Asset Health Appraisal of Transformers in Eskom's Distribution Network

Adesh Singh

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Supervisor: Andrew Swanson

As the candidate’s Supervisor I agree to the submission of this dissertation

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DETAILS OF CONTRIBUTION TO PUBLICATIONS that form part and/or include research presented in this thesis (include publications in preparation, submitted, *in press* and published and give details of the contributions of each author to the experimental work and writing of each publication)

Publication 1

A. Singh and A. Swanson, “Analysis and improvement of the plant health index used by Eskom to assess the condition of the power transformers in its distribution fleet," 19th International Symposium on High Voltage Engineering, Pilsen, Czech Republic, 2015, ISBN 978-80-261-0476-6.

Publication 2

A.Singh “Transformer technologies, customized maintenance and the resultant improvement in the performance of distribution transformers,” Eskom Doble Conference, Midrand, South Africa, 2014

Publication 3

A.Singh “Emerging Technologies in the Power Transformer Environment,” Distributech PowerGen conference, Cape Town, South Africa, 2015

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Abstract

Eskom is the state owned power utility in South Africa and is the biggest single generator, transmitter and distributor of electricity in Africa. Its Distribution Division comprises of nine operating units and contains a power transformer fleet of over 4000 transformers which range from 1-160 MVA with a maximum voltage of 132 kV.

In its effort to improve operational reliability, allocation of resources and to reduce the financial burden of costly failures, Eskom has employed the use of a Plant Health Index as a part of the life cycle management of key assets. It allows for customization of maintenance plans for transformers depending on their condition rating. This optimises resources and allows for early detection of faults while allowing sufficient time to plan interventions to address problematic transformers.

The Plant Health Index in its current guise has severe weaknesses that impact the accuracy as a transformer life assessment tool. It does not meet the immediate need for the Distribution Division of Eskom as it is too heavily weighted for long term plant assessment and as a result is unable to serve the distribution business where it is needed most, i.e. short and medium term assessments as indicated by the number of failures attributed to mechanical failure. This is mainly due the index placing major emphasis and weighting of the scores on the paper degradation. Total Dissolved Combustible Gases is the only method used for dissolved gas analysis while oil quality indicators are totally ignored.

An amended index redresses the weighting between long term assessments (paper degradation), and short to medium term assessments (dissolved gas analysis). In addition to the Total Dissolved Combustible Gases method of dissolved gas analysis, methods looking at the ratio of the various gases present in the oil are employed for more accurate dissolved gas analysis interpretation. Oil quality indicators are introduced to the index. The reasoning for this is that the life of the transformer is ascertained by the life of the paper, which in turn is relies on the quality of the insulating oil. Since the quality of the oil plays a major role in the insulation system of the transformer and if allowed to oxidize, sludge and degrade will place the transformer at a greater risk of failure, it should also be represented in any health assessment of transformers.

An accurate health index is imperative for effective transformer life cycle management and the amended index better serves this need for Eskom Distribution.

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Acronyms

APM	Asset Performance Management
PRA	Plant Risk Analyst
PHI	Plant Health Index
DGA	Dissolved Gas Analysis
DP	Degree of Polymerization
PCB	Polychlorinated biphenyl
ppm	Parts per million
TDCG	Total Dissolved Combustible Gases
LTPHI	Long Term Plant Health Indexes
OEM	Original Equipment Manufacture
OU	Operating Unit
DX	Distribution Division

1 Introduction

Power transformers are employed in the network to transform power from one voltage level to another in order to reduce the transmission losses (step-up), and to make the power available to customers at the agreed voltage level, adequate for their equipment (step-down or step-up). A transformer forms a major portion of the capital investment required for a substation and therefore the life management of this asset cannot be over-emphasized. The expected lifespan of a transformer employed in the distribution network is 40 years when operated at rated conditions (40 years is specified by Eskom as a minimum lifespan in its transformer design criteria). This lifespan can be exceeded depending on various factors including design safety margins, operation, maintenance, and good life cycle management practices from the initial installation of the transformer. Conversely, the lack of transformer life cycle management can reduce the lifespan of a transformer.

The fundamental cause of paper ageing is heat which is generated from core and copper losses when the transformer is loaded. The ageing rate is accelerated by the presence of moisture and oxygen which aid in the degradation of the paper molecules. There are various sources of moisture in the insulation system, which can either be external (atmospheric air through leaks or air ingress during maintenance), internal (ageing itself produces water), or residual (improper drying at the factory). The main source of oxygen is from the atmosphere [1].

Modern day transformers are designed and manufactured in a more precise engineering manner than older transformers when the technology was still primitive. This has allowed better safety margins for cooling coupled with reduced losses. The drying techniques have improved during manufacturing and the residual moisture levels have been gradually reduced. Major improvements have over the years been introduced in terms of life cycle management practices.

A transformer health assessment is a method to manage the transformer through its lifecycle by quantifying the condition of the transformer according to certain parameters. Ideally, the transformer health assessments should be based on four parameters, namely, the paper life, dissolved gas analysis, condition of the auxiliary components and electrical diagnostic tests. Often, there is limited availability to assess the latter two parameters due to outage constraints and/or a lack of resources. Most utilities employ an abbreviated health assessment that makes use of the data most readily available and the accuracy of the ranking system is dependent on the quality of the transformer information captured. Nevertheless, the plant health index (PHI) is a convenient tool to combine the condition monitoring data into categories related to the assets condition and provides a snapshot of the condition of transformers. This allows for the planned implementation of corrective actions.

1.1 Research Question

The research questions that need to be answered include:

- Is the current plant health index applicable to power transformers across the distribution network?
- What have other utilities done and how was the plant health index derived?
- What can be done to improve the plant health index?

1.2 Hypothesis

The hypothesis is that the current health index can be improved upon by using information already available to the utility. The health index that takes into account the environment in which the asset is installed will better quantify the risk to transformers.

1.3 Importance of Study and Contribution

The health index will be used for the asset management of power transformers within the Distribution network with the aim of reducing the number of failures, improving operational reliability and allowing for the more effective use of resources in managing transformers.

1.4 Dissertation Structure

Chapter 2 covers a literature review of transformers, focussed on the construction of the transformer, the condition monitoring, the various faults that may occur on the transformers and the management of the transformer. The covers the plant health index as it currently stands and investigates how it was constructed.

Chapter 3 covers the application of the plant health index to the distribution transformers, and analyses and critiques the index. A case study of the application of the plant health index is undertaken and illustrates why the index does not work.

Chapter 4 covers the application of an amended plant health index and illustrates that the index covers long term as well as short and medium term health assessments.

Chapter 5 concludes the dissertation and recommends further research in the area of asset management

2 A Literature Review of Transformer Fundamentals and Asset Management

2.1 Transformers

A transformer is an electro mechanical device that transfers electrical energy between two or more circuits via electromagnetic induction. It was invented in 1885 and is primarily used to step voltage levels up or down to suit the needs of transmission and distribution systems [2].

2.1.1 Basic Construction and Operation

The power transformers consists of paper covered coils or windings constructed around a magnetic iron core and immersed in oil. The current carrying coils are usually copper or aluminium and are the primary source of power and heat losses in the transformer. The losses fluctuate with the current drawn during operation and are thus referred to as load losses. The function of the iron core is to channel the magnetic flux between the magnetically coupled circuits. The iron core is constructed on finely cut sheets which result in lower eddy currents and hence lower eddy losses. Iron losses are ever present in transformers, irrespective of the load and are hence commonly referred to as No-Load losses. No load losses are made up of Eddy and Hysteresis losses which can be reduced by the choice of better core material and more advanced methods of construction. This increases the initial capital cost of transformer but is more efficient and environmentally friendly over the lifetime of the transformer than a cheaper less efficient transformer. Total cost of ownership models have therefore been introduced to ensure that utilities obtain the cost effective transformer over the lifetime of its operation [3].

2.1.2 Insulation (Oil/Paper)

A transformer is in general made from non-ageing materials except for the insulation system. The copper conductors are insulated with normal cellulose Kraft paper or thermally upgraded paper. The insulation distances between the coils and between the coils and the yokes/clamping structures are filled with other solid insulation, and the entire active part is immersed in mineral oil. The mineral oil and the solid insulation of the transformer deteriorate with age.

Age assessment tests are done to determine the ageing characteristics of the oil/paper insulating system by means of chemical analysis of the insulating oil.

The insulating paper is made up of chains of polymers called furans. Longer chains equate to the greater integrity of the paper and when the paper deteriorates, these chains break down and dissolve in the oil. The furans in the oil are thus used to estimate the degree of polymerization (DP) of the paper insulation in a transformer. Alternatively, the degree of polymerization can be determined by analysing a sample of the paper insulation of the transformer but this comes with operational complications as the process is intrusive and involves removing the transformer from service. Estimation of the DP is therefore favoured by many utilities. New Kraft paper has a DP of around 1200 while paper with a DP approaching 200 has little remaining strength and is considered as approaching the end of its useful life [4].

Mineral insulating oils contain mixtures of hydrocarbon molecules and are made up of the CH_3, CH_2 and CH chemical groups. Gas molecules are formed due to the degradation of the oil and include [5]:

- Hydrogen (H_2),
- Methane (CH_4),
- Ethane (C_2H_6),
- Ethylene (C_2H_4), and
- Acetylene (C_2H_2).

The formation of the gases is dependent on temperature where at low temperatures H_2, CH_4 and C_2H_6 may form, at intermediate temperatures C_2H_4 may form and at high temperatures (such as when arcing occurs) C_2H_2 is formed [5].

The thermal degradation of paper insulation leads to the production of Carbon Dioxide (CO_2) at low temperatures and Carbon Monoxide (CO) at high temperatures. Oxygen (O_2) and Nitrogen (N_2) are additionally present in the oil, but are not formed due to the degradation processes [5]. The formation of CO_2 and CO are however dependent on the amount of O_2 in the oil [5].

The insulating oil ages in the presence of oxygen, heat and moisture. Breakdown of the oil results in the production of acid, moisture and sludge which impacts the integrity of the paper, reduces circulation and cooling, and further worsens the rate of ageing of the oil. Oil quality measurements such as electric strength, interfacial tension, and moisture in oil, acidity, and dissipation factor are used to determine the suitability of the oil to perform its function in the transformer.

While aged oil can be replaced or regenerated, there is no economical way of replacing the insulating paper, and therefore when it reaches its end of life, the transformer is considered to have reached the end of its useful life [4].

2.2 Ageing of the Transformer and Failure Mechanisms

The environment in which the transformer operates impacts the rate of ageing and the lifetime of the transformer. Factors such as loading, climate (lightning etc.) and the integrity of the network can create stresses on transformers that result in premature ageing and failures of transformers.

2.2.1 Ageing

When the insulating paper reaches its end of life, the transformer is considered to have reached the end of its useful life. The ageing of transformers is therefore best measured in terms of the insulating paper. Transformer DP should be measured and trended to monitor the rate of ageing such that informed decisions can be made regarding the replacement of the transformer before the insulating system (due to the paper) fails. Transformers that reach their end of life in this manner are generally regarded as success stories as they provide a return on the capital investment outlaid for their installation.

The fundamental cause of paper ageing is heat which is generated by losses when the transformer is loaded. The ageing rate is accelerated by the presence of moisture and/or oxygen. There are various sources of moisture in the insulation system, which can either be external (atmospheric air through leaks or air ingress during maintenance), internal (as a by-product of ageing), or residual (improper drying at the factory). The main source of oxygen is from the atmosphere and is the primary reason that air bags are fitted in the conservator of modern transformers. The bag limits the exposure of the oil and paper to oxidation by confining the oxygen to the bag and occupying the space that would ordinarily be filled with air [6]. The effect of temperature on the ageing of the paper, and hence the effective remaining life transformers is described by the Arrhenius equation, which shows that for an increase of 6°C above 110°C, the life of insulation is halved [6] [7].

$$per\ unit\ life = A.\exp\left(\frac{B}{\theta_H + 273}\right) \tag{1}$$

Where Θ^H is the temperature and for thermally upgraded paper A = 9.8x10^{-18} and B = 15000

The end of life criteria using the Arrhenius equation are given in Table 1.

Table 1: Normal insulation life of a well-dried, oxygen-free thermally upgraded insulation system at the reference temperature of 110 C from SANS 60076-7 [6]

	Normal insulation life	
Basis	**Hours**	**Years**
50 % retained tensile strength of insulation	65 000	7.42
25 % retained tensile strength of insulation	135 000	15.41
200 retained degree of polymerisation in insulation	150 000	17.12
Interpretation of distribution transformer functional life test data	180 000	20.55

Emsley et al , Lundgaard et al and Kuen performed analysis and comparison experiments with the oil/paper insulation system for transformers, with the focus on the degree of polymerisation [1] [4] [8]. Emsley's model differs from that in the standards and is given by [1]:

$$DP_t = \frac{1}{\left(Aexp(\frac{-E}{R(T+273)})t\right) + \frac{1}{DP_0}} \tag{2}$$

Where:

DP_t = remaining DP-value after time t (200 at end of life)

DP_0 = initial degree of polymerization (1000 after drying process)

A = factor representative of chemical environment (moisture, oxygen, acidity)

R = the molar gas constant (8,314 J/mole/K)

T = the absolute temperature in C

E = activation energy in kilojoules per mole (111 kJ/mole)

t = time spent to pass from DP_0 to DP_t (hours)

Figure 2-1 illustrates the equation for a range of temperatures for thermally upgraded paper with A = 0.67×10^8 for dry and clean paper and Figure 2-2 illustrates for different water contents A = 1.1×10^8 for 1% water added paper and A = 2.6×10^8 for 3% water added paper. The figures show the effect of increased operating temperature and increased moisture in paper, on the ageing of the paper.

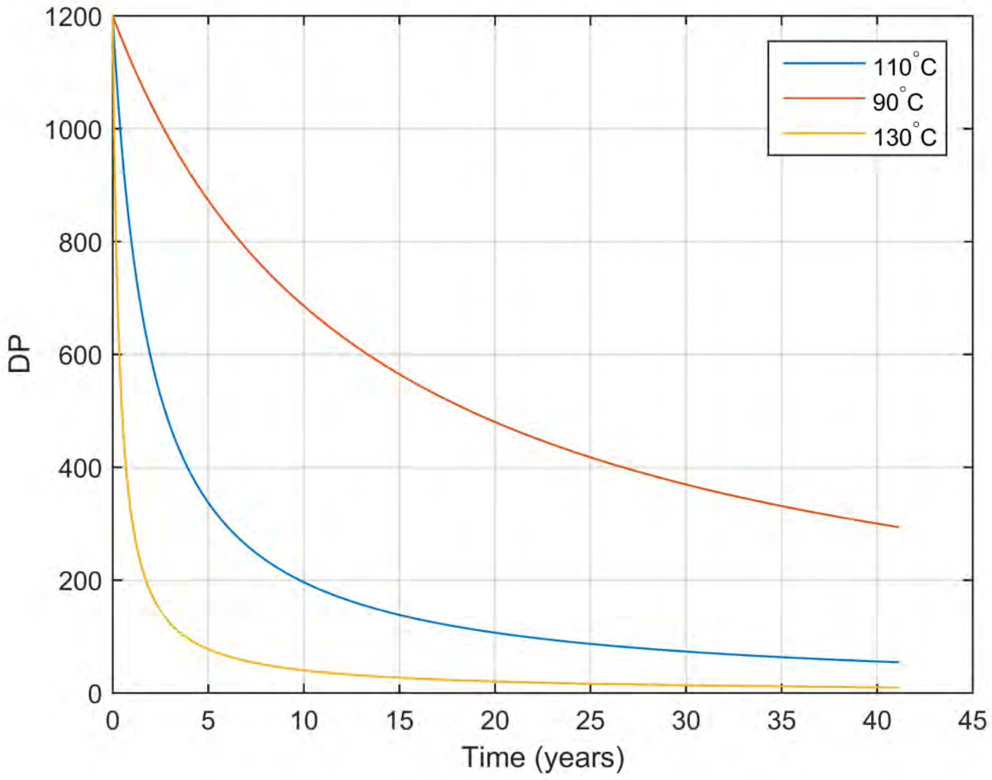

Figure 2-1: Rate of Reduction in the Degree of Polymerisation for Operating Temperatures

