AGEING ASSESSMENT OF TRANSFORMER INSULATION THROUGH OIL TEST DATABASE ANALYSIS

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ABSTRACT

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"Ageing Assessment of Transformer Insulation through Oil Test Database Analysis"

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Transformer ageing is inevitable and it is a challenge for utilities to manage a large fleet of ageing transformers. This means the need for monitoring transformer condition. One of the most widely used methods is oil sampling and testing. Databases of oil test records hence manifest as a great source of information for facilitating transformer ageing assessment and asset management.

In this work, databases from three UK utilities including about 4,600 transformers and 65,000 oil test entries were processed, cleaned and analysed. The procedures used could help asset managers in how to approach databases, such as the need for addressing oil contamination, measurement procedure change and oil treatment discontinuities. An early degradation phenomenon was detected in multiple databases/utilities, which was investigated and found to be caused by the adoption of hydrotreatment oil refining technique in the late 1980s. Asset managers may need to monitor more frequently the affected units and restructure long term plans.

The work subsequently focused on population analyses which indicated higher voltage transformers (275 kV and 400 kV) are tested more frequently and for more parameters compared with lower voltage units (33 kV and 132 kV). Acidity is the parameter that shows the highest correlation with transformer in-service age. In addition, the influence of the length of oil test records on population ageing trends was studied. It is found that it is possible to have a representative population ageing trend even with a short period (e.g. two years) of oil test results if the transformer age profile is representative of the whole transformer population.

Leading from population analyses, seasonal influence on moisture was investigated which implies the importance of incorporating oil sampling temperature for better interpretation of moisture as well as indirectly breakdown voltage records. A condition mismatch between dielectric dissipation factor and resistivity was also discovered which could mean the need for revising the current IEC 60422 oil maintenance guide.

Finally, insulation condition ranking was performed through principal component analysis (PCA) and analytic hierarchy process (AHP). These two techniques were demonstrated to be not just capable alternatives to traditional empirical formula but also allow fast, objective interpretation in PCA case, as well as flexible and comprehensive (objective and subjective incorporations) analysis in AHP case.

DECLARATION

I declare that no portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

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CHAPTER 1: INTRODUCTION

1.1 Overview

The introduction of high voltage transformers towards the end of the 19^{th} century was the prelude to rapid development of high voltage alternating current (HVAC) power system that could supply distant loads, making possible electrification of large geographical areas [1]. Ever since, transformers have been indispensable in optimising generation, transmission, distribution and utilisation of electricity [2].

Briefly, design life of a transformer is the life derived from specifications and manufacturing process whereas expected life is the service life taking into consideration operational experience. With design life of about 45 years and 60 years respectively for transmission and distribution transformers, ageing of large fleets of in-service transformers is one of the biggest challenges faced by electrical utilities particularly in the UK and other developed countries where large populations of transformers were commissioned in the 1960s [3-9]. As most transformers are insulated with oil and paper/pressboard, great amount of research has been conducted on the ageing mechanisms of these insulation entities [1, 10-19].

For insulating oil (typically mineral oil), the primary ageing mechanism is oxidation where oxygen is involved in the extraction of a hydrogen atom from a hydrocarbon molecule, forming radicals that then undergo propagation, branching and termination stages of oil oxidation [10-12]. Through these reactions, acids, moisture and other polar compounds such as alcohols and hydroperoxides are produced [10-12].

As for paper/pressboard, ageing starts with oxidation before the auto-acceleratory hydrolysis becomes dominant [13-15, 18]. In essence, acids and moisture produced from not just solid insulation oxidation but also oil oxidation, will initiate hydrolysis which in turn increases further the acids and moisture of the insulation system [13-15, 18]. Hence, hydrolysis is self-acceleratory [13-15, 18]. In addition to acids and moisture, solid insulation ageing also produces carbon oxides and furans [13-18].

Considering the inevitable ageing processes, there is strong motivation to uphold the reliability of in-service transformers which are important in the current as well as the future power network with greater energy demands and distributed generations; all within sound economic viabilities of electrical utilities. This combination of the need for high technical performance and strict financial constraints has seen transformer ageing assessment or condition monitoring greatly adopted to facilitate justifying and enforcing asset management decisions [20-23].

Asset management can be defined as the coordinated activity of an organisation to realise value from assets over their lifetimes while ensuring fulfilment or conformance to service, regulatory or security requirements [24-27]. From utilities point of view, there is hence a need for prudent ways to manage ageing transformer fleets in terms of finding a compromise between not under-investing (leading to poorer reliability of electricity supply) and not over-investing (leading to greater costs). Information on transformer health in the form of oil test results is therefore one of the key aspects in decision making for effective asset management of large in-service transformer fleets.

Knowing the ease of accessing oil, it has been a common practice for utilities to sample and test transformer oil for several parameters that can indicate the insulation condition. The measured values could then be interpreted based on recommendations as stipulated in an international standard such as IEC 60422 before performing any corrective or remedial actions like increasing the frequency of testing, scheduling oil reclamation procedures and so forth; all part of transformer asset management [28].

1.2 Research Motivation

Transformer ageing assessment based on oil tests is a straightforward notion and is analogous to human health check through blood tests. Even though there has been considerable research done on laboratory ageing experiments, there is a distinct lack of in-service transformer ageing information. This has posed a challenge to asset managers in managing large fleet of ageing in-service transformers. It is therefore of great interest to address this gap of knowledge which can only be obtained from analysing and interpreting oil test data collected from in-service transformers.

Data corresponding to a large fleet of in-service transformers can be computationally taxing. Furthermore, with inevitable data quality issues, careful handling is needed to maximally extract useful information out of raw data. Currently, IEC 60422 presents some recommendations on how to interpret results but there is still no general guideline on how to approach, process, clean, analyse and interpret information gained from large databases of in-service transformer oil test measurements.

With careful handling and analyses of the databases, knowledge can be gained on any generic anomalies, phenomena or trends as observed from the in-service transformer populations. This information could be valuable to asset managers not just for short term addressing of any issues affecting transformer reliabilities, but also for future capital planning or general fleet expansions. In fact, the knowledge and understanding gained from analysing databases from three contributing utilities in this work could be beneficial towards other utilities as well.

