency response.

1.3 Replacement

- Replace 15 power transformers recommended by the reliability modelling and the remaining five Condition 5 power transformers that are approaching end of life within next 10 years.
- Where economic replace high risk power transformers as part of major station rebuild projects.

2 Introduction

2.1 Purpose

The purpose of this document is to define the asset management strategies for the Victorian electricity transmission network's population of power transformers and oil filled reactors over the next decade.

2.2 Scope

This asset management strategy applies to oil filled power transformers and reactors that have a winding rated for 500 kV, 330 kV, 275 kV, 220 kV, 66 kV or 22 kV associated with the Victorian electricity transmission network.

The Station Service transformers which provide auxiliary AC and DC for secondary systems in terminal stations are excluded from the scope of this document.

The strategies in this document are limited to maintaining installed capability in terms of equipment performance and rating. Improvements in quality or capacity of supply are not included in the scope of this document.

2.3 Objectives

The objectives of the asset management strategy are to:

- present an overview of the power transformer and oil filled reactor fleets;
- manage business and network risks presented by power transformers and oil filled reactors economically and within sustainable limits;
- achieve supply reliability, equipment availability and market impact parameter targets taking account of risk, costs and customer expectations;
- ensure the economic inspection, testing maintenance, refurbishment and replacement of power transformers and oil filled reactors throughout their life-cycle; and
- demonstrate that power transformers and oil filled reactors are being managed prudently and economically.

2.4 References

This asset management strategy forms part of a suite of documentation that supports the management of AusNet Services' assets, which include the following:

AMS 01-01	Asset Management System – Overview
AMS 10-01	Asset Management Strategy – Transmission Network
AMS 10-19	Plant and Equipment Maintenance
AHR 10-67	Asset Health Review for Power Transformers in Terminal Stations
PGI 80-40-01	Transformer On Load Tap Changer Maintenance – Plant Guidance and Information
PGI 80-01-01	Transformers, Regulators, Oil filled Reactors and Neutral Compensators Overhaul – Plant Guidance and Information
PGI 02-01-02	Summary of Maintenance Intervals – Transmission
SMI-80-01-02	Transformer Condition Monitoring in Terminal and Zone Substations

3 Asset Summary

3.1 Population

3.1.1 Power Transformers

AusNet Services' assets include a total of 142 transformer banks with ratings from 30 MVA to 1000 MVA. These are made up of 45 single-phase and 127 three-phase transformers, operating at 66 kV, 220 kV, 330 kV and 500 kV. The majority of the power transformer fleet can be classed as either main tie transformers or connection transformers but also include special purpose transformers for reactive plant such as Static Var Compensators and Synchronous Condensers.

With the exception of four 35 MVA transformers at Kerang (KGTS) and Red Cliffs terminal stations (RCTS), and a 55 MVA transformer at Yallourn power station (YPS), all 220 kV and 330 kV transformers installed prior to 1964 are of single-phase construction and, in many instances, there are compatible spare single-phase units available on site. From 1964, all the 220 kV transformers installed have been of three-phase construction, with the standard size of metropolitan 220/66 kV transformers being 150 & 225 MVA.

Seventeen different manufacturers have supplied transformer units across the fleet. The quantities are shown in the Tables 1 through 4 below according to each voltage class.

Tie Transformer Voltage Ratio	Number of single phase transformers	Number of 3 phase transformers	Total number of transformers & banks	Total Capacity (MVA)	Most Common Size (MVA)
500/330 kV	3	0	1	1000	1000
500/275 kV	0	2	2	740	370
500/220 kV	21	1	8	5650	250
330/220 kV	9	3	6	2415	700
TOTAL	**33**	**6**	**17**	**9805**	

Table 1 – Tie Transformers

Connection Transformer Voltage Ratio	Number of single phase transformers	Number of 3 phase transformers	Total number of transformers & banks	Total Capacity (MVA)	Most Common Size (MVA)
330/66 kV	0	2	2	150	75
220/66 kV	6	92	94	12890	150
220/22 kV	0	14	14	1320	75
220/11 kV	6	1	3	164	55
66/22 kV	0	2	2	120	60
66/11 kV	0	3	3	150	50
TOTAL	**12**	**114**	**118**	**14794**	

Table 2 – Connection Transformers

Special Purpose Transformer Voltage Ratio	Number of single phase transformers	Number of 3 phase transformers	Total number of transformers	Total Capacity (MVA)	Most Common Size (MVA)
220/10.5 kV	0	2	2	200	100
220/4.5 kV	0	2	2	100	50
66/22 kV	0	2	2	250	125
66/14.5 kV	0	1	1	112	112
TOTAL	**0**	**7**	**7**	**662**	

Table 3 – Special purpose transformers

All Transformers	Number of single phase transformers	Number of 3 phase transformers	Total number of transformers & banks	Total Capacity (MVA)	Most Common Size (MVA)
TOTAL[1]	**45**	**127**	**142**	**25261**	**150**

Table 4 – Most Common Transformer Rating

The installed capacity shown by the use of the transformer is shown in Figure 1 to Figure 3.

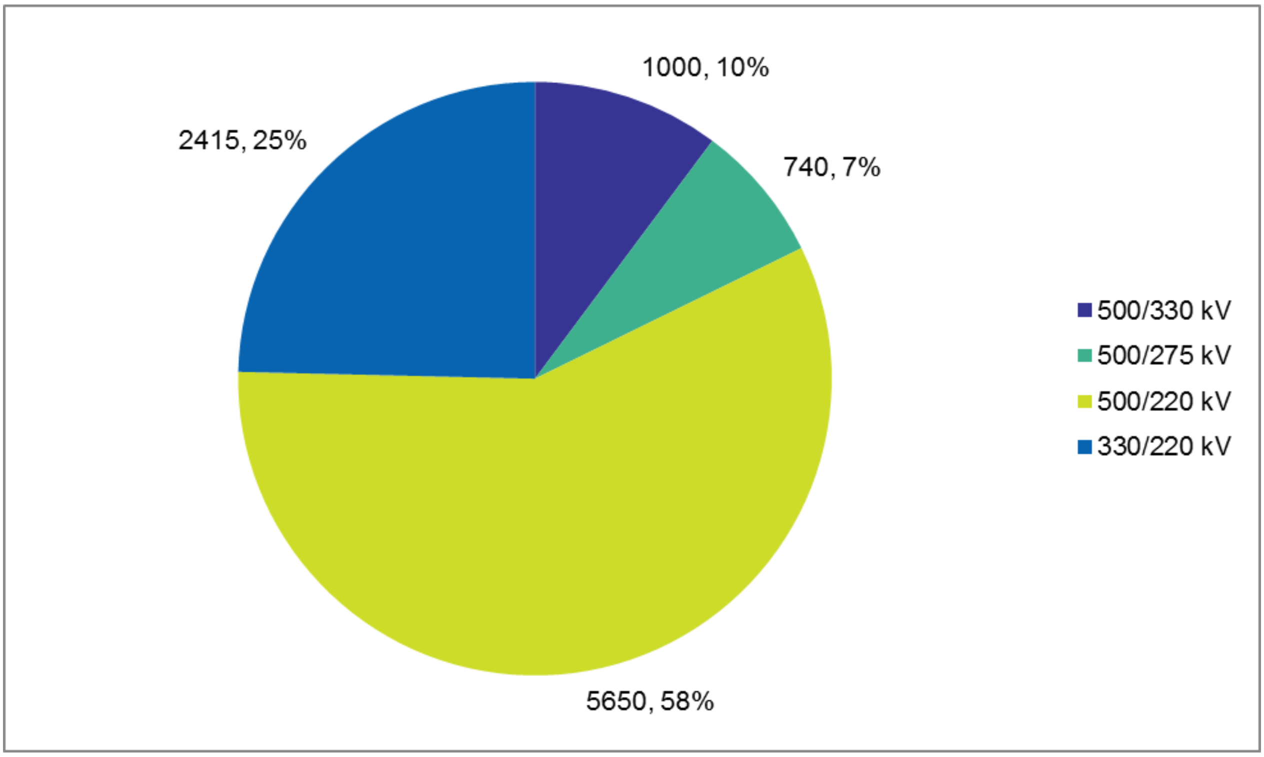

Figure 1 – Installed Capacity (MVA & as a percentage) of Main Tie Transformers by Voltage Ratio

[1] This table includes some temporary transformer installations to facilitate re-arrangement of switchyards during the staging of major projects.

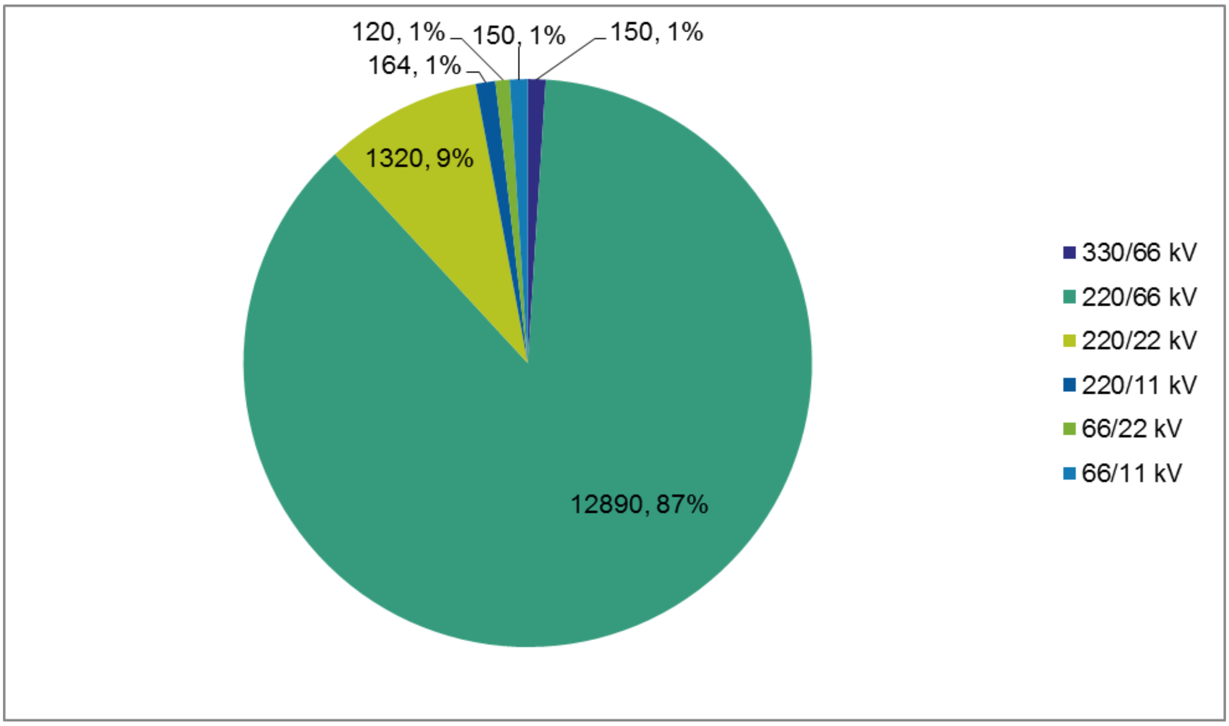

Figure 2 – Installed Capacity (MVA & as a percentage) of Connection Transformers by Voltage Ratio

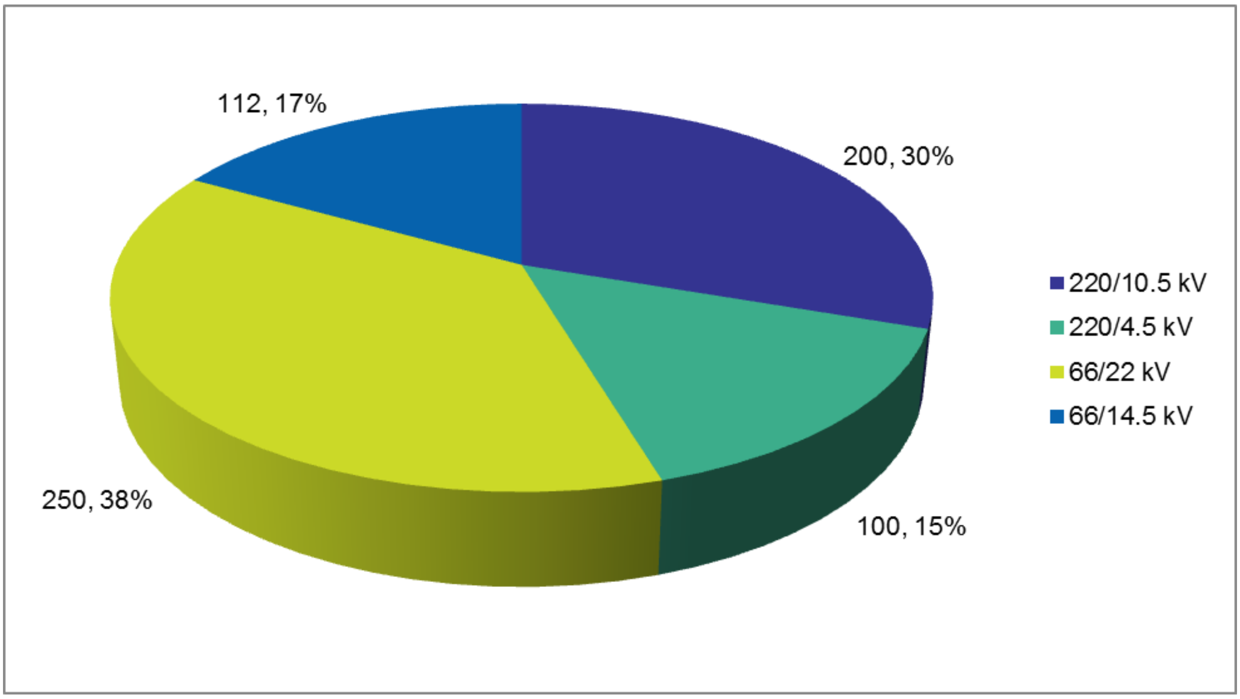

Figure 3 – Installed Capacity (MVA & as a percentage) of Special Purpose Transformers by Voltage Ratio

During the last three years, 20 new power transformers were installed in 10 terminal stations in the Victorian transmission network. Most of these transformer installations except one at Tyabb terminal station (TBTS) are to replace maintenance intensive, aging transformer assets in very poor condition.

At Bendigo terminal station (BETS), six 220/66/22 kV single-phase transformers forming two transformer banks 2A and 2B were retired and one 150 MVA 220/66 kV transformer was commissioned supplying the 66 kV buses in parallel with one existing 125 MVA 230/66/22 kV transformer. Two 75 MVA 220/22 kV transformers were commissioned to supply the 22 kV load. The former arrangement at BETS used secondary and tertiary windings of the 220/66/22 kV transformers for 66 kV and 22 kV supples. Under the new arrangement B3 and

B4 three-phase transformers provide 220/66 kV transformation while L2 and L4 transformers provide 220/22 kV transformation.

At Brooklyn terminal station (BLTS), a three-phase transformer (B4) and 21 single-phase transformers forming B1, B2, B3A, B5A, B5B, L1 and L2 transformer banks were replaced by three 220/66 kV three-phase transformers and two 220/22 kV three-phase transformers. At Dederang terminal station (DDTS) three 330/220 kV single-phase transformers forming the H1 transformer bank were replaced with a 330/220 kV three-phase transformer.

Six 220/66 kV single-phase transformers forming B1A and B1B transformer banks at Glenrowan terminal station (GNTS) were replaced with a 150 MVA 220/66 kV three-phase transformer (B3). The B1 and B3 220/66 kV three-phase transformers at Geelong terminal station (GTS) were replaced with similar units. At Keilor terminal station (KTS) the B1 and B2 220/66 kV transformers were replaced with similar units.

At Richmond terminal station (RTS), a B6 220/66 kV transformer was temporarily installed to provide the emergency transformation capacity requested by CitiPower and UED Distribution Network Service Providers until the completion of RTS rebuild project, XA09. Two L transformers at RTS will be replaced in this project. The B6 transformer installed at RTS was the Ringwood terminal station (RWTS) spare transformer, moved to RTS to enable staging and will stay at RTS as a permanent transformer.

Six 220/66 kV single-phase transformers forming L2 and L3 transformer banks at RWTS were replaced with L2 and L3 three-phase transformers while the U1 66/22 kV transformer was retired. The B1 220/66 kV transformer at Thomastown terminal station (TTS) was replaced with a similar unit and the existing transformer was retained as a cold spare.

AusNet Services has prevented adverse consumer impact by replacing transformers showing high probabilities of failure based on condition and remaining service potential. Where economic and technically viable, energy losses in the Victorian electricity transmission network have been reduced by replacing single-phase transformers with more efficient three-phase units. This practice also extends maintenance cycles and reduces the probability of transformer failure by rationalising the number of transformers in service.

3.1.2 Oil Filled Reactors

Oil-filled reactors are similar in construction to transformers having paper & oil insulation and steel cores. They are manufactured in transformer works and have similar maintenance requirements. Details of the oil filled reactors installed in the Victorian electricity transmission network are summarised in Table 5 below.

Voltage Class (kV)	Type	Rating (MVAR)	Manufacturer	Quantity	Location	Comments
500	Shunt	121	[C.I.C]	2	MLTS	2 similar units at [C.I.C] are owned by PSS
0	Neutral	0.13	[C.I.C]	2	MLTS	Installed with the 500 kV shunt reactors.
220	Shunt	121	[C.I.C]	1	MLTS	
66	Shunt	15	[C.I.C]	2	RCTS	
66	Shunt	19.4	[C.I.C]	1	HOTS	
66	Shunt	19.4	[C.I.C]	3	HOTS, KGTS, RCTS	
22	Series		[C.I.C]	4	RTS	Installed on transformer 22 kV cables.
22	Series		[C.I.C]	4	WMTS	Installed on transformer 22 kV cables.
			TOTAL	**19**		

Table 5 – Installed Oil-filled Reactors

3.2 Service Age Profile

3.2.1 Power Transformers

The average service age of the power transformer fleet is 31 years with the oldest being the 59 year old 220/11kV Group 5 transformer at Yallourn power station (YPS) which was installed in 1956.

The average service age of the transformer fleet has reduced 6% over the last three years from an average of 33 years in 2012. This is attributed to the replacement of 19 deteriorated transformers at nine terminal stations and the installation of a new transformer at Tyabb terminal station (TBTS). The service age of power transformers and oil insulated reactors is illustrated in the following figures, Figure 4 through Figure 7.