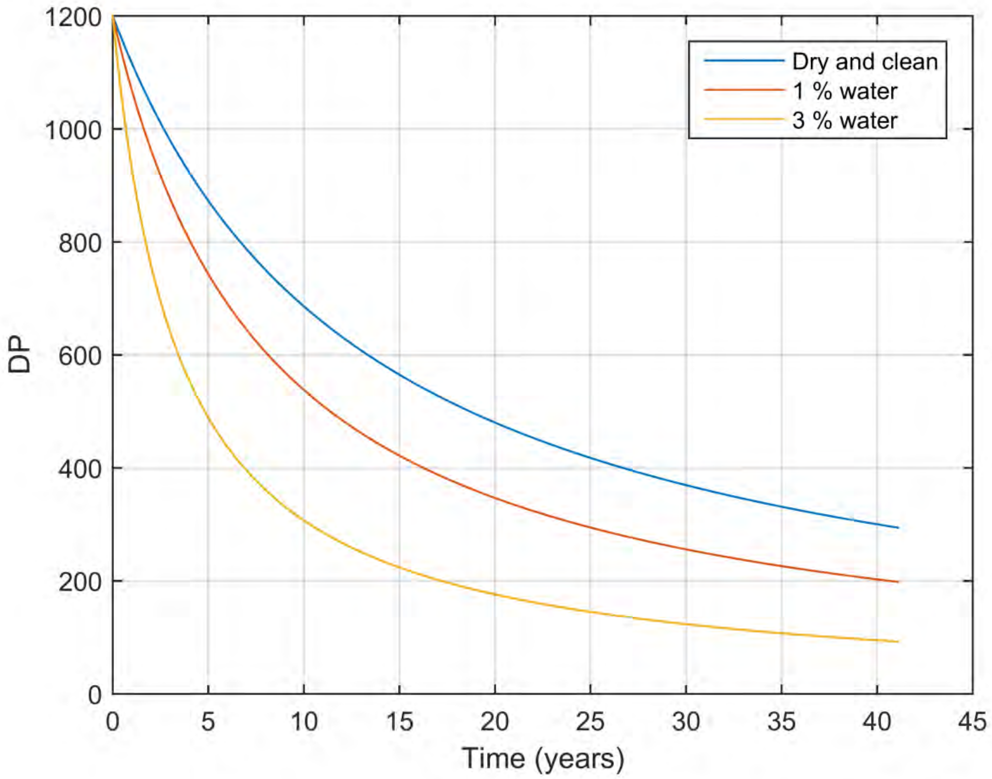

Figure 2-2: Degree of Polymerisation for different Temperatures for moisture contents

The ageing is significantly more complicated in operation as the transformer load varies throughout the day and between different types of customers (e.g., domestic versus industrial). Over time, the transformer may develop leaks which may increase the moisture in oil and paper. This will cause premature ageing of the paper, and oil which may then result in the formation of sludge and more moisture that will have further negative effects on the transformer lifespan. It is therefore imperative that routine checks and maintenance is carried out timeously to preserve and extend the life of the transformer.

2.2.2 Failure Mechanisms

Figure 2-3 illustrates a typical transformer failure pattern depicting the failure rate against the transformer age. Failures in transformers consist of infant mortality failures which occur early on in a transformer life and wear out failures where the rate of failure typically increases with the age of the transformer.

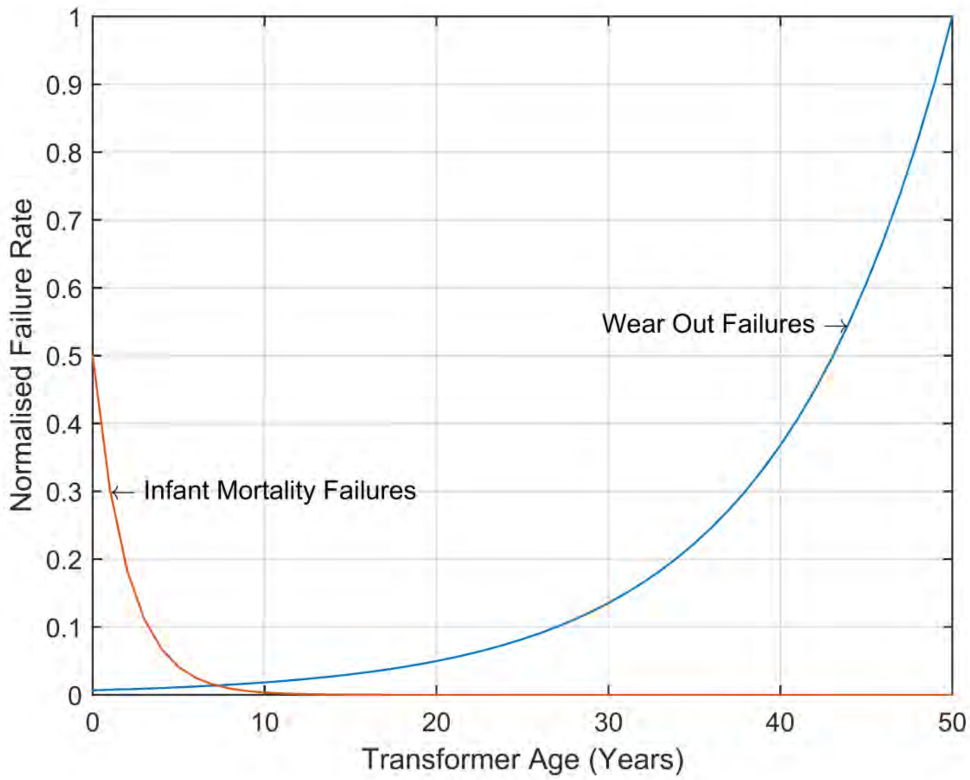

Figure 2-3: Typical transformer failure pattern [5]

Transformers may fail prematurely for several reasons. This includes mechanical failures from short circuit activity, failure of transformer components such as bushings and tapchangers, manufacturing defects and incorrect application of the transformer by the user. Infant mortality is usually experienced due to one of these factors and utilities have taken to enforcing stringent controls to mitigate these occurrences.

Factories are accredited prior to tender award and the manufacturing processes and infrastructures are scrutinized to ensure that the factory is suitable for high quality transformer manufacturing. The temperature and moisture of the winding assembly area is one such control that is necessary to ensure that the insulating paper is as dry as possible. This promotes longevity of the transformer paper and hence contributes to a longer lifespan of the transformer. Design reviews take place before manufacturing of the transformer can commence. The onus falls on the transformer manufacturer to prove to the customer that the transformer is designed to international specifications with sufficient safety factors to accommodate for amongst others, short circuit forces and temperature rises. Inspection and hold points are also available to the customer to provide quality assurance at key points in the manufacture of the transformer. Once completed, the transformer is then subjected to a barrage of tests to ensure that it is suitable of operation [2].

Failure of components such as on load tapchangers and transformer bushings often result in the failure of the transformer. There is also a great risk of fire when oil type tapchangers and bushings fail. Regular inspections, tests and maintenance are imperative in assessing the condition of these components and preventing costly failures.

Tapchangers have specified limits for the number of operations that can be tolerated before service and/or replacement of the tapchanger contacts. The advent of vacuum tapchangers has reduced the maintenance requirements for tapchangers significantly as all switching occurs in a vacuum bottle instead of oil. This limits arcing and prevents carbonisation of the oil thus allowing a longer lifespan of the contacts. Most reputable vacuum tapchangers allow for 300 000 operations before any maintenance is required as compared to between 50 000 – 100 000 operations for most oil type equivalents **[9]**.

Oil impregnated paper bushings must be regularly inspected for leaks and tested for dissipation factor as an indication of the insulation of the bushing. These bushings are susceptible to moisture ingress and may fail violently and catastrophically for the transformer. As a result dry bushings formed from resin impregnated paper (RIP) or synthetics (RIS) have gained in popularity as they have superior insulating properties and are oil free, which reduces the risk of fire during failure [10].

Transformers are also greatly impacted by single, two or three phase faults on the network. The severity of the impact of the fault on the transformer depends also on the distance of the fault from the transformer, as the fault current is damped by the impedance of the conductors on the transmission/distribution system. By the principle of its operation, the transformer is under constant magnetic forces that are withstood under rated conditions by the mechanical clamping, bracing and build of the transformer. Under fault conditions, the current seen by the transformer exceeds rated values. The force experienced by the transformer is proportional to I^2t so the impacts of the increased fault current results in forces on the mechanical build of the transformer that may be overcome, resulting in mechanical failure [3]**.** Mechanical failures are prominent on poor performing networks and it is imperative that the substation protection is functioning and correctly graded to prevent such failures. In extreme cases fault limiting reactors may be employed to restrict the fault current.

Other faults internal to transformer such as thermal faults and partial discharges may develop into more serious conditions that eventually lead to the dielectric breakdown of the transformer insulation. These faults can be monitored via the analysis of the gases in the transformer oil and from electrical tests on the transformer. Interventions to address the problems can then be planned and carried out under controlled conditions. It is therefore imperative that the plant health assessment criteria be as relevant and effective as possible. This is only possible with accurate field data.

2.3 Condition Monitoring

Indications of the condition of transformers and its components are possible by the collection and analysis of data pertaining to the operation of the transformer. Data from the transformer oil (DGA and DP), tapchanger oil (DGA and particle analysis) and from oil and winding temperature gauges are readily and easily available to users for analysis and trending. In recent times, direct measurement of the winding hotspot temperatures via fibre optic have been made available, as well continuous data of the voltage and current measurements from the transformer bushings.

The data from electrical tests of the transformer and its components can also be trended to determine the condition of a transformer and whether its condition is deteriorating [11].

2.3.1 Dissolved Gas Analysis

There are several established techniques for the analysis of dissolved gases in transformer oil. This includes, amongst others, the IEC Basic Gas Ratio Method, Key Gas Method, Total Dissolved Gases (TDG), Duval's Triangle, Doernenburg's Ratio Method etc. Some methods rely on the parts per million (ppm) of the different gases (TDCG) in oil for interpretation while others preferred to look at the ratio of the various gases to each other.

TDCG is used to detect the possibility of a fault and is formed by adding the concentrations of H2, CH4, C2H6, C2H4, C2H2 and CO to find the total concentration in ppm [12] [5]. IEEE Std C57.104 defines 4 conditions as illustrated in Table 2.

Table 2: TDCG Conditions

Condition	TDCG (ppm)	Description
1	TDCG<720	Transformer is operating satisfactorily
2	721<TDCG<1920	Transformer exceeds normal values, additional investigation is required, key gases should be checked for a fault
3	1921<TDCG<4630	High level of decomposition, additional investigation is required, key gases should be checked for a fault
4	4630<TDCG	Excessive decomposition. Continued operation could result in failure

Key gas method is used to identify the type of fault as there is a dominant or key gas produced depending on the temperature and type of fault [12] [5]. The key gases are summarised below [12] [5]:

- Thermal – Oil – C_2H_4
- Thermal – Cellulose – CO
- Electrical - PD – H_2
- Electrical – Arcing – C_2H_2

Ratio methods relate the ratios of gases to the type of fault. Considering the following ratios [5].

- Ratio 1 CH_4/H_2
- Ratio 2 C_2H_2/C_2H_4
- Ratio 3 C_2H_2/CH_4
- Ratio 4 C_2H_6/C_2H_2
- Ratio 5 C_2H_4/C_2H_6
- Ratio 6 C_2H_6/CH_4

The Doernenburg Ratio uses ratios 1, 2, 3 and 4, while the Rogers ratio uses 1, 2, 5 and 6 to interpret the type of fault occurring [12] [5]. The IEC defines a Basic Gas Ratio as shown in Table 3 which gives the fault conditions shown in Table 4 [12] [5].

Table 3: Gas ratio codes for Basic Gas Ratio

Gas Ratio	**Range**	**Code**
C_2H_2/C_2H_4	<0.1	0
	<3 and >0.1	1
	>3	2
CH_4/H_2	<0.1	0
	<1 and >0.1	1
	>1	2
C_2H_4/C_2H_6	<1	0
	>1 and <3	1
	>3	2

Table 4: Fault classification

Fault Type		**C2H2/C2H4**	**CH4/H2**	**C2H4/C2H6**
Normal aging, no fault		0	0	0
Partial discharge (low energy)		Insignificant	1	0
Partial discharge (high energy)	PD	1	1	0
Discharges of low energy	D1	1 to 2	0	1 to 2
Discharges of high energy	D2	1	0	2
Thermal fault of <150 °C		0	0	1
Thermal fault of > 150 °C and < 300 °C	T1	0	2	0
Thermal fault of > 300 °C and < 700 °C	T2	0	2	1
Thermal fault of > 700 °C	T3	0	2	2

Michel Duval of Hydro Quebec developed the Duval Triangle in the 1970's. It was developed by analysing DGA databases and relating the DGA to the root cause analysis. The Duval's triangle was first used in IEC 60599 and has since proven to be a reliable method for the identification of the type of faults on transformers with a known problem. Duval Triangle uses 3 gas ratios in a triangle as shown in Figure 2-4 with the fault conditions listed in Table 5 The more recent Duval Pentagon uses 5 gas ratios in a pentagon as a tool to interpret the dissolved gas [5] [13]. As Duval's Triangle does not have a normal condition, it should not be used for fault type prediction [14].

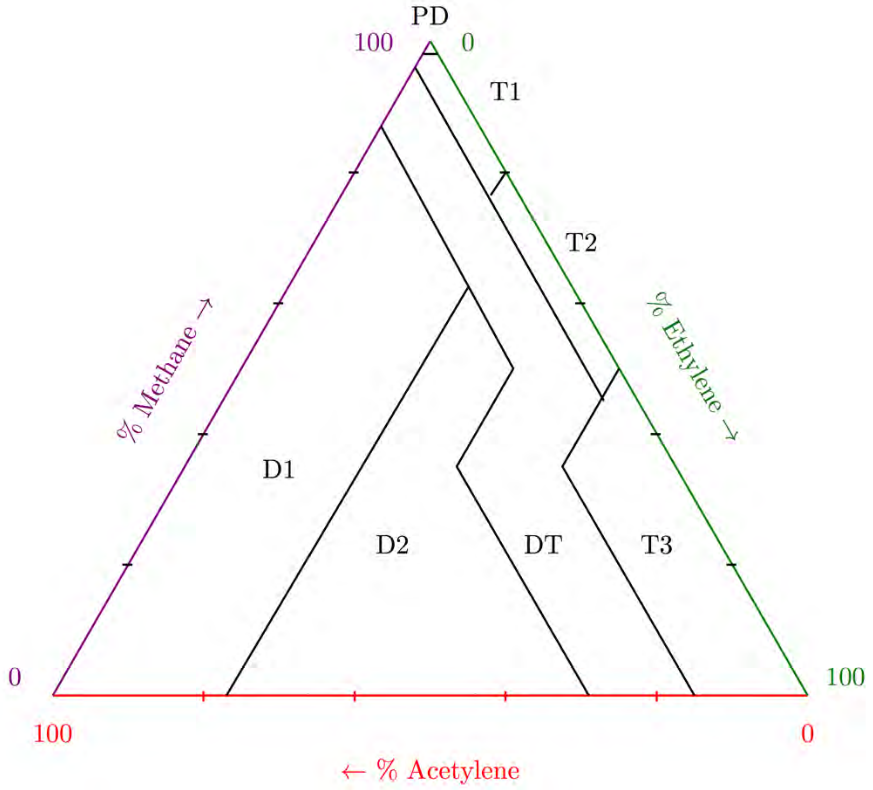

Figure 2-4: Revised Duval's Triangle

Table 5: Duval's Triangle

Fault Code	Fault Type
PD	Partial discharge
D1	Low energy discharge
D2	High energy discharge
DT	Mixture of electrical and thermal faults
T1	Thermal faults $T < 300\ ^{o}C$
T2	Thermal faults $300\ ^{o}C < T < 700\ ^{o}C$
T3	Thermal faults $T > 700\ ^{o}C$

For the transformer operator it is important that oil sample data is not looked at in isolation. It is best used in conjunction with operational information and in comparison to the baseline of normal operation of the transformer [12]. Trending of oil sample data is essential in establishing clear baselines that will easily highlight deviations from the normal condition. It is also advisable to use multiple methods of oil analysis to diagnose faults as different methods have complimenting strengths and weaknesses. For example, methods that focus mainly on ppm values tend to struggle with the early detection of faults due to their reliance on ppm thresholds for analysis. Methods that rely solely on ratios may provide false indications as even minor changes in the composition of gases may create unfavourable ratios. Methods such as the Duval Triangle and Key Gas Method do not have a normal condition and are thus best used for root cause analysis once it is known that a fault exists [15].