Apart from that, insights can be obtained on how oil test parameters represent transformer ageing. Some parameters might be more useful towards specific stages of ageing or purpose of analysis. Moreover, the influential factors on transformer ageing can be studied. Notable factors that can be explored are the transformer voltage levels, manufacturers, loading, sampling temperature and so forth. Besides that, with reference to IEC 60422, information obtained could be used to perhaps fine-tune the practice of that standard in transformer ageing assessment.

Finally, it is also of great interest to explore new approaches towards health index formulation through the use of mathematical techniques. With regards to this, in-service transformer oil test results represent a beneficial foothold from which the approaches can be developed from and applied to.

1.3 Research Aim and Objectives

In the light of large transformer populations edging closer or even beyond their design life, the aim of this work is to analyse large oil test databases of in-service transformers for identifying crucial patterns, trends, information that can aid ageing assessment and asset management of large transformer fleets. To achieve the aim, the following objectives are identified.

1.3.1 Database Analysis

Oil test databases manifest as a huge source of information. Nevertheless, database processing and cleaning will need to be performed before extracting the maximum amount of useful information from analysis and interpretation. All these will need knowledge on mathematical and statistical procedures, combined closely with in-depth understanding on transformer ageing mechanisms and oil test parameters.

Studies on databases will aid identification of abnormalities that could be potentially useful for asset managers to be aware of. In addition, database studies could be useful towards revealing common characteristics, trends or patterns shared by different parameters, transformer voltage levels, manufacturers, loadings and even utilities.

1.3.2 IEC 60422 Interpretation

IEC 60422 manifests as a reference on which ageing assessment can be performed. The essence of IEC 60422 such as the criteria for condition classification and recommended actions will be summarised and discussed. With reference to those criteria and recommended actions, there are challenges that need to be addressed. For instance, understanding on a relatively local transformer fleet needs to be considered in tandem with recommendations from an international standard. Part of this research will serve to raise awareness on those challenges and provide ways to cope with them.

1.3.3 Alternative Health Index Formulation

Oil test information of multiple parameters needs to be aggregated for ranking different transformers according to their conditions. Moreover, suggestion could also be made on how different information gathered from database studies could be used to formulate health indices for in-service transformers. That will require exploration into algorithms involving condition ranking not just in terms of conventional use of empirical condition scoring formula but also advanced mathematical techniques.

1.4 Research Scope

This research focuses on ageing assessment of in-service transformers through comprehensive analysis on databases provided by three utilities in the United Kingdom, namely National Grid, Scottish Power and UK Power Networks. As illustrated by Figure 1.1, most of the transformers from the three utilities involved in this research have been in-service for a period of time that is either approaching to or even longer than their designed operational lifetimes. There is thus a need for improving ageing assessment through effective oil test database analysis.

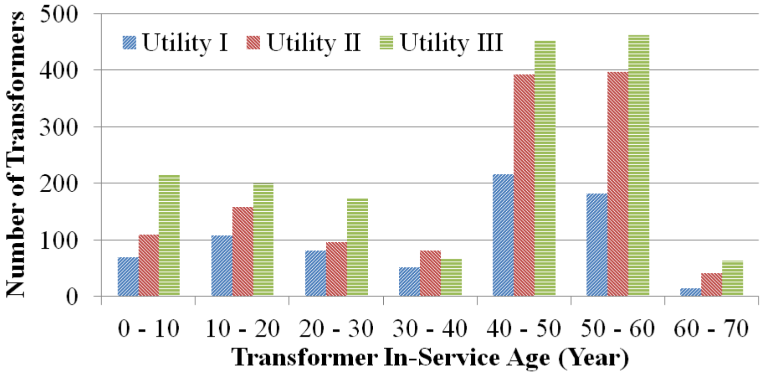

Figure 1.1: Transformer age profiles of three UK utilities (all voltage levels)

The databases are generally in the form of transformer individual details and historical oil test results. The information acquired total to approximately 65,000 oil test entries pertaining to around 4,600 in-service transformers. These transformers are mostly free breathing with silica gel breathers, with a small number of which fitted with a rubber bag in their conservator. Most of these transformers are insulated with ordinary (non-thermally upgraded) Kraft paper and filled with mineral oil.

Apart from that, the transformers in this study are operating at primary voltage levels of 33 kV, 132 kV, 275 kV and 400 kV with power rating ranging from 5 MVA to 1100 MVA. With reference to IEC 60422, these transformers would be classified as Class O (> 400 kV), Class A (170 kV – 400 kV inclusive), Class B (72.5 kV – 170 kV inclusive) and Class C (≤ 72.5 kV) [28].

1.5 Thesis Layout

The thesis has eight chapters. Brief description of each chapter can be found below.

Chapter 1 provides an overview on transformer ageing assessment and asset management. Research motivation, aim, objectives and research scope are also stated.

Chapter 2 reviews transformer insulation system which consists of oil and paper in terms of roles, characteristics, composition and more importantly ageing mechanisms. Parameters for monitoring ageing and the corresponding condition classification based on IEC 60422 are also discussed. In addition, asset management and health index formulation techniques are introduced.

Chapter 3 presents the databases used for this research. Besides that, methodologies employed to process, clean and analyse the large number of data are introduced.

Chapter 4 deals with an early degradation phenomenon affecting units primarily manufactured in the late 1980s and the early 1990s. The cause of which was investigated and recommendations on managing transformer fleet were discussed.

Chapter 5 reports population analyses on the different databases in terms of frequency of testing, correlation with age of the parameters, testing year period sensitivity and the influence of different aspects of a population in study on ageing.

Chapter 6 follows from Chapter 5 by integrating the observations into providing asset management suggestions. Seasonal influence on moisture, breakdown voltage interpretation, a condition mismatch issue and oil treatment usage will be discussed.

Chapter 7 delves into insulation condition ranking based on oil test data. The algorithms used could be from empirical experience or from advanced mathematical techniques such as principal component analysis and analytic hierarchy process.

Chapter 8 encapsulates the conclusions achieved by analysing oil test databases in this work. Future work will also be discussed.

CHAPTER 2: LITERATURE REVIEW

Oil-filled transformers, which are the majority of the transformers in-service worldwide, have an insulation system consisting of both liquid (typically mineral oil) and solids (customarily Kraft paper and pressboard). Degradation occurs to this oil-paper insulation system as transformers age and failures of transformer could occur due to degrading integrity of the insulation system.