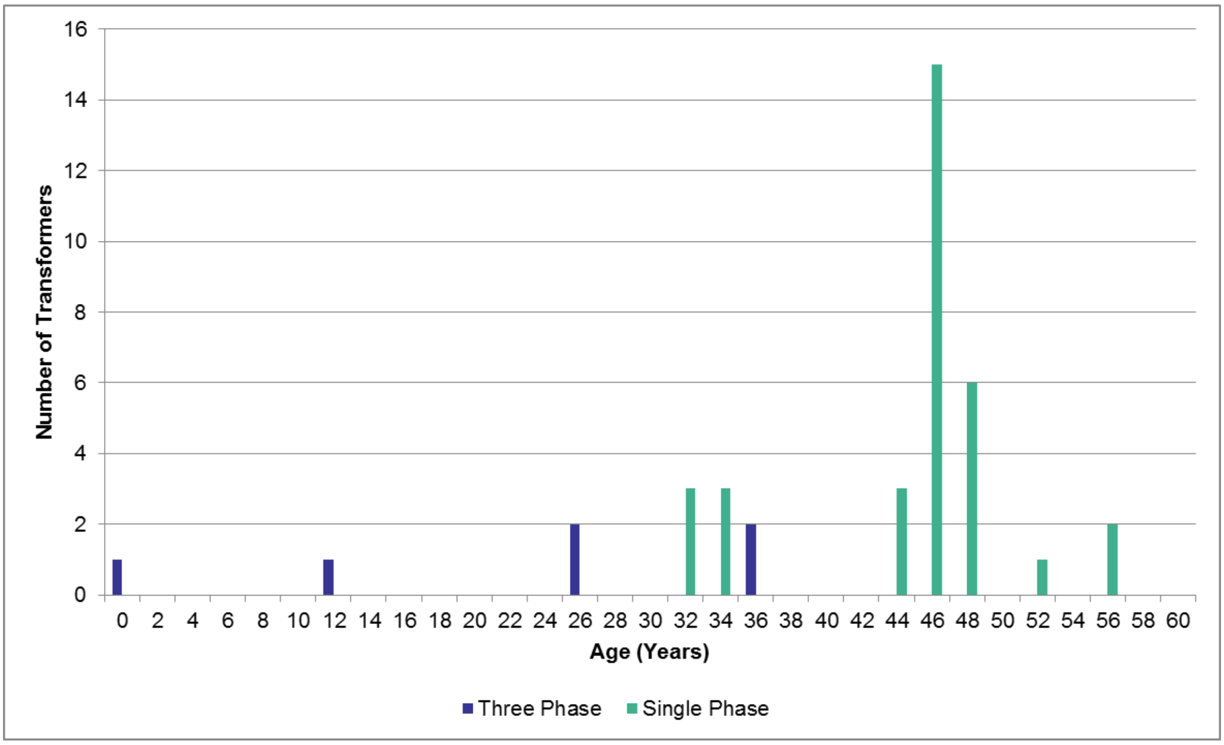

Figure 4 – Service Age of Main Tie Transformers

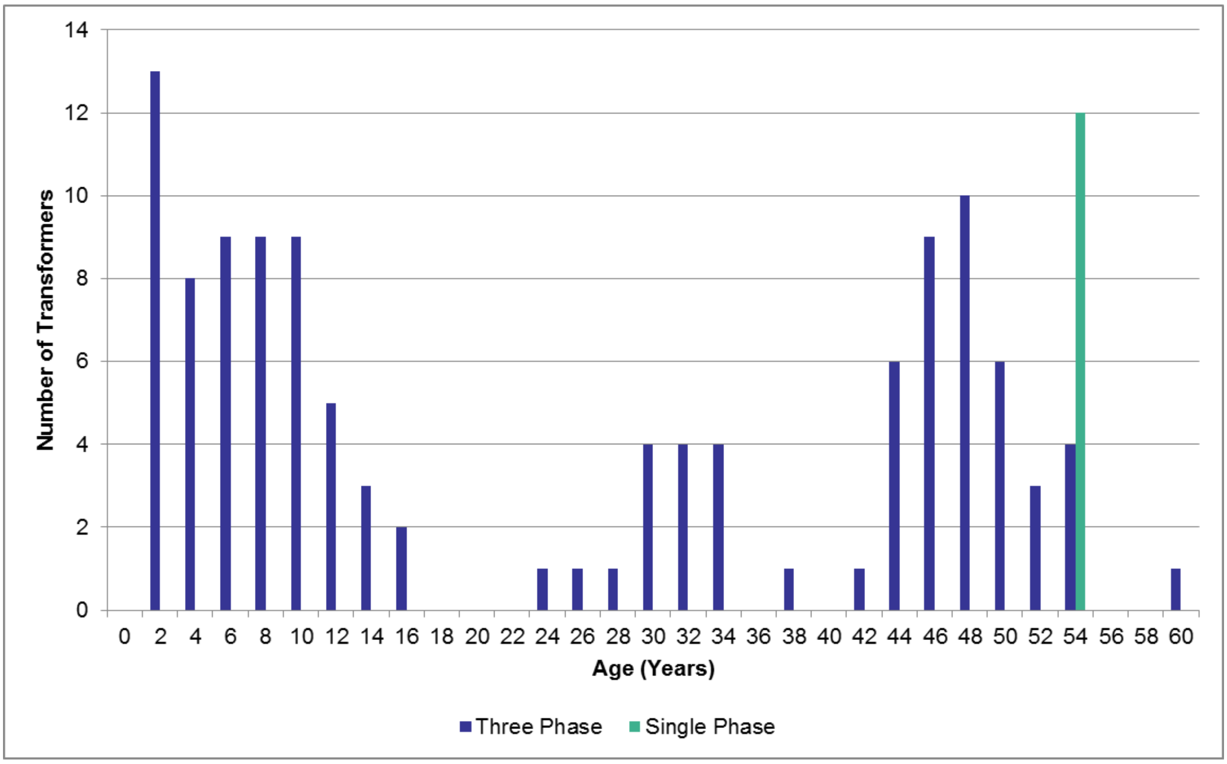

Figure 5 – Service Age of Connection Transformers

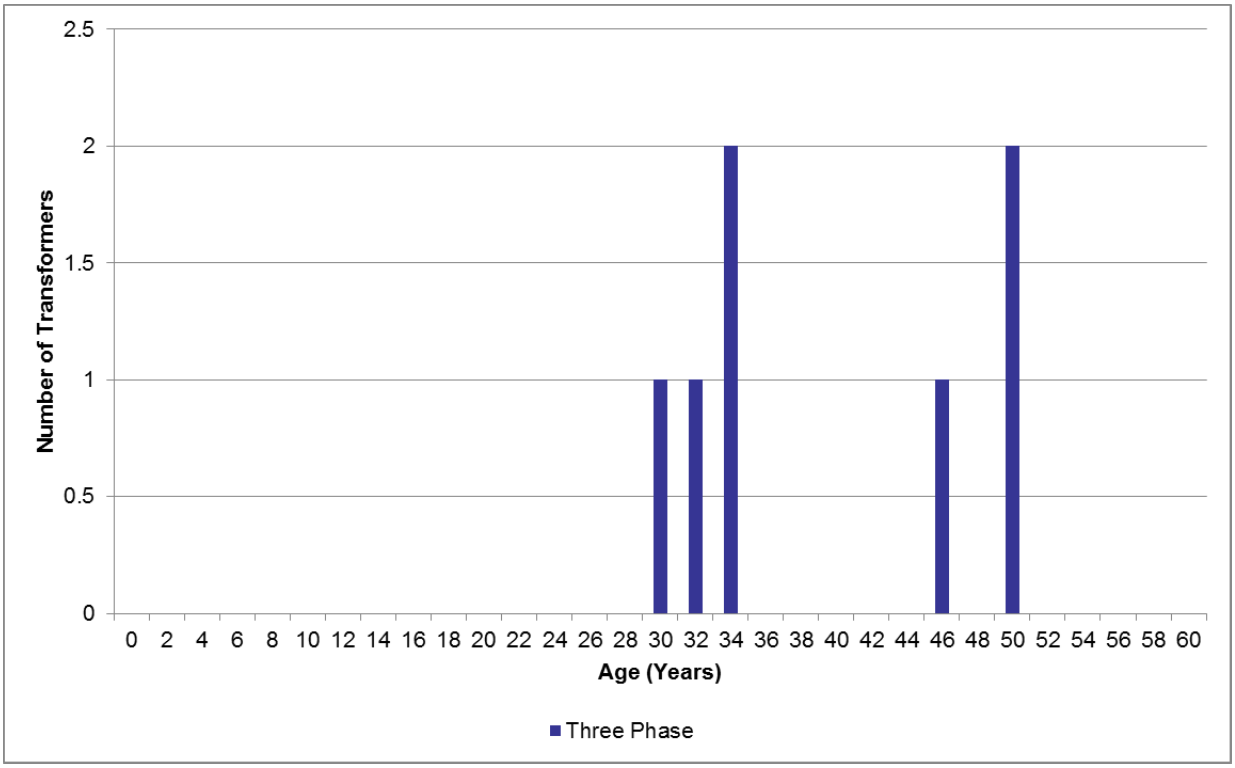

Figure 6 – Service Age of Special Purpose Transformers (SVC and Synchronous Condenser Transformers)

3.2.2 Oil Filled Reactors

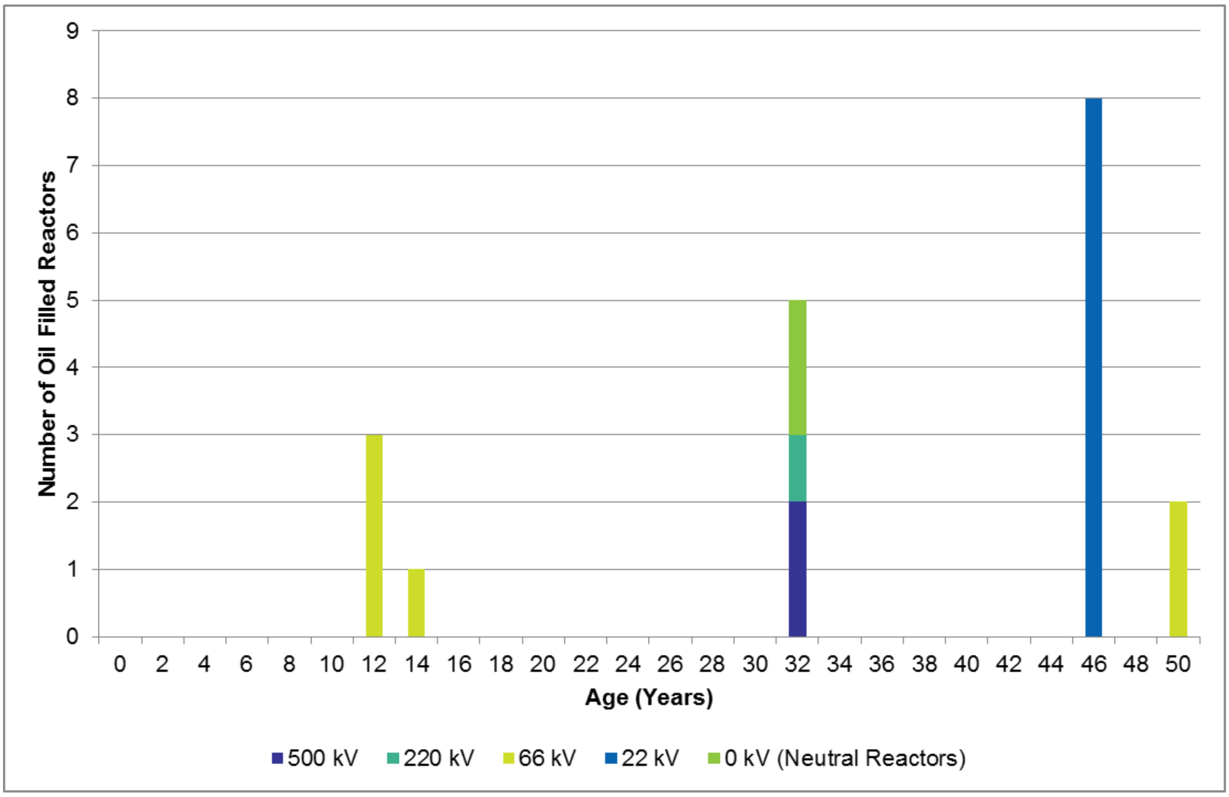

Figure 7 – Service Age of Oil Filled Reactors

3.2.3 Expected Service Life

The technical life of a power transformer is expected to range from 40 to 60 years. However, those transformers that have been subjected to high average loading (resulting in advanced insulation deterioration) and those which have a significant defect, including incipient faults, such as high moisture content or winding displacement, will have higher failure probabilities and replacement may prove economic before this technical life is achieved

During the lifecycle of the transformer varying degrees of refurbishment work is required (e.g. the repair of major oil leaks). Refurbishment of some older transformer units may prove to be uneconomic or impractical due to low availability of transformer components, appropriate technical expertise and the complexity involved.

3.3 Condition

3.3.1 Power Transformers

Until 2000, inspection and monitoring of transformers was made in response to system incidents and problems found during scheduled maintenance. In 2000, a program was instituted to assess the condition of each transformer on an individual basis.

AusNet Services employs routine monitoring processes for power transformers by testing the transformer oil condition for deterioration and incipient events and every six to eight years performs detailed tests to determine key deterioration factors used in detail condition assessment for each major component. The condition assessment is an essential step in analysing the risk of failure and planning economic replacement before failure. Transformers are explicitly required to operate satisfactorily at the cyclic, emergency cyclic and short time ratings. The transformer condition and ranking are used as inputs to the asset planning process, which includes impact of failure on the community, coordination with augmentation projects, customer requirements, risk and economic analysis models. The foregoing informs the development of economic refurbishment and replacement projects.

Condition assessments examine each critical component of the transformer from the following perspectives:

- Dielectric and thermal condition;
- Physical and operating condition;
- Historical information; and
- Design suitability and limitations.

The condition monitoring tests specifically assess the current insulation condition with a determination of the transformers remaining service life. It is therefore a requirement that the results achieved are as accurate as possible with external influences eliminated as far as practicable or identified as a contributing factor. Condition monitoring includes offline electrical testing and due to the intense nature of the condition inspection regime occurs once every six years for each transformer on the network.

The combination of inspection methods utilised in condition monitoring to determine transformer condition are:

- Frequency Response Analysis (FRA);
- Dielectric Dissipation Factor (DDF) & Capacitance measurements;
- Dielectric Response Measurement;
- DC Winding Resistance through tapping range;
- Insulation Resistance (IR);
- Plant Inspection.

For example; values from Dielectric Dissipation Factor (DDF) and Capacitance tests are utilised for condition assessment of deteriorated transformer windings as demonstrated in Table 6 below.

DDF	Indicative Condition	Description
0.15% to 0.3%	C1	Acceptable
0.3% to 0.5%	C2	Fair
0.5% to 0.7%	C3	Deteriorated
0.7% to 1.0%	C4	Poor – Investigate & compare with previous results
>1.0%	C5	Very Poor – compare with previous results

Table 6 – Dielectric Dissipation Factor (DDF) and Capacitance tests

In addition to the detailed condition monitoring performed each six to eight years, to determine the ‘end of life’ deterioration factors, the incipient failure conditions are also monitored for each transformer via periodic diagnostic oil tests. Dissolved gas analysis (DGA) is one of these key diagnostic tests which occurs each year or as required depending on the management plan in place on the asset. Table 7 identifies typical DGA analysis evaluation however any one of these characteristic faults can lead to major failure.

Case No	Characteristic Fault	$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_2}{C_2H_6}$	Indicative Condition	Typical Examples
0	No fault	0	0	0	C1	Normal ageing.
1	Partial discharges of low energy density	0 but not significant	1	0	C2	Discharges in gas filled cavities resulting from incomplete impregnation, or supersaturation or cavitation or high humidity.
2	Partial discharge of high energy density	1	1	0	C3	As above, but leading to tracking or perforation of solid insulation.
3	Discharges of low energy (see Note 1)	1 - 2	0	1 – 2	C3	Continuous sparking in oil between bad connection of different potential or to floating potential. Breakdown of oil between solid materials.
4	Discharges of high energy	1	0	2	C4	Discharges with power follow through. Arcing breakdown of oil between windings or coils or between coils to earth.
5	Thermal fault of low temperature <150°C (see Note 2)	0	0	1	C4	General insulated conductor overheating.
6	Thermal fault of low temperature range 150°C – 300°C (see Note 3)	0	2	0	C5	Local overheating of the core due to concentration of flux. Increasing hot spot temperatures; varying from small hot spots in core, shorting links in core, overheating of copper due to eddy currents, bad contacts/joints (pyrolytic carbon formation) up to core and tank circulating currents.
7	Thermal fault of medium temperature range 300°C – 700°C	0	2	1	C5	
8	Thermal fault of high temperature >700°C (see Note 4)	0	2	2	C5	

Table 7 – Interpreting Results by Ratios of Gases Analysed

When gas content results indicate guide values have been exceeded, further consideration of plant performance is warranted. This includes reviewing history of full condition monitoring in conjunction with DGA, recent loading history, or checking if any sustained voltage or frequency abnormalities have occurred. Further information on DGA can be found in PGI 57-01-03 Insulating Oil Requirements, Treatment, Testing and Limits of Acceptability.

Following completion of Condition Monitoring, DGA and additional assessment, final condition scores are compiled against five separate critical components of the transformer, namely:

- Oil;
- Core and windings (coils);
- Bushings;
- OLTC (On-Load Tap Changer); and
- Tank, wiring, auxiliary components and cooling systems.

The methodology for test analysis and combined condition assessment of transformers is represented by Figure 8 below.

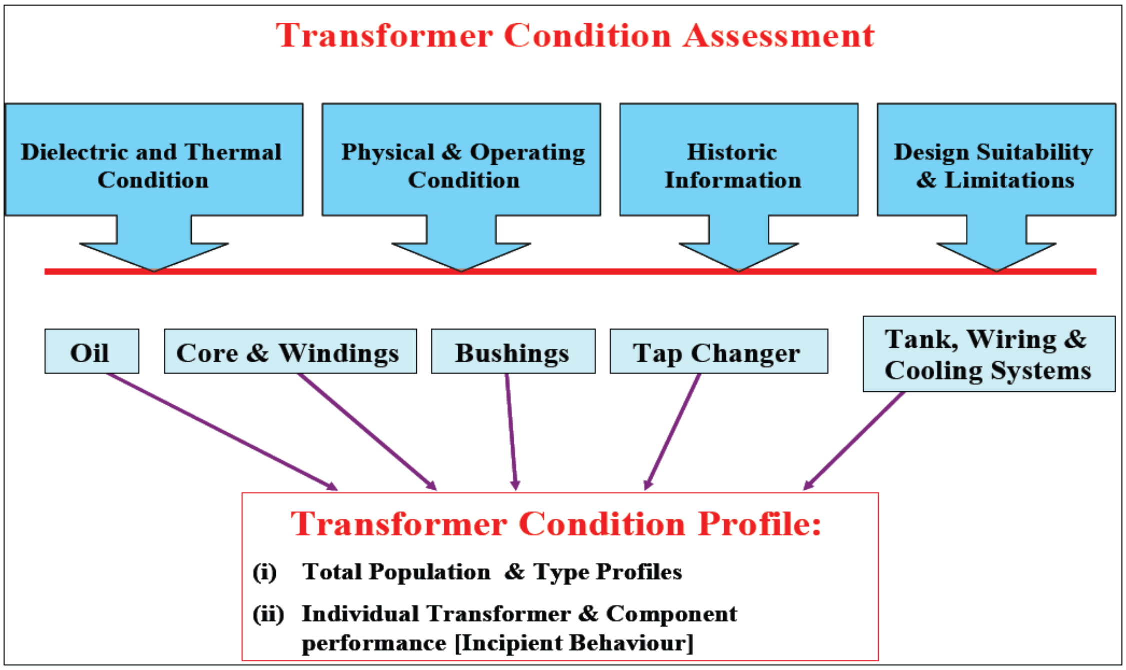

Figure 8 – Flow Chart for objective Condition Assessment Methodology

This process is consistent with best practice and in combination with other inspection methods cumulatively assists in calculating the condition for the transformer as demonstrated in Figure 8. Further information for condition monitoring, testing and analysis techniques can be found in SMI 80-01-02 Transformer Condition Monitoring in Terminal and Zone Substations.

Condition of Critical Components

The overall assessed transformer condition cascades from the objective test analysis identified during condition monitoring, DGA, and subsequent inspection. The condition score is primarily based on best practice condition assessments, as described in section 3.3, which include inherent transformer design limitations from materials used and network operating parameters. Finally these assessments indicate the condition of the five critical components of the power transformers on a scale of C1: Very Good in Initial Service Condition to C5: Very Poor exhibiting extreme deterioration approaching End of Life.

A condition score of C1 to C3 corresponds to an acceptable condition where no additional action (apart from continued routine maintenance and condition monitoring) is proposed. However, a condition score of C4 or C5 corresponds to the transformer having a high to very high probability of failure. These transformers are expected to require remedial action in a relatively short timeframe.

The condition scoring criteria is summarised in Table 8 below.

Condition Score	Likert Scale	Condition Description	Recommended Action
C1	Very Good (as new)	Initial service condition and complies with all system performance requirements.	No additional specific actions required, continue routine maintenance and condition monitoring.
C2	Good (low deterioration)	Low deterioration for service age or refurbished component initial condition.	
C3	Average for age	Expected deterioration for service age and no constrained system performance.	
C4	Poor	Advanced deterioration – Increase risk of service failure due to a system disturbance or contingency event.	Potentially increase monitoring for adverse deterioration behaviour and plan remedial action to occur within 2-10 years.
C5	Very Poor	Extreme deterioration – approaching ***'end of life'*** high risk of service failure due to minor system disturbance and/or constrains system performance due to its deteriorated state.	Remedial action/replacement within 1-5 years.

Table 8 – Condition score definition and recommended action

The condition scores for each of the five critical components for all power transformers are shown in Figure 9 to Figure 13 below.