2.3.2 Oil Quality

Oil quality indicators such as, moisture in the oil, electric strength, dissipation factor, interfacial tension and acidity, can be continuously monitored to determine the suitability of the oil to perform its primary functions. This information can be used by the operator to determine the point at which the oil requires replacement or regeneration. Inhibited mineral oil must also be monitored for passivator content as a depletion of the passivator will lead to oxidation of the oil. Pipers chart illustrated in Figure 2-5 relates the moisture in the paper to the moisture in the oil for a given temperature and is mathematically expressed by [3]:

$$T = 31.52 - 26.605\ln(pct) + 17.524\ln(ppm) \qquad (3)$$

Where:

T = temperature (^{o}C)

pct = Percentage water in paper

ppm = ppm water in oil

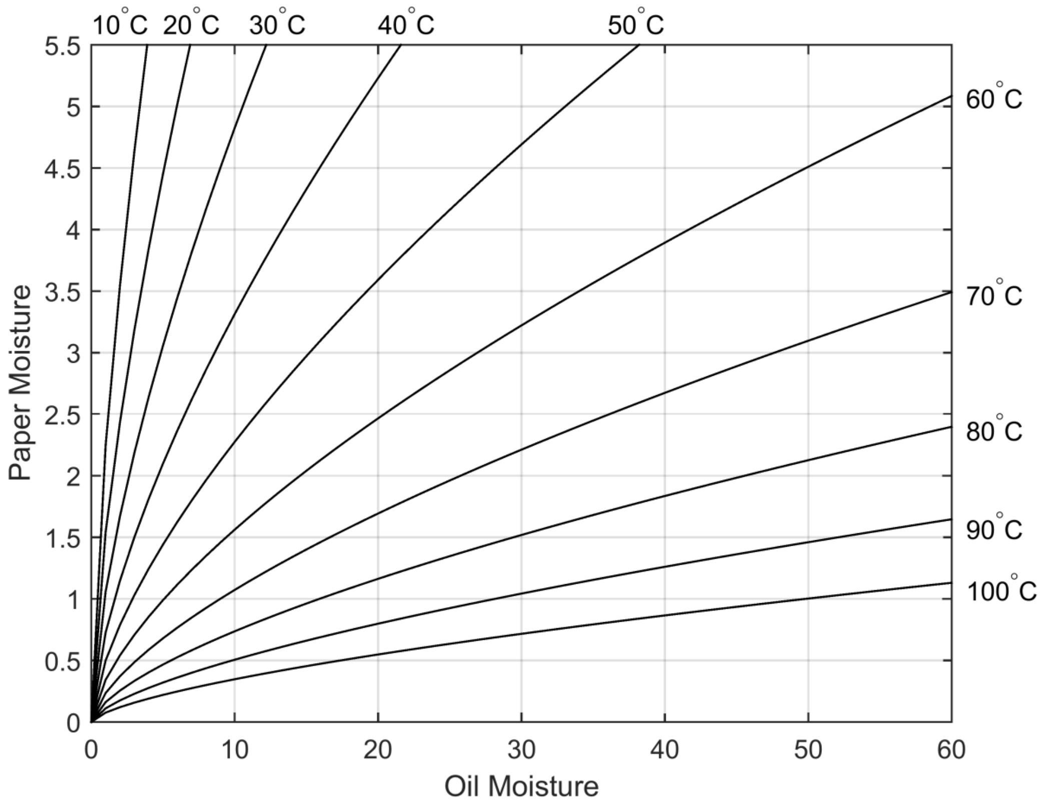

Figure 2-5: Piper's chart

2.4 Transformer Lifecycle Management

A transformer forms a major portion of the capital investment required for a substation and therefore the life management of this asset cannot be over-emphasized. The specified lifespan of a transformer employed in Eskom's distribution network is 40 years when operated at rated condition. This lifespan can be exceeded depending on various factors including design safety margins, operation, maintenance, and good life cycle management practices from the initial installation of the transformer. Conversely, the lack of transformer life cycle management can reduce the lifespan of a transformer. Health or condition assessments are a key ingredient in the lifecycle management of the transformer fleet. It allows for customization of maintenance plans for transformers depending on their condition rating. This optimises resources and allows for early detection of faults while allowing sufficient time to plan interventions to address problematic transformers. An accurate health index is therefore imperative for effective transformer life cycle management. As a result, it is vitally important to use accurate data used for the transformer condition.

It is also important to learn from previous failures. Accurate root cause analysis of failures is imperative in preventing mistakes from being repeated. Deficiencies in particular makes, types and designs can be identified and rectified in future transformers at design stage, while repeat transformer failure sites can be flagged for more in-depth investigation of the substation and surrounding network.

2.4.1 Plant Health Index

Ideally, the transformer health assessments should be based on four parameters, namely, the paper life, dissolved gas analysis, condition of the auxiliary components and electrical diagnostic tests. Often, there is limited availability to assess the latter two parameters due to outage constraints and/or a lack of resources. Most utilities employ an abbreviated health assessment that makes use of the data most readily available and the accuracy of the ranking system is dependent on the quality of the transformer information captured.

Nevertheless, the plant health index (PHI) is a convenient tool to combine the condition monitoring data into categories related to the assets condition and provides a snapshot of the condition of transformers. This allows for the planned implementation of corrective actions [16] [17].

Naderian et al present their work on a health index for power transformers and extend on the typical quantities such as DGA, oil quality, furfural and power factor and include other operational conditions, observations and history performance. They use a set of 20 inputs that are weighted according to importance. Interestingly the furan analysis has a lower weighting than the DGA, power factor and load history. They relate the health index to the condition of the transformer, the expected lifetime and what the requirements are for maintenance or replacement [17].

Jahromi et al develop a health index based on [16]:

- DGA
- Oil quality
- Furfural
- Power factor (dissipation factor)
- Tap changer
- Load history
- Maintenance data

The last two criteria are significantly important to the PHI, as they will be used in predicting the future life of the transformer. They illustrated how to relate the health index to the rate of failure and determine a probability of failure as well as determining the remaining life of the transformer and relate this to the cost of replacing the units [16].

The above method would be most effective in established networks with constant load profiles such as those found in first world countries. For developing countries such as South Africa, Brazil and India, the above PHI would be difficult to accurately implement as the networks and loads are constantly changing as customer base increases and, the need for industrialization and infrastructure grows. There is a significant amount of maintenance data available on Eskom’s Distribution Networks but the integrity of this data varies between the different Operating Units (OUs). Until the data is verified, it may lead to inaccurate PHIs for some OUs.

Miletic presents work on medium voltage transformers where he combines the history, a visual inspection and a diagnostic inspection to formulate his index. The history includes the age, loading, fault and maintenance criteria. The visual inspection includes any identifiable defects. The diagnostic includes infrared assessment, oil quality and winding tests (this is an offline test). Importantly the index again does not consider the degree of polymerization [18].

Malik et al present a health index that look at two indices, namely, tier 1 which considers oil analysis, power factor and excitation current, operation and maintenance history and age, and tier 2 which considers turns ratio and SFRA. Tier 2 is offline, whereas tier can be done on line. Importantly the study includes information about furan analysis but does not consider the analysis in the scoring of the index, but uses the total dissolved combustible gases. They only give a single example of how the health index is applied [19].

Taengko et al develop a health index based on historical (loading, age, fault history) and condition factors (offline and online) tests. They determine the overall PHI using a matrix that correlates the two sets of information to determine the health of the transformer [20]. Haema et al present a health index that uses over 21 factors where DGA again outweighs the furan; they do include the on load tap changer in their condition assessment [11]. Satriyadi Hernanda et al formulate their PHI using DGA, oil quality and furan analysis. They also rate the DGA higher than both the oil quality and furan [21].

Scatiggio and Pompili have developed a health index that combines transformer dependent data such as dielectric and thermal conditions (DGA, furan), mechanical condition (SFRA), oil condition and non-transformer dependent data such as lightning frequency, substation layout, and re-occurrence of events at the site. They do not give details in this paper of the non-transformer dependent data; this is of importance for determining the risk of the transformer. They show that the age of the transformer cannot be used alone in determining the condition of the transformer [22].

Scatiggio and Pompili present an extension of the work to consider the number of dangerous events, and average damage per event with the health index to quantify the risk to the transformers [23].

This is an important consideration as external aspects such as lightning ground flash density, fault level at the transformer, climatic conditions can be considered part of the overall health index.

One of the fundamental issues of the published information is that there are too many factors and as such it is difficult to get the weighting correct. There is no standard for which to adhere and all the weighting factors differ dependent on the region they are applied in. The large fleet sizes of power transformers in the Eskom Distribution network means that it is not practical that all factors can be taken into account. A different system needs to be initially used and this system must be continually honed as the availability and integrity of relevant data increases. The PHI should then form one input into a risk matrix that also considers previous failures at site, external factors such as the locations, lightning density and earth resistance, and network performance.

2.5 Plant Health Index

The Eskom Plant Health Index is calculated from the oil sample results per transformer. The PHI is places a greater emphasis on paper ageing than DGA. Moisture in oil is the only oil quality index considered and is used to estimate the moisture in the paper, which again focuses on ageing of the paper. To this effect the Eskom PHI differs from the models presented by Naderian et al, Jahromi et al, Malik et al, Taengko et al and Scatiggio and Pompili [17] [16] [19] [20] [22].

The drawback of a PHI that is heavily weighted towards paper ageing is that short and medium term failures are not detected. This poses a greater operational risk for the utility with major financial implications than units failing after many decades of service. A more affective PHI would give greater consideration to the readily available DGA and oil quality indexes, in addition to the DP of the paper. If weighted correctly, this would provide a PHI that is focused on early detection of problems while still managing to provide accurate data on the end of life criteria.

The following parameters are currently being used to score the condition of each transformer [24] :

- Moisture in Paper (10%) - The ppm value of moisture in oil and the top oil temperature at the time of sampling is used to estimate the moisture in paper.

- DGA (30%) - Total dissolved combustible gases (TDCG) which looks at ppm thresholds of flammable gases in the oil is used for DGA interpretation, and

- DP (60%) – DP estimated from the presence of furans in the transformer oil is used for scoring of the transformer ageing.

In cases where oil samples have not been taken for DP analysis, the user is able to estimate the DP by using models based on the type of load experienced by the transformer and the transformers age in years. This method of DP estimation is flawed as ageing is significantly more complicated in operation than predicted by the models. The transformer load varies throughout the day and between different types of customers (e.g. domestic versus industrial). In many cases a single transformer may serve both domestic and industrial customers. Also, the model does not cater for operational issues such as leaks, and malfunctioning radiators and fans that may accelerate the ageing of the oil and paper.

In recent times, the DP analysis from oil samples have been performed on a routine basis within Eskom and all laboratories are equipped for DP analysis from furans. The models are therefore no longer needed for DP estimation.

2.5.1 Moisture in Paper (10%)

Oil moisture content and temperature of the oil are the critical input variables for this assessment. The percentage moisture in paper is calculated using a moisture indicator based on the Pipers Chart, (Figure 2-5) .This criterion carries a weight of 10% to the total PHI.

Table 6: Scoring of Moisture assessment

Moisture (10% weighting)	**Score**
% Moisture per dry-weight > 5 % and high confidence	4
5% >% Moisture per dry-weight > 3 % and high confidence	3
3% > % Moisture per dry-weight > 2 % and high confidence	2
Low moisture	1

2.5.2 Dissolved Gas Analysis (30%)

Dissolved gas is an indication of heat generation due to operating conditions as well as an indication of excessive heat due to a possible fault condition in the transformer. Heat accelerates the ageing of liquid as well as solid insulation systems. The scoring of the DGA is based on the total dissolved combustible gas analysis (TDCG). This criterion carries a weight of 30% to the total PHI.

Table 7: Scoring of DGA assessment

DGA (30% weighting)	Score
TDCG >1200	8
TDCG > 720 and CO2 less 50%	4
TDCG > 720	3
TDCG > 430	2
Low TDCG	1

2.5.3 Degree of polymerization (DP) via Furan Analysis (60%)

The DP model represents the ageing of a transformer based on the operating conditions and is used in the calculation of the PHI where the actual DP value (calculated from the analysis of furans in the oil) is not available. The different loading models are as follows [24].

DOMESTIC – is selected if the transformer is feeding domestic customers

INDUSTRIAL – is selected if the transformer is feeding industrial customers

LINEAR – is selected if the transformer feeds a combination of both domestic and industrial customers

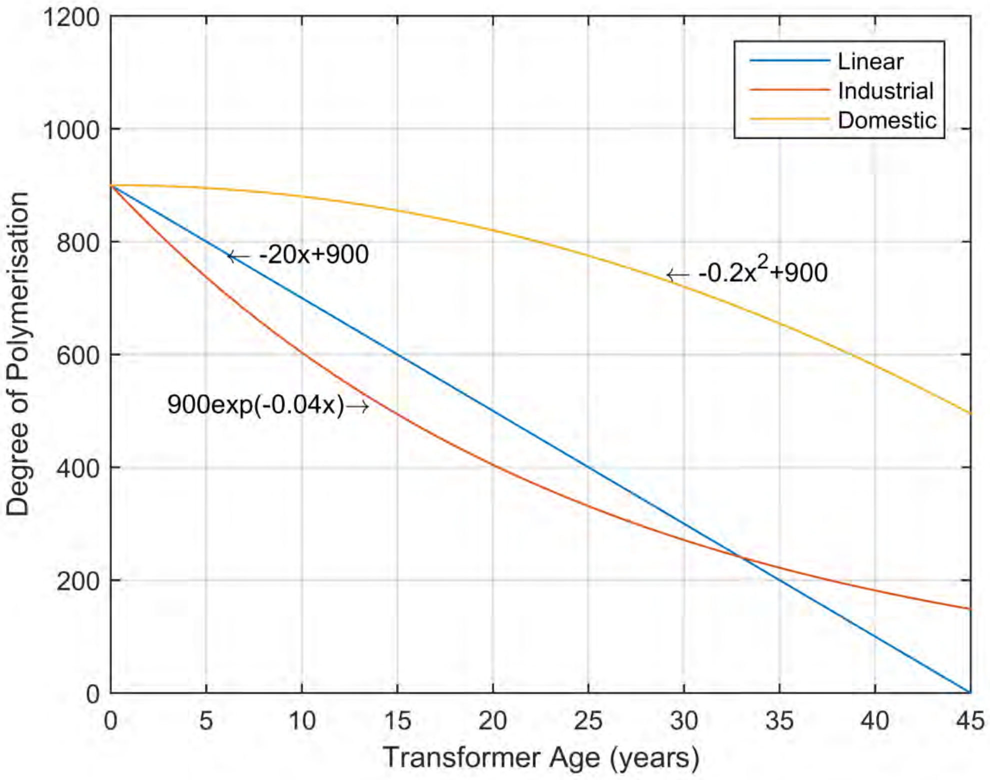

Figure 2-6: DP models for different Applications

The following table is used to score the degree of polymerisation after mapping the calculated DP against the age of the transformer using the linear model.