The beginning of Chapter 2 is dedicated to understanding oil and paper insulations and their respective ageing mechanisms. Subsequently, oil test parameters that can be used in transformer ageing assessment are discussed; followed by IEC 60422 condition classification. Finally, asset management principles and health index formulation will be covered.

2.1 Transformer Liquid Insulation (Oil)

Oil primarily takes the role of an electrical insulation which is vital for a transformer [1, 4]. Moreover, oil is essential in impregnating the solid insulation to prevent voids or spaces in the solid insulation manifesting as a source of partial discharge [1, 4].

Apart from being an electrical insulation or dielectric, oil is a cooling agent that absorbs heat generated from the windings due to losses and also the core, subsequently transmitting the heat to tank surfaces or radiator of a transformer by either natural convection or forced circulation [1]. This would help maintaining transformer hot spot temperature below a specific thermal design requirement, allowing an acceptable working life for the transformer [1].

Other than that, transformer oil is also an information carrier containing valuable diagnostic information about the condition or the health of transformers [1, 11, 28]. Due to the ease with which oil can be accessed with minimum interruption to transformer operation, sampling and testing transformer oil is an essential prerequisite to subsequent transformer asset management actions [1].

2.1.1 Mineral Oil

Several types of oil could satisfy the roles and the characteristics required for transformer insulating oil which includes mineral oil, natural ester, synthetic ester, silicone liquids, gas-to-liquid (GTL) and so forth. Since the transformers involved in this research are filled with mineral oil and considering most in-service transformers around the world are still mineral oil filled, the discussion henceforth about liquid insulation will essentially be on mineral oil.

Citing its excellent properties, wide availability and low cost, mineral oil, which is obtained from crude petroleum, has been used in electrical equipment (including transformers) for more than one century [1, 29, 30]. This long usage of mineral oil as liquid insulation presents an opportunity to extract large amount of information on historical transformer insulation condition for understanding how transformers age in-service as well as to predict remaining usable transformer lifetime.

Looking into the composition of mineral oil, it is a complex mixture comprising of different arrangements of carbon and hydrogen atoms into three broad hydrocarbon classes which are the paraffins (C_nH_{2n+2}), naphthenes (C_nH_{2n}) and aromatics (C_nH_{2n-6}) [1, 30]. These are illustrated in Figure 2.1 [31].

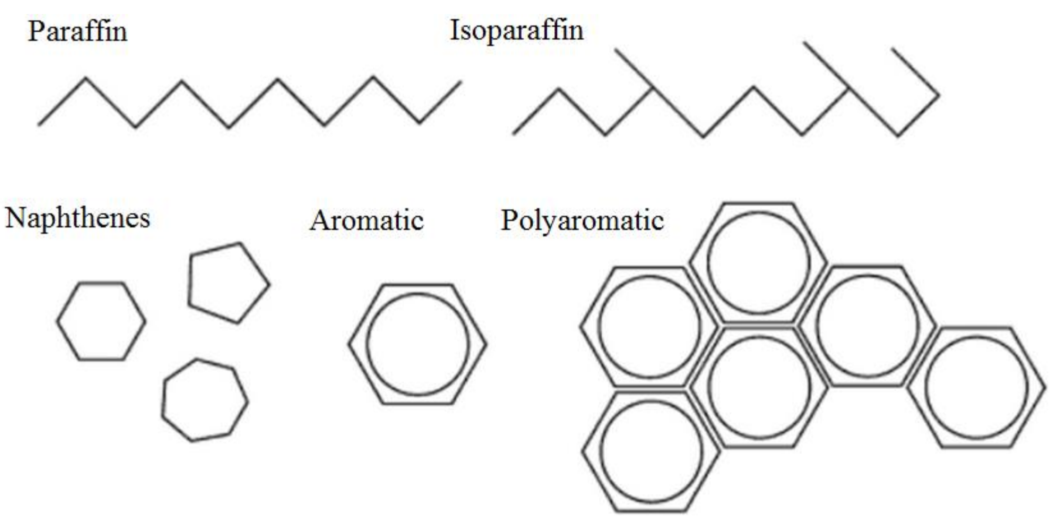

Figure 2.1: Different types of hydrocarbons found in oil [31]

A paraffinic structure can be further subdivided into paraffins which have a straight chain of carbon atoms; and isoparaffins that have side chains branching from the individual carbon atoms in the main chain [1, 31]. As for naphthenes, they have ring structures with six-membered rings (rings with six carbon atoms) the most common [1]. Aromatics have six-membered rings too but unlike naphthenes, some of the carbon atoms are joined by double bonds, thus making them unsaturated and more reactive [1]. Aromatics can also be subcategorised into monoaromatic with single rings and polyaromatic with two or more rings [1, 31].

Out of the three hydrocarbon structures, naphthenes and paraffins are more abundant [1]. These two saturated hydrocarbons share similarities in terms of being mildly polar or even non polar, hydrophobic and having a relatively low boiling point [32-34]. In terms of differences, paraffinic oil has a lower density implying a decreased tank weight of a specific volume [10]. Another feature of a paraffinic oil is its high viscosity index (a small decrease in viscosity with increasing temperature), which might not be desirable for cooling [10, 35]. In addition, paraffinic oil has a high pour point, possibly requiring depressants that could help mitigating its waxing tendency particularly in cold climate applications [10, 35]. Besides that, paraffinic oil has a low solubility towards oxidation products where sludge would precipitate sooner [10, 35]. Desirable proportions of both naphthenic and paraffinic structures can be achieved via oil refining procedures which will be discussed in Section 2.1.2.

Apart from naphthenes, paraffins and also aromatics, mineral oil does have minor proportions of polar and ionic species. Polar species customarily contain oxygen, nitrogen and sulphur, whereas organic salt is one example of the ionic species found in mineral oil [32]. These species which are present as minorities do significantly influence the performance of the mineral oil as an insulating medium such as in terms of a reduced dielectric strength or even corrosive sulphur issue that could afflict oil that is under-refined or with dibenzyl disulphide (DBDS) additive [28, 32, 36, 37].