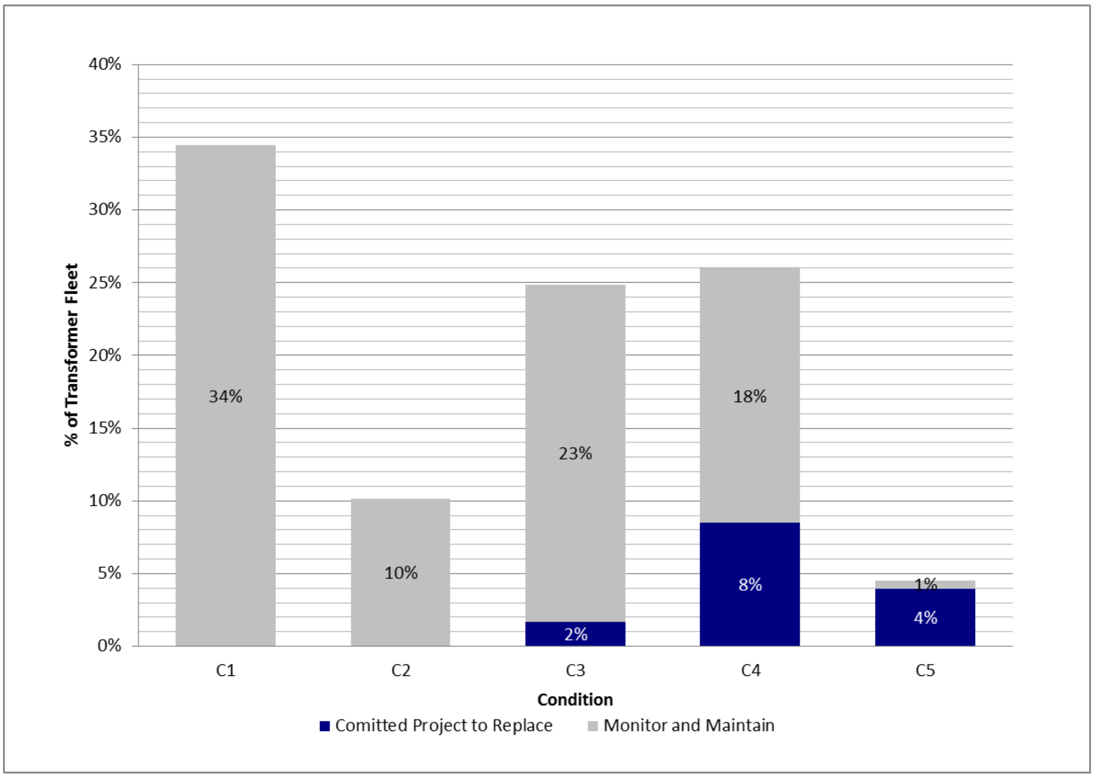

Figure 9 – Core and Windings (Coils) Condition Score

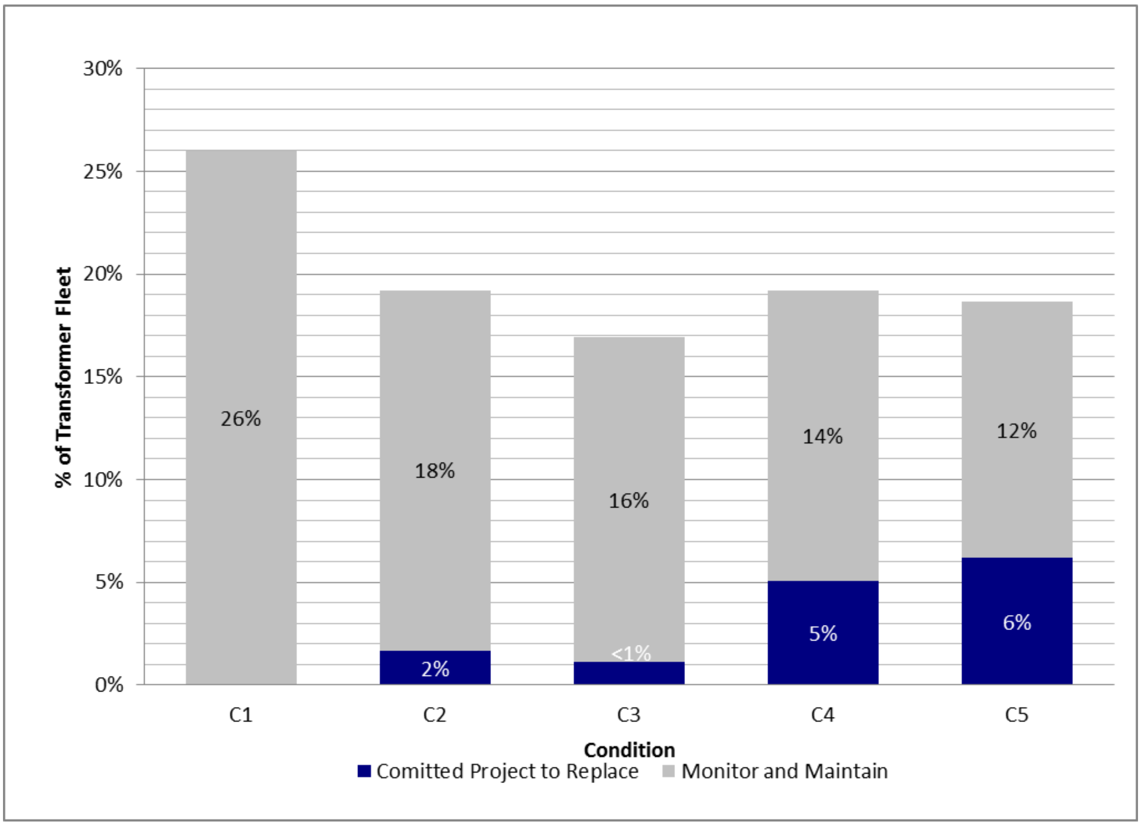

Figure 10 – Bushings Condition Score

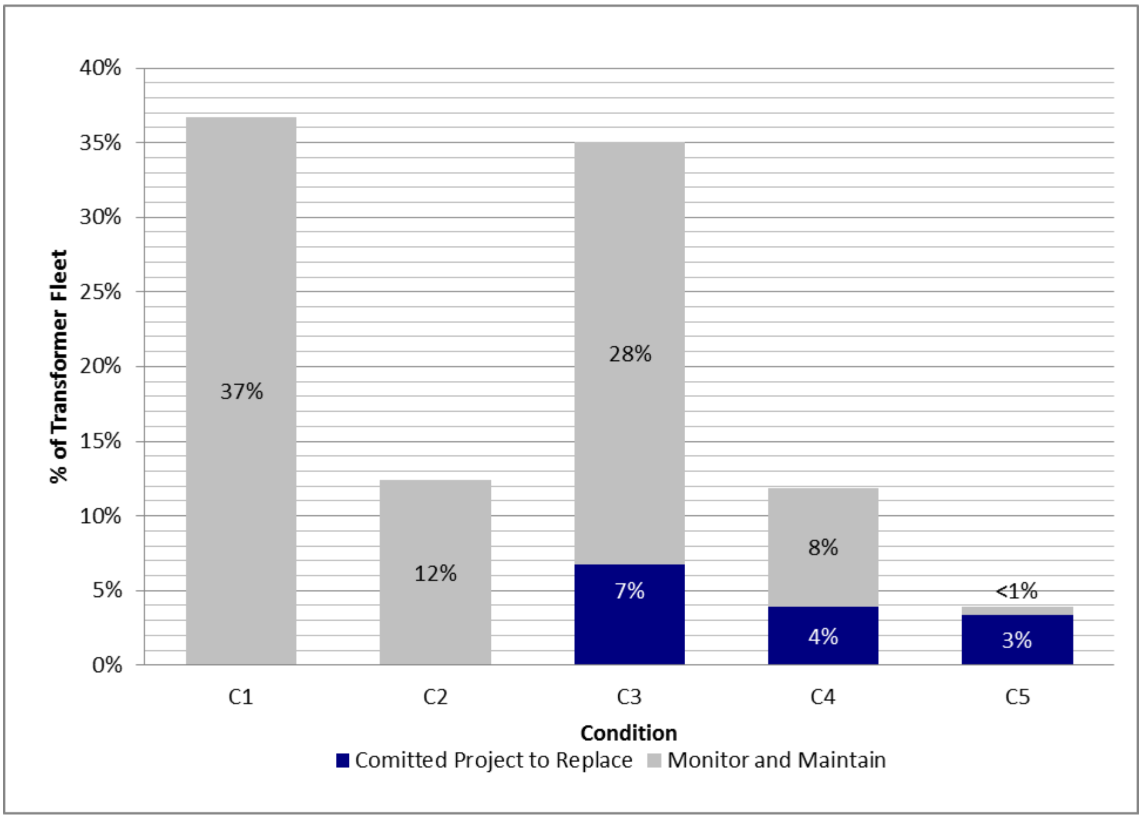

Figure 11 – Oil Condition Score

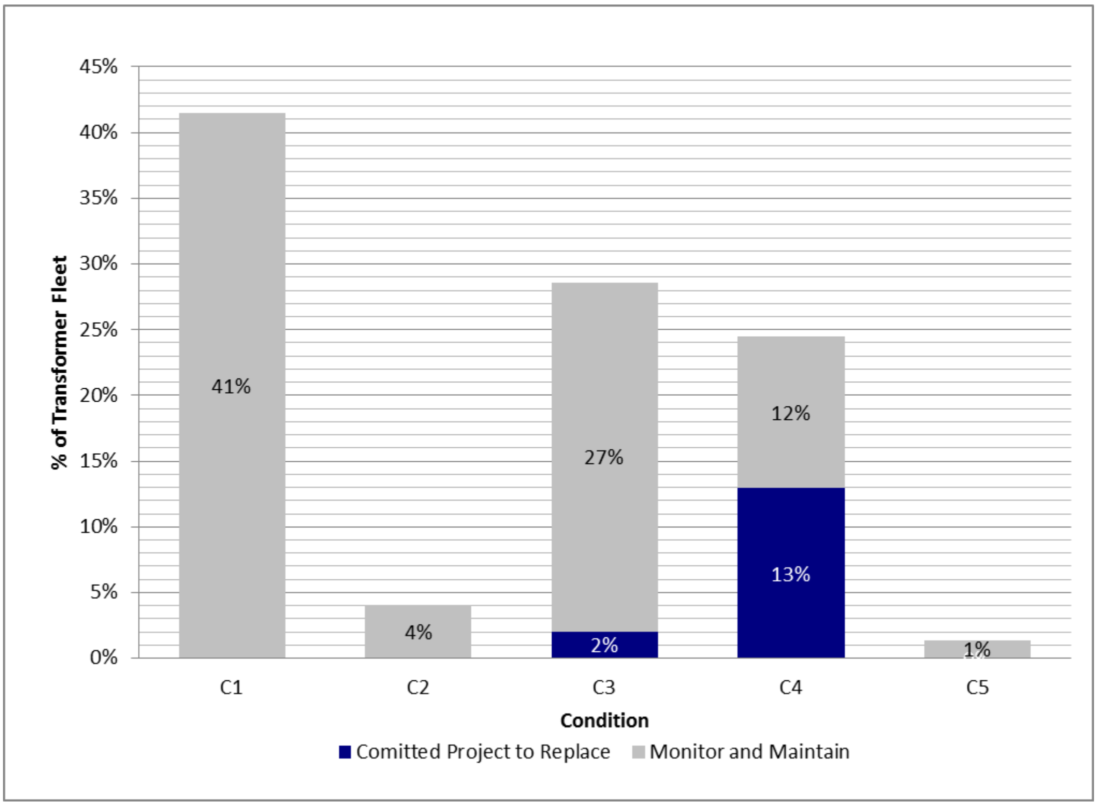

Figure 12 – OLTC Condition Score

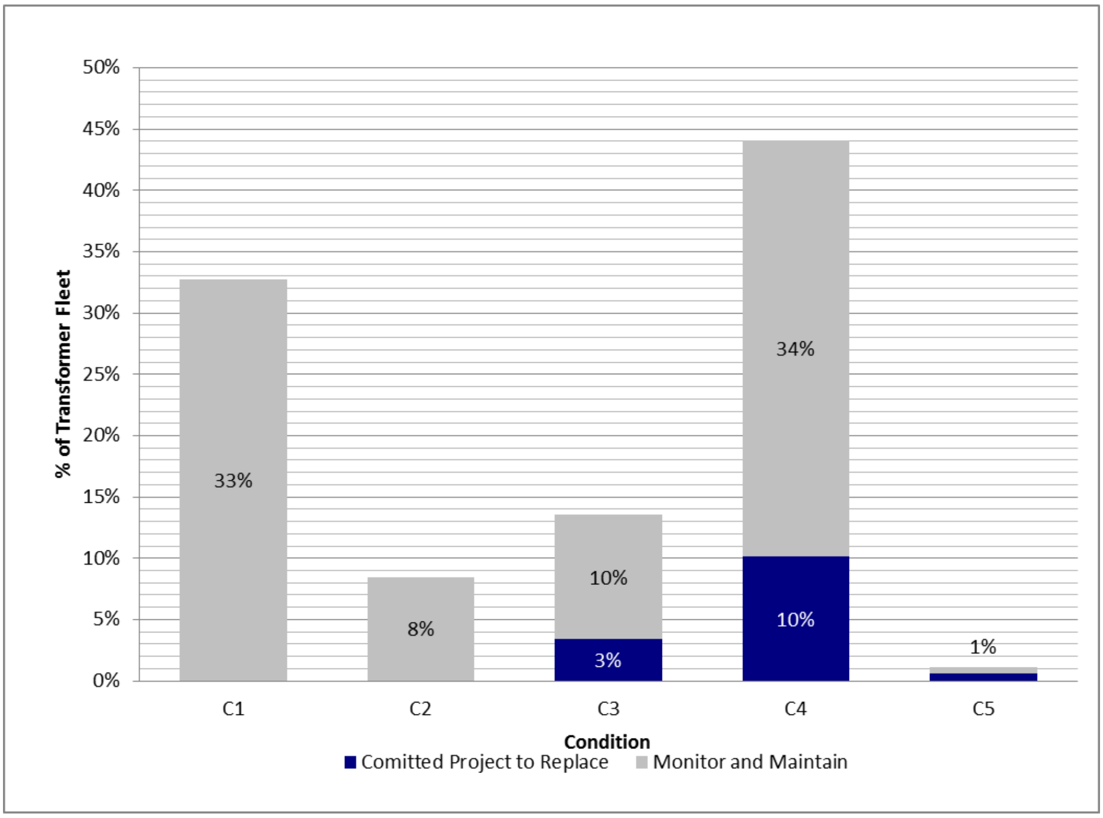

Figure 13 – Tank, Wiring, Auxiliary Components and Cooling Systems Condition Score

Note: *Single-phase transformers are treated as an individual unit and therefore a transformer bank formed from single-phase units will have three scores compared with a single condition score for a three-phase transformer.*

Overall Condition Scores

The condition scores are summarised into two single scores highlighting two important aspects of the performance of the transformer and its component risk:

- Overall Transformer 'End of Life' Score; and
- Component Highest Risk of Failure Score.

Overall Transformer 'End of Life' Condition Score:

The transformers overall 'End of Life' condition score is derived as a weighted average from assessed condition of the critical components and indicates action is required within a period of time to manage the risk of an in-service failure. The decision of the action path is derived from consideration of:

- The type of component/s (eg: core and coils) of concern;
- The system planning requirements; and
- The most cost effective solution – replace or refurbish.

The weighted average condition score system has been developed to tackle issues of both a collective and individual component nature on a case by case basis, with consideration given to the overall performance level of the transformer and the most important of the critical components i.e. the core and coils.

Table 9 outlines the critical component weighting used to calculate the transformers weighted average score:

Transformer Critical Component	Weighting
Core and windings (coils)	4
Oil	3
Bushings	2
OLTC (On-Load Tap Changer)	2
Tank, wiring, auxiliary components and cooling systems	1

Table 9 – Weighting used to calculate overall weighted 'End of Life' score

Figure 14 shows the percentage of transformers held in each overall weighted condition score.

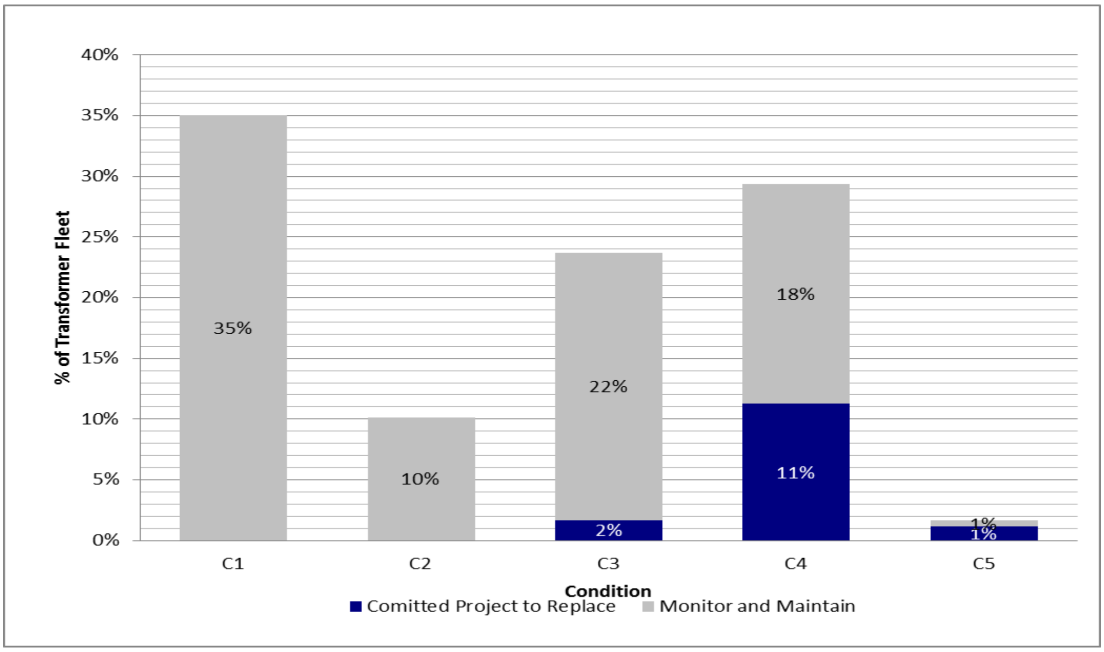

Figure 14 – Overall Weighted Average Condition Score of Transformers

Figure 14 illustrates 31% of power transformers have an average weighted condition score greater than C3 with respect to continued operation under the present environment and loadings.

The number of transformers that have incipient faults or major defects, impairing the capability of transformers, is low compared to the number of transformers in the fleet. The failure rate for major failures (requiring factory repair or major on-site repair) has traditionally been below 0.13% per transformer year, but since 2000 has progressively increased beyond the CIGRE Australia failure rate of 0.4% per transformer year. For more details about failures please refer to the Section 3.4.1 of this document.

It should be noted that the majority of the fleet have been subjected to high utilisation and high ambient temperatures during the period 2000 to 2010. High peak utilisation and high cyclic utilisation, during periods of high ambient temperatures, inherently consumes remaining service life more quickly than stable loads within the nameplate rating at moderate temperatures such as been the case for the last five years.

The overall transformer normalised condition score against service age is shown in Figure 15 below. The condition score is normalised to the highest condition scored transformer and hence the weighted average condition scores of all transformers are between zero and one.

Figure 15 shows that the condition of the transformers typically deteriorates with service duty. Most of the transformers that are in a poor condition are more than 40 years old as they have accumulated the greatest exposure to deterioration factors such as high loading and mechanical shocks due to through faults.

Component Highest Risk of Failure Score:

As well as the overall "End of Life' score, the condition scoring is designed to highlight the individual highest risk component that potentially could cause an early failure of the transformer before the "end of life' is reached. Thus the 'Highest Risk of Failure Score' allows for asset maintenance programs to be derived addressing any pending early failure of a component. It also demonstrates a holistic approach to how each transformer is tracking with any potential incipient condition which may be lost in the final 'end of life' assessment.

The deterioration of the individual component may lead to the total failure of the transformer but it by itself does not indicate the transformer is at its economical end of life but needs to be addressed to reduce an early failure of the component and or transformer. For details of its use refer to AHR 10-67 Asset Health Review for Power Transformers in Terminal Stations.

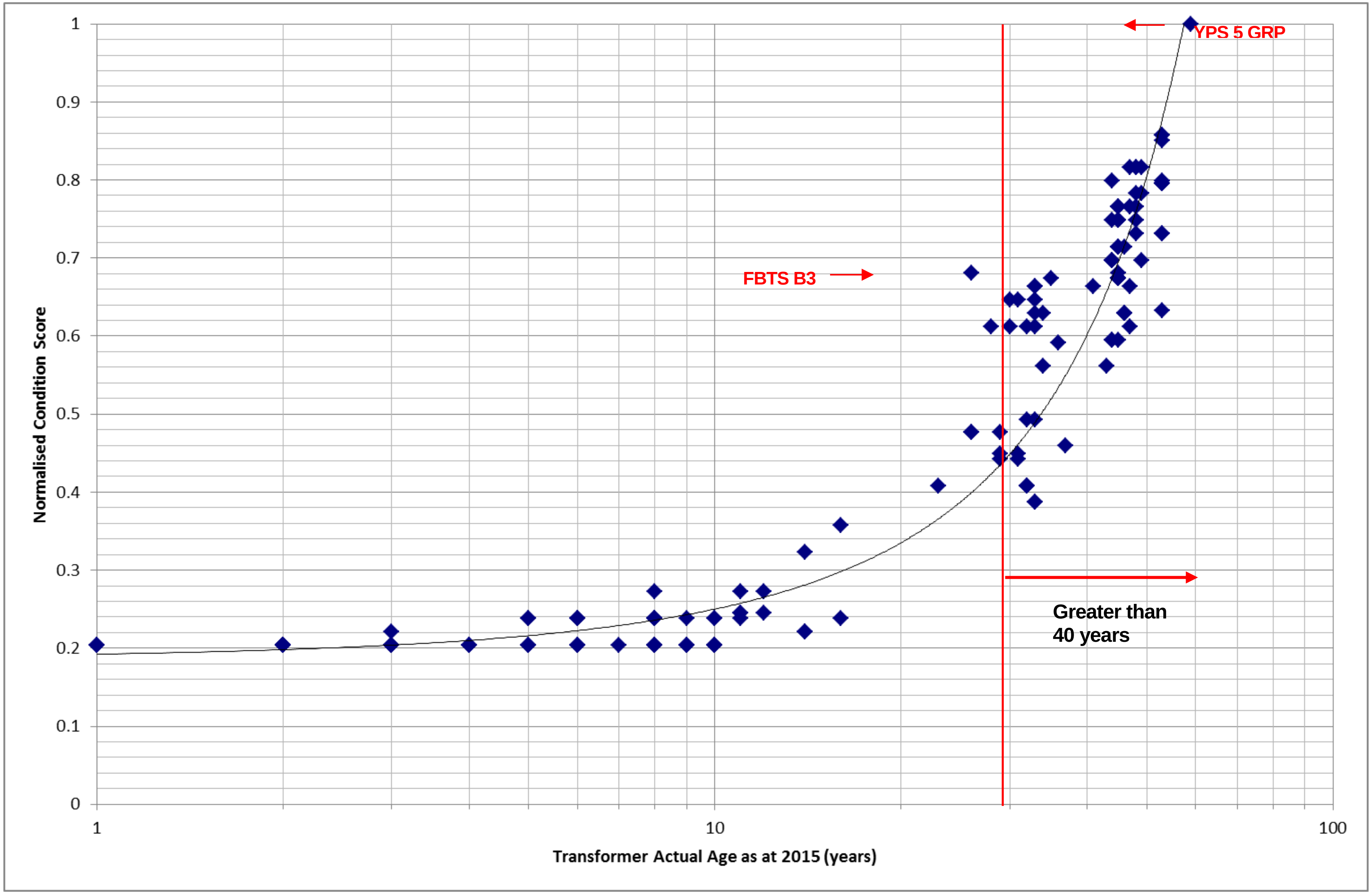

Figure 15 – Overall transformer normalised condition score against service age (excludes committed projects)

Some transformers have a poor condition even with a lower service age. For example; FBTS B3 has a normalised score of 0.68 at age of 26 years due to poor condition scores across each of the transformer components in particular the core and coil at condition C4 which relates to a high risk of an in-service failure due to an identified weakness in design for short circuit performance.

A transformer may be in a poor condition as a result of either a major component or a number of components contributing to a poor condition. Typically poor condition/performance of transformer components is directly attributable to transformer duty cycles with repeated application of high utilisation and high ambient temperatures coupled with through faults. Although there is a correlation between transformer age, condition and transformer functionality, it is still imperative to properly recognise duty cycles and understand the conditional indices to determine the transformers remaining service potential. For more detail on transformer health please refer to AHR 10-67 Asset Health Review for Power Transformers in Terminal Stations.

3.3.2 Oil Filled Reactors

Oil filled reactors utilise the same condition assessment methodology as transformers. The following sections summarise the condition score of major components and overall weighted average condition scores of oil filled reactors. The two 66 kV shunt reactors at RCTS as Identified as a condition C5 in Figure 16 below are proposed for retirement and AEMO has indicated these shunt reactors are not required and potentially will not be replaced

3.3.2.1 Condition of Oil Filled Reactor Critical Components

The condition of the critical components of oil filled reactors is shown in Figure 16 to Figure 19.