Table 8: Scoring of Furans assessment

DP (60% weighting)		**Score**
End of Life Criteria	Resample annual age < 35	4
Extensive Deterioration	Resample 2 Yearly (350 < Y < -20X+900)	3
Moderate Deterioration	Resample 2 Yearly (200 < Y < 350 AND Y> -20X+900	2
End of Life Criteria	Resample annual age > 35	4
Healthy	Resample 5 yearly	1

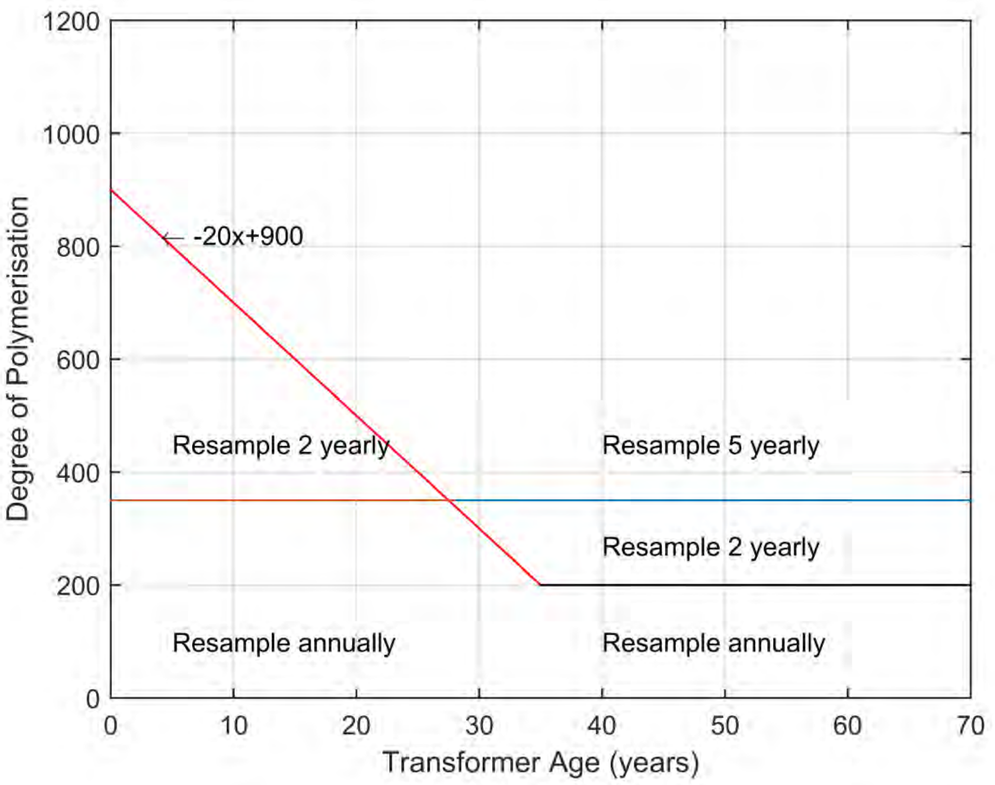

Figure 2-7: Degree of Polymerisation Graph

New paper has a DP of 1200 but a DP of 900 can be expected from a newly manufactured transformer as a result of the drying out procedures prior to final tanking of the active part. The rate of reduction in the DP is then used to determine deterioration of the paper. A DP of 200 is considered as the end of life of the paper.

2.5.4 Plant Health Index (PHI)

The plant health score is the sum of 60% DP score, 30% DGA score and 10% Moisture score. A PHI score is then assigned to each transformer using the scoring shown in Table 9.

Table 9: PHI Categories

Category Descriptions	**Score**
A – Low risk	score < 1.01
B – Low to Medium Risk	1.01 <= score <2.01
C – Medium Risk	2.01 <= score <3.01
D – High Risk	3.01 <=score

3 The Plant Health Index for Eskom Distribution's Power Transformers.

The PHI in its current guise provided an analysis of the transformers in Eskom Distribution's Power transformer fleet.

3.1 Plant Health Index Analysis

An accurate health index is imperative for effective transformer life cycle management. As a result, it is vitally important to use accurate data used for the transformer condition. This allows for the optimization of resources and allows for early detection of faults while allowing sufficient time to plan interventions to address problematic transformers. Missing and incomplete data hampers the PHI and poses an operational risk to the utility, which is stripped of the benefits of the PHI for transformers with missing or inaccurate data.

3.1.1 Transformer Age

There were 4359 transformers installed on the distribution network at the time of analysis. The transformers ranged from 1 MVA to 160 MVA units within a voltage range of 2.2 kV to 132 kV. The age profile in Figure 3-1 shows that the transformers' age varied from 1 to 83 years old. There were 42 transformers at 83 years of age installed in distribution division. There were 524 transformers (12% of all the transformers in the Division) that were missing data for a successful PHI calculation including 276 transformers (6% of all the transformers in the Division) that were missing the year of manufacture. The PHI is hampered by missing and incomplete data and poses a risk to the utility as the condition of 12% of the transformer base has not been assessed by the PHI. In cases where oil samples have not been taken for DP analysis, the utility is able to estimate the DP by using models based on the type of load experienced by the transformer and the transformers age in years. This is not possible for the 276 transformers that are missing the year of manufacture.

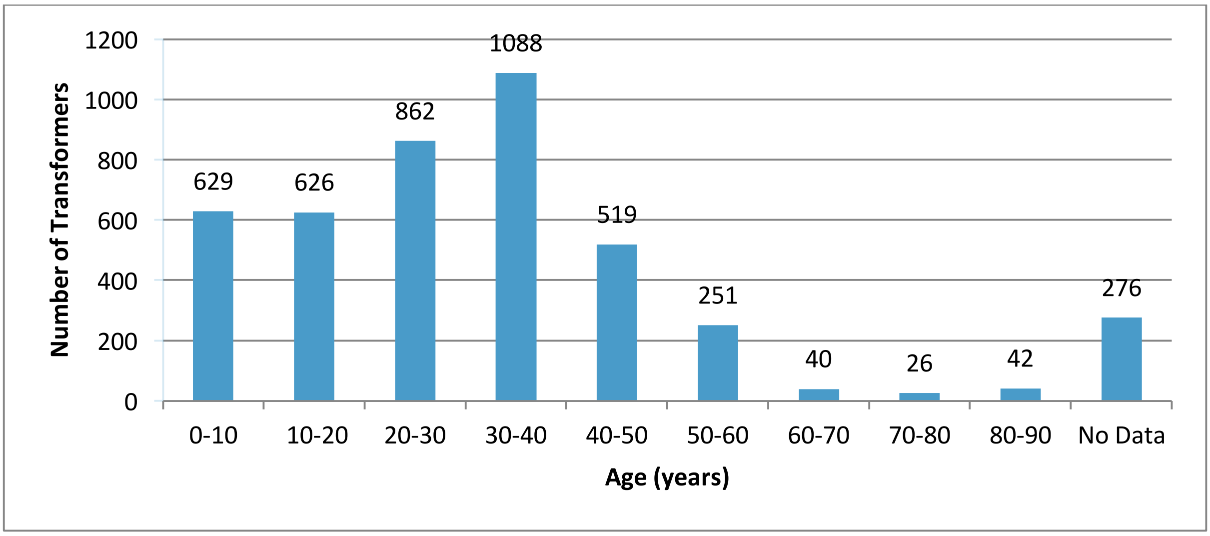

Figure 3-1: Transformers Age Analysis

3.1.2 Moisture in Paper

Figure 3-2 illustrates the number of transformers according to the categories defined in Table 6. Moisture in paper analysis was not possible for 364 transformers due to missing data or discrepancies in the data capturing. It is expected that the highest number of transformers would be in the low moisture content category and the lowest number would be in the highest moisture content category.

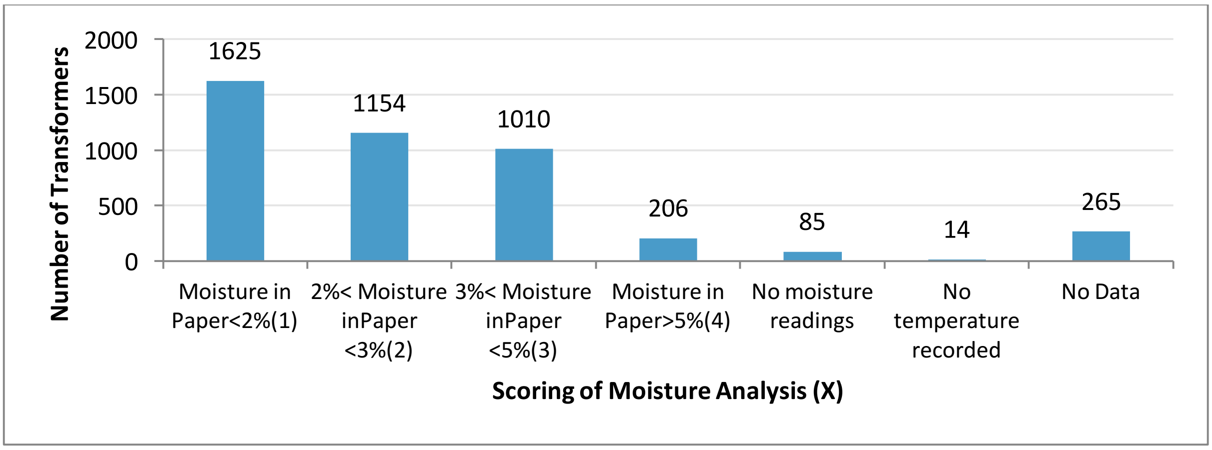

Figure 3-2: Number of Transformers per Moisture Analysis Score

3.1.3 Dissolved Gas Analysis

Figure 3-3 illustrates the number of transformers for the DGA categories defined in Table 7. It is expected that the highest number of transformers would be in the category with the lowest TDGC. Notably, the TDCG data for 335 transformers were incorrectly captured on the PHI and DGA was not possible for these transformers. This poses an operational risk to the utility as a large percentage of transformers have not been assessed for faults that could have been detected by dissolve gas analysis. Unexpected failures are possible and may negatively impact the utility.

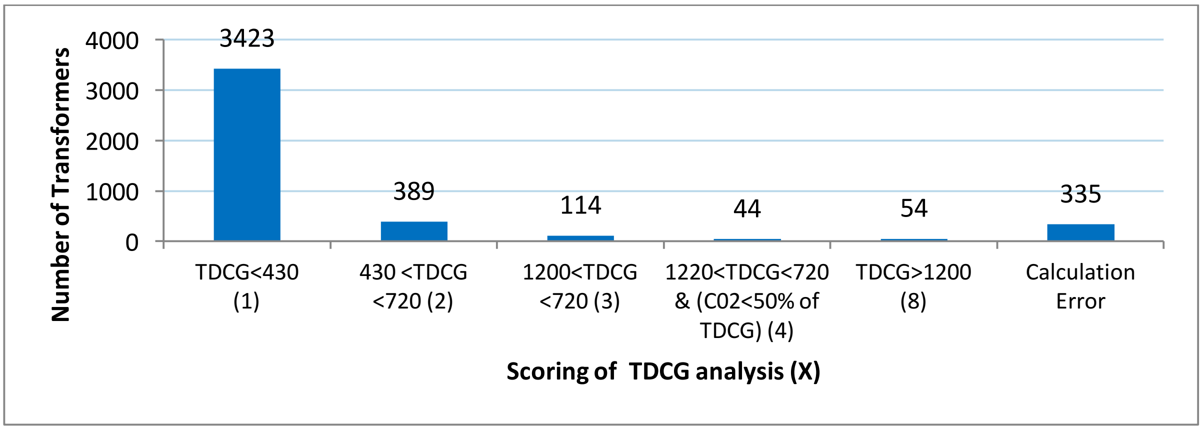

Figure 3-3: Number of Transformers per DGA Analysis Score

3.1.4 DP Analysis

Figure 3-4 illustrates the percentage of transformers against the type of DP data used i.e. whether the DP is obtained from the oil sample or from one of the models defined in Section 2.5.3. It can be seen that 80% of the DP values used the actual value, whereas 16% use estimated DPs and there was 4% of data missing. This means that 20% of the transformers in the distribution fleet do not have accurate information as will be shown later.

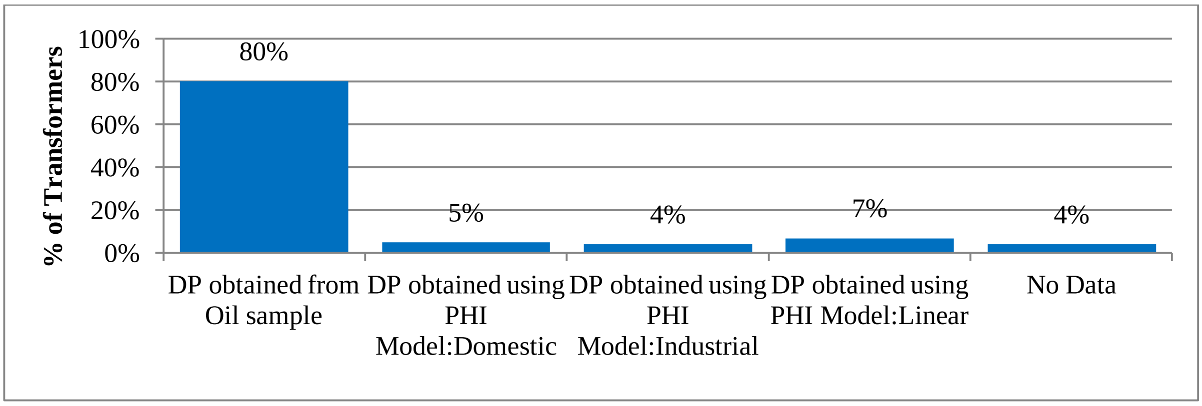

Figure 3-4: Percentage of transformers with DP obtained from Oil Analysis vs. the % of DP obtained by using the PHI Models

Figure 2-1 illustrates the number of transformers in the categories defined by Section 2.5.3. The figure illustrates that the majority of transformers have healthy paper with the next highest number being that of the paper being at end of life. Again, the ageing analysis is hampered by missing data. The risk posed to the utility is that transformers approaching end of life will go undetected and may result in unexpected failures.

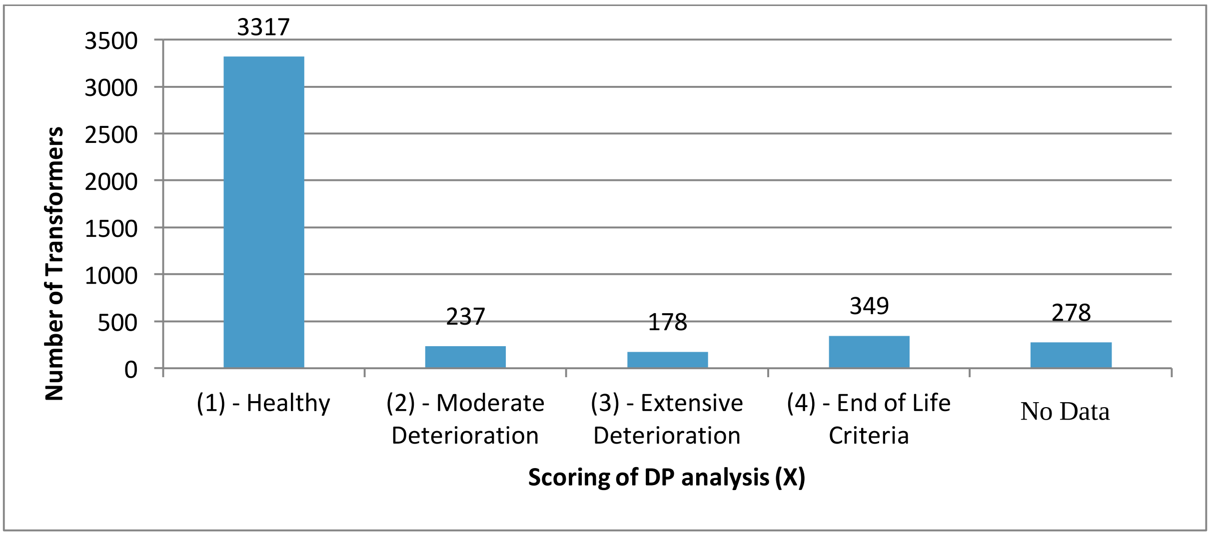

Figure 3-5: Number of Transformers per DP Analysis

3.1.5 Plant Health Index

Of the 4359 transformers in operation, there was accurate PHI data for 3835 (88% of all the transformers in the Division) units. Figure 3-6 illustrates the number of transformers per PHI category. The PHI shows that:

- 1044 (24% of all the transformers in the Division) are rated as low risk and require normal maintenance,
- 2211(51% of all the transformers in the Division) as low to medium risk, indicate minor deterioration but still require only normal maintenance,
- 436 (10% of all the transformers in the Division) as medium risk, require remedial attention and increased condition monitoring,
- 144 (3% of all the transformers in the Division) are rated as high risk, indicating severe deterioration and require immediate attention. Replacement of the unit is a distinct possibility. Electrical Diagnostic tests, furan analysis and frequent oil samples to monitor the DGA is recommended.
- 524 transformers (12% of all the transformers in the Division) that are missing data for a successful PHI calculation including 276 transformers (6% of all the transformers in the Division) that are missing the year of manufacture.