2.1.2 Oil Refining

Oil refining procedures are required for tailoring crude oil in a series of physical and chemical treatments to produce an end product suitable for transformer applications [1, 38]. In general, oil refining serves three purposes which are the separation of various hydrocarbon types found in crude oil, the conversion of those separated hydrocarbons into more desirable products and finally the elimination of undesirable species [39].

Typical refining steps would start with fractionated distillation of crude oil at atmospheric pressure that removes the low boiling point fractions [1, 10]. This distillation residue is sometimes also distilled under vacuum before the lightest vacuum fraction is chosen for the production of insulating oils [1, 10].

Depending on the source of the crude oil, the distillation products, also known as distillates are typified by a high concentration of aromatics and heterogenics as well as being either neutral or acidic [10]. Subsequently, the distillates would be subjected to one or even a combination of the prominent refining methods including acid and clay treatment, solvent extraction and hydrotreatment / hydrogenation.

2.1.2.1 Acid and Clay Treatment

Figure 2.2 summarises the constituent processes in acid and clay oil refining method. Feedstock or transformer oil distillate is first brought into contact with sulphuric acid to reduce the aromatics and heterogenics [10, 40]. This chemical reaction will produce acid sludge which will be separated from the oil by centrifuges to not just remove the sludge, but also some of the harmful sulfonic acids and nitrogen bases [10, 40]. The result is an oil with low acidity and with some oil-soluble acidic compounds that are also products from the sulphuric reaction [10, 40].

These remaining oil-soluble acidic compounds are then removed as acid salts through neutralisation involving sodium carbonate or soda which is performed simultaneously while the oil is extracted using alcohol [10, 40]. Next is the stripping of alcohol and water from the neutralised oil through application of steam [40]. Finally, the oil will be filtered using clay to remove any residual compounds not removed by the acid treating phase and sodium sulfonate traces from sulfonic acid neutralisation [40].

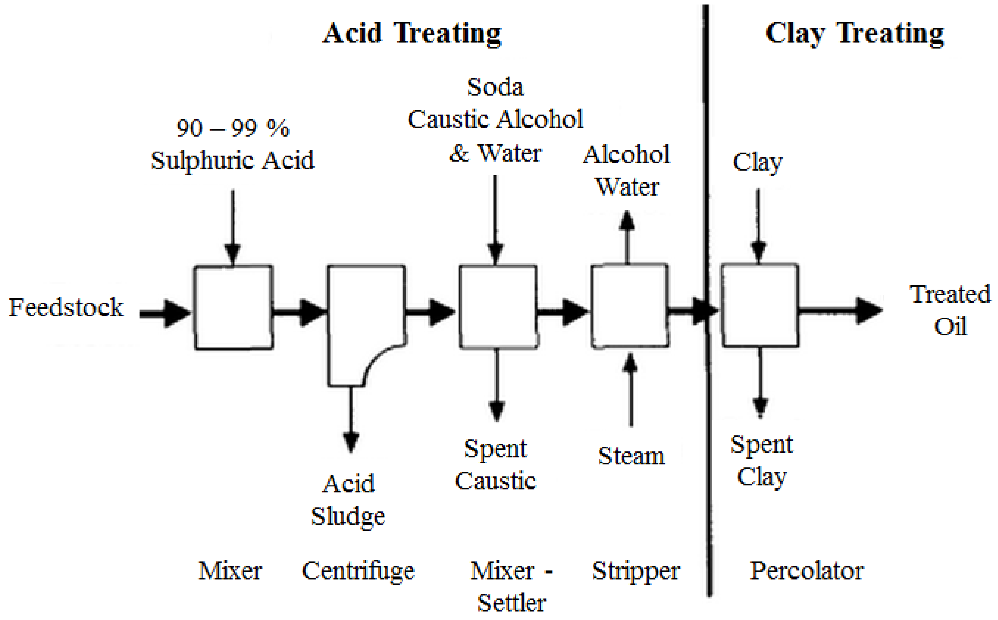

Figure 2.2: Process flowchart of acid and clay treatment [40]

Acid and clay refining method had been popular approximately from the 1930s to the 1950s but the disposal cost and environmental impact of its waste products have since rendered it an obsolete oil refining method [10]. This method is however still used as a supplement for solvent extraction oil refining method [10].

2.1.2.2 Solvent Extraction

Solvent extraction oil refining method was introduced in the early 1950s and it involves the countercurrent flow of feedstock or oil distillate in contact with an immiscible or partly miscible solvent in either a centrifugal extractor or a treatment tower as in Figure 2.3 [10, 40]. The resulting oil distillate after contact with the solvent, called raffinate, will have some amount of dissolved solvent and will be propagated through a stripping system to not just recover the solvent for future reuse, but also to obtain the treated oil [40]. In a parallel branch involving bulk of the solvent that contains a certain amount of oil, called extract, solvent is recovered for future reuse too through separation achieved in another stripping system [40].

More details on the solvent used, phenol and 2-furfural (2-FAL) are the most used solvent types, but N-methyl-2-pyrrolidone and liquid sulphur dioxide are also suitable choices [10, 40]. A solvent is denser than the oil and is aromatic selective, thereby solvent extraction method is useful towards keeping appropriate concentration of natural antioxidants such as thiophenes and organic sulphides that are beneficial towards retarding oxidation of insulating oil [10, 40, 41].

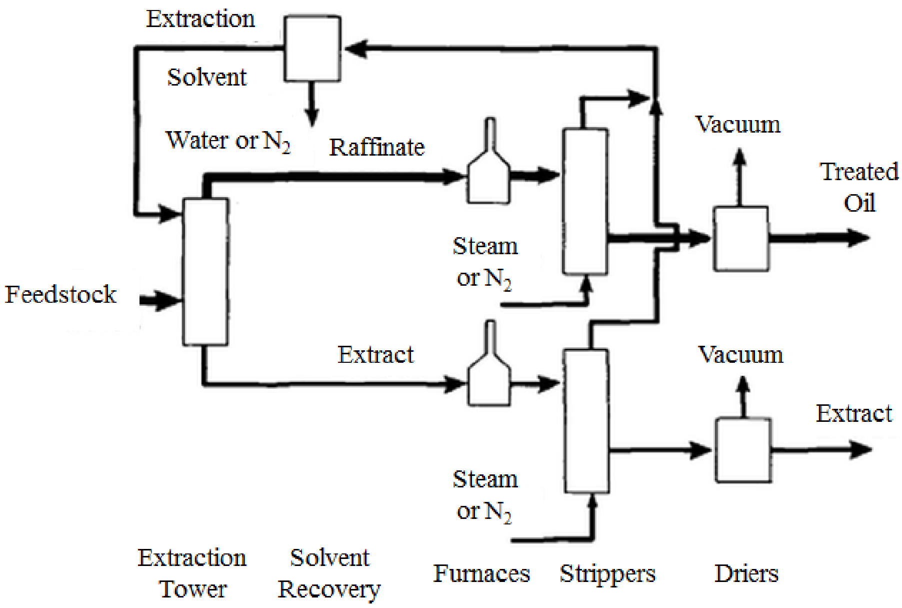

Figure 2.3: Process flowchart of solvent extraction [40]