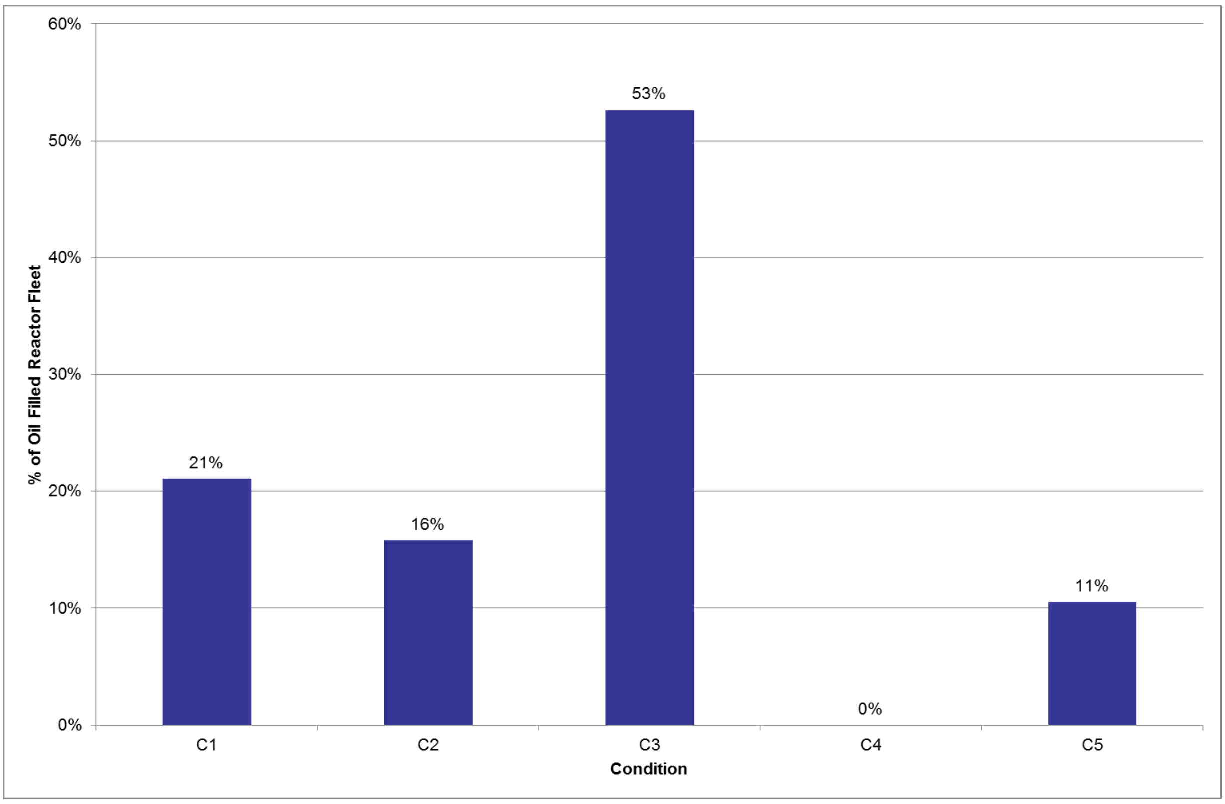

Figure 16 – Core and Windings (Coils) Condition Score

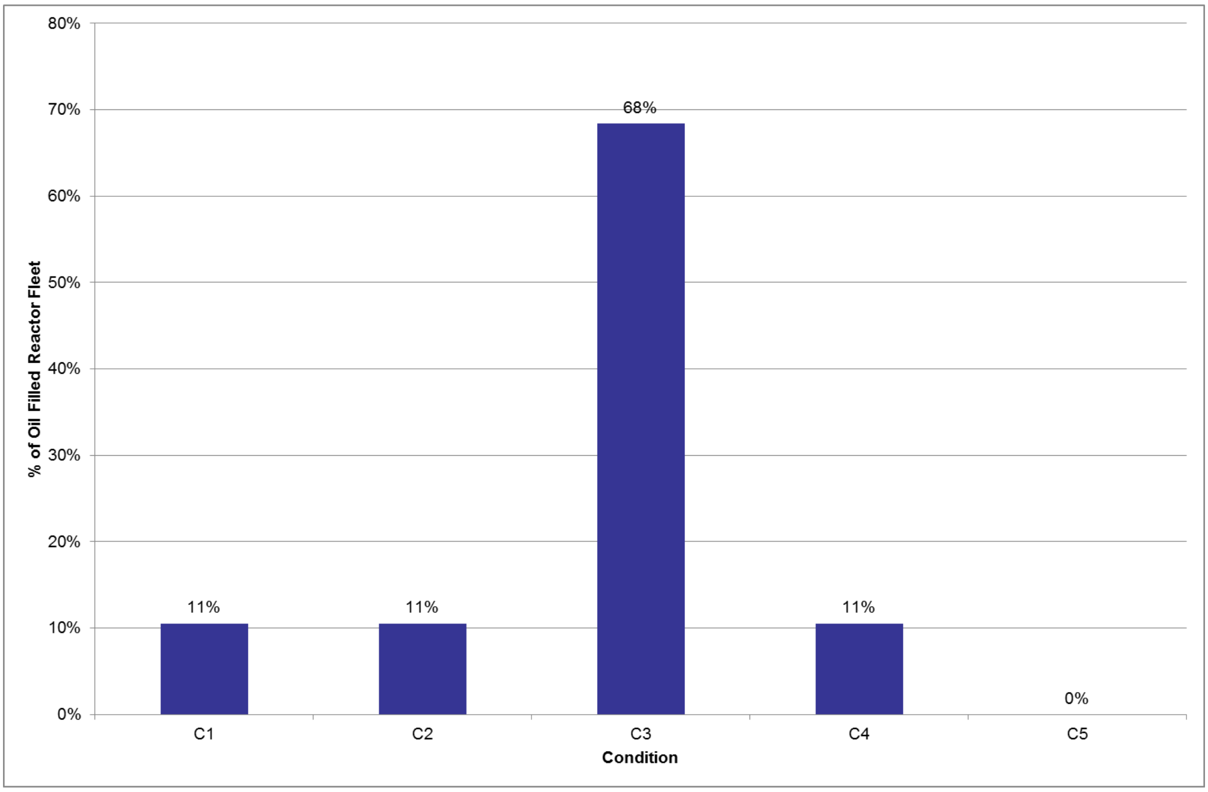

Figure 17 – Bushings Condition Score

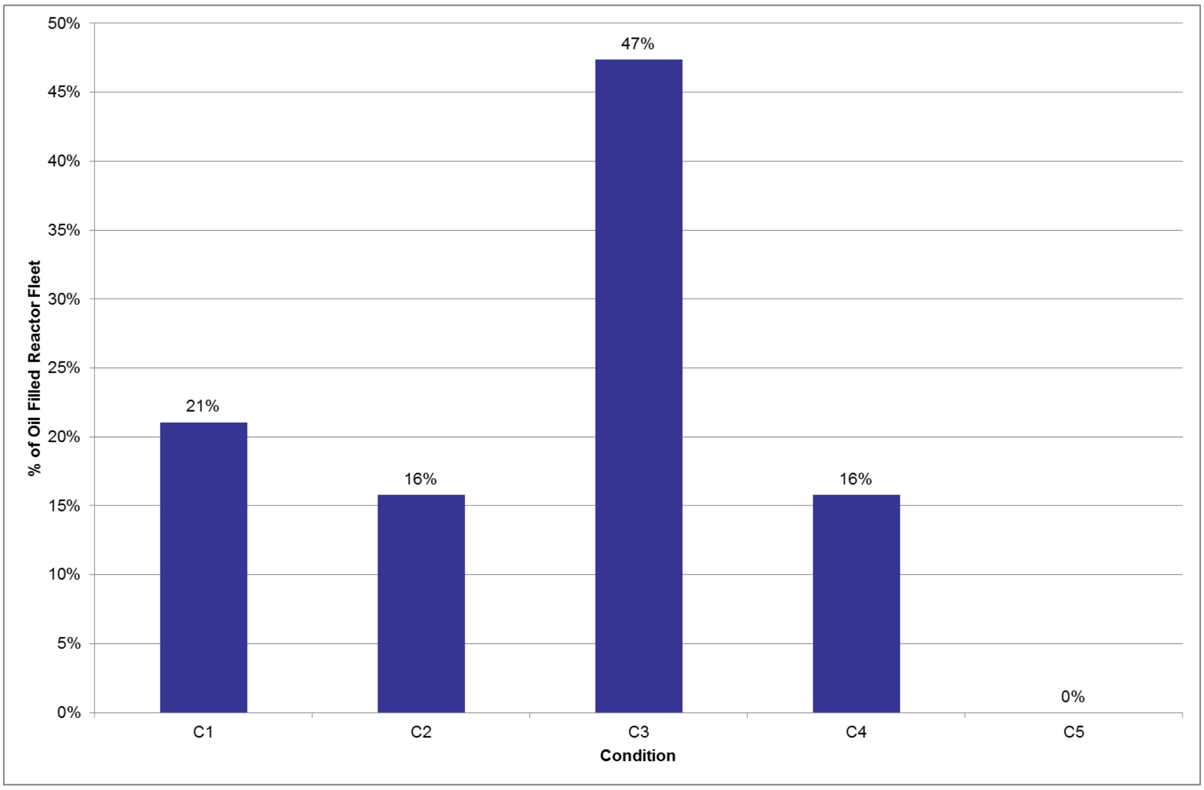

Figure 18 – Oil Condition Score

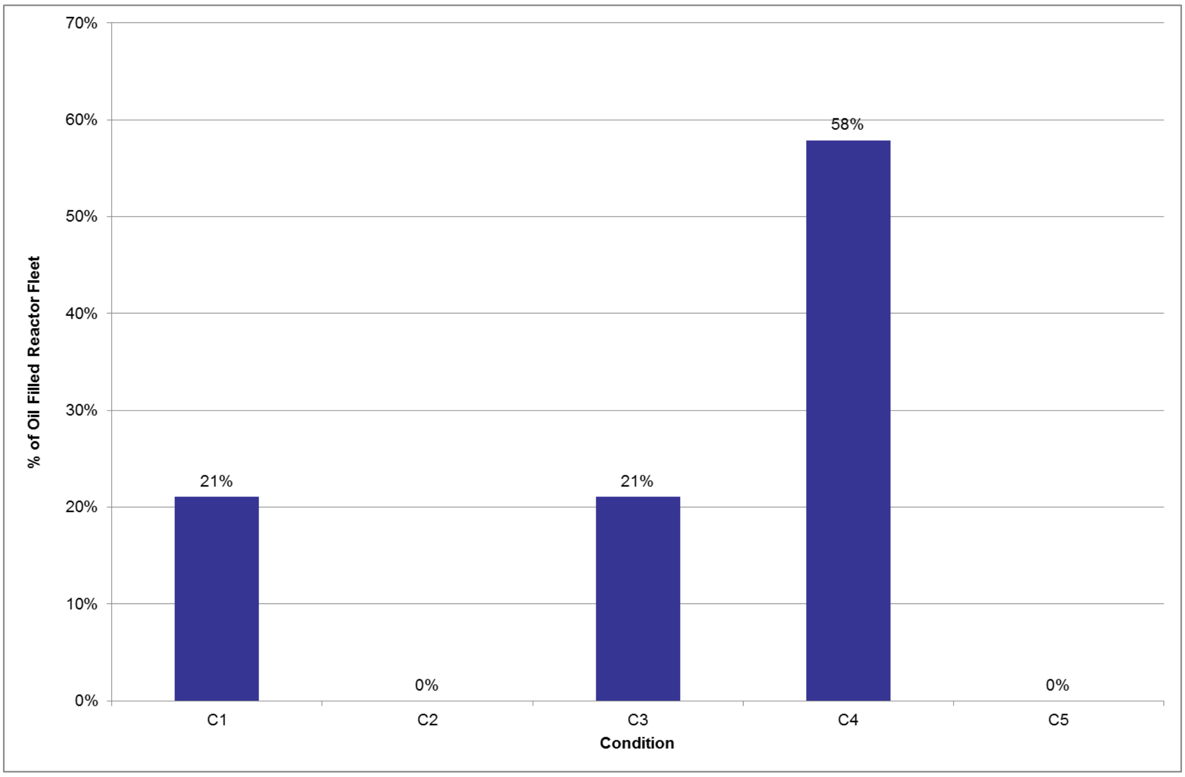

Figure 19 – Tank, Wiring, Auxiliary Components and Cooling Systems Condition Score

The core & winding condition has deteriorated further since the 2012 condition assessment. In 2012 there were 11% reactor assets with core & winding in "poor" condition (C4) that moved to "very poor" condition (C5) in 2014 as shown in Figure 16. As represented in Figure 17, 11% of the transformer bushings across the fleet have a "Poor" condition (C4). This is typically attributed to the 66 kV shunt reactors at RCTS which are currently in poor condition. To manage the RCTS shunt reactors through to replacement, excessive oil leaks will be repaired and the increasing vibration closely monitored.

3.3.2.2 Overall Weighted Average Condition Score of Oil Filled Reactors

The average age of the oil filled reactor fleet is 36 years. It indicates that the majority of the fleet have passed their mid-life (for more details of the service age profile refer to the Section 3.3.2). Analysis of weighted average condition scores highlighted by Figure 20 show 69% of the oil filled reactors are in condition C3 or above. It implies that over the coming decade the condition of oil filled reactors will require increasing maintenance and drive more refurbishment and replacement works than in the last decade.

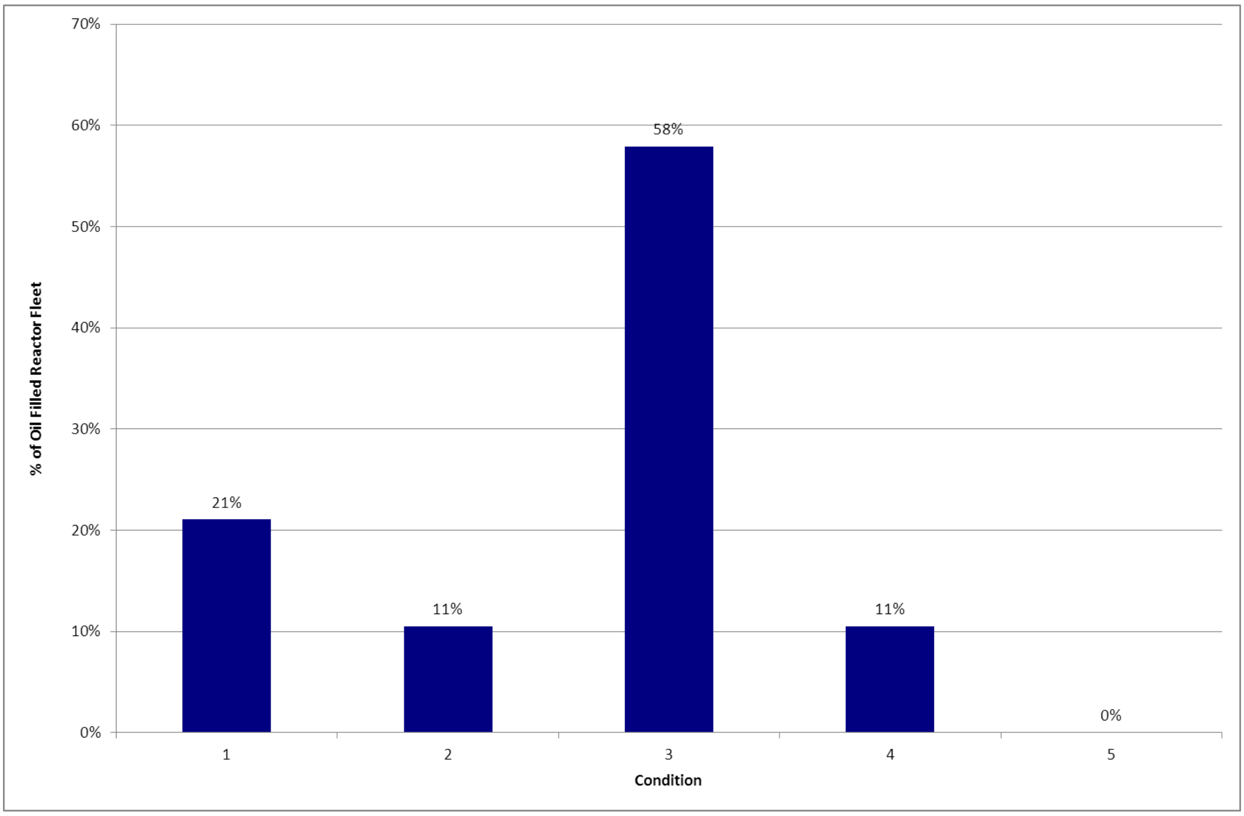

Figure 20 – Weighted Average Condition Score of Oil Filled Reactors

The overall oil filled reactor normalised condition score against service age is shown in Figure 21 below. The condition score is normalised to the highest condition scored reactor and hence the weighted average condition scores of all reactors are between 0 and 1.

As represented in Figure 21 the condition of the oil filled reactors deteriorates with increasing service duty. The No 1 & 2 66kV oil filled reactors at Redcliff's terminal station (RCTS) are in a poor condition with a weighted average condition score of C4.

Figure 21 also shows a number of reactors nearing the end of their service duty with 53% of reactors beyond 40 years old. However some reactors have a poor condition even with a lower service age. For example MOPS No.2 500 kV Line Shunt Reactors at MLTS has a normalised condition score of 0.68 at a service age of 32 years. Similar to transformers these oil filled reactors are in a poor condition as a result of either a major component or a number of components contributing to a poor condition.

Typically poor condition of reactor components is directly attributable to duty cycles with repeated application of high utilisation and high ambient temperatures coupled with through faults. Although there is a correlation between the oil filled reactor's service age and its condition it is imperative to recognise the contribution of duty cycles and understand conditional indices to determine remaining service potential of these assets. For more details of the reactor health refer to the AHR 10-67 Asset Health Review for Power Transformers in Terminal Stations.

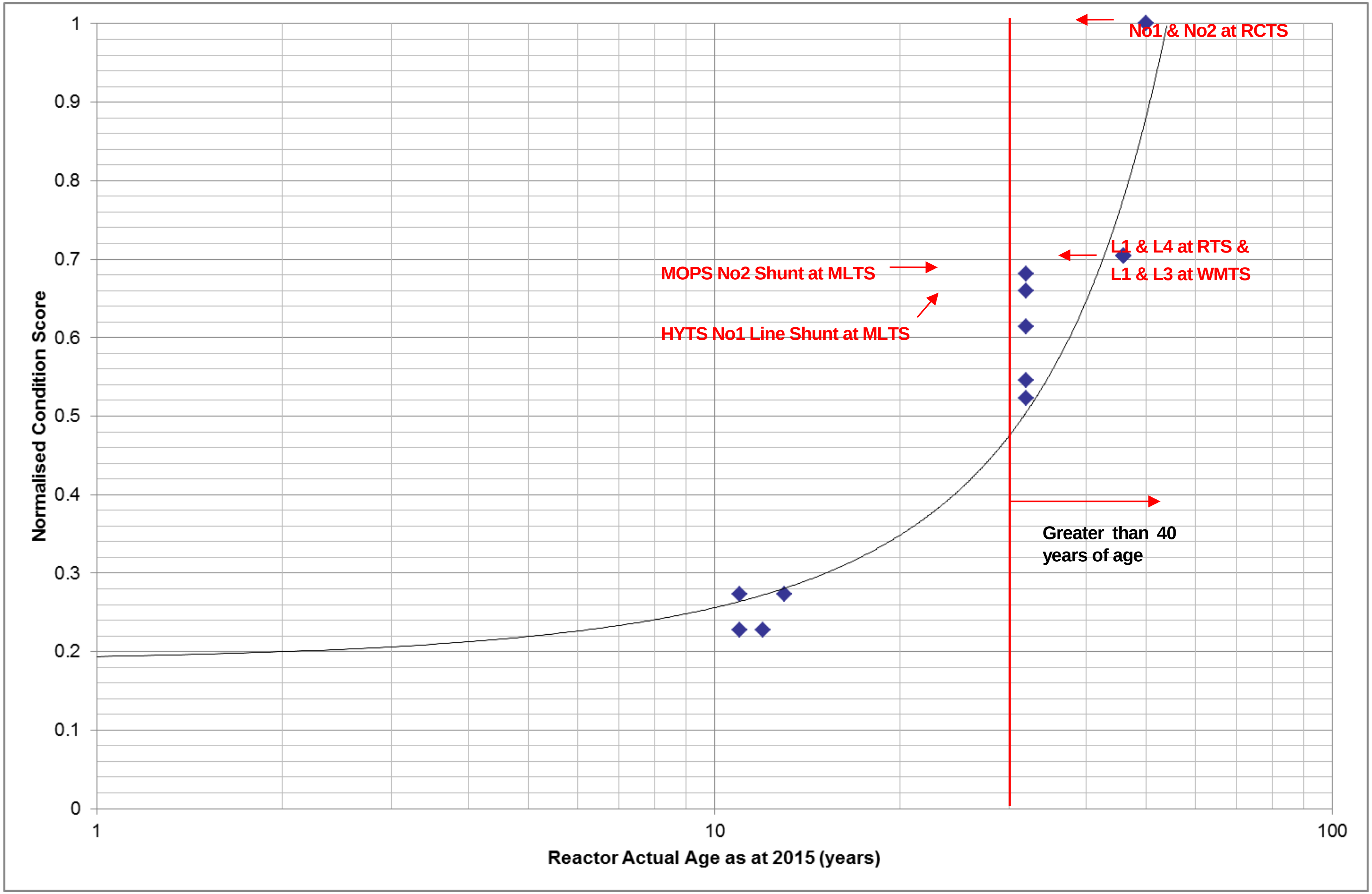

Figure 21 – Oil Insulated Reactors Weighted Average Condition Score by Service Age

3.4 Performance

This section provides an overview of performance issues associated with the transformer and oil filled reactor populations and identifies failure modes, effects and criticality via Failure Modes, Effects and Criticality Analysis (FMECA).

3.4.1 Defects, Failures and Impact of Failures

3.4.1.1 Power Transformer Major Failures

This section summarises the major failures of power transformers in the Victorian electricity transmission network since 1977.

AusNet Services has experienced 12 major failures associated with its transmission power transformer population since 1977 which resulted in an extended outage and removal of transformers from site for repair or replacement as summarised in the following table, Table 10. Since 2012 there has been no major failure of a power transformer requiring an unplanned replacement[2]. During the same period the condition monitoring process has identified a number of incipient conditions developing that were either immediately rectified on site before a failure or are managed in service under a planned process and currently considered a low risk of failure.

[2] Since drafting this document a major power transformer failure occurred at Ballarat terminal station (BATS) on 1 July 2015 (B1 transformer).