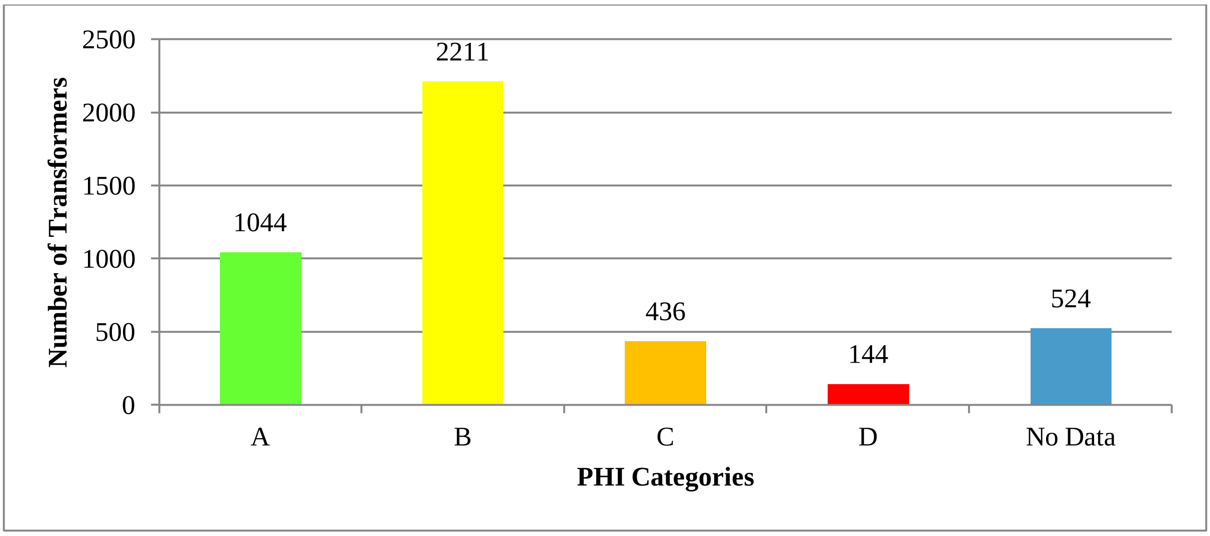

Figure 3-6: Transformers per Category

Figure 3-7 further illustrates the number of transformers per category per age. As expected, 74.7% of the transformer base fall into the low to medium risk category which requires no more than routine maintenance. 10% of the transformer base is rated at medium risk. Transformers in this category must be closely monitored such that they do not deteriorate and add to the 3.3% of transformers in the distribution fleet into the high risk category. It is envisaged that these transformers would need to be replaced in the near future. The 12% of the transformer base that do not have sufficient data for a PHI calculation have the potential to change the overall PHI outlook of the utilities transformer fleet. It is therefore imperative that the missing data is sourced for a PHI calculation.

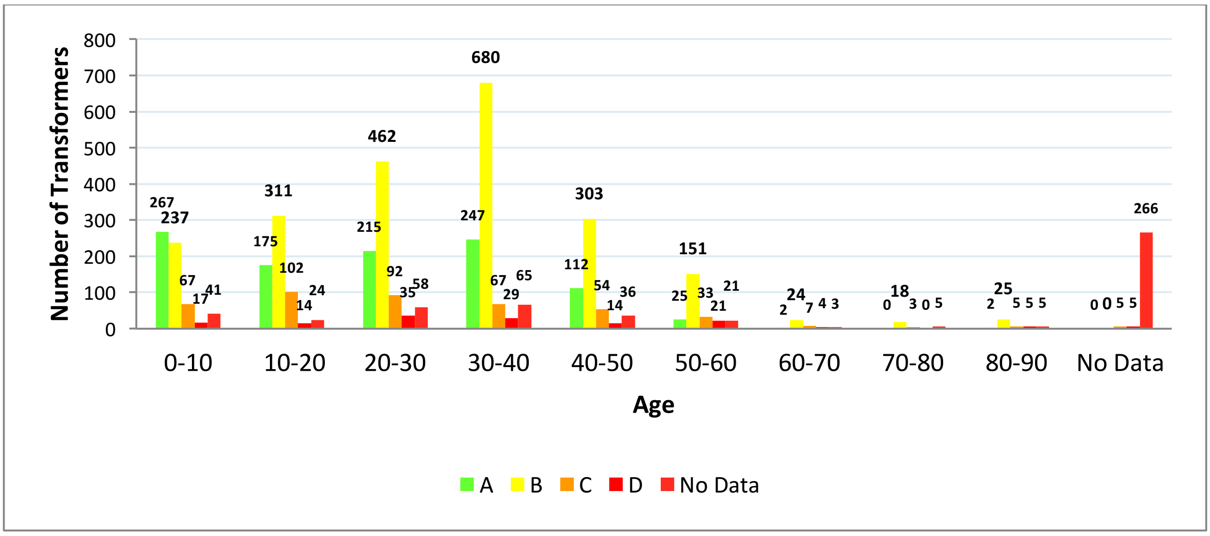

Figure 3-7: Transformers per Category per Age

The condition assessment has been performed with the intention of analysing the transformer fleet and identifying transformers that pose a risk of failure in the network. By using the assessment as a guide, distribution operating units can determine the transformers in the network that required more attention and resources can be more wisely used in order to obtain better performance and fewer transformer failures. The PHI in its current guise places a greater emphasis on paper ageing than DGA and is geared toward long term plant assessments.

The drawback of a PHI that is heavily weighted towards paper ageing is that short and medium term failures are not detected. This poses a greater operational risk for the utility with major financial implications than units failing after many decades of service. A more affective PHI would give greater consideration to the readily available DGA and oil quality indexes, in addition to the DP of the paper. If weighted correctly, this would provide a PHI that is focused on early detection of problems while still managing to provide accurate data on the end of life criteria.

The PHI performed for the Distribution Division's 4359 transformers was severely hampered by missing or incomplete data in all of the analysis categories.

Nevertheless, of the 4359 transformers, there is an accurate PHI calculation for 3835 (88%) transformers. The PHI calculation shows that 1044 (24%) of the transformers are rated as a low risk, 2211 (51%) as low to medium risk which are indicated to have a minor deterioration, 436 (10%) as medium risk which require remedial attention and increased condition monitoring, and 144 (3%) are rated as high risk which are indicating severe deterioration and require immediate attention. Replacement of the unit is a distinct possibility.

Of great concern are the 77 (2%) transformers in the 0 -10 year range that fall into PHI categories C and D. The PHI indicates premature ageing of these transformers as the PHI of the transformers in this age group should be in categories A and B. These transformers must be investigated immediately via analysing updated electrical tests, DGA and furan samples and the PHI recalculated. If these transformers still fall into category C, customized interventions based on the type of fault condition of the transformer may be required to improve the health of the transformer.

3.2 Failures

The failures of distribution power transformers since the analysis of the PHI results in September 2013 were compared to the results of the PHI model. The results are as follows:

Figure 3-8 illustrates the number of transformer failures according to the PHI classification and the OU. There were a total of 92 failures on Eskom's Distribution network since the PHI analysis in September 2013.

- 18 of the transformers that failed were classified by the PHI as category A.
- 31 of the transformers that failed were classified by the PHI as category B.
- 4 of the transformers that failed were classified by the PHI as category C.
- 5 of the transformers that failed were classified by the PHI as category D.
- 34 of the transformers that failed were not classified by the PHI due to missing information.

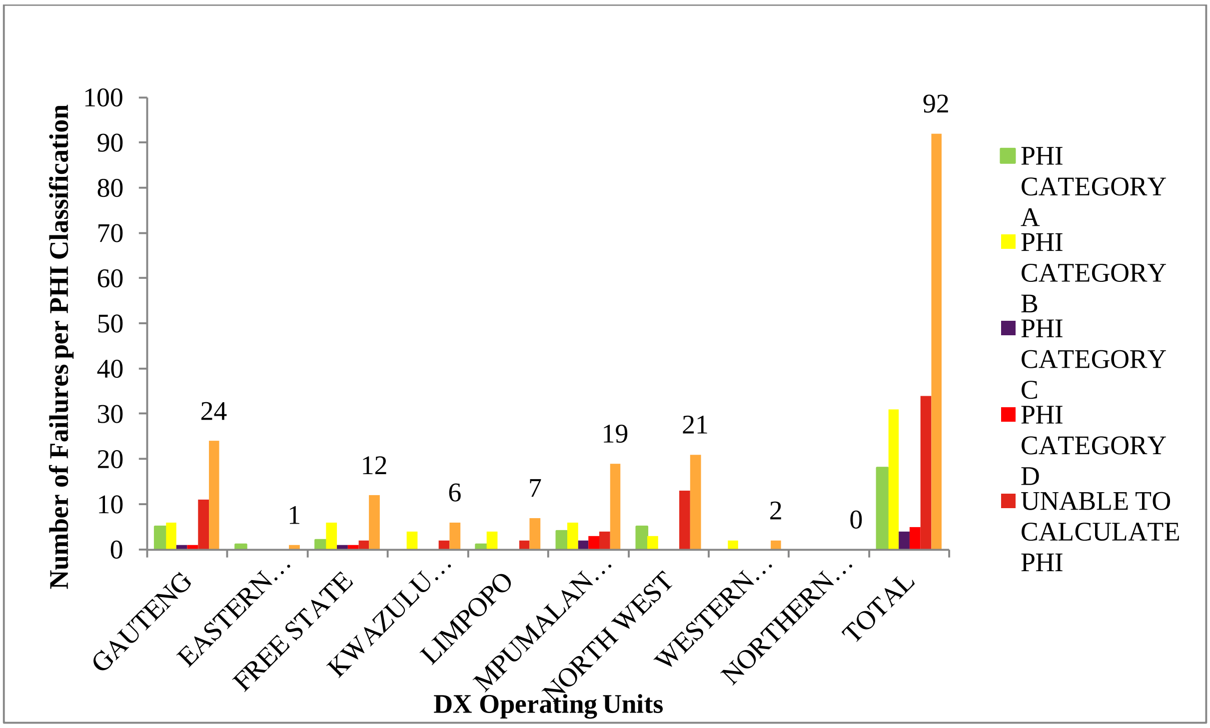

Figure 3-8: Failures of Transformers

The data shows that 34 of the transformer that failed were not classified by the PHI due to insufficient information and indicates the OUs have to greatly improve their data capturing to correctly manage the asset. It can be seen that 9 of the 92 transformers that failed were listed by the PHI as in a poor or in a very poor condition. Importantly, 49 of the transformers that failed were listed by the PHI as in a good or very good condition. This indicates that the PHI may not be serving its purpose.

Table 10 and Figure 3-9 show the failure modes of the 92 failed transformers. Mechanical damage due to faults on the distribution network was responsible for 41 of the 92 failures.

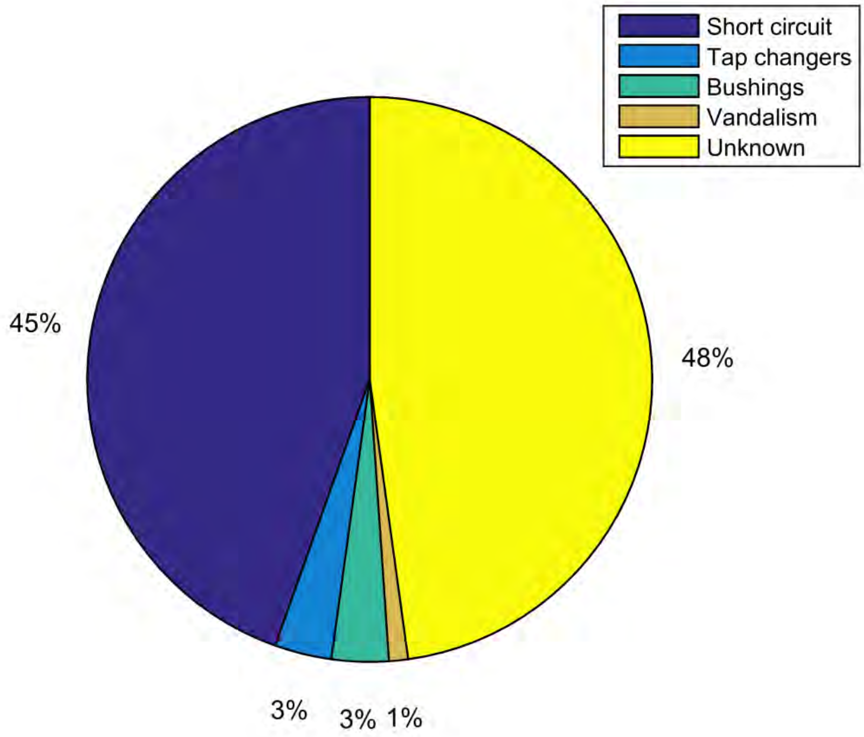

Figure 3-9: Transformer Failure Analysis

Table 10: Failures Modes

Failure Mode Information	Total
Mechanical Damage Due To Short Circuit	41
Tapchanger Failures	3
Bushing Failure	3
Vandalism	1
Data Not Available	44

As a long term health assessment tool the PHI is unable to predict these failures as they occur suddenly often without any progression on the trends of the DGA. Eskom's distribution transformers are only sampled annually and are not fitted with online gas analysers. As a result, the PHI is unable to account for the rapid changes in the condition of transformers due to the impact of network operations. In essence, a healthy transformer in an unhealthy operating environment will be prone to failure and is thus “unhealthy”.

In order for the utilities to accommodate for such eventualities the PHI must be used in conjunction with other key inputs to determine the probability of failure of the transformer. To account for mechanical forces on transformers the fault levels and performance of the network must be known [2] [17].

3.3 PHI Case Study for Gauteng Operating Unit

Gauteng Operating Unit (GOU) showed a number of failures and was used as a particular case study to critique the PHI. There was a total 925 transformers with accurate data:

- 80 transformers were not included in the PHI due to lack of data
- 26 transformers were categorised as high risk with a likelihood of failure
- The DP values of 20 transformers were calculated from furan analysis of the oil, 3 from the industrial model, 2 from the domestic model and 1 from the linear model.

The PHI score for GOU is illustrated in Figure 3-10, it can be seen that there is minimal relationship between age and the PHI score. It is also important to note that the PHI scores are clumped around 1. This may be due to the PHI score being weighted in favour of the DP and being unable to cater for short term faults such as the mechanical due to short circuit activity.

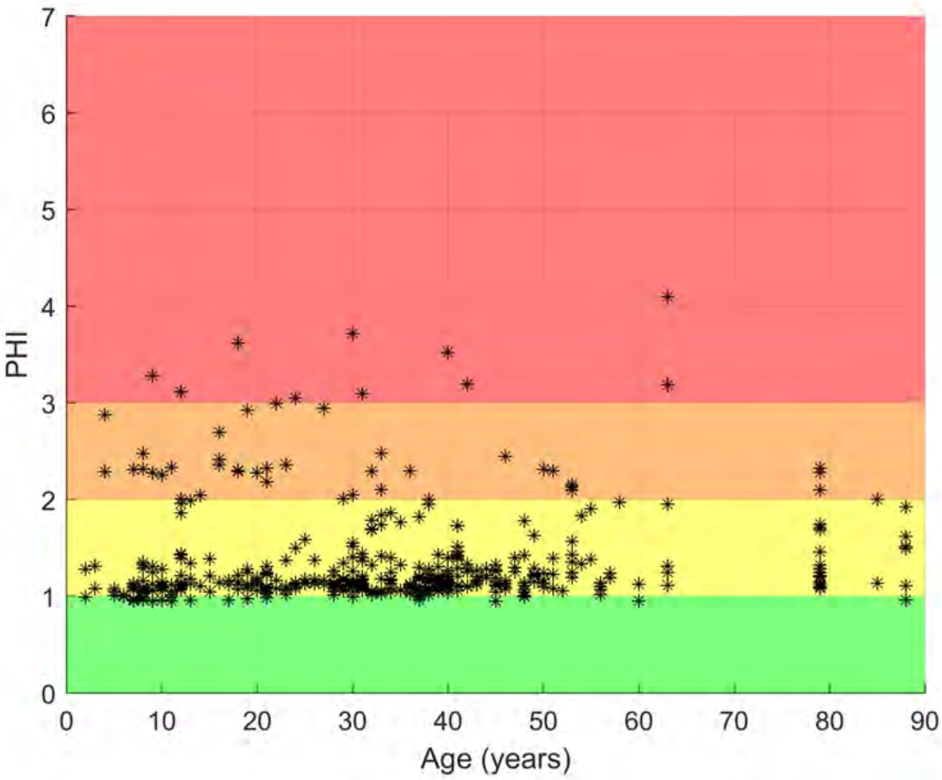

Figure 3-10: PHI in GOU

A comparison of the DP values obtained via furan analysis, to those obtained by using the domestic model showed that in some instances the model predicted more favourable DP values than the actual results obtain via oil analysis and vice versa, this is illustrated in Figure 3-11 where the DP values obtained from the oil analysis are plotted against the models. Deeper analysis into the PHI's per operating unit showed that the users were favouring the domestic model when unsure to improve their statistics. Figure 3-4 showed that 20% of transformers do not have measured values of DP, together with Figure 3-11 emphasises the importance of collecting accurate information.