Back to solvent extraction refining technique as a whole, it is commonly combined with a final acid and clay treatment to achieve oil that is high in oxidation stability and having excellent electrical properties [10, 40]. Nonetheless, it is deemed an expensive refining process where the extracted by-product ("Extract" in Figure 2.3) has a low economic value [10].

2.1.2.3 Hydrotreatment / Hydrogenation

Hydrotreatment was introduced in the 1960s [10, 40]. As shown in Figure 2.4, it involves the chemical reaction between transformer oil distillate with hydrogen gas at elevated temperatures and pressures [10, 40]. Hydrogen plays the role of reacting with harmful species in oil such as sulphur compounds, naphthenic acids and nitrogen compounds to form stable hydrocarbon compounds as well as water and gases like methane, hydrogen sulphide and ammonia [40]. Subsequent propagation through a separator and a steam stripper will remove the gases [40]. Drying of the oil can also be achieved through a vacuum stripper [40].

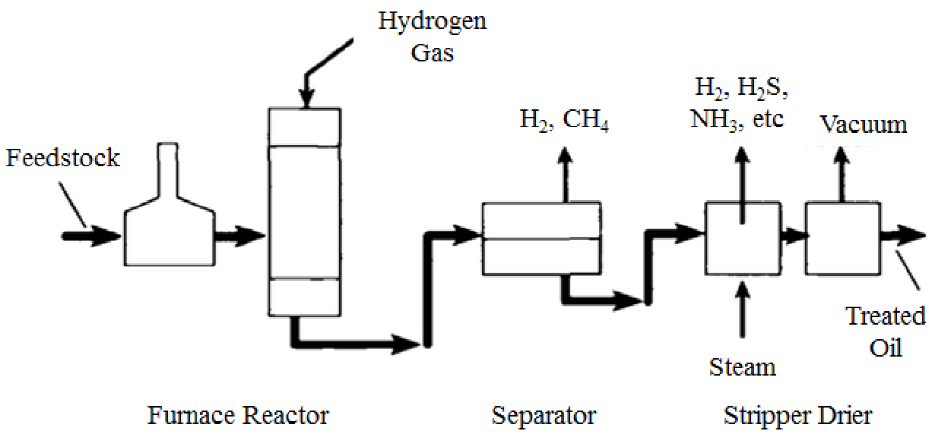

Figure 2.4: Process flowchart of hydrotreatment / hydrogenation [40]

Initial hydrotreatment by itself is too mild to remove deleterious compounds from the oil and was introduced commonly as a combination with other refining methods, such as being the finishing process for solvent extraction method, collectively known as hydrofinishing oil refining method [10, 40]. This combinatory hydrofinishing method became popular and was widely used until the 1980s.

With advances in catalyst science and the use of higher temperatures and pressures (higher refining intensity), hydrotreatment (hydrogenation) by itself gained prominence as a complete oil refining method from the late 1980s onwards, citing its ability to greatly reduce both aromatic and polar compounds [10, 40]. If compared with the initial hydrotreatment introduced for hydrofinishing, the standalone hydrotreatment involves greater intensity of refining [42]. The worldwide preference of hydrotreatment from the late 1980s onwards is due to its versatility, lower cost, higher yields and lower amount of toxic sludge all resonating well with scenarios arising from the late 1980s where there existed a fuel oil demand shortfall, refinery closures or mergers and an increased emphasis on the relative quantity and quality of refined oil [1, 43-46].

2.1.3 Oil Ageing

Once put into operation, exposure to miscellaneous conditions such as contact with air, atmospheric moisture, metallic parts and high operating temperature will promote decomposition of transformer oil molecules regardless of the oil's composition of hydrocarbon blend and degree of purity [11, 41, 47, 48]. Among all the factors influencing oil decomposition, contact with oxygen or oxidation is regarded to be the primary oil ageing mechanism considering the large population of free breathing transformers, particularly in the UK [47].

2.1.3.1 Oxidation

Owing to its biradical character, oxygen which has two unpaired electrons in its ground state is capable of attacking the hydrocarbon molecules of the oil through the abstraction of a hydrogen atom from a hydrocarbon molecule, culminating in free radicals [4, 11, 12]. Other than that, electrical stress through electronic excitation of hydrocarbon molecules caused by the collision with free electrons that are liberated from the surface of the metal conductor as well as thermal stress; would cause the generation of free radicals culminated by the loss of a hydrogen atom of the hydrocarbon molecules [10, 47]. This initial generation of free radicals from the oil hydrocarbon molecules marks the **initiation** stage of oxidation.

$$RH + In^{\bullet} \rightarrow R^{\bullet} + InH \qquad \textbf{\textit{Equation 2.1}}$$

$$RH \rightarrow R^{\bullet} + H^{\bullet} \ \textbf{\textit{(electrical and thermal)}} \qquad \textbf{\textit{Equation 2.2}}$$

From Equation 2.1 and Equation 2.2, R represents the hydrocarbon functional group, RH is collectively known as the hydrocarbon molecule, In denotes any chemical with one or more unpaired electrons, inclusive of oxygen and finally any term with a dot symbolises a free radical with unpaired valence electron(s) [4, 10].