Station	Transformer	Rating	Manufacturer	Failure Date	Age at Failure	Nature of Failure	Extent of Damage	Remedial Action
TTS	B3	150 MVA 220/66 kV	[C.I.C]	8/09/1978	11 yrs	Tap changer operated beyond end tap resulting in a tap change from tap 1 to tap 10 – flashover in diverter switch.	Failed tapping windings, 66 kV windings and tertiary on two phases, tertiary on one phase faulted to core – fault current extensively through core – core had to be complexly dismantled.	Transformer repaired at a high cost.
DDTS	H1 W ph	75 MVA (Single phase) 330/220 kV Auto	[C.I.C]	31/12/1986	27 yrs	220 kV bushing failed resulting in a fire.	This is a shell type design – Windings completely burnt out, foundations damaged, connecting busbars & conductors damaged, adjacent Surge arresters and one bushing damaged, cubicles burnt.	Transformer repaired using spare winding. Foundation, etc was rebuilt.
SVTS	B3	150 MVA 220/66 kV	[C.I.C]	6/04/1995	35 yrs	Interstrand fault in "b" phase 66 kV winding resulted in gassing when on load. No other damage.	Conductor insulation burnt at site of failure at a transposition point.	Transformer repaired at a cost of [C.I.C] using a spare winding in order to effect a quick return to site. Then later repaired the failed removed winding.
MTS	L2 W ph	15/18.5MVA 210/22/10 kV	[C.I.C]	April 95	26 yrs	Winding failure following external short circuit – LV and tertiary winding damage (in hindsight we believe some movement occurred during a similar fault some 15 years earlier.	LV and tertiary winding damaged and had to be replaced.	Transformer repaired at a cost of [C.I.C]
BATS	B1	150 MVA 220/67.5 kV	[C.I.C]	12/12/2000	30 yrs	Open circuit developed on one connection in the diverter switch resulted in a fault of the "W" phase selector	Selector Switch barrier boards ruptured and the tapping windings on "W" phase damaged.	Transformer repaired at a cost of approximately [C.I.C] using Spare windings to replace "W" phase

Station	Transformer	Rating	Manufacturer	Failure Date	Age at Failure	Nature of Failure	Extent of Damage	Remedial Action
						switch.		windings in order to effect quick return to site.
DDTS	H2 R ph	75 MVA (Single phase) 330/240 kV Auto	[C.I.C]	17/12/2000	37 yrs	Transformer taken out of service due to collection of gas in Buchholz relay. DGA sample suggest Partial discharge/ sparking fault	Extensive on site testing has confirmed partial discharges but could not locate.	Transformer retired and replaced with a three-phase spare. Held old H2 bank as a spare transformer. Estimated cost was [C.I.C]
MBTS	Tie Transformer W ph	15 MVA (Single phase) 230/70 kV	[C.I.C]	30/03/2004	49 yrs	Internal earth fault on tertiary of White Phase Unit	Winding Damaged.	Replaced with single phase spare.
MBTS	Tie Transformer W ph	15 MVA (Single phase) 230/70 kV	[C.I.C]	14/02/2005	50 yrs	Internal earth fault on tertiary of White Phase Unit. This is the spare unit installed in the previous failure on 30/3/2004. This failure is also similar to previous failure.	Winding Damaged	Transformer bank was already been planned to replace due to lack of fault capability. Therefore, temporarily replaced with the 150 MVA country spare. Later replaced with 2 off 50 MVA Transformers (Tie plus sp).
TTS	B2 W ph “B” unit	15/18.5 MVA (single phase) 210/66/6.6	[C.I.C]	31/03/2007	45 yrs	Transformer tripped on gas protection followed by gas alarm due to a through fault.	Site testing confirmed winding failure with winding faults on LV and Tertiary and winding displacement. Also winding displacement in white phase “C” unit.	Replaced with a new 3 phase transformer. Also new foundations, etc.

Station	Transformer	Rating	Manufacturer	Failure Date	Age at Failure	Nature of Failure	Extent of Damage	Remedial Action
		kV White phase "B" unit						
TTS	B1	150 MVA 220/66 kV	[C.I.C]	4/03/2009	23 yrs	Transformer tripped on gas protection followed by gas alarm approximately 1.5 hours after a close- in through fault.	DGA confirmed internal arcing fault and site tests indicated "A" phase LV and TV winding displacement and winding faults. Transformer removed from location. Fault found in "A" phase 66 kV winding. It was established that TV winding has inadequate short circuit strength for TV faults and Phase to Earth through faults. Neutral reactor helps.	Replaced with a new transformer.
MWTS	B1	165 MVA 230/66 kV	[C.I.C]	31/01/2010	44 yrs	Transformer tripped on gas protection due to a close-in through fault. DGA was conducted and DGA was OK. Tripped from diff protection with gas alarm when re-energised.	Tapping winding displacement.	Replaced with the country spare and retired the failed transformer.
KTS	A2 W ph	250 MVA (Single phase) 500/220/22 kV Auto	[C.I.C]	4/05/2011	40 yrs	Transformer tripped on gas protection and gas alarm came up. DGA confirmed an internal fault. High resistance found in the "A" leg common winding	Fault in "A" leg common winding – turn to turn and disc to disc within top 10 discs confined between two spacer blocks.	Replaced with a spare transformer (single phase) and failed transformer was repaired at Alstom Rocklea (Queensland) replacing all windings with spare windings. The cost was [C.I.C]

Table 10 – Victorian electricity transmission network Power Transformer Major Failures since 1977

Figure 22 displays the occurrence of major failures over time and the service age of each transformer when the major failure occurred. It is important to note that after 2004 the frequency of major failures in units beyond a service age of 40 years has accelerated due to declining condition caused by high ambient temperatures and high utilisation.

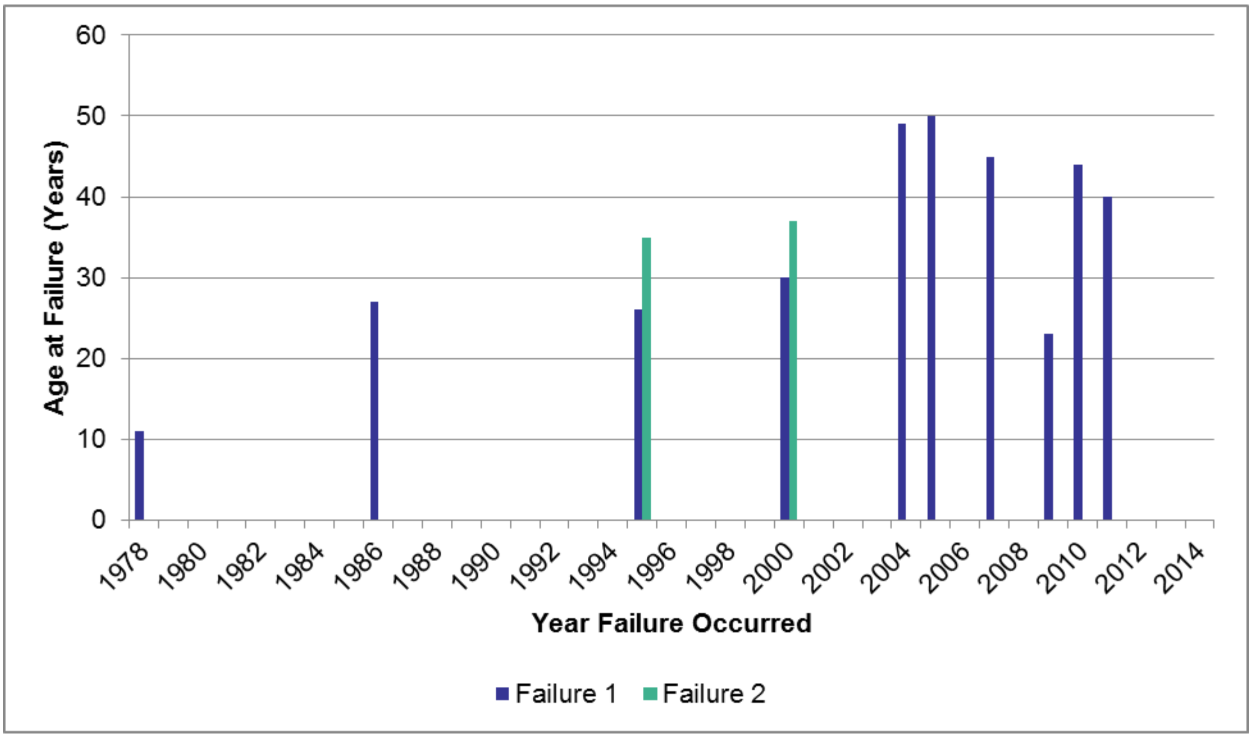

Figure 22 – Year and Service age at time of Major Transformer Failures

Figure 22 shows that over time major failure rates within the transformer fleet has increased dramatically. The major in-service failures at Thomastown (TTS), Keilor (KTS) and Morwell (MWTS) terminal stations between 2007 and 2011 has contributed significantly to the rising level of major failure rates. Since 2012 major transformer failures stabilised due to targeted conditional based replacements, maintenance programs and comparatively low transformer loading.

Figure 23 shows that since 1978 there has been a significant reduction in the mean time between major transformer failures from 8 years to expecting a major failure at least once every 3 years on average in 2011. This is a 63% reduction in the number of years that a major transformer failure is expected to occur and the trend is steadily decreasing till 2011. In actual fact, since 2004 AusNet Services was experiencing a major transformer failure at least once every 1.4 years.

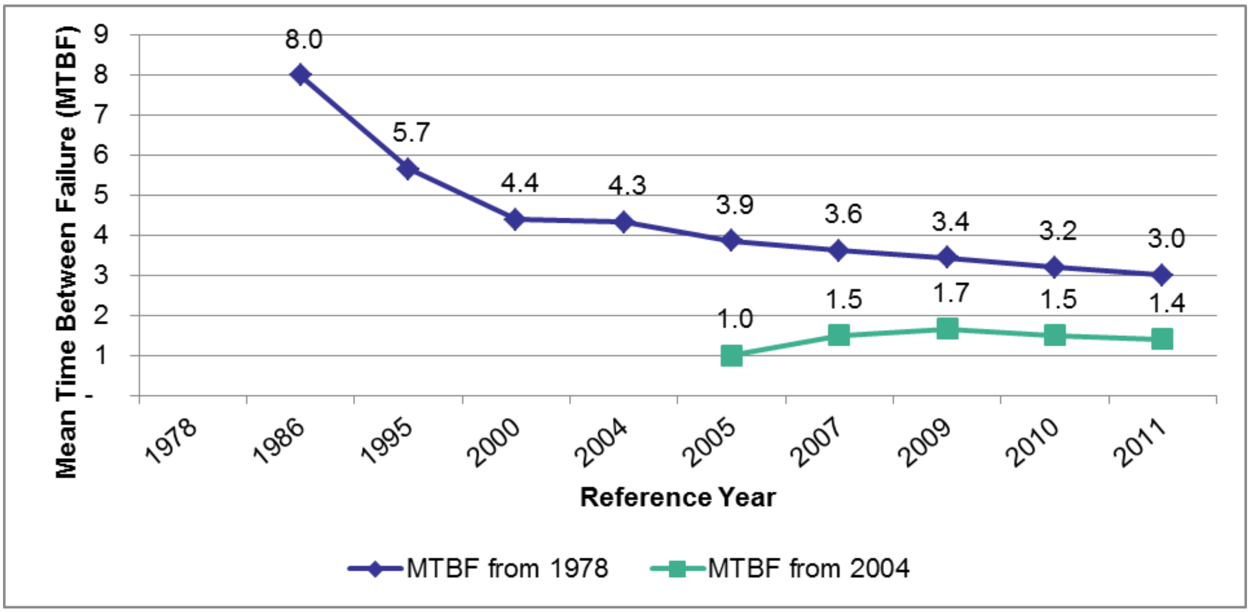

Figure 23 – Mean Time Between Major Transformer Failure (MTBF)

The level of investment in transformer maintenance, refurbishment and replacement programs during recent years has barely managed to stabilise the rate of failure. There has been no transformer major failure since 2011 and the MTBF has begun to improve. However the current MTBF is still significantly lower than the historical values and continuing investment is required on the deteriorating transformer fleet to restore the situation.

Major transformer failures can result in:

- Outages of the transformer;
- Repair costs;
- Penalties arising from the performance incentive schemes;
- Unserved Energy;
- Safety impacts;
- Environmental impacts.

Major failures cause extended equipment outages. The outage time will vary according to the type of transformer, voltage class, the availability of a spare, and to a lesser extent the type of fault which has occurred. In general, for distribution network connection transformers (with typical ratios of 220/66kV and below) the outage time (Weighted MTTR) is approximately 6 months where the major failure requires off-site repairs. Metropolitan or country spare transformers have been utilised when available however transformer spares are limited and are not always interchangeable with the failed unit. It is important to note that if a spare is not available it has taken up to 9 months to replace with a new transformer.

Weighted MTTR = (3 months to replace with a spare + 9 months for new or repaired transformer) / 2 = 6 Months.

In general for a major failure of main system transmission transformers (typical ratios A: 500/220kV, F: 500/330kV, H: 330/220kV, and M: 500/275kV) it will take approximately 3 months to replace if a spare is available and will take between 18 to 24 months to replace with a new transformer if no spare is available. This repair time can be significantly reduced where spares are available as exemplified when Keilor (KTS) A2 Transformer (3 x Single Phase Units) White Phase failed in May 2011 when the time to repair was reduced to 1 month. In this instance AusNet Services had a perfectly matching spare unit stored at KTS and therefore the replacement time was optimised. In contrast component replacement of transformer windings can take 12 months to repair at a cost of approximately [C.I.C] even with a spare winding available.

Repair costs of transformers can vary considerably depending on the extent of damage to the transformer, associated equipment and infrastructure. Further MTTR constraints can be attributed to the availability of spares and the manufacturer's workshop availability.

Transformer failures can result in significant revenue penalties due to performance incentive schemes.

Further, if the failure occurs in a high demand period there could be significant unserved energy if the demand exceeds the station's firm capacity. According to the Transmission Connection Planning Report (TCPR) 2014 the value of unsupplied energy (the "value of customer reliability" or "VCR") can be calculated at $33,036 per MWh to $43,484 per MWh depending on the energy being supplied from a specific terminal station.

Safety and environmental impacts from major failure are discussed further in Section 5.1.1 of this document.

3.4.1.2 Power Transformer Failures, Long Outages and Considerable Onsite Repairs

The following Table 11 outlines the failures AusNet Services experienced over approximately 15 years in its transmission power transformer fleet that resulted in long plant outages and considerable onsite repair works.

Station	Transformer	Size	Manufacturer	Failure Date	Age at Failure	Description of Failure	Repair performed
WOTS		75 MVA 330/66/22 kV	[C.I.C]	1990s		Transformer tripped due to pressure relief diaphragm getting distorted. An operation of the Tap changer at same time as a through fault has increased the pressure in OLTC diverter switch.	Replaced the distorted diaphragm.
ERTS	B1	150 MVA 220/66/11 kV	[C.I.C]	July 2001	31 Years	DGA indicated sparking discharge and noticed noise from inside of the transformer. Therefore transformer taken OOS to do remedial actions. Later found it was due to a loose corona shield on 220kV bushing.	Initially transformer taken OOS due to sound level of discharge and removed all oil and inspected. Failed to find anything. Then refilled and noise was still present. Then discharge detected and acoustic location was found with DDF test volts. Then the loose corona shield of the 220kV bushing was replaced.
ERTS	B1 & B3	150 MVA 220/66/11 kV	[C.I.C]	2003	33 Years	DGA indicated increasing gas levels higher in Selector switch. Higher resistance on some taps and as a result selector contacts had burnt.	Burnt Selector contacts were replaced. Oil removed in B1.
HYTS	M2	370 MVA 500/275/22 kV	[C.I.C]	22/03/2005	16 years	Tertiary earth fault alarm as a result of tertiary VT failure. Investigation found White Phase 22 kV VT burnt & arcing.	The transformer was returned to service pending sourcing of a replacement VT which was subsequently fitted on 29/3/05.
HYTS	M2	370 MVA 500/275/22 kV	[C.I.C]	20/05/2005	16 years	Red Phase 500 kV bushing voltage tapping discharging.	Initially cable removed and voltage tapping earthed to return the transformer in to service soon. Later further outages to be arranged to test and repair the capacitor tap and replace the cable to the VT matching unit. New cable purchased to be fitted to another phase to avoid replacing bushing.
HWTS	A1	600 MVA 515/230/22 kV	[C.I.C]	Oct 2006	26 Years	Temperature rise in Blue phase bushing head. It was 120 ^{0}C compared with others at 30 ^{0}C. Contact inside head had made poor contact (ERMA fitting).	Replaced top cap.

Station	Transformer	Size	Manufacturer	Failure Date	Age at Failure	Description of Failure	Repair performed
ROTS	A2	1000 MVA 500/220/22 kV	[C.I.C]	22/6/2007	4 months	Discharges noted on tertiary cables (Note there was no tertiary earth fault alarm – later found that it was due to incorrect settings). It was found that this is due to water in VT switch cubicle.	Repaired the tertiary cables.
KTS	A4	750 MVA 500/22/22 kV	[C.I.C]	2/01/2008	38 years	Flashover on 500 kV bushing of A4 Transformer when fire spray system of A3 operated inadvertently due to a worn deluge valve and water pressure increase of the system.	Replaced worn deluge valve.
HYTS	M1 & M2	370 MVA 500/275/22 kV	[C.I.C]	06/04/2008	19 years	Tertiary earth fault alarms on M1 Transformer. Moisture in cubicle and on VT's. Upon investigation M2 transformer Red phase also showed similar sings.	Replaced VT and repaired the cubicle.
HWTS	A1	600 MVA 515/230/22 kV	[C.I.C]	29/01/2009	29 years	Tertiary earth fault alarm as a result of failure of 22kV/415 V single phase unit transformers.	Unit transformer was replaced.
ATS	B4	150 MVA 220/66/11 kV	[C.I.C]	09/02/2009	1 Year	Fault on tertiary bushings (POLYCAST 24 kV bushings). Two bushings failed to flange resulting in a three phase fault – third phase earthed (no external connections). Found debris in transformer.	Debris in transformer had to be removed and core & windings inspected and transformer tested. Replaced both bushings with spares of same type and transformer restored to service. The duration of the outage was 17.3 days.
MTS	B3	225 MVA 220/66/11 kV	[C.I.C]	31/07/2009	2 years	OLTC pressure switch operated and tripped transformer.	Switch replaced
HWTS	A3	600 MVA 515/230 kV	[C.I.C]	14/01/2010	40 Years	White phase 220 kV bushing oil leak at porcelain to flange external seal. Needed constant topping up.	Bushing replaced with a spare bushing. The duration of the outage was 4 days.

Station	Transformer	Size	Manufacturer	Failure Date	Age at Failure	Description of Failure	Repair performed
HWTS	A4	1000 MVA 500/220/22 kV	[C.I.C]	19/1/2012	42 years	Earth fault alarm. Moisture in PIB in particular at the bushings from PIB to 22 kV VT and fuse cubicle.	Cleaned out and dried out. The duration of the outage was 4 days.
RTS	L4	165 MVA 215/22-22/11	[C.I.C]	6/7/2013	44 years	Condition monitoring tests revealed a high winding resistance on one phase of the 22 kV L2 windings.	Drained oil and repaired poor contact on 22 kV terminations. Outage over weekend.
TSTS	B2	150 MVA 220/66/11 kV	[C.I.C]	12/9/2014	48 years	The routine oil sample indicated a step change in arcing fault gasses and transformer switched out for investigation and repairs. A core frame flux shield had moved and started to arc to the lower end of the bushing termination insulation.	The total outage was in the order of four weeks and cost [C.I.C].

Table 11 – Power Transformer Failures Resulting in Long Outages and Considerable Onsite Repairs

3.4.2 Work Order Analysis

3.4.2.1 Power Transformers

AusNet Services maintains records for unplanned work undertaken on power transformers in the Maximo asset management system (and in SAP from May 2015). Figure 24 depicts the overall number of unplanned work orders issued per annum for the period between January 2000 and December 2014. As shown by Figure 24 unplanned work orders for power transformer maintenance have progressively increased from a low point of 112 per annum in 2003 to an average of 191 per annum. From 2012 to 2014, unplanned work on power transformers has increased by 29%. On average there have been 0.97 unplanned work orders per transformer per annum.

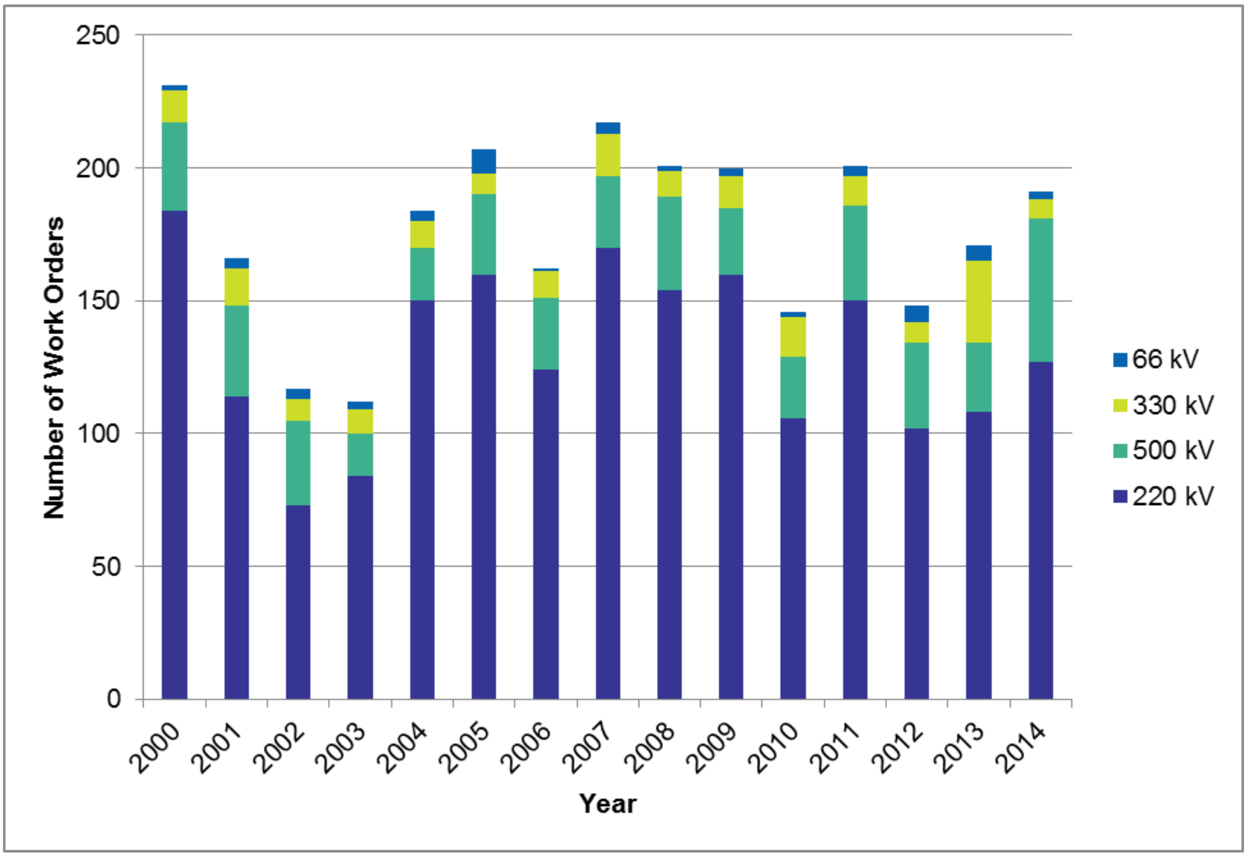

Figure 24 – Unplanned transformer work orders 2000 to 2014

Figure 25 indicates the average number of work orders per annum have decreased by approximately 26%, from 2005-09 to 2010-14 due to condition based replacement of power transformers.