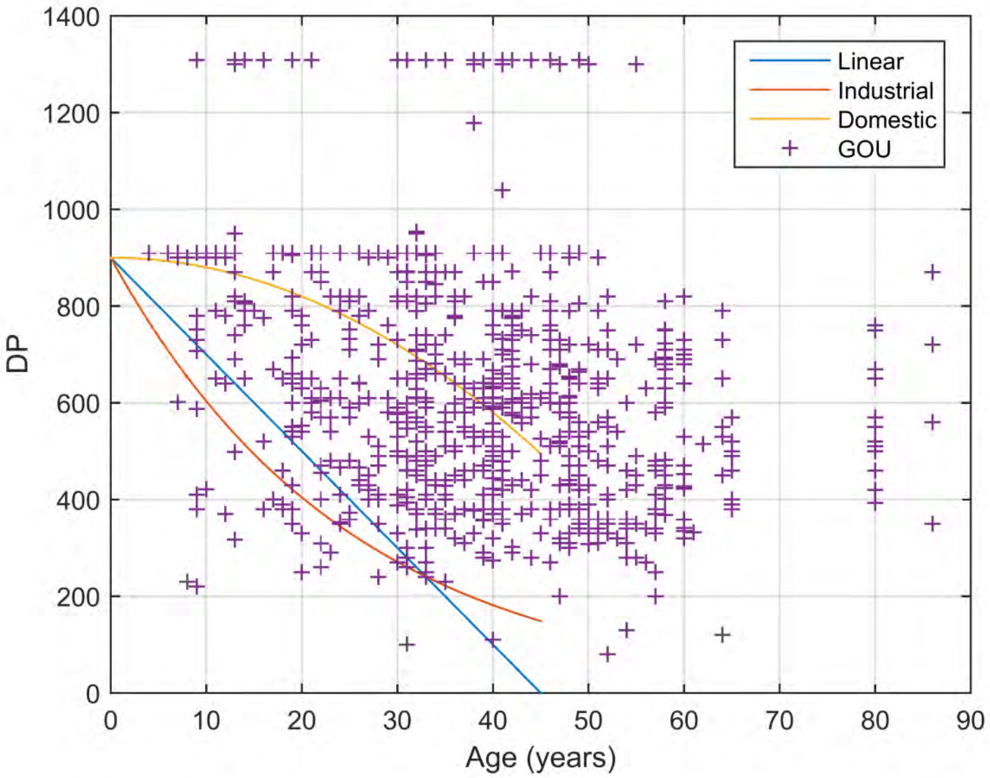

Figure 3-11: Degree of Polymerisation in GOU

Between October 2013 and September 2015, GOU experienced 33 power transformer failures. Of these failures, only 2 were listed as high risk by the PHI performed in September 2013. This indicates that the PHI is not working as desired for this operating unit, and prompted further investigations into the failures in GOU.

Analysis of the oil sample data for the transformers in the low to medium risk showed that 8 transformers had Total Dissolved Gases in excess of 1000 ppm yet were still classified as low to medium risk. Further analysis of these 8 results showed that one of the 8 transformers DGA results would be classified as having a thermal fault using the Duval's triangle for analysis, 1 of the unit's oil had an electric strength of 20 kV and 2 unit's oil had high acidity levels (0.18 and 0.44 mgKOH/g).

The findings above calls into question the use of only TDCG for DGA analysis in the PHI instead of a consensus of the different recognised methods. It also shows that long term indicators of the oil need to be taken into account when determining the risk of failure. The life of the transformer is dependent on the life of the paper, which in turn relies on the quality of the oil.

3.3.1 Analysis of Failures

At the time of the analysis, GOU possessed 24% of the Distribution Division's power transformers but contributes to 41% of all the failures in Distribution (12 Month Moving Average (12 MMA)) as listed in Table 11. The failure rate of power transformers in operation in GOU is 2.79% and is significantly higher than the 1.65% average.

Table 11: Power transformer performance

OU	Installed Base	Failures	Months	12MMA
Eastern Cape (EOU)	213	0	12	0.00%
Free State (FOU)	532	8	12	1.50%
Gauteng (GOU)	**1005**	**28**	**12**	**2.79%**
KwaZulu-Natal (KZNOU)	387	2	12	0.52%
Limpopo (LOU)	423	5	12	1.18%
Mpumalanga (MOU)	587	11	12	1.87%
Northern Cape (NCOU)	164	1	12	0.61%
North West (NWOU)	530	14	12	2.64%
Western Cape (WCOU)	331	0	12	0.00%
Distribution Total	**4172**	**69**	**12**	**1.65%**

Figure 3-12 shows the number of transformer failures per age of transformer from 2011 to 2015. It is noticeable that transformers of all ages are failing in GOU; it cannot be said that the age of the transformers are the main cause of the high failure rate or that newer designs are failing more regularly on the network. The data points to a greater problem in the OU. Analysis of the manufacturer versus the number of failures was also done and no clear trend could be determined, i.e. all makes of transformers are failing in this operating unit.

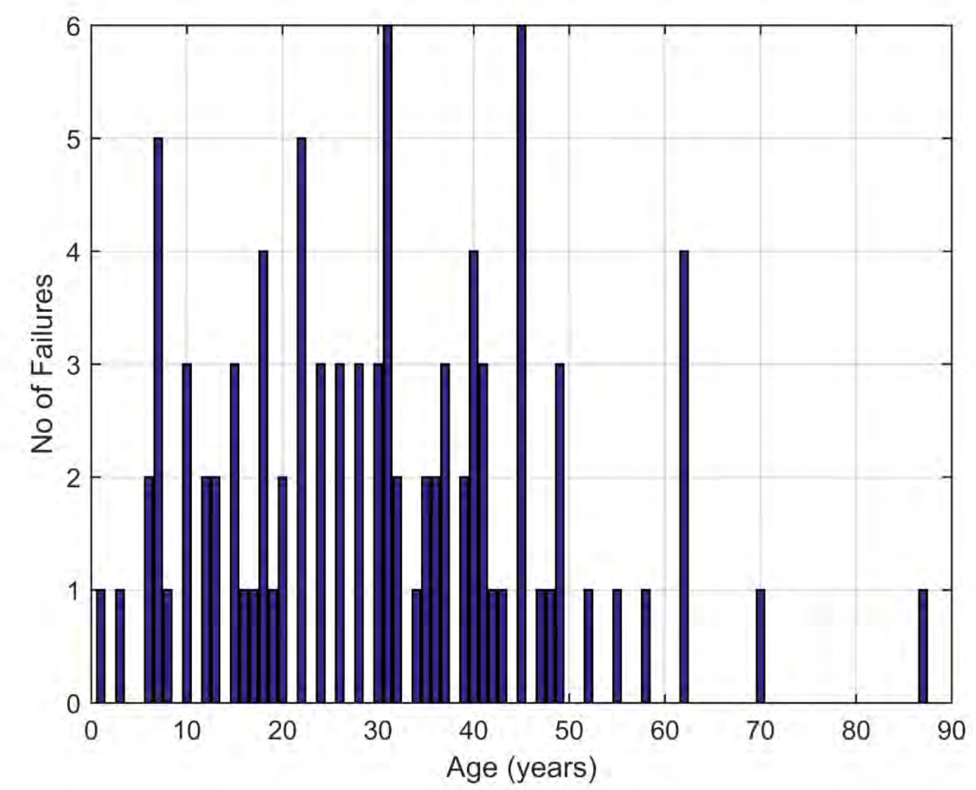

Figure 3-12: Number of transformer failures according to transformer age

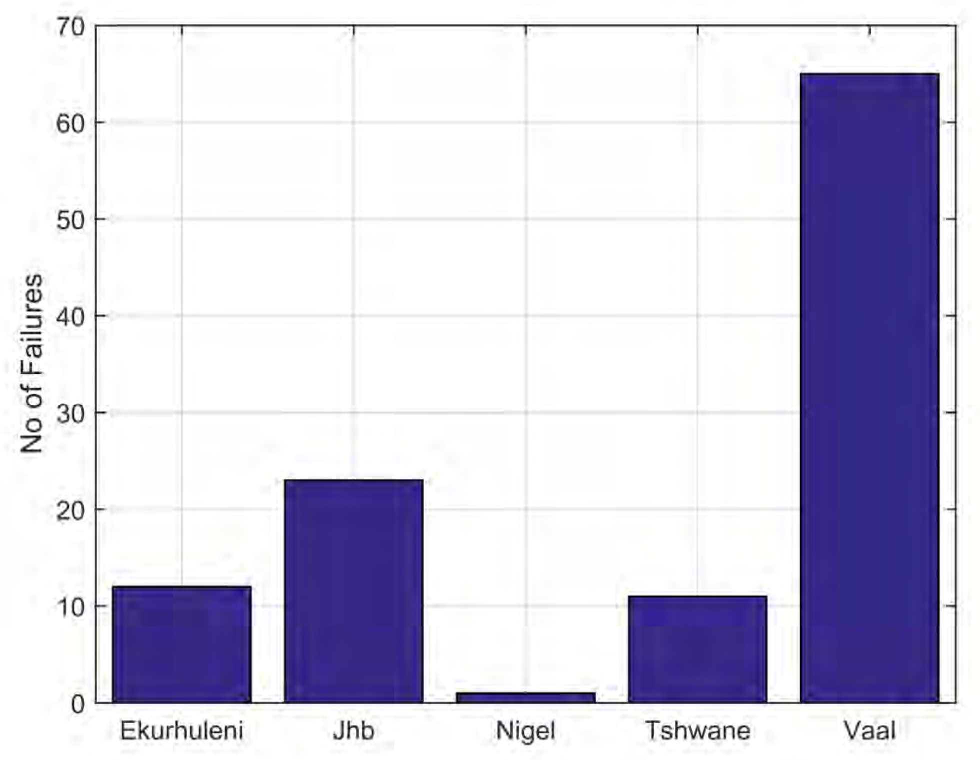

Figure 3-13: Number of failures per zone in GOU from 2011-2015

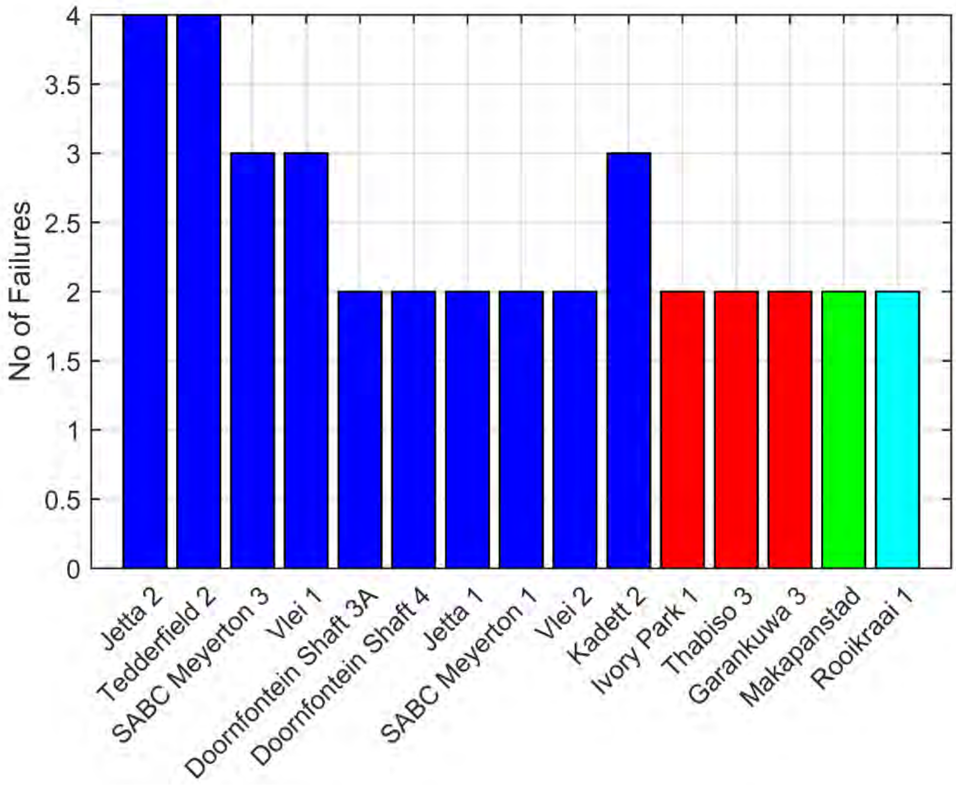

Figure 3-14: Multiple failures per substation per zone for 2011-2015

Each operating unit is separated into zones of operation. GOU contains five zones as shown in Figure 3-13 above. The statistics show that 65 failures of the 115 failures from 2011-2015 occurred in the Vaal zone (57% of GOU's transformer failures).

Figure 3-14 indicates where there are repeat transformers failures and shows the zone that they occur in. The Vaal zone has 9 transformer bays that have experienced multiple transformer failures. The failures at only these substations contributed 35 of all failures in GOU from 2011-2015.

Subsequent inspections of the substations and the surrounding networks in this area revealed that a significant number of the 22 kV networks that passed through populated settlements were overhead networks of the bare conductor type, and installed on structures built for 11 kV and 6.6 kV applications. This resulted in insufficient clearance between the conductors and hence a high number of phase to phase faults. The Vaal area is also prone to vandalism and theft, with 'wire throwing' a common tactic to lock out the circuit breakers. Thieves are then able to remove the conductor and pole mounted transformers to sell as scrap metal. Similar issues are being experienced at Ivory Park and Kadett substations in the Johannesburg zone, and recorders installed at Ivory Park transformer 1 have shown in excess of 100 through faults experienced by the transformer per month. Unsurprisingly given the operating conditions and the exposure to continuous through faults, phase to phase faults and three phase faults, the teardowns have revealed that the transformers that failed at these sites have exhibited significant mechanical damage. It is also the reason that the pending failures were not detected by the PHI as the tool is ill equipped in this regard.

3.4 Conclusions and Recommendations

It is clear that PHI while devised with the best of intention has several major drawbacks that prevent it from achieving its original target, that is to provide the operating units with a risk profile of the transformers in its fleet, and to prevent in-service failures by detecting deterioration of their condition sufficiently in advance such that the operating unit may act to prevent the failure.

The PHI has failed in the following areas and can be improved upon to be more affective:

DGA Analysis: One of the transformers listed as low-medium risk had a Total Dissolved Combustible Gases greater than 1000~ppm that would have been recognized as a developing thermal fault using other methods. Rather than using only the Total Dissolved Combustible Gases as an indication of DGA, the tool would be better served to use a consensus of the several established methods.

Long Term Health Indicators of the Oil: Analysis of the oil sample data for the transformers in the low to medium risk showed that 8 transformers had Total Dissolved Gases in excess of 1000~ppm yet were still classified as low to medium risk. Further analysis of these 8 results showed that, 1 of the unit's oil had an electric strength of 20 kV and 2 units' oil had high acidity levels (0.18 and 0.44 mgKOH/g). The long term indicators of the oil need to be taken into account when determining the risk of failure. The life of the transformer is dependent on the life of the paper, which in turn relies on the quality of the oil. In addition to the Electric Strength and acidity, the tan delta and interfacial tension of the oil must be catered for.

Degree of Polymerisation: There are 306 transformers in PHI categories C and D that have DP values below or approaching the end of life criteria (DP = 250). Of the 306 transformers; 173 have DP values obtained from oil samples and 133 have DP values obtained by using PHI DP models (Industrial, Domestic and Linear). It is evident that the models do not correctly predict the DP values. Predicted DP and DP models should be replaced by actual furans. Eskom conducts annual oil samples for DGA on all of its transformers and this practice can be extended to long term health indicators of the oil, and furan analysis.