Next in the **propagation** stage of oxidation, chemical reactions involving the free radicals will produce peroxy radical ($ROO^{\bullet}$) and hydroperoxides ($ROOH$) in addition to more free radicals [4, 10, 11, 41, 47]. As long as oxygen is present, these free radicals would further promote the auto-oxidation process as the reactions will continue in such a manner [10].

$$R^{\bullet} + O_2 \rightarrow ROO^{\bullet} \qquad \textbf{\textit{Equation 2.3}}$$

$$ROO^{\bullet} + RH \rightarrow ROOH + R^{\bullet} \qquad \textbf{\textit{Equation 2.4}}$$

Proceeding to the **branching** stage, the weak and unstable peroxidic bonds culminate in the decomposition of hydroperoxides which are shown by Equation 2.5, Equation 2.6 and Equation 2.7 [4, 11, 12, 38, 47, 49]. With reference to the equations, $RO^{\bullet}$ represents alkoxy radicals, $OH^{\bullet}$ refers to hydroxyl radicals and ROH denotes alcohols that includes methanol, ethanol and isopropyl alcohol [10, 12].

$$ROOH \rightarrow RO^{\bullet} + OH^{\bullet} \qquad \textbf{\textit{Equation 2.5}}$$

$$RO^{\bullet} + RH \rightarrow ROH + R^{\bullet} \qquad \textbf{\textit{Equation 2.6}}$$

$$OH^{\bullet} + RH \rightarrow H_2O + R^{\bullet} \qquad \textbf{\textit{Equation 2.7}}$$

Essentially, two hydrocarbon radicals are produced through the branching of a hydroperoxide molecule, which potentially explains the accelerating nature of hydrocarbon oxidation after the initial induction period [10].

The final oxidation stage is **termination** which entails the reaction between two peroxy radicals ($ROO^{\bullet}$) [10, 50]. From Figure 2.5, the reaction between two peroxy radicals produces alcohol, oxygen and aldehydes [10, 51]. Aldehydes are then oxidised to form peracids which could decompose into carboxylate radicals [10]. Through beta-elimination process, these carboxylate radicals can dissociate into carbon dioxide and more new radicals [10]. Alternatively, carboxylate radicals can react with hydrocarbon molecules to engender carboxylic acids in addition to more new radicals [10].

With reference to the aldehydes produced after the initial reaction between two peroxy radicals, ketones such as acetone and methyl ethyl ketone can be generated instead of aldehydes depending on the substitution pattern [10, 12]. In fact, the cleaving of ketones is what actually forms aldehydes [38]. Apart from having the same flow of reactions as previously discussed, a possible variation involving ketone is the generation of esters from the reaction between ketones and peracids [10]. As a side note, the reaction between alcohols and carboxylic acids can also form esters [10].

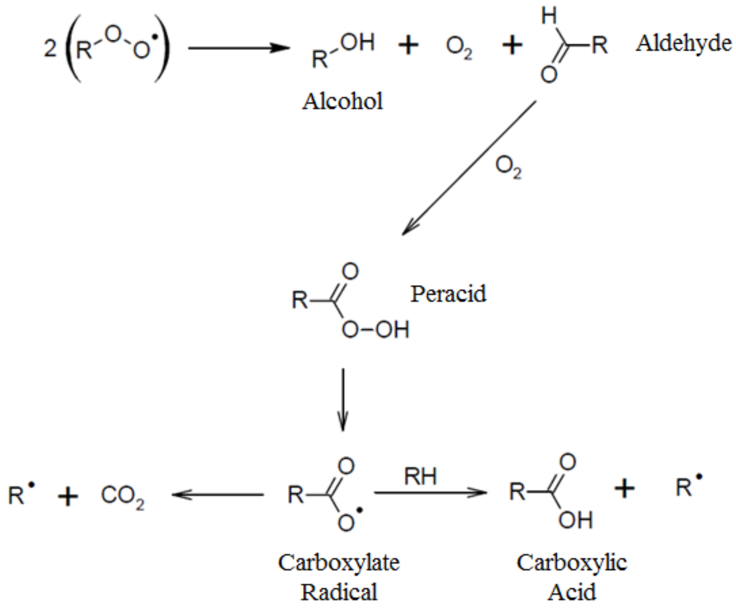

Figure 2.5: Oxidation termination stage [10]

In general, the oil oxidation reactions as discussed are further catalysed by heat in terms of providing the necessary activation energy for the reactions to occur as well as roughly doubling the rate of chemical reactions with a 6 – 10 ℃ temperature increase [1, 31, 35, 49]. Furthermore, presence of metals does contribute to the ageing process as well by either reacting directly with the oil or contribute to the formation of metal cations that are catalytic to the reactions by means of reducing the necessary activation energy, thereby increasing the total reaction rate [10, 15, 41, 51].

2.1.3.2 Oil Oxidation Stability and Enhancement

With oxidation the key oil ageing mechanism, oxidation stability is therefore a desirable property for transformer insulating oil. According to IEC 60422, oxidation stability is defined as "*the ability of unused mineral insulating oil to withstand oxidation under thermal stress and in the presence of oxygen and a copper catalyst*" [28]. Pertaining to that, natural compounds such as thiophenes and organic sulphides that are found in refined oil do aid oxidation stability [41]. This type of oil, with only natural existing oxidation inhibitors or antioxidants, is called as uninhibited oil [28].

Another type of oil, inhibited oil, has synthetic oxidation inhibitors such as 2,6-Di-Tert-Butyl-Paracresol (DBPC) and 2,6 Di-Tert-Butyl-Phenol (DBP) added into the oil in order to enhance its oxidation stability [4, 28]. Owing to their scavenging inclination towards free radicals that are present in oil, the added synthetic oxidation inhibitor will interrupt, disrupt as well as terminate the harmful free radical process of the auto-oxidation process by yielding relatively inactive radicals [4, 51, 52].