The majority of these work orders are being issued for 220 kV transformers which represent the majority of the fleet. On average there had been at least one unplanned work on each 220 kV transformer annually. Average annual unplanned work orders on 500 kV transformers and 330 kV transformers are 0.97 and 0.8 respectively. The average annual unplanned work on 66 kV transformers is the lowest being 0.42 per transformer.

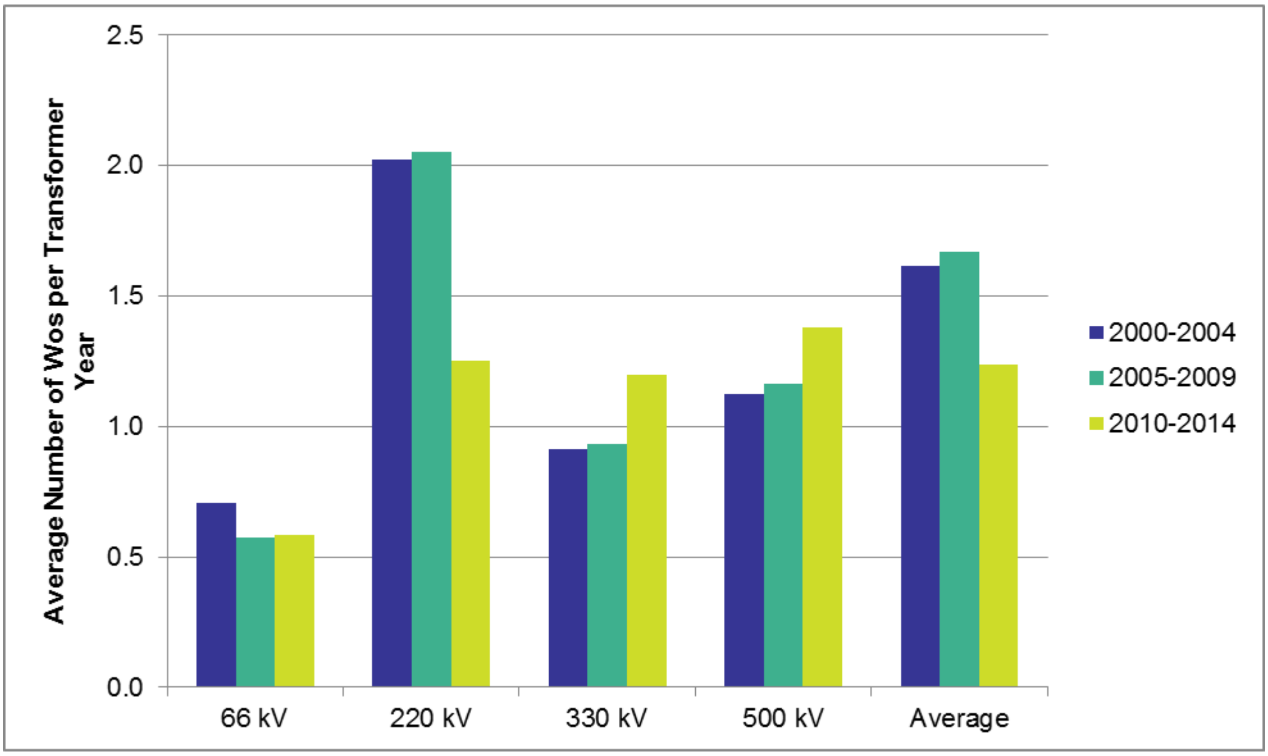

Figure 25 – Average number of unplanned work orders per transformer year

As represented in Figure 25, during the period 2005-2009 the average number of work orders issued for 220 kV transformers is greater than other transformer voltage classes. However, in recent years work orders on 220 kV transformers have decreased and more work orders have been issued for 330 kV and 500 kV transformers. The decrease of unplanned work orders for 220 kV transformers in recent years is partly due to 24% of the 220 kV transformer fleet being installed after 2009 and is in "very good" condition.

Average number of unplanned work orders of 330 kV transformers during 2010-2014 has increased by approximately 29% compared to 2005-2009. The significant increase of unplanned work orders is contributed by approximately 69% of 330kV transformers that are in either "poor" or "very poor" condition and have provided more than 45 years of service.

Maximo stored a problem code for each work order to help identify the failure mode. The problem code is used to categorise the suspended failures and the average number of work orders issued per year by transformer component for the period is depicted in Figure 26 below. Since May 2015, Maximo was replaced by the Enterprise Asset Management system, SAP.

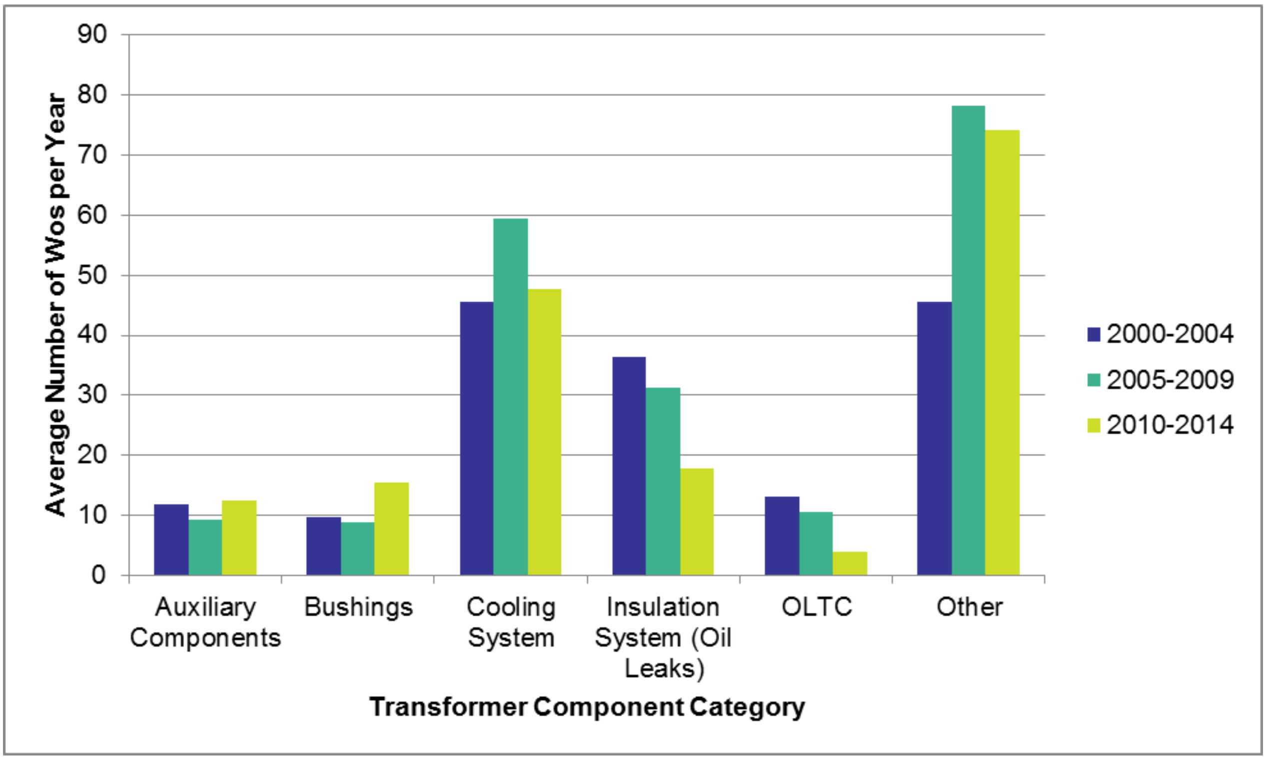

Figure 26 – Average number of work orders per year by component

Figure 26 provides evidence that Cooling System issues and Oil leaks are the most common cause of unplanned work orders or suspended failures. Such an increase in the period 2005 to 2009 is to be expected as the impact of the prolonged drought and its high ambient air temperatures at times of peak network load have stressed transformers in the Victorian electricity transmission network. Suspended failures relating to bushings and auxiliary components are also shown to have increased significantly in recent years.

3.4.2.2 Oil Insulated and Cooled Reactors

Similar to transformers, records for unplanned work undertaken on the oil filled reactors were maintained using Maximo that was recently replaced with the SAP based Enterprise Asset Management Information System. Figure 27 depicts the overall number of unplanned work orders issued per annum for oil filled reactors in the period between January 2000 and December 2014.

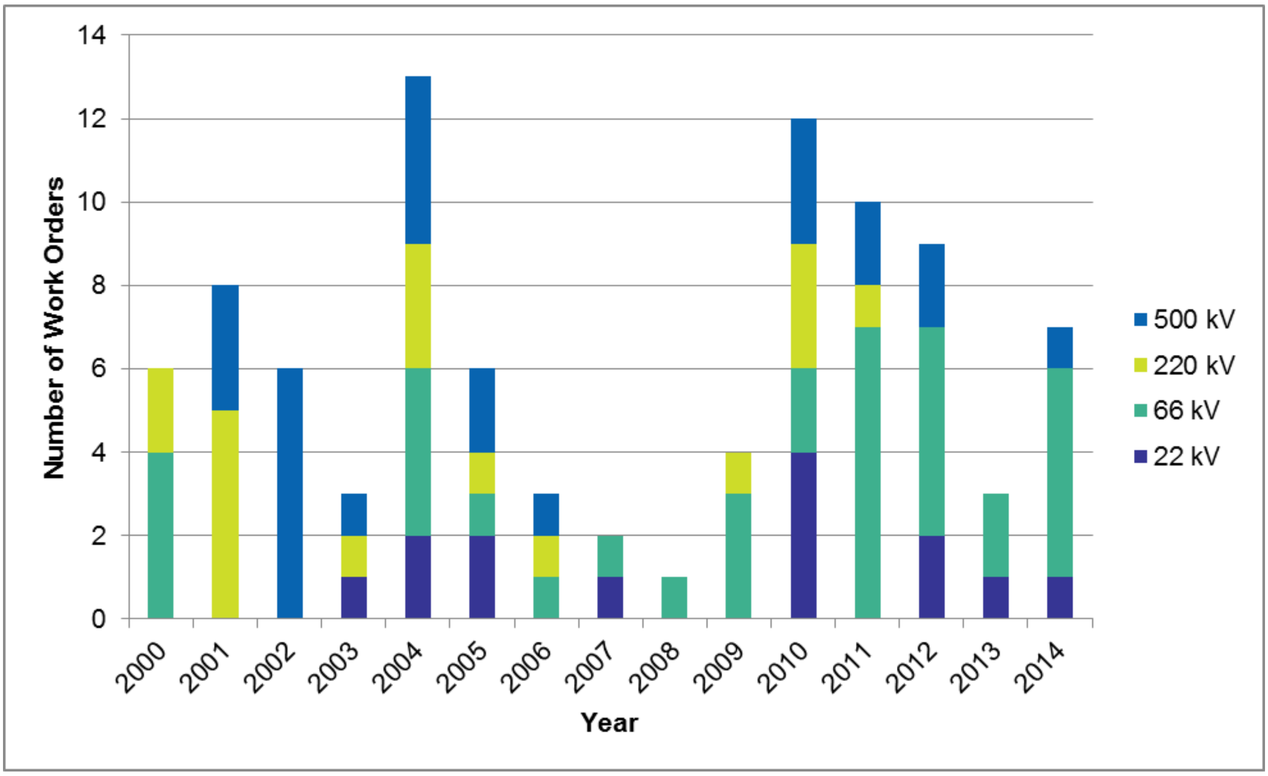

Figure 27 – Work order history by oil filled reactor voltage

Figure 28 identifies the average number of work orders per reactor per year over different time periods. According to Figure 28 it is evident that after 2007 the number of unplanned work orders has increased rapidly from 2.3 per year in 2007-2009 periods to 10.3 per year in 2010-2012 and then declined during recent years.

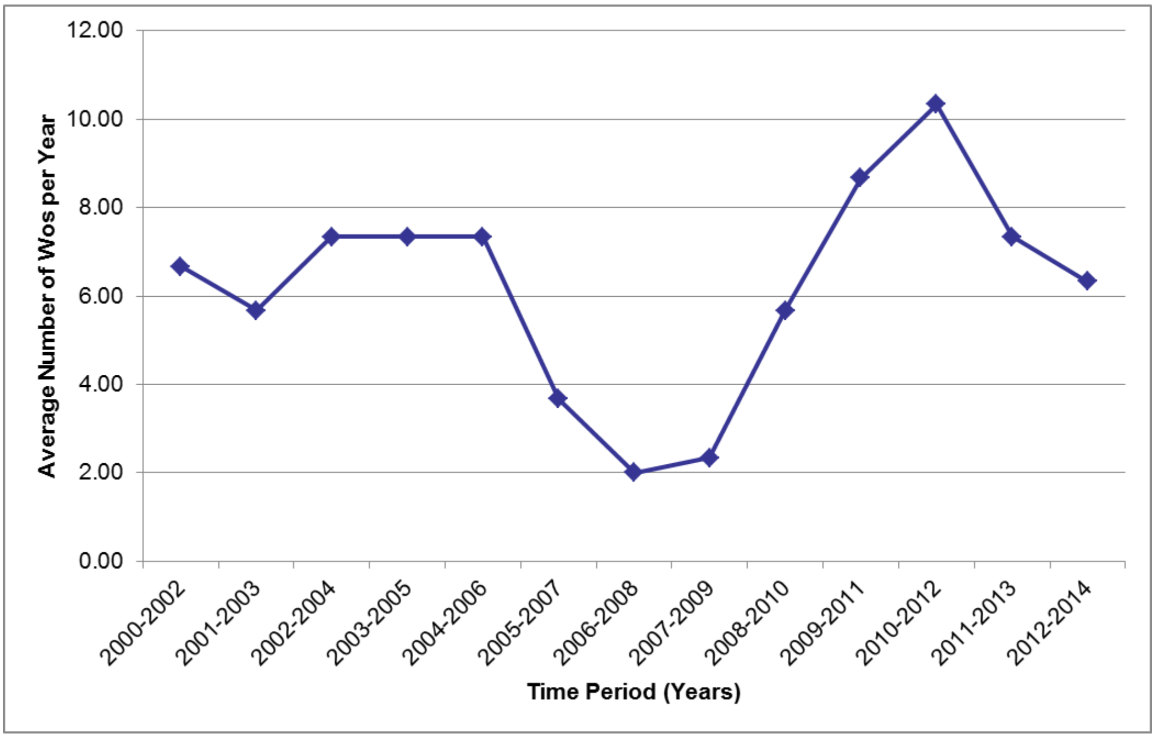

Figure 28 – Average number of work orders per year during different time periods

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Figure 29 below depicts the average number of work orders per year during different time periods for different oil filled reactor voltages.

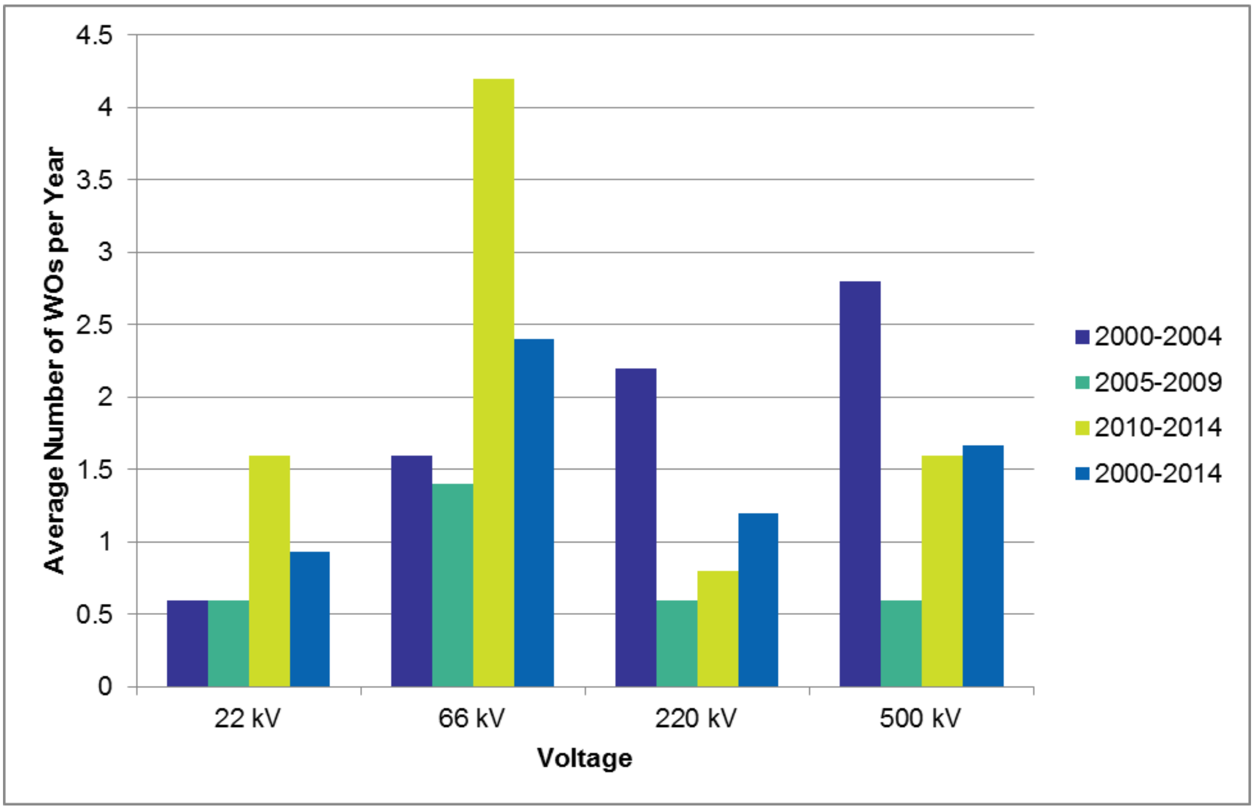

Figure 29 – Average number of work orders per year during different time periods per voltage

As per Figure 29 it is evident that the average number of work orders issued per year during 2010 to 2014 has increased in comparison to the average number of work orders issued during 2005 to 2009 for all voltages. In particular the average number of work orders issued for 66 kV oil filled reactors has increased dramatically during the recent years. This is a result of No1 66 kV and No2 66 kV reactors at RCTS being in a poor condition and therefore a number of unplanned work orders have been issued for these reactors in recent years. The average number of work orders issued for 22 kV and 66 kV oil filled reactors during recent years are much more than the 15 year average for respective voltage classes.

4 Strategic Factors

4.1 Safety

A range of safety hazards exist that is common to both power transformers and oil filled reactors.

4.1.1 Explosive failure

Typically the main source of explosive failure risk relates to bushing failures; however there is also a small chance that the pressure wave from an internal fault could rupture the main tank and cause an external explosion as super-heated oil and air mix in the presence of an electrical arc. The risk of an explosive failure is managed through a range of condition monitoring and inspection routines, which includes replacement programs for bushings with observed defects and exposure minimisation measures.

Bushing replacement is being completed under the following programs:

1. X834 – 220kV Transformer Bushing Replacement Program: 27 bushings 2008-2015 expected.
2. XC72 – 220kV Transformer Bushing Replacement Program Stage 3: 30 bushings 2015-2018 expected.

4.1.2 Fire

Once a fire has taken hold of a transformer it is usually difficult to extinguish until the fuel (oil and paper) have been consumed. Typically firefighting efforts are undertaken to minimise risk of collateral damage rather than save the burning transformer. The installation of fire deluge systems for main system transformers and fire walls and self-drained oil bunds with flame traps act to reduce the assets requiring protection and reduce the duration of fire by removing as much fuel as possible. Further information on transformer fire prevention can be found in AMS 10-140 Fire Protection for Power Transformers and Oil Filled Reactors.

4.1.3 Working at heights

The most significant safety hazard exposure facing transformer maintenance and testing personnel is working at heights. Various fall restraint methods are utilised to minimise this hazard including hand rails, maypole and other harness attachment methods. Work methods that include elevated work platforms act to minimise activities on top of the transformer. Seeking compliance with the latest statutory obligations; XC69 - Transformer Safe Maintenance Access is currently in progress. This primary works program includes retrofitting 62 transformers with safe access facilities. The expected completion of this program is the 30th of March 2018.

4.1.4 Polychlorinated Biphenyls (PCB)

AusNet Services has no scheduled PCB in its power transformers or oil filled reactors, however non-scheduled PCB and PCB contamination of insulating oils occur in a number of transformers in the fleet. Transformer oils are handled in accordance with Health and Safety Procedure - Chemical Management HSP 05-10.

4.2 Environment

The power transformer and oil filled reactor fleet present environmental risks related to sound level, energy losses, oil management and PCB contamination of insulating oils.

4.2.1 Sound Level

Power transformers emit a low frequency hum related to magnetisation of the iron core that increases in energy as transformer loading increases. The cooling fans may also emit a higher frequency noise.

Transformer installations are designed to be able to accommodate sound walls or full sound enclosures to control the sound level emissions of new transformers. New transformers are purchased to the sound levels as determined in AS60076 Part 10. Addition of transformers or layout changes to a site may require sound controls to be added to ensure emissions do not exceed regulatory limits or inconvenience neighbours.

4.2.2 Losses

The electrical losses in transformers indirectly contribute to CO_2 emissions by network generators. Modern core steels reduce electrical losses. When purchasing the transformers, AusNet Services takes into account the losses of the transformer over its life time by adding the cost due to the losses to the total capitalised cost of the transformer as specified in the Power Transformer Technical Specifications Part A document. This encourages the manufactures to optimise their design to reduce the losses.

4.2.3 Oil Management

Sealed floor bunds are installed to ensure capture and separation of oil and water in dedicated separation facilities to ensure discharge of water from terminal stations does not contain oil concentrations exceeding Environmental Protection Authority requirements. Further information on AusNet Services' guidelines for oil management can be found in EMS 21-56-1 Oil Spill Control Guidelines.