Risk of Mechanical Failure: The analysis of the failures in Gauteng operating unit also show that mechanical factors must be incorporated into any condition/risk tool used by Eskom. Eskom distribution maintains performance files on all its circuit breakers, and power system modelling is conducted annually to determine among other things, fault levels at every substation. It is suggested that number of breaker operations be combined with fault levels, and furan analysis to produce a risk index for mechanical failure. For example, high furans in the oil combined with high fault levels and frequent breaker operations would result in a transformer with a high risk of mechanical failure. This would assist operating units such as GOU predict failures more accurately.

4 Amended Plant Health Index

This chapter proposes an amended plant health index and transformer condition risk indicator. The PHI in its current guise is heavily weighted for long term plant assessment and as a result is unable to serve the distribution business where it is needed most, i.e. short and medium term assessments. The formula for the calculation of the PHI score can be amended to place more emphasis on DGA. Additionally, the current PHI is reliant on solely TDCG for DGA analysis. For the TDCG to detect a fault in the transformer, it requires a combined ppm value for all the combustible gases to be greater than 430 ppm. It is quite foreseeable that the TDCG would fail in the early detection faults due to its reliance on a minimum ppm threshold of combustible gases and therefore incorrectly classify a transformer with an infancy fault condition as operating normally. A better solution would be to incorporate some of the other well-known methods for gas analysis together with the TDCG. Methods that employ analysing the ratio of the gases present in the oil will negate the drawbacks of solely considering the ppm value of gases in the oil. It is recommended that the basic gas ratio and the Eskom LTPHI method be incorporated into the scoring for DGA. Duval's triangle and the key gas method will not be able to be used for the PHI as it does not recognise a normal condition and hence can only be used for identification of faults once it is determined that there is a problem with the transformer.

The current PHI also ignores the importance of the oil quality in the longevity of the transformer. The life of the transformer is ascertained by the life of the paper, which in turn is relies on the quality of the insulating oil. Since the quality of the oil plays a major role in the insulation system of the transformer and if allowed to oxidize, sludge and degrade will place the transformer at a greater risk of failure, it should also be represented in any health assessment of transformers.

4.1 Amended Index

The amended plant health index (APHI) is illustrated in Figure 4-1, this index endeavours to account for the shortcomings of the current PHI by accounted for the aspects that were critiqued.

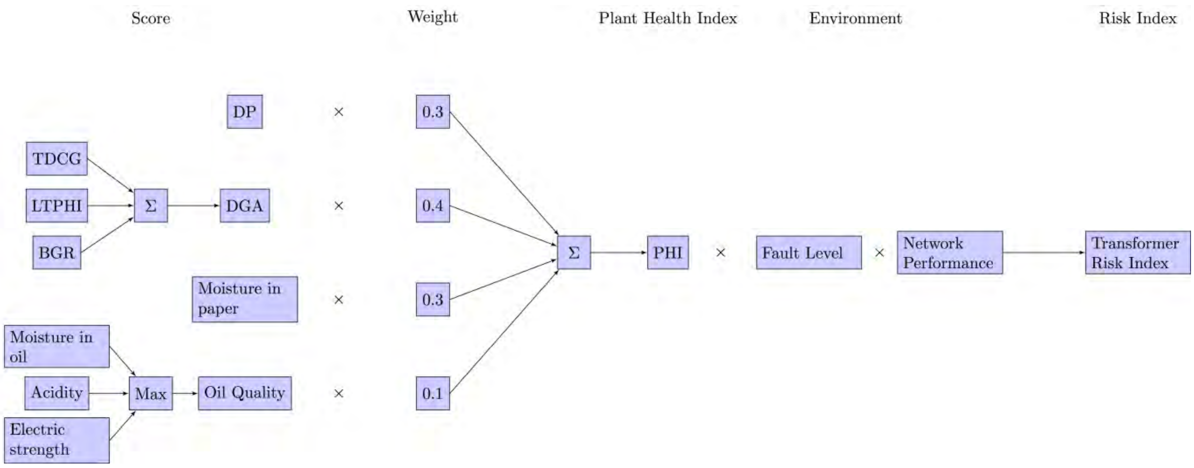

Figure 4-1: Amended Plant Health Index

4.1.1 Moisture in Paper (30%)

Oil moisture content and temperature of the oil are the critical input variables for this assessment. The percentage moisture in paper is calculated using a moisture indicator based on the Pipers Chart. Table 12 lists the criteria and scoring of the moisture in paper and the criterion. This criterion carries a weight of 30% of the total APHI.

Table 12: Scoring of moisture in paper assessment

Moisture (30% weighting)	**Score**
% Moisture per dry-weight > 5 % and high confidence	4
5% >% Moisture per dry-weight > 3 % and high confidence	3
3% > % Moisture per dry-weight > 2 % and high confidence	2
Low moisture	1

4.1.2 Dissolved Gas Analysis (30%)

Another weakness of the PHI is its reliance on solely TDCG for DGA analysis. For the TDCG to detect a fault in the transformer, it requires a combined ppm value for all the combustible gases to be greater than 430 ppm. Floating potential and early stage discharge type faults are generally typified by low levels of acetylene (10-50ppm) and hydrogen (100ppm) with small amounts of methane (10-50ppm), ethane (10-50ppm) and ethylene (10-50ppm) also present. It is quite foreseeable that the TDCG would incorrectly classify a transformer with such a fault condition as operating normally.

A better solution would be to incorporate some of the other well-known methods for gas analysis together with the TDCG. Methods that employ analysing the ratio of the gases present in the oil will negate the drawbacks of solely considering the ppm value of gases in the oil. It is recommended that the basic gas ratio and the Eskom LTPHI method be incorporated into the scoring for DGA. Duval's triangle and the key gas method will not be able to be used for the APHI as it does not recognise a normal condition and hence can only be used for identification of faults once it is determined that there is a problem with the transformer.

The dissolved gas analysis described in Section 2.3.1 consists of three components:

- The basic gas ratio, shown in Table 13, which carries a weighting of 40%
- The total dissolved combustible gases, shown in Table 14, which carries a weight of 30%
- The LTPHI, shown in Table 15, relates the quantity of the individual dissolved gas to a score. The highest score is used for this component.

Table 13: Scoring of Basic Gas Ratio Assessment

The Basic Gas Ratio (40% weighting)	**Score**
D1	2
D2	5
T1	2
T2	3.5
T3	5
PD	3

Table 14: Scoring of TDCG assessment

TDCG (30% weighting)	**Score**
TDCG >1200 ppm	8
TDCG > 720 ppm and CO2 less 50%	4
TDCG > 720 ppm	3

TDCG > 430 ppm	2
Low TDCG	1

Table 15: Scoring of LTPHI assessment

LTPHI (30% weighting)			Score
C2H2	<	5 ppm	0
	>	5 ppm	4
	>	15 ppm	6
	>	35 ppm	8
H2	<	50 ppm	0
	>	50 ppm	4
	>	150 ppm	6
	>	250 ppm	8
C2H6	<	50 ppm	0
	>	50 ppm	4
	>	100 ppm	6
	>	150 ppm	8
C2H4	<	50 ppm	0
	>	50 ppm	4
	>	100 ppm	6
	>	150 ppm	8
CH4	<	75 ppm	0
	>	75 ppm	4
	>	150 ppm	6
	>	250 ppm	8
CO	<	500 ppm	0
	>	500 ppm	1
	>	750 ppm	2.5
	>	1000 ppm	4

The DGA assessment is a combination of the three components as shown in Table 16.

Table 16: Weighting of DGA assessment

DGA (30% weighting)	**Score**
Basic Gas Ratio	0.4
TDCG	0.3
LTPHI	0.3

4.1.3 Oil Quality (30%)

Another method of improving the PHI would be to include oil quality parameters. The life of the transformer is ascertained by the life of the paper, which in turn is relies on the quality of the insulating oil. The oil provides dielectric strength, and facilitates cooling of the transformer. The quality of the oil plays a major role in the insulation system of the transformer and if it is allowed to oxidize, sludge and degrade, it will place the transformer at a greater risk of failure. It should therefore be represented in any health assessment of transformers. The key oil quality indexes are electric strength, moisture in the oil, acidity, dissipation factor (tan delta) and interfacial tension (IFT). Until then the electric strength, moisture in and acidity can be used ascertain a score for oil quality. All three parameters are readily available.

The oil quality score consists of:

- Moisture in oil, shown in Table 17
- Electric field strength, shown in Table 18
- Acidity, shown in Table 19

The maximum or the highest value of the scores is used.

Table 17: Scoring of Moisture in Oil Assessment

Moisture in Oil	**Score**
Moisture > 40 ppm	30
20 ppm < Moisture < 30 ppm	10
10 ppm < Moisture < 20 ppm	4
Moisture < 10 ppm	2

Table 18: Scoring of Electric Field Strength assessment

Electric Field Strength	**Score**
Electric field Strength < 40 kV/mm	30
50 kV/mm < Electric field Strength <= 40 kV/mm	12
60 kV/mm < Electric field Strength <= 50 kV/mm	5
>60 kV/mm	0

Table 19: Scoring of Acidity Assessment

Acidity	**Score**
0.25 mg KOH/g < Acidity < 0.4 mg KOH/g	30
0.1 mg KOH/g < Acidity < 0.25 mg KOH/g	12
Acidity < 0.1 mg KOH/g	5

4.1.4 Degree of polymerization (DP) via Furan Analysis (30%)

The accuracy of the PHI can be further enhanced by removing the option of using the DP models for DP prediction. As all of Eskom's transformers are sampled at least once a year for oil quality and DGA, it is possible to take oil samples for furan analysis at the same time. Annual DP analysis will also allow for trending of the DP and will allow rate of change analysis rather than using the absolute value of the DP.

Table 20: Scoring of Furans assessment

Degree of Polymerisation		**Score**
End of Life	Resample annual age < 35	4
Extensive Deterioration	Resample 2 Yearly (350 < Y < -20X+900)	3
Moderate Deterioration	Resample 2 Yearly (200 < Y < 350 AND Y> -20X+900	2
End of Life	Resample annual age > 35	4
Healthy	Resample 5 yearly	1

4.1.5 APHI Score

The expected life of a transformer in the Eskom Distribution network is 40 years and it is not expected that the paper will degrade to catastrophic proportions in the first 10 to 15 years, even if highly loaded. By reducing the weighting of the DP score and increasing the weighting of the DGA score will assist in the detection of problems in the medium term, and even short term if the sampling frequency for unhealthy units is increased – transformers that fall into Category D should be sampled every three months, those in Category C should be sampled every six months while those transformers listed in Categories A and B should be sampled annually.

The APHI score is the sum of 30% DP score, 40% DGA score, 30% moisture score and 10% oil quality. A PHI score is then assigned to each transformer using the scoring shown in Table 21 and Figure 4-2.

Table 21: APHI Categories

Category Descriptions	**Score**
A – Low risk	score < 1.01

B – Low to Medium Risk	1.01 <= score <2.01
C – Medium Risk	2.01 <= score <3.01
D – High Risk	3.01 <=score

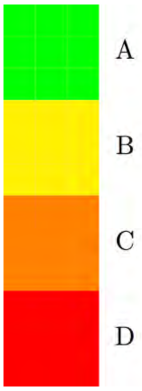

Figure 4-2: APHI Categories

4.1.6 Transformer Risk Index

The PHI is taken further to account for the network characteristics

- A fault level score, shown in Table 22, is used to quantify the fault level of the network where the transformers is installed. The higher the fault level the more likely the transformer will experience damage to the windings in the event of a fault.

- Network performance score, shown in Table 23, where a score is assigned according to the occurrence of faults on the particular network. Breaker operations, which would include load shedding and faults on the network, dips on the network, reference to the location. It is currently difficult to quantify or trend as this information is not currently recorded.

These scores are in the form of multipliers as illustrated in Figure 4-1 and are combined with the PHI or APHI to give a risk index. Figure 4-3 illustrates how the PHI is combined with the to give a more appropriate risk index.

Table 22: Fault Level Score

Category Descriptions	Score
Low <=3000A	1
Medium >3000A and <=5000A	2
High >5000A	3

Table 23: Network Performance Score

Category Descriptions	Score
Good	1
Moderate	2
Poor	3
Very Poor	5

Table 24: Risk Index Categories

Category Descriptions	Score
A – Low risk	score < 1.01
B – Low to Medium Risk	1.01 <= score <2.01
C – Medium Risk	2.01 <= score <3.01
D – High Risk	3.01 <=score

Figure 4-3: Risk Index Categories

4.2 Case Study 1 – Jetta Substation

Case Study 1 investigates the effect of fault level and network performance on the risk index. Jetta substation in Gauteng OU has suffered multiple transformer failures due issues on the 22 kV network. The 22 kV uncovered conductors are strung along towers meant for 11 kV covered conductors. As a result, the network is prone to phase to phase faults and to three phase faults (due to vandalism – vandals throw chains across the uncovered conductors, creating a three phase fault and causing the pole mounted circuit breakers to lock out. The conductors are then stolen). Even though the fault levels are low, the continuous faults eventually result in mechanical damage to the medium voltage windings of the transformer. At present, the substation is operating with two 20 MVA transformers that are approximately 8 years old. Both transformers have DPs of 910. There are no concerns with respect to the DGA as the total dissolved gases for both transformers are below 430 ppm, indicating normal operation. The PHI also indicates that there is very little moisture in the paper of the transformer. The PHI therefore lists both transformers in a good condition.

Table 25: PHI for the Transformers at Jetta Substation

Substation	MVA	Age	DP	TDCG	Moisture Score	PHI Score	PHI
Jetta 88/22/11kV	20	8	910	180	2	1.09	B
Jetta 88/22/11kV	20	7	910	57	1	0.96	A

This gives a false impression of the situation at Jetta substation as the transformers are at a high risk of failure while the defects on the network remain unattended. A more accurate assessment would be to incorporate the PHI with appropriate measures taken into account the fault level and the network performance. An example of this is shown in Table 26, where it can be seen that the risk of failure is quantified.

Table 26: Risk of Failure for the Transformers at Jetta Substation

Substation	PHI Score	PHI	Fault Level	Network Performance	Risk Index	Risk of Failure
Jetta	1.09	B	Low	Very Poor	5.44	Very High
Jetta	0.96	A	Low	Very Poor	4.61	Very High

4.3 Case Study 2 – PHI Comparison with Poor Quality Oil

Case Study 2 investigates the effect of oil quality on the health index with the details of the transformer found in Table 27.

Table 27: Transformer Details for Case Study 2

Substation	MVA	Age	DP	TDCG	Moisture
MODDER SHAFT TRFR 1	5	12	910	249	215

Table 28 illustrates the results for a transformer with the PHI shown in blue against the APHI shown in green.

Table 28: Comparison of PHIs for Case Study 2

DP Score	DGA Score	Moisture Score	PHI Score	PHI	APHI	APHI Score	Moisture in Paper Score	DGA Score	Oil Quality Score
1	1	5	1.40	B	D	5.5167	5	3.67	30

This example shows an appreciable jump in the score from 1.4 to 5.5. With the DP being common between the two, it is clear that oil quality and DGA have heavily influenced this elevation in health index categorization. To determine whether this increase is warranted, a look at the oil sample values is required. This is shown in the tables below.

Table 29: Oil Sample Results for Case Study 2

Moisture (ppm)	Electric Strength (kV/mm)	Acidity mg KOH/g	Sampling Temperature (°C)
215	15	0.04	20

Table 30: Dissolved Gas Content for Case Study2

H2 (ppm)	O2 (ppm)	N2 (ppm)	CH4 (ppm)	CO (ppm)	CO2 (ppm)	C2H6 (ppm)	C2H4 (ppm)	C2H2 (ppm)
63	9083	45206	11	152	2260	2	12	9

Table 29 and Table 30 illustrate that the poor oil quality value is as a result of the extremely low (E_S = 15 kV/mm) electric strength of the oil and the high moisture content (215 ppm). Eskom's minimum threshold for electric strength and moisture for new oil is E_S = 70 kV, moisture = 20 ppm. This provides an indication of how severely the oil has deteriorated. As this is not a factor in the PHI and negatively impacts the longevity of the transformer, the APHI is an improvement. With such a low electric strength, the high risk attributed to this transformer is warranted.

4.4 Case Study 3 – PHI Comparison with high DGA score

Case Study 3 investigates the effect of a high DGA on the health index with the details of the transformer found in Table 31.