In terms of the scavenging nature towards free radicals, a synthetic oxidation inhibitor can either be a donor or an acceptor. Firstly about a donor, it provides labile hydrogen atoms as a competition towards hydrocarbon molecules in reacting with radicals [4, 51]. The following equations demonstrate chemical reactions between donors (represented by AH) with radicals that eventually produce comparatively inert antioxidant radicals denoted by $A^{\bullet}$ [4].

$$R^{\bullet} + AH \rightarrow RH + A^{\bullet}$$ ***Equation 2.8***

$$RO^{\bullet} + AH \rightarrow ROH + A^{\bullet}$$ ***Equation 2.9***

$$ROO^{\bullet} + AH \rightarrow ROOH + A^{\bullet}$$ ***Equation 2.10***

$$OH^{\bullet} + AH \rightarrow H_2O + A^{\bullet}$$ ***Equation 2.11***

On the other hand for acceptors, this type of synthetic inhibitor will acquire free radicals in the oil to form stable chemical compounds [51]. Such reactions are described by the following equations [51].

$$A^{\bullet} + R^{\bullet} \rightarrow RA$$ ***Equation 2.12***

$$A^{\bullet} + ROO^{\bullet} \rightarrow ROOA$$ ***Equation 2.13***

Apart from improving oxidation stability of oil through addition of synthetic inhibitors, oil ageing can be retarded by implementing nitrogen blankets or membranes in the expansion tank for extracting or diffusing the dissolved oxygen gases found in oil into the inert gas above the oil to deter oil oxidation [15, 47]. Besides minimising the contact of oil with oxygen, other possible measures to retard oil oxidation are adequate cooling in view of temperature catalytic effect on oil oxidation; as well as the addition of metal passivators and chelating additives to stabilise catalytic metal ions that can otherwise participate in oil oxidation [1, 41, 53].

2.2 Transformer Solid Insulation (Paper & Pressboard)

Transformer solid insulation is mainly composed of cellulose in the form of paper and pressboard (multiple paper layers – typically 35 layers per mm) [53-56]. Paper is commonly used to wrap around the copper winding conductors, whereas pressboard typically presents as strips, spacers, large cylinders and barriers [55, 57].

Mechanical stability is one of the most important roles of solid insulation in a transformer [53, 54]. This is particularly true in the context of withstanding high mechanical stresses arising from through current or short circuit fault forces on the winding, with the pressure surges up to possibly 100 N/mm^2, to prevent deformation or explosive destruction of a transformer [13, 14, 53, 58, 59].

Solid insulation is also important in providing electrical insulation, which together with oil yield better electrical performance than the individual materials especially if both materials have close dielectric constants [54, 56]. Solid insulation could also help partitioning large oil gaps into smaller ones to mitigate volume effect that could reduce oil breakdown voltage [1, 60]. Besides that, the structured presence of solid insulation, for example in the form of spacers and barriers, will not just divide large oil gaps for improving overall dielectric strength, but also help in creating space and directing oil flow inside a transformer, thus facilitating cooling performance [54, 55].

2.2.1 Kraft Paper

There are a few types of paper that can be used as transformer solid insulation, such as Kraft paper, cotton paper, creped paper and so forth [1]. The most common type is Kraft paper due to its outstanding oil impregnation characteristic, high availability, low cost, excellent electrical and mechanical properties [14, 54]. A Kraft paper is predominantly composed of cellulose (75% - 85%), to be followed by hemicellulose (10% - 20%), lignin (2% - 6%) and some inorganics (< 0.5%) [14].

Cellulose is a natural polymer of glucose with a degree of polymerisation (DP) of about 2,000 [1, 61]. DP is defined as the number of "links" in the long cellulose polymer chain or more technically, the number of anhydro-β-glucose monomers,

$C_6H_{10}O_5$ in the long cellulose polymer chain [1, 62]. Figure 2.6 depicts the chemical formula for cellulose [1]. When fully extended, a cellulose molecule resembles a flat ribbon where hydrophobic hydrogen atoms linked directly to the carbon atoms are found on the surface; whereas highly hydrophilic hydroxyl groups capable of forming intra and inter molecular hydrogen bonds are found protruding laterally from the flat ribbon structure [14].

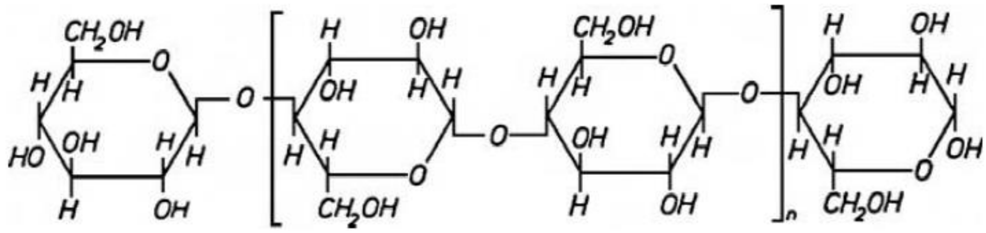

Figure 2.6: Chemical formula for cellulose [1]

Cellulose chains are known to amalgamate in both the crystalline and amorphous regions to form microfibrils that are fundamental in the subsequent formation of first fibrils and ultimately fibres; both major contributors to the paper mechanical strength [13]. On the other hand for hemicellulose and lignin, they are amorphous and sticky substances that serve to provide or facilitate the connection of cellulose fibres [1, 14]. As a quick mention, the crystalline and amorphous regions differ in the sense that amorphous regions are more susceptible to chemical attack and therefore ageing [13].

2.2.2 Paper Ageing

After a series of purification, manufacturing, winding and processing procedures, Kraft paper in new transformers will typically have a DP of around 1,000 as opposed to the high DP in native cellulose [14, 61]. As transformers are put in-service, degradation of paper through ageing processes undermines the paper's electrical property but not as markedly and severely as the mechanical properties typified by the progressive reduction in tensile strength and DP [59, 63-66].

Paper ageing is irreversible and deemed to be one of the limiting factors to a transformer's usable lifetime [64]. Once the DP has dropped to approximately 200 (equivalent to about 20% – 25% of its original tensile strength), the paper is widely considered to have arrived at its end of life [13, 67].

Essentially, cellulosic polymer chains decompose or depolymerise during paper ageing which can be caused by hydrolysis, oxidation and pyrolysis [13, 67, 68]. These ageing mechanisms have different reaction rates depending on not just their respective activation energies, but also the environment or the condition in which the paper insulation is as well as the temperature [14].

2.2.2.1 Hydrolysis

Hydrolysis involves water and hydrogen ions percolating into the amorphous, non-crystalline paper regions and subsequently weakening the attraction forces among cellulosic chains [14, 69]. Note that hydrogen ions can be generated by water as well as acids [14, 69]. With the presence of both water and acids, hydrolysis is initiated and is also considered to be the **primary paper ageing mechanism** due to the widely reported multiplicative effect that both water and acids have on paper ageing [18, 58, 70]. This hydrolytic paper degradation involving water and acids as the catalyst, that targets and breaks the oxygen bridge is illustrated in Figure 2.7 [70, 71].