4.2.4 Polychlorinated Biphenyls (PCB)

Detailed PCB management plans are in place to address the environmental management of PCB contaminated oil. Further information on PCB management is provided in EMS 21-51-1 Aspects Guidelines.

4.3 Electrical Utilisation

In the early 2000s; AEMO's and DNSP's probabilistic planning techniques began to impact on the average utilisation of power transformers in the Victorian electricity transmission network.

Coincidently the prolonged 2003 to 2009 drought caused a significant uptake in domestic air conditioning and strong growth in peak demand at times of high ambient air temperatures. This combination has contributed to the accelerated deterioration of transformer insulation, resulting in the need for more sophisticated condition monitoring, increased maintenance and earlier refurbishment and replacement.

Peak demands in summer when air conditioning is being used extensively and the capability of the network is at its lowest due to higher ambient temperatures introduce high transformer duty. These peak demands can be up to 200% of the average demand and are only present for 20 to 50 hours of the year. High ambient temperatures accompanied by peak demand periods increase the duty cycles on the transformer with transformers often operating to cyclic ratings well above the name plate rating. Inherently this introduces high probabilities of core and coil failure amongst those assets where the condition of the core and coil has already begun to deteriorate such as in units which have already provided some 30 plus years' service.

Figure 30 below graphically depicts the significant increase in peak demand on connection point transformers over the fifteen years since 1994/95. However since 2010/11 overall peak demand on connection point transformers has decreased by 10% though some connection point transformers such as Red Cliffs 22 kV and Terang experienced over 20% increase in peak demand. During the last five years the energy sales have slowed dramatically and growth in demand has slowed. This has significantly reduced the rate at which transformers are deteriorating.

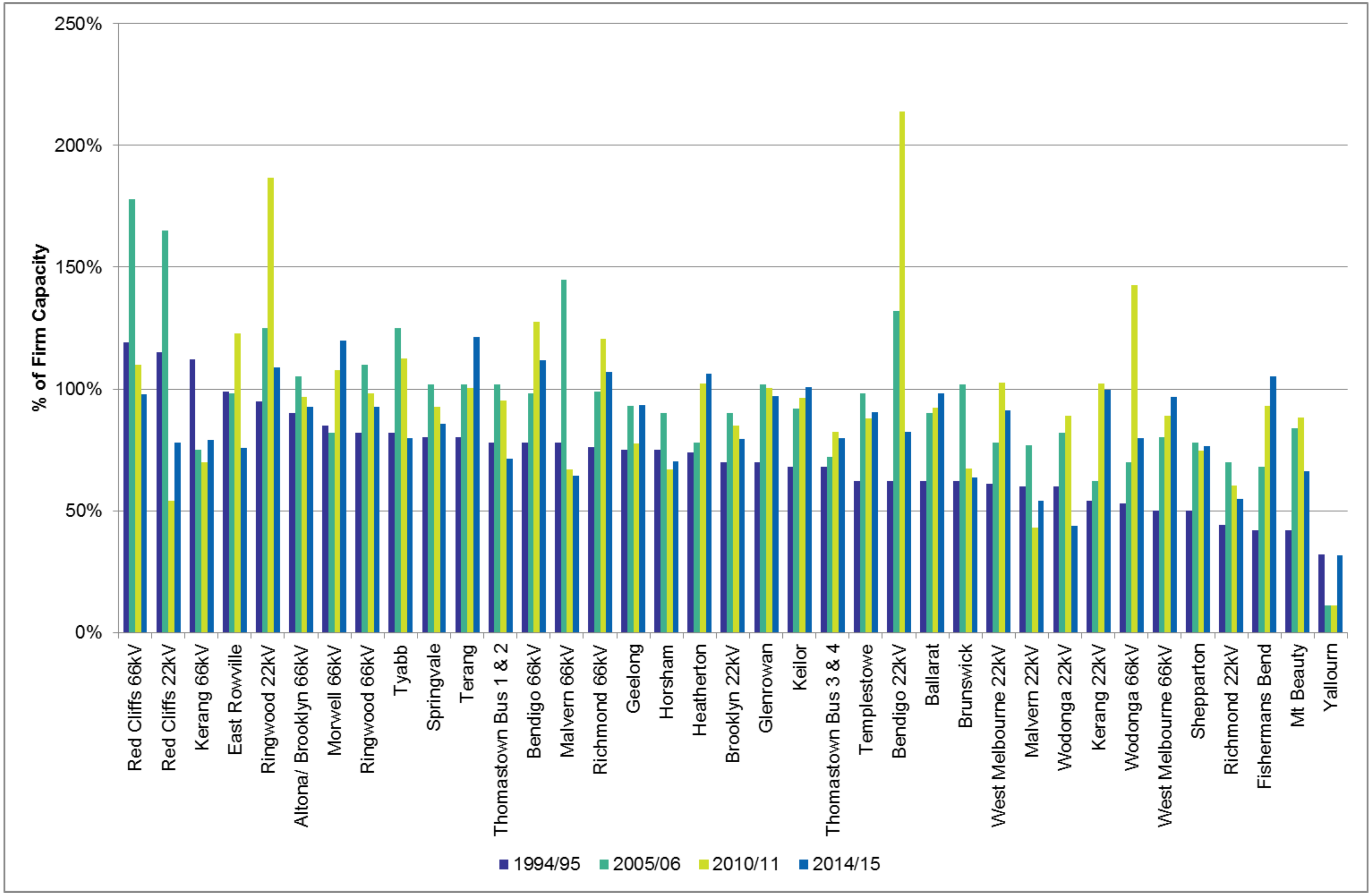

Figure 30 – Connection point loading at terminal stations during different time periods

4.4 Overload Ratings

With increased utilisation, the use of cyclic ratings and the perceived benefit of dynamic rating is becoming more significant. Network planners and operators are seeking higher short-time overload ratings, up to the maximum of 1.5 times the cyclic rating. Whereas transformers manufactured (since 1976) have undergone proof tests to ensure their short-time rating capability, older transformers only have a limited 'type proven capability'. The application of cyclic ratings and dynamic ratings to power transformers designed in the middle of the last century involves additional uncertainty as their behaviour under high loads is not proven by type test and is difficult to monitor due to the absence of appropriate sensing devices at critical points within the windings.

4.5 Operational Monitoring

Due to the higher utilisation of transformers (coupled with probabilistic planning), there have been occasions for a number of terminal stations when the loss of a transformer will result in unacceptable loading of the remaining transformers. To protect the remaining transformers from damage, the station load is reduced by automatically tripping feeders using the Overload Shedding Scheme for Connection Assets (OSSCA) as defined in TOC 101-04 OSSCA Operation. Under these conditions and subsequent to such events, it is important the network operating controllers have the most accurate information about the transformer temperatures, tap position and state of cooling systems.

This will require replacement of less accurate winding hot spot temperature measurement equipment and provision of tap position and further cooling system information. Additional temperature measurements and thermal behaviour modelling are required. Additional facilities are required for remote control of transformer cooling, to ensure during the high-risk summer season all cooling is switched on.

4.6 Maintenance

To maintain a high level of reliability and to ensure that every transformer is capable of operating satisfactorily at its assigned ratings, a certain level of maintenance is necessary. This tends to increase with deteriorating condition and increasing service age, particularly with respect to oil leaks, bushing insulation, tap-changer wear and ongoing physical corrosion. Typical maintenance activities include Tap Changer overhauls, oil level checks and top ups, oil preservation system maintenance, cooler and bushing cleaning and leak repairs. Of these activities; the on-load tap changer (OLTC) maintenance requires the most expertise, manufacturer information and spare parts support.

The OLTC is the largest and most complicated accessory on a transformer. OLTCs have a large number of moving parts. Historically switching arcs occurring under insulating oil have resulted in the greatest number of defects and components requiring maintenance. The defects range from minor problems to major failures which can result in extensive damage to the transformer. The number and frequency of operations that an OLTC is subjected to is the main cause of deterioration. The basic relationship is that accelerated deterioration occurs as a result of a high number of operations occurring in a short period of time. Older tap-changers tend to require additional maintenance by comparison with later models. This is further complicated by the variety of OLTC manufacturers and models placed in service over the last half century.

Maintenance work that is needed to restore the internal condition of a transformer (e.g. oil reclamation, dry-out and re-clamping of windings) requires long outages and costs up to 18% of the replacement cost. Extensive maintenance or refurbishment of on transformer core and coils is uneconomical in many cases. Any internal work on a transformer that requires removal of oil also requires the service provider to access a vacuum capability to re-fill the transformer and remove air voids. Oil leaks also need to be repaired in order to carry out this work.

There is a difficulty in obtaining experienced maintenance staff, both within AusNet Services and in the industry that are capable of maintaining or refurbishing ageing plant items. Inexperienced staff increase maintenance costs because of lower productivity and the training required. Inexperienced practitioners also have the potential to reduce the quality of maintenance or refurbishment work. There is lack of specialist advice and support from manufacturers for maintenance of very older plant items as explained in Section 4.7of this document.

4.7 Technical Support

Original equipment manufacturers for many of the older transformers and accessories are no longer in business. While some information has been transferred to present manufacturers, older designs are rarely compatible with modern designs and manufacturing methods. A single winding fault may require replacement of all windings of that phase or even all phases within the affected power transformer. As a result, in most cases the economic arguments for replacement of the transformer outweigh core and coil repair and refurbishment options. In cases where AusNet Services does carry spare windings for single-phase transformers, the decision regarding repair or replacement becomes an assessment of the most economical solution based on factors such as mean time required to repair; including time taken to obtain a replacement or the availability of a spare transformer. The level of demand for new transformers can determine the capability of local manufacturers to undertake bespoke repair and refurbishment work for older equipment in a timely and economic manner.

Direct replacements for major components such as bushings and tap changers are often not available for older transformer designs, necessitating detailed and expert re-design when attempting to fit components of later specification.

The design and manufacture of shunt reactors is even more specialised as each application is unique to its position in the network. This unique nature leads to even lower manufacturer support and the smaller fleet makes spares holdings uneconomic.

4.8 Spare Transformers

The fleet of 500/220 kV transformers is covered by two spare single-phase transformers located at Keilor Terminal Station and Moorabool Terminal Station. Most of the 220/66 kV connection transformers are covered by the two metropolitan configuration spare transformers and the country configuration spare transformer. These have proved economic in covering significant transformer failures at Mt Beauty, Morwell, Thomastown and Keilor terminal stations since 2004.

Spare transformers are not currently held for the smaller transformation ratio fleets including the 330/220 kV transformers at South Morang Terminal Station (SMTS) and the 500/275 kV transformers at Heywood Terminal Station (HYTS). But under the proposed staging of the replacement program for SMTS 330/220 kV transformers potentially over the next 10 years, and during the transition from stage1 [Project XC19] to stage 2; the replaced in-service units will be temporarily used as a spare bank, until stage 2 is completed which its proposed to purchase a single phase spare unit for the SMTS 330/220 kV transformation.

Compatibility and deliverability issues may under some circumstances limit the economic application of spare transformers in particular network locations. Fault levels, tapping ranges and voltage levels must be matched when considering the installation of a spare transformer. In particular, changes to the nearby access roads are encroaching on to the delivery of transformers to inner urban sites threatening the timely delivery of spare transformers.

The importance of spares has increased as a result of AEMO and DNSPs changing to a probabilistic planning standard. Besides purchasing new spare transformers, transformers displaced from service may also be a source of spares, provided they have sufficient remaining life. As loads continue to grow, transformers will be replaced with larger units, and these older units will be available for reuse if in reasonable condition.

With total reliance on off-shore sourcing for EHV and large MVA transformers it has increased AusNet Services' exposure to higher delivery risk and potential longer delays in purchasing new or replacement units. Also, the ability to perform factory required repairs is almost nonexistence in Australia and only can be performed to a limited capacity locally, thus the contingency spares should match the risk and potential costs of long delays in purchasing replacement units.

4.8.1 Contingency Spare Transformers

It is uneconomic to hold a large number of spare transformers as they are high cost items and there are compatibility and inter-changeability issues across the fleet. However, insurance spares for grid transmission equipment are required to meet reliable operation of the grid and is in the best interests of all the connected parties. Insurance spares are held to ensure that achievement of the transmission system availability performance target is not compromised by not having a replacement for failed in-service equipment.

4.9 Technology

This section provides an overview of technology issues and opportunities associated with the transformer and oil filled reactor population.

4.9.1 Condition Monitoring

The installation of condition monitoring equipment can provide an early warning of defects and developing faults, particularly for those transformers with high strategic importance in the transmission network.

As a single item of plant, the installed value of a transformer is economically significant compared with most other terminal station plant. Consequently, the high inventory cost is an important factor in making the installation of monitoring equipment an attractive proposition to allow higher utilisation rates, maintain and extend expected service potential over the life of the asset.

Manufacturers have been rapidly developing condition monitoring devices for continuous monitoring of transformer temperatures, load, dissolved gases and other indicators of transformer condition. More advanced modelling of transformer thermal performance and new oil testing techniques has advanced the awareness of transformer deterioration mechanisms.

The lower cost of off-line testing equipment should have facilitated more sophisticated and higher frequency off-line testing regimes across the fleet. However increasing asset availability requirements and the limited availability of suitable testing staff and transformer experts to analyse results inhibits this analysis. With the maturity and high reliability of the on-line monitoring systems especially for critical components that previously required offline access to confirm condition and the difficulty of getting maintenance access due to the high system duty requirements to perform the critical off-line condition based measurements it is proposed to install on the main system inter-connecting transformers an early warning HV bushing monitoring system to provide real time performance of the HV bushings thus less reliant on the Off-line measurements. The systems will be installed by 2019 on the critical inter connecting transformers at HYTS,

4.9.2 Continuous oil treatment

Various molecular sieve and vacuum devices are available to actively remove moisture and dissolved gases from the oil, reducing the availability of oxygen and slowing the degradation of the cellulose insulation. The moisture and gas removed are both a cause and a signature of degradation and any external process that impacts the concentration of these materials impacts the ability to assess the condition of the transformer windings. For this reason continuous oil treatment is only appropriate for nursing a transformer with a known issue until it can be replaced.

5 Key Issues

5.1 Deterioration Drivers

This section describes the more generic technical issues of transmission power transformers in the Victorian electricity transmission network.

5.1.1 Moisture Content

Moisture is removed from transformer insulation during manufacture, generally to around 0.5 – 1% by weight and is kept relatively low by the oil preservation system of modern transformers. Typically transformers purchased since 1978 are fitted with a rubber bag 'sealed' conservator to maintain a low moisture and oxygen content which thus far appear to be functioning well. AusNet Services specifies sealed oil preservation systems in new transformers.

However, the oil preservation system specified for transformers before 1978 was a free-breathing conservator type which has resulted in a gradual increase of moisture in insulating oils over time. It has also meant that the oil contains oxygen (O_2) at equilibrium levels in the order of 23%.

In the 220/22kV [C.I.C] L2 and L3 transformer banks at Ringwood terminal station (RWTS) high levels of water equal to 30ppm have been detected.

The six H1 and H2 single-phase 330/220kV [C.I.C] auto transformers at South Morang terminal station (SMTS) are exhibiting a high transformer oil and insulation moisture level. [C.I.C] SRBP bushings have suffered problems with broken oil level gauges and increasing DDF measurements, possibly caused by moisture entry. These bushings are progressively being replaced.

High levels of moisture (greater than 4%) in transformer insulation leads to a reduction in dielectric strength. This can result in the inception of partial discharges or dielectric thermal runaway due to high dielectric losses at elevated temperatures. Under application of sudden overload, moisture levels as low as 2 – 2.5% can result in the formation of gas bubbles that can precipitate dielectric failure depending on the transformer pre-loading, temperature and the magnitude of the overload.

Under normal operation the rate of deterioration of paper insulation systems increases in relation to an increase in moisture content, this is particularly true at high loadings and the highest ambient temperatures. This is further increased by oxygen in the oil. Ageing cellulose (paper and pressboard) also produces moisture.

The moisture content in several older transformers is approaching the point where a dry-out is needed. For some of these transformers, particularly those requiring other refurbishment/ replacement work is often not economical.

5.1.2 Oil Degradation

The oxidation or degradation of oil with time, particularly with free breathing oil preservation systems, produces compounds that accelerate the deterioration of solid insulation, particularly at elevated temperatures. Products of oxidation can also decrease the partial discharge inception voltage and lead to the onset of partial discharges in EHV transformers.

Based on new testing methods it is suspected that some new transformer oil supplied from 1990 to 2006 could contain corrosive sulphur properties. This oil was supplied in new transformers and added to some existing transformers during insulating oil maintenance. Tests for corrosive sulphur have shown its presence in some transformers and passivator has been added as required to reduce the reaction of this sulphur with copper and the longer term risk of deterioration and failure.

In 2010, the B1 220/66/11 kV 150/165 MVA [C.I.C] transformer at Morwell terminal station (MWTS) failed following a 66 kV heavy current fault at the nearby Morwell power station MPS. The post-mortem indicated advanced deterioration of the cellulose insulation suggesting high oil operating temperatures when serving full load under high ambient temperatures. This event provided further evidence of the high probabilities of failure of the [C.I.C] transformer fleet under high loads and high ambient temperatures.

There are also several types of transformer bushing exhibiting oil degradation. The [C.I.C] 220 kV SRBP bushings installed in 220 kV [C.I.C] transformers have a problem of de-lamination of the SRBP core allowing oil to slowly flow from the bushing into the transformer. Bushing oil levels need frequent monitoring and topping up.

The A1 (500/220 kV) transformer at Rowville terminal station, which is owned by RTF, has clearly indicated presence of corrosive sulphur. Passivator has been added to the oil in all three phases. DGA monitoring of the blue-phase transformer has suggested a thermal fault which has not been confirmed by off-line electrical tests.

In advanced cases of insulating oil moisture contamination, sludge is formed which, in addition to reducing dielectric strength, can affect cooling of the windings. To manage this effect in the past it has been considered necessary to replace or reclaim oil in a limited number of transformers. With increased operation at higher loads and higher ambient temperatures, it is likely that it will be necessary to carry out this operation on more of the remaining 'free-breathing' transformers. It is expected that the oil in transformers with sealed oil preservation systems will not require this remediation measure.

To mitigate insulating oil degradation AusNet Services specifies high grade naturally inhibited oil with known rates of degradation to facilitate analysis of key performance indicators.

5.1.3 Insulation Deterioration

The main insulating material in transformers is kraft paper, or mixture of kraft and manila paper and pressboard (transformer board) impregnated with oil. Deterioration of these materials is a function of temperature, moisture, oxygen and certain products of oil oxidation. Insulation deterioration can be monitored using chromatography to detect defects and adjust utilisation. Appropriate maintenance regimes managing the rate of deterioration can extend the service life of the dielectric insulation. Cellulose insulation is generally considered to be at 'End-of-Life" when the insulation degree of polymerisation drops to 200 (DPv) from its original value of around 1000. While deteriorated oil can be reclaimed and replaced, deteriorated paper insulation cannot be restored and complete replacement of the windings is required.

Although the deterioration of paper insulation only has a small effect on the electrical withstand strength it has a large effect on its mechanical strength. This reduction in mechanical strength reduces the ability of the transformer windings to withstand the effects of fault currents arising from faults in downstream circuits. Obviously this is less critical at remote locations where the maximum prospective fault currents are low, but for some transformers, the increased risk of winding movement due to through-fault current, and possible, subsequent complete insulation failure plays an important part in the decision to replace the transformer.

While the mechanical strength of deteriorated insulation cannot be restored, the deterioration rate is determined by operating temperatures. Operating temperatures can be reduced by the planning authorities, AEMO and distribution companies, reducing the loading on the transformer. The deterioration has been evident on the following:

- Insulation deterioration is most evident in the population of [C.I.C] 220/66/11 kV 150 MVA transformers where insulation shows accelerated deterioration due to poor cooling at high loads and high ambient temperatures. [C.I.C] transformers at Keilor terminal station exhibited advanced thermal deterioration of the insulation structure due to inadequate cooling. Thus it was determined by condition monitoring the KTS B1 & B2 transformers were at the 'End of Life' condition and a high risk of failure therefore the KTS B1 & B2 units were replaced in 2012 and a post-mortem on the cellulose material on the windings confirmed the Degree of Polarisation [DP] as low as 180 ranging up to low 300's. The low range of DP supports the observed key furanic compound detected in the routine oil analysis during the service life of the transformers and was confirmed to be at the technical 'End of Life'. Also, similar analysis were performed on the replaced GTS B1 & B3 and TTS B3 transformers which also confirmed the in-service monitoring analysis correctly confirm the transformers were at the 'end of Life'.
- Addition to the winding analysis the [C.I.C] HV bushings of similar vintage to the above transformers are of the SRBP type are exhibiting HV insulation de-lamination leading to a potential dielectric discharge issues and are currently being replaced under a staged replacement program.
- In addition to the [C.I.C] transformers, the [C.I.C] B2 220/66 kV transformer at Richmond terminal station is experiencing degradation due to high ambient temperatures associated with enclosure of cooling area. As an interim the oil has been replaced to reduce risk of dielectric failure before its programmed replacement under station rebuild project XA09.
- The three A4 500/220 kV single-phase [C.I.C] transformers at Keilor terminal station have been subjected to overheating due to blockage of insulating oil coolers. This has led to a greater deterioration of the solid insulation medium compared with the similar transformers forming the A2 and A3 500/220 kV banks. Also the 500/220 kV A2 white-phase transformer experienced a winding failure after a service life of 40 years (2011) which included operation for an extended period at close to name plate rating. This increase in utilisation resulted in incipient failures; potentially a latent winding defect failure.

- Accelerated deterioration has also occurred on some force-cooled transformers when the high efficiency oil/air heat exchangers have been blocked by airborne material.
- Design faults were identified in the 220/66 kV B1 transformer in Thomastown terminal station (TTS) where a through fault from a pole outside the station caused the winding to physically move resulting in a dielectric failure in the transformer. The TTS transformer was subsequently replaced and similar [C.I.C] transformers at FBTS, RWTS and TBTS are to be tagged as limited fault current rated to help prevent this type of failure.

5.1.4 Slack Windings

Part of the manufacturing process is to apply sufficient compression force to the transformer windings to keep them tight and able to withstand the axial forces that occur during through-faults. Due to the type, thickness and deterioration of insulating materials, the clamping pressure can be reduced over time to the point where there is no pressure and even a gap, which can result in winding displacement. Transformers with layer-type windings, those with a soft grades of pressboard, and those where the insulation has been dried out are at higher risk of having slack windings.