Table 31: Transformer Details for Case Study 3

Substation	MVA	Age (years)	DP	TDCG (ppm)	Moisture (ppm)
RATANDA TRFR 1	10	37	910	326	10

Table 32 illustrates the results for a transformer with the PHI shown in blue against the APHI shown in green. The greater emphasis on DGA in the A PHI is due to the introduction of a short term DGA diagnostic tool, the Basic Gas Ratio, into the DGA score. The inclusion of this tool is intended to reduce the prediction horizon as this diagnosis is performed annually. It is imperative that the gas composition be included in the analysis to supplement the TDCG as a means to improve diagnostic reliability. This is achieved to some extent as deficiencies in one tool are covered by the other.

Table 32: Comparison of PHIs for Case Study 3

DP Score	DGA Score	Moisture Score	PHI Score	PHI	APHI	APHI Score	Moisture in Paper Score	DGA Score	Oil Quality Score
1	1	2.78	1.18	B	D	3.134	2.78	**5**	0

In this case study, the elevated PHI is due to the sharp increase in the DGA score from 1 to 5. The reason behind the increase is supported by the gas composition in the Table 33 and Table 34.

Table 33: Oil Sample Results for Case Study 3

Moisture (ppm)	Electric Strength (kV/mm)	Acidity mg KOH/g	Sampling Temperature (°C)
10	65	0.02	35

Table 34: Dissolved Gas Content for Case Study 3

H2 (ppm)	O2 (ppm)	N2 (ppm)	CH4 (ppm)	CO (ppm)	CO2 (ppm)	C2H6 (ppm)	C2H4 (ppm)	C2H2 (ppm)
37	21167	50292	28	84	626	3	59	**115**

The high level of acetylene (C2H2) indicates that discharges are occurring in the transformer. The Basic gas ratio and Duval's Triangle Figure 4-4both indicate that this is the case.

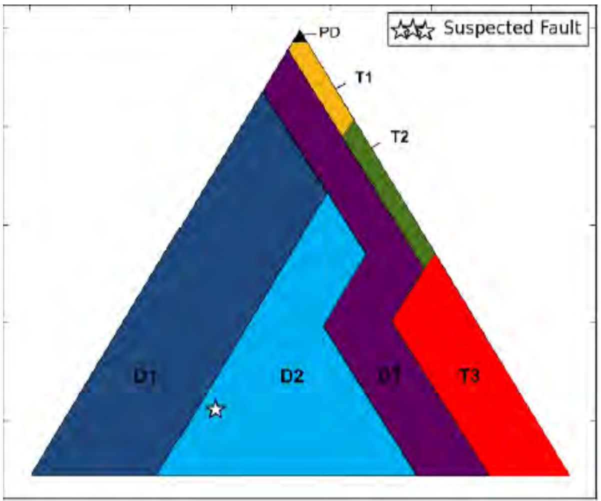

Figure 4-4: Duval's triangle for the transformer in Case Study 3

The elevation in risk from category B to category D is therefore warranted. The PHI incorrectly rated the transformer as in a low to medium risk, as it failed to recognize the discharge type fault as the combined total dissolved gases were less than 430 ppm.

4.5 Case Study 4 – PHI Comparison with low DGA score

Case Study 4 investigates the effect of a low DGA on the health index with the details of the transformer found in Table 35.

Table 35: Transformer Details for Case Study 4

Substation	MVA	Age (years)	DP	TDCG (ppm)	Moisture (ppm)
MANOR TRFR 1	40	12	1300	2789	7

Table 36 illustrates the results for a transformer with the PHI shown in blue against the APHI shown in green. The index is downgraded from a D to a C. This is because the PHI uses only the TDCG to gauge the DGA risk weighting. In the APHI, the DGA score is taken from a combination of 3 analyses to even out the deficiencies of each method. The oil sample results and the gas composition in the oil are listed in Table 37 and Table 38.

Table 36: Comparison of PHIs for Case Study 4

DP Score	DGA Score	Moisture Score	PHI Score	PHI	APHI	APHI Score	Moisture in Paper Score	DGA Score	Oil Quality Score
1	8	1.18	3.12	D	C	2.654	1.18	5	0

Table 37: Oil Sample Results for Case Study 4

Moisture (ppm)	Electric Strength (kV/mm)	Acidity mg KOH/g	Sampling Temperature (°C)
7	72	0.01	58

Table 38: Dissolved Gas Content for Case Study 4

H2 (ppm)	O2 (ppm)	N2 (ppm)	CH4 (ppm)	CO (ppm)	CO2 (ppm)	C2H6 (ppm)	C2H4 (ppm)	C2H2 (ppm)
9	1707	60769	**277**	208	2571	**2259**	36	0

The total dissolved gases in the oil for this transformer is above 1200 ppm and is hence rated as high risk by the current PHI. The APHI, however, recognizes that the high levels of ethane (C2H6) and methane (CH4) are indicative of low level heating. This condition is not ideal but is of a lower priority than severe overheating (Ethylene C2H4, Methane CH4) and discharge type (Acetylene C2H2, Hydrogen H2), and can be continuously managed by monitoring oil sampling, infrared scans and loading without effecting supply. Should future oil samples indicate an increase in Ethylene C2H4 and Methane CH4, the risk would be graded in Category D.

4.6 Reclassification according to APHI in GOU

The transformers are rescored and classified using the APHI as illustrated in Figure 4-5 and Figure 4-6. In comparison to Figure 3-10, it can be seen that there is less clumping around the score of 1 and the APHI have become significantly more distributed. It can be seen in Figure 4-6 that over 50 transformers previously categorised in category B have moved to categories C and/or D. This is expected as the APHI accounts for short and medium term components.

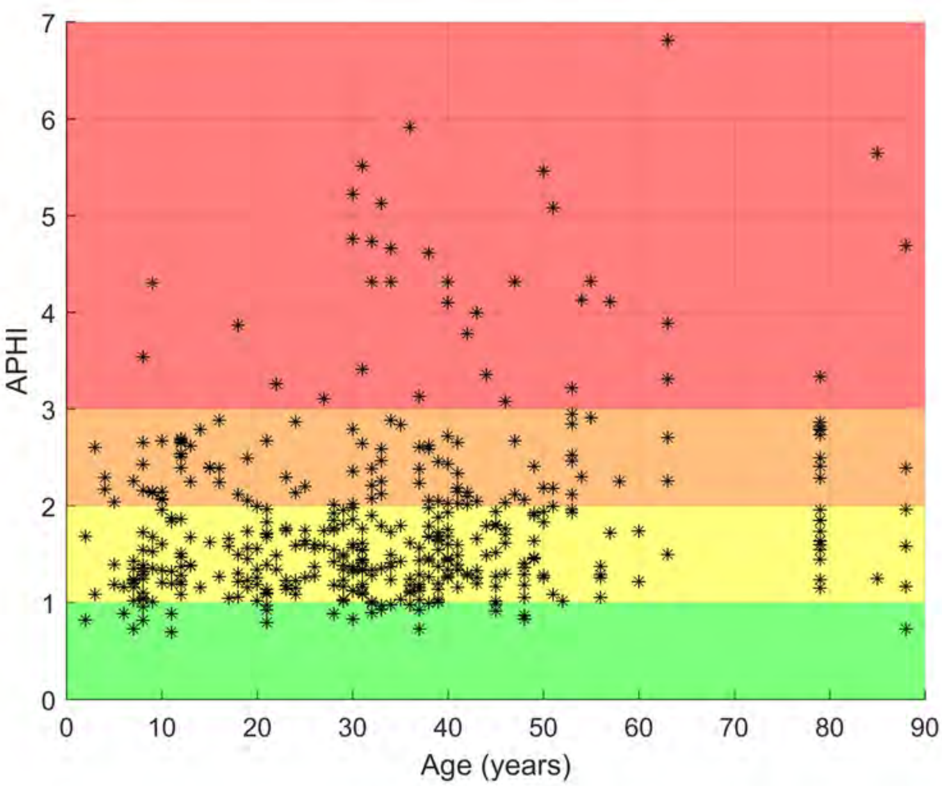

Figure 4-5: Rescoring of Transformers in GOU

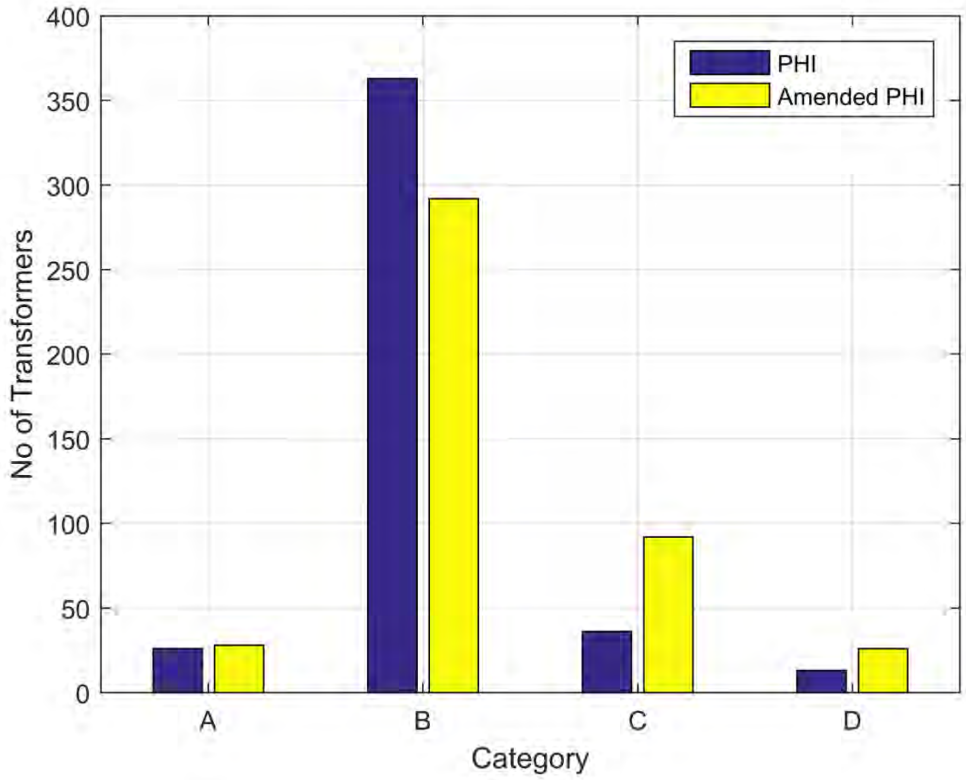

Figure 4-6: Reclassification of Transformers in GOU

Naderian [17] [25] reported a similar trend where the majority of transformers were in low risk category and significant proportion were in the fair to higher risk categories, the age of the transformers was not clear. The sample size was over 1000.

In Figure 3-8 the failures according to the PHI categories are shown. The results are reproduced by in Figure 4-7, by using the ratios of the PHI to APHI in each category it can be seen that the no of failed transformers in categories C and D increases.

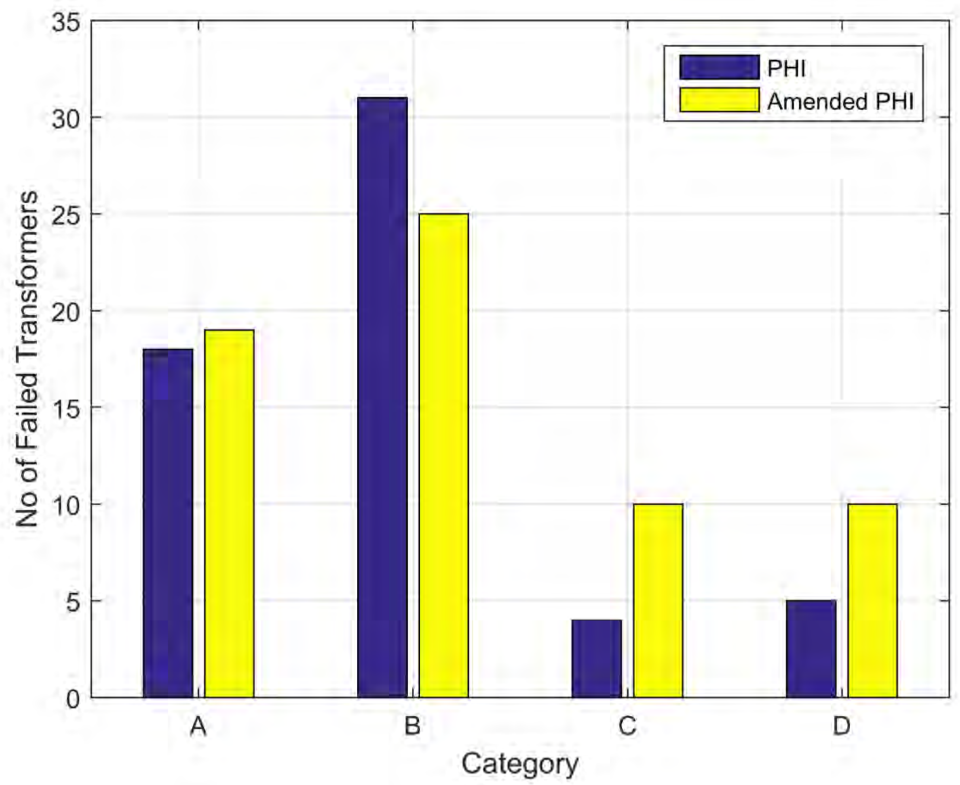

Figure 4-7: Reclassification of Transformers Faults for all of Distribution Transformers

The addition of the network performance and fault level scores would further categorise the risk posed to transformers (i.e. as they are in the form of multipliers, they can only move to a higher score). At the time of writing there was not enough information to track the failure rates of the categories. This information would allow for further improvement of the APHI, particularly the scales of the risk index components.

5 Conclusion

The PHI in its current guise does not meet the immediate need for the Distribution Division of Eskom. As can be seen from the correlation of transformer failures to the prediction model, 49 of the last 92 transformers that failed were categorised as being in a good or very good condition by the PHI. 41 of the 92 failures were attributed to mechanical damage to the transformer due to faults on the distribution network. As a long term health assessment tool the PHI is unable to predict these failures as they occur suddenly often without any progression on the trends of the DGA. As a result, the PHI is unable to account for the rapid changes in the condition of transformers due to the impact of network operations. In essence, a healthy transformer in an unhealthy operating environment will be prone to failure and is thus “unhealthy”.

In order for the utilities to accommodate for the detection of short and medium term failures, the PHI must be used in conjunction with other key inputs to determine the probability of failure of the transformer. To account for mechanical forces on transformers the fault levels and performance of the network must be known. This information is easily readily available to the utility and is easily implementable.

The formula for the calculation of the PHI score can be amended to place more emphasis on DGA to cater for short and medium term assessments. Another weakness of the current PHI is its reliance on solely TDCG for DGA analysis. For the TDCG to detect a fault in the transformer, it requires a combined ppm value for all the combustible gases to be greater than 430 ppm. It is quite foreseeable that the TDCG would fail in the early detection faults due to its reliance on a minimum ppm threshold of combustible gases and therefore incorrectly classify a transformer with an infancy fault condition as operating normally.

The current PHI also ignores the importance of the oil quality in the longevity of the transformer. The life of the transformer is ascertained by the life of the paper, which in turn is relies on the quality of the insulating oil. Since the quality of the oil plays a major role in the insulation system of the transformer and if allowed to oxidize, sludge and degrade will place the transformer at a greater risk of failure, it should also be represented in any health assessment of transformers.

5.1 Recommendations

It is recommended that the PHI be amended to address the deficiencies highlighted above in the following manner:

Change the PHI scoring formula to include oil quality parameters and redress the weighting of scores as follows:

Include the basic gas ratio and Eskom LTPHI methods in the DGA scoring criteria to accommodate for gas ratios and early detection of faults.

Introduce a functionality the will allow the distribution operating units to incorporate the risks associated with high fault levels and poor network performances as shown in Figure 13.

It is recommended that only DP values predicted from oil sample analysis be used for the end of life criteria. The frequent sampling of transformers for DP will also allow for the analysis of the rate of change on DP. This will be a more accurate method of predicting the remaining life of the paper in the transformer.

It is also recommended that the operating units place more emphasis on the accurate capturing of transformer information. Any condition assessment model is only as accurate as the information used to populate it. At present, the data capturing is not at an acceptable level.

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