At present, the only way of making a positive check of the winding pressure is to physically inspect the winding, its clamping system and, where possible, apply pressure with hydraulic jacks. This requires full access into the transformer tank following removal of all insulating oil. It also involves work in a confined space, which presents its own hazards and is only considered when absolutely necessary. This therefore is not a routine activity and to this point it has only been carried out when access has been required during investigation of a fault or as part of a refurbishment or a major repair. The windings must be checked after any major dry-out of a transformer. Even where access can be readily gained, such as when the lid is removed, some designs (mainly [C.I.C] transformers) cannot be properly re-clamped without un-tanking the transformer which requires special assembly jigs.

A risk assessment and cost-benefit analysis is necessary when considering inspection/dry-out and re-clamping of aged windings. Diagnostic tests and condition monitoring techniques that may indicate slack windings are of great interest. The winding clamping is evident in the following system transformers:

- The Thomastown B3 [C.I.C] transformer was previously refurbished in 1997 to extend the life of the asset which resulted in an extra 12 years duty. The transformer was finally replaced in 2009 due to slack winding tensions and winding movement caused by an increase in acetylene (C2H2). This is representative of faults which result in slack windings initially caused by movement on the electrostatic shields and produced arching. Once transformers begin to exhibit evidence of slack windings it is unlikely that refurbishment will provide the most economic outcome.
- The South Morang H1 and H2 transformers currently have slack cores due to the overall design of the clamping system on the core. These transformers are being closely monitored and the H2 is now due for replacement under project XC19 – SMTS H2 Transformer bank.

5.1.5 Oil Leaks

Oil leaks from transformer tanks, coolers, pipe work, valves and other fittings are probably the most common problem with oil insulated power transformers. Apart from the environmental problem caused by oil leaks, oil on the tank surface increases the risk of a fire. The heat caused by oil burning on the tank surface tends to increase the flow rate at the point where it has been leaking, escalating the intensity of any fire. In the early years of a transformer's life, oil leaks can often be stopped, by tightening gasket-joints. However, as these gaskets harden, this solution becomes ineffective and a major outage and oil removal is needed in order to replace affected gaskets. Examples of oil leaks are shown in Figure 31.

One of the major types of oil leak and most difficult to repair, is a leak from the main tank-to-tank cover joint on older transformers. Replacement of these gaskets is a major task requiring removal of bushings, turrets, wiring, etc. before the tank cover can be removed. Furthermore, this does not necessarily cure the problem. A lower cost process of welding a steel strip across the flanges of the cover and the tank, and replacing the bolts with dome nuts and 'O' rings (or similar) to seal the bolt holes, has been reasonably successful. Welded lids have been specified for new transformers for some time.

Figure 31 – Significant Transformer Oil Leaks

Oil leaks on transformers, particularly old transformers are not being resolved by normal maintenance and for heavily loaded transformers the long outages needed to repair these leaks are difficult to arrange for reasons of load at risk and network security. These leaks do not pose an immediate risk of transformer failure, but can result in environmental and health and safety issues. An audit in 2011, identified more than 30% of the fleet had significant (> 100 litres per year) and there is renewed focus and approved projects to fix major leaks over the next 2 years or have plans to replace the transformer.

The following is a summary of major oil leak issues:

- The B4 [C.I.C] transformer at Thomastown is currently exhibiting oil leaks. These [C.I.C] transformers have been found to have oil leaks resulting from high loading on the 220 kV [C.I.C] SRBP bushings causing oil to leak into the tank due to de-lamination. These types of failures have been previously detected on the replaced 220/66 kV single at Glenrowan B1A and B1B transformers and the 220/22 kV L1 and L4 units at Richmond terminal station. Similarly the L3 220/22 kV transformer at West Melbourne Terminal Station (WMTS) is showing serious oil leaks at the bushing interfaces.
- All nine of the Keilor terminal station (KTS) 500/220 kV A2, A3 and A4 single-phase 500/220 kV transformers are also showing tank oil leaks. At least 3 of the 220 kV bushings on these transformers have been found to have bad oil leaks at the flange of the bushing and will be required to be replaced as part the stage 3 HV bushing replacement program to be completed in 2018.
- 515/230 kV A1 transformers at Hazelwood terminal station (HWTS) oil leaks were a concern around the main HV turrets and the main lid gaskets and have been partially addressed in 2014 under a previous repair program but are still showing signs of leaking.
- [C.I.C] 515/230 kV A2, A3 & A4 Transformers at HWTS have exhibited high risk oil leaks from major interface seals on bushings and main tank flanges. There is a frequent need to top up bushings due to oil leaks. A spare 220 kV bushing is not available until the badly leaking bushing is replaced with an adapted designed bushing. [C.I.C] will not provide information to help repair the bushings as they believe the bushing is too old to be repaired.
- RCTS No1 reactor windings and tank are highly deteriorated and close to 'end of life' with excessive oil leaks and high paper deterioration.

5.1.6 Noise

All power transformers and reactors produce audible sound. The sound emanating from transformer tanks is by its nature 'tonal' and is therefore draws a 5 dB(A) penalty when measured according to environmental pollution standards. It is caused by the magnetostriction in the core and the windings when on-load. The sound emanating from the core increases with flux density, which increases with the voltage applied to the transformer. Voltage tapping's are normally on the high voltage side of the transformer and are generally operated to reduce the turn's ratio to provide voltage regulation as the load increases. This increases excitation and is accompanied with an increasing sound level.

Modern core material and methods of handling and clamping transformer cores have resulted in reduced transformer sound levels. However, the sound level due to load current is becoming more prominent when load approaches the transformer's capacity rating. Residential growth around a number of terminal stations, the addition of more transformers to stations and increased utilisation is placing some stations at risk of noise complaints. By their nature, shunt reactors can be a high-level noise source.

The fans on older transformers have higher noise levels in particular fans in high-efficiency coolers or heat exchangers have been the cause of complaint. Modern units are supplied with slower speed, quieter fans which require more radiator elements to achieve the same cooling.

To mitigate noise AusNet Services are currently using enclosures where necessary and all transformers purchased are now specified to go inside a sound enclosure. The cooler bank on new transformers also designed with a low noise capability and a 54 dbA sound pressure. Refer to AMS 10-14 Environmental Management for more details.

5.1.7 Wiring

The secondary wiring and cabling mounted on the transformers deteriorates with time and this deterioration is accelerated by increases in operating temperature and also if soaked in leaking oil. Some transformers that have been operated at elevated temperatures have been found to have severely deteriorated wiring. Where wiring is in poor condition has created reliability issues replacement occurs in conjunction with transformer maintenance or malfunction of components.

The replaced L Transformers at Brooklyn were deteriorated and had oil transferring through the strands of the cable. Oil will deteriorate the polymer insulation reacting with plastics resulting in making the material brittle. Once the wiring is exposed shorting of the conductors occurs and results in faults in the protection and monitoring circuits. Deteriorated wiring on these transformers was replaced in the late 90s. Finally the L transformers were replaced in 2012 due to age deterioration and poor voltage regulation causing system constraints operating outside system code.

Oil leaking from secondary terminals in CT terminal boxes has flowed down cables, resulting in deterioration of the insulation as illustrated in Figure 32 below.

Figure 32 – Oil Leaks and Secondary Cables

5.1.8 Poly Chlorinated Biphenyls (PCB) in Oil

Oil from all power transformers has been tested for poly-chlorinated biphenyls (PCB). There are no power transformers that contain scheduled PCB that is with a concentration greater than 50 ppm. However, there are a number of transformers that have PCB levels exceeding the threshold of two ppm, classifying these as 'non-scheduled PCB'.

While the non-scheduled PCB classification permits the oil to remain in use in the transformer until the end of the transformer's life, it does require certain actions to be taken when handling any of this oil and specified procedures for oil that has leaked from the transformer. Furthermore, it causes contamination to any oil treatment plant used to remove or treat this oil. The following transformers are found to contain high levels of PCB:

- A2, A3 and A4 single phase transformers at Hazelwood (HWTS) with 3.5 to 5.8ppm;
- A1 Three phase Trans at Hazelwood (HWTS) 10ppm;
- B1 Trans at Fisherman's Bend (FBTS) with 12ppm; and
- B4 Trans at Brooklyn (BLTS) with 14ppm.

At present there is no licensed portable equipment available in Australia to remove PCB from oil in transformers in situ. The oil must be removed and taken to a treatment plant and returned or replaced with PCB-free treated or new oil. For most transformers with non-scheduled PCB oil of less than five ppm, it is not likely that any action is required. However, for the few transformers with levels over 10 ppm and serious oil leaks or requiring major maintenance, this is an issue that requires appropriate consideration. Refer to AMS 10-14 Environmental Management for more details.

5.1.9 Winding Temperature Indicators and Cooler Control

Both local and remote winding temperature indicators (WTIs) used on transformers are 'thermal image' type, which employ a heater inside the same pocket as the temperature sensor bulb (local) or RTD (remote). Current in the heater is adjusted to represent the current in the transformer winding to increase the reading, proportional to the winding temperature gradient. A number of these temperature indicators are known to provide inaccurate readings due to thermal losses or gains from ambient changes at the pocket, no temperature grading change for change of cooling and impracticable methods of adjusting the heater current to the correct gradient.

There are more than 20 [C.I.C] 220/66 kV 150 MVA transformers currently in service. The [C.I.C] fleet has a thermal performance design deficiency under high loading factors and high ambient temperatures causing aggressive rates of non-recoverable winding deterioration when the load has consistently operated towards its full and cyclic ratings. At the highly loaded stations, RTS and WMTS, the [C.I.C] units have demonstrated extreme levels of winding deterioration and are at their technically 'end of life'. The [C.I.C] transformers installed at SVTS and HTS also have indications of advanced winding deterioration, and are approaching 'end of life' and will require replacement over the within ten-year planning period.

There are still a number of transformers that do not have winding temperature control of the transformer-forced cooling system. In the past, the cooler start settings have been set too high, resulting in accelerated deterioration of the solid insulation. Modern electronic temperature indicators and monitoring systems enable the setting process to be simplified. Recent projects to improve the performance of oil and winding temperature indicators have been completed at:

- V884-0 – Replacement of OTI's on 500kV transformers at KTS (10 Units across the [C.I.C] transformers at Keilor).
- XB10 – WTI Replacement of Highly Loaded transformers (9 Units) and the following need addressing in future programs of works for transformers at BATS, SHTS, RCTS, TGTS, TSTS and main connecting transformers pre 1992 to align the loading behaviour with the correct temperature measurement.

5.1.10 Test Tapping's on Bushings

The test and voltage tappings on bushings have been found with various problems, mainly as a result of corrosion (incorrect metal surfaces) and water entry. It is important that these are checked on a regular basis. These problems have been exacerbated when the tapping has a cable connection for a CVT or other monitoring equipment. An example of corrosion of a bushing test tap is shown in Figure 33.

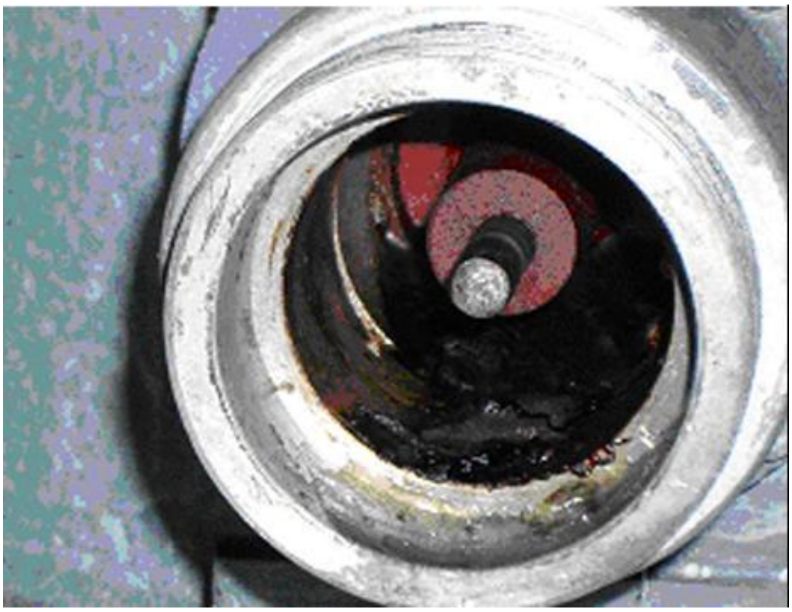

Figure 33 – Corrosion of Bushing Test Tap

5.2 Specific Issues

Those specific items which are considered to be major issues or concerns are described in AHR 10-67 Asset Health Review for Power Transformers and Reactors in Terminal Stations document, along with some indication of risk and the measures currently being taken to improve the situation where applicable.

6 Risk Assessment

AusNet Services uses a range of techniques to assess risk and thus determine the replacement requirements for each asset class. These techniques include dependability management methodology and modelling, engineering review of condition assessment data, calculation of long run sustainability based on expected asset life and total population of assets, assessment of projects in progress and engineering knowledge of assets and the operational environment. The various techniques are applied depending on the asset type and the asset data available. The range of resulting risk assessments and replacement forecasts are compared, contrasted and brought together using engineering judgement to inform the management of risk and development of the replacement forecast.

6.1 Dependability Management

Dependability management brings together asset condition data, asset failure rates and the cost impact of asset failure to determine economic replacements. The dependability management program employs Availability Workbench software to provide an economic analysis of terminal station assets over a ten-year period.

This section summarises the reliability modelling of power transformers located within terminal stations. It sums the probabilistic replacements and equivalent risk costs and identifies the economic power transformer replacements or refurbishments required to prudently maintain failure risks. Key inputs to this dependability process are asset condition, remaining service potential (RSP%), failure rate and the effects of asset failure.

The following scenarios demonstrated are:

- Run to Failure[5] ; and
- Risk Optimised Scenario.

Please refer to AMS 20-11 Dependability Management for more detail on the dependability management methodology.

6.1.1 Run to Failure Scenario[3]

A total life cycle cost of [C.I.C] comprising the impact of loss of supply on customers, health & safety costs, environment costs, collateral damage costs and reactive power transformer replacement costs (labour, equipment and spare) over ten future years are shown in **Error! Reference source not found.**.

[3] Replace on condition where there is no economically significant safety or environmental impact in relation to the optimised maintenance or replacement of an asset.

[C.I.C]

Error! Reference source not found. shows that a run to failure strategy would result in a total effect cost (loss of supply costs, health & safety costs and environment costs) of [C.I.C] over the next 10 year period. This effect cost is disproportionate to the corrective maintenance (replacement) costs of approximately [C.I.C]. This effect cost is largely distributed between those assets assessed as in deteriorated condition; Condition 4 or Condition 5.

Over the 10 year period, reliability modelling suggests that a run to failure strategy would result in 32 power transformer failures with associated corrective maintenance (replacement) costs of [C.I.C] (labour, equipment and spare purchases) over the 10 year period.

The run to failure scenario does not include preventative maintenance (planned replacement) of power transformers; it demonstrates the minimum costs required to maintain service from this fleet of assets following in-service failures. It does not represent the minimum life cycle cost and is subsequently not recommended as the most efficient use of limited resources. This scenario is not the most prudent investment for customers and is presented here for comparison with a risk optimised scenario described in the next section.

6.1.2 Risk Optimised Scenario

The risk optimised scenario considers replacing assets where the combination of effects and corrective maintenance costs associated with asset failure outweighs the cost of planned replacement. **Error! Reference source not found.** shows a [C.I.C] total life cycle cost for the risk optimised management of power transformers over the next 10 years. It shows a significant [C.I.C] reduction in the total impact on customers and corrective maintenance costs compared with the run to failure scenario:

[C.I.C]

Comparison of **Error! Reference source not found.** and **Error! Reference source not found.** shows selective replacement of 34 power transformers primarily in Condition 3, Condition 4 and Condition 5, will increase replacement costs from [C.I.C] over the 10 year period and provide a significant reduction in the effect cost from [C.I.C].

Reliability modelling demonstrates that a Risk Optimised Scenario is the most economic use of limited resources and provides a significantly lower life cycle cost to customers. The Risk Optimised Scenario represents the minimum life cycle cost for power transformers and is recommended as the most efficient use of limited resources and a prudent investment for customers.

6.1.3 Dependability Management Replacement Forecast

AusNet Services is managing the risk for those assets in Condition 1, 2 and 3 unless otherwise required due to conditional replacement. Of the remaining Condition 4 and Condition 5 assets, 15 power transformers are considered economic for optimised replacement based on their high failure effects on the community.

The power transformer asset fleet consists of 46 power transformers in Condition 4 and nine power transformers in Condition 5 (End of life score). It is considered prudent to forecast replacement of the remaining five Condition 5 power transformers that are approaching end of life and are expected to require replacement within 6.75 years based on the modelling.

Seven of 15 power transformers recommended to be replaced by the reliability modelling during next ten years are included in already approved business cases to replace and seven more are included in the Planning Reports to replace under terminal station rebuild projects within next seven years.

7 Strategies

The complex nature of power transformers and oil filled reactors requires well considered integration of numerous technical strategies predominantly targeting issues related to the major components. Each of the following major components has a targeted regime of condition assessment and management:

- Windings and paper insulation;
- Core;
- Oil;
- Oil preservation and conservator;
- Bushings;
- Tank and gaskets;
- On Load Tap Changer (OLTC); and
- On line monitoring and control systems.

The strategies outlined in this section are applicable to both power transformers and oil filled reactors.

7.1 New Assets

- Continue to improve the tender specification for power transformers by making use of experience gained by maintenance, refurbishment and emerging and tested new technologies. Some specific examples include:
    - Continue to install on-board condition monitoring, cooler control and limited dissolved gas monitoring on all new transformers.
    - Continue use of New Vacuum Technology for new transformers to overcome oil contamination from contact wear.
    - Encourage long lasting sealing technology like o-rings as a preference above flat cork gaskets.
    - Continue the standardisation of transformer components where possible to maximise compatibility with spare transformer components.
    - All transformers since 1990 are replaced with sealed units as specified in the tender requirements.
    - Continue to define overload requirements in tender documents and include the testing requirements to verify the capability of new transformers to operate at these conditions without adverse loss of life.
    - Continue to define minimum degree of polymerization requirements for new transformers in order to ensure maximum life available at the start of service.
    - Continue to define appropriate temperature rises and ambient conditions that will enable transformers to achieve expected ageing under service conditions.
    - Continue to include appropriate corrosion protection requirements in the transformer specification.
    - Continue use of resin impregnate paper [RIP] HV bushings with silicone weather sheds eliminating the potential for explosive bushing failures.
    - Continue to incorporate safe access systems.
    - Continue to standardise where economic the physical layout to match a standard station layout.

- Continue to evaluate suppliers for their ability to provide transformers that economically meet the requirements of the AusNet Services transformer tender specification.
- Continue to conduct Design reviews to ensure that suppliers understand the requirements contained in the AusNet Services transformer tender specification.
- Continue to inspect and monitor transformers during critical stage of manufacture to ensure compliance with the requirements of the transformer contract.
- Perform transformer tests to confirm that the transformer meets design expectations and operational performance before the end of manufacturer's warranty period.
- Align current purchasing specifications with latest vacuum technology that will benefit the long term reliability and reduces the reliance on short term overhauls during the life of the transformer.

7.2 Inspection & Monitoring

- Continue to carry out routine monitoring and testing of transformers on a periodic basis to detect incipient failure behaviour and indicate general condition.
- Monitor closely any transformer that has a deteriorating individual component i.e. core and winding, bushings, oil condition, OLTC or external components, which typically being assessed at C4 or C5 condition.
- Continue to monitor paper degradation indicators and trend the rates of degradation and early indicators of insulation breakdown in order to adjust replacement plans on a 12 monthly cycle with a 6 yearly offline electrical analysis.
- Continue to monitor ageing by-products in the oil to assess condition of the transformer. Free breathing transformers are being replaced with sealed transformers.
- Install bushing monitoring systems for critical transformers to reliably monitor the key deterioration factors associate with each bushing.
- Perform OLTC oil sampling periodically and continue to improve the knowledge about OLTC oil analysis to give an early indication of abnormal behaviour of the OLTC.

7.3 Maintenance

- Continue to revise transformer cyclic ratings as network loading profiles and transformer condition changes with time by assessing load profile every 5 years and adjusting transformer ratings to suit the cyclic load profile. Transformers are required to operate above name plate due to system pressures.
- Perform autopsies on selected replaced transformers to verify physical condition and deterioration model for the remaining fleet and link key deterioration indicators to support best practice replacement. As examples, the Morwell B1, Keilor B1 and Thomastown B3 have been assessed to provide a calibration check for 'end of life' and operating methodology for the 220 kV 150 MVA in-service fleet.
- Treat insulating oil and replace deteriorated oil sealing systems where economically justified to ensure ongoing reliability for suitable transformers.
- Continue the program to repair all significant oil leaks and oil damaged wiring on transformers.
- Continue to paint and treat corrosion on transformers which exhibit poor external condition as where identified above.
- Align maintenance cycles with industry best practice based on duration and number of operations reducing intrusive maintenance with condition assessment techniques as defined in:
  - SMI 80-01-02 Transformer Condition Monitoring in Terminal and Zone Substations.
  - PGI 80-40-01 Transformers, Regulators, and Oil Filled Reactors and Neutral Earth Compensators Including On Load Tap Changers: Installation and Overhaul.
- As indicated above continue the prioritised program to replace the unreliable types of analogue winding temperature indicators with accurate digital type with remote indication at Network Operating Centre.
- Investigate and replace faulty in-service Hydrans (online dissolved gas and moisture monitors) under project VC78: Transformers – On-Line Gas and Moisture [Hydran M2] Analyser Replacement.
- Continue to identify and salvage critical spares from retired transformers to support the remaining fleet of transformers where like components are available.

- Continue to hold appropriate contingency spare transformers and components in order to provide a satisfactory network contingency response[4].

7.4 Refurbishment

- Undertake mid-life refurbishment of transformer in a proactive manner to extend asset life.
- Implement necessary repair or refurbishment to manage the risk of unexpected transformer outage due to a faulty component.
- Continue replacement program for SRBP and Oil impregnated paper bushings identified as being in poor condition.
- Investigate and overhaul problematic OLTC, such as [C.I.C] and [C.I.C] and other transformers.

7.5 Replacement

- Replace 15 power transformers recommended by the reliability modelling and the remaining five Condition 5 power transformers that are approaching end of life within next 10 years.
- Where economic continue to replace high risk power transformers under major station rebuild projects.

[4] 'System Contingency Plan for Transmission Assets'.