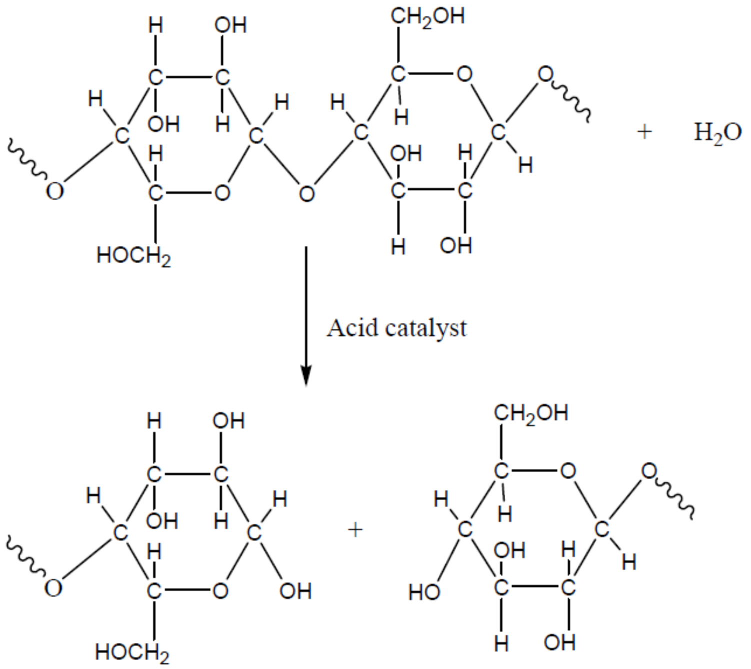

Figure 2.7: Hydrolytic degradation of cellulose [71]

In addition to atmospheric ingress, water originates from insulation degradation (both oil and paper) [14, 33]. Interestingly, the increase of water content in the solid insulation is thought to improve its mechanical properties such as tearing resistance, but the depolymerisation process caused by the hydrolytic degradation of the paper more significantly undermines the paper mechanical properties [70].

One molecule of water is consumed for each separation when the inter-unit linkages in either cellulose or hemicellulose are hydrolysed [13]. A subsequent series of acid-catalysed dehydration reactions generates three water molecules, culminating in a net production of two water molecules for each separation of the inter-unit linkages [13].

Apart from water, hydrolytic decomposition of paper also produces carbon monoxide, carbon dioxide and furans, with 2-furfuraldehyde (2-FAL) and 5-hydroxymethyl-2-furaldehyde (5-HMF) the main types of furans produced [13, 72]. Out of the two furan compounds, 5-HMF is not so stable, readily dissociating into levulinic acid and formic acid [17]. Levulinic acid can polymerise to generate a dark brown and acidic polymer known as "caramel" which constitutes part of sludge whereas formic acid can subsequently dissociate to form carbon monoxide and water [13].

The preceding paragraphs detail the production of paper ageing by-products that include both water and acids. With both water and acids also the cause of paper hydrolysis, these by-products themselves will therefore pose a multiplicative or acceleratory effect on paper ageing [13]. Generally, degradation is said to be ten or more times faster in a paper with 3 – 4% increase in humidity compared with dry paper typically at 0.5 – 1.0% humidity [64].

2.2.2.2 Oxidation

Paper oxidation, which might not be as deleterious to paper as hydrolysis, does separate glucose ring and disrupt cellulosic chains instigated by the attack of dissolved oxygen in oil on the alcohol groups as illustrated in Figure 2.8 [18, 73].

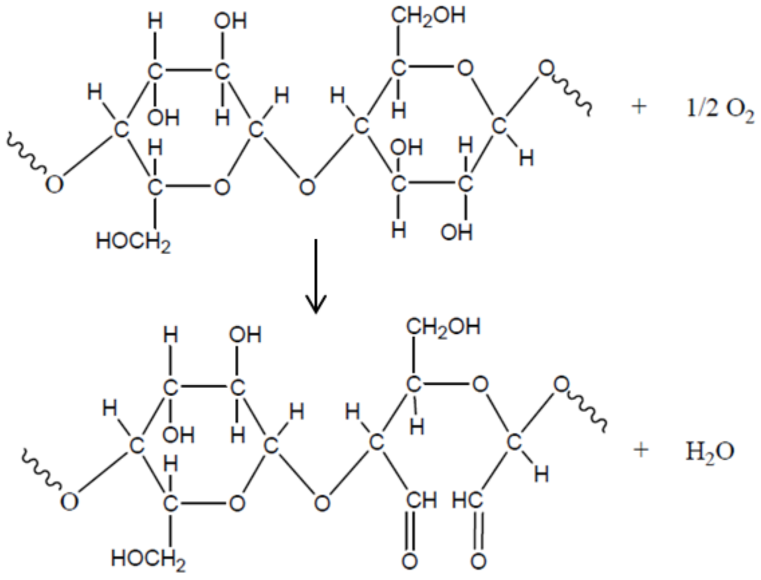

Figure 2.8: Oxidative degradation of cellulose [73]

It is worth mentioning that hydroxyl radicals ($OH^{\bullet}$) catalyse the oxidative degradation of paper [13]. These hydroxyl radicals on the other hand are found from the dissociation of hydrogen peroxide (H_2O_2), which in turn is the reaction product between water and oxygen with metallic ions as reaction catalysts [13].

Back to the oxidative paper degradation, paper ageing is about two times faster in the presence of air (oxygen) than without [61, 64]. In terms of by-products, intermediate reaction by-products include 2-furfuraldehyde (2-FAL), 5-hydroxymethyl-2-furaldehyde (5-HMF) and carbon monoxide [74]. Apart from these by-products that are also produced in hydrolysis, intermediate paper oxidation produces exclusively three other furans which are 5-methyl-2-furaldehyde (5-MEF), 2-acetylfuran (2-ACF), 2-hydroxymethylfuran (furfuryl alcohol, 2-FOL) [74, 75]. Towards the later stages of paper oxidation, not just carbon dioxide, but also water will be produced, thereby initiating and accelerating the primary cause of paper ageing - hydrolysis [74].

2.2.2.3 Pyrolysis

Pyrolysis is a thermal degradation process that is possible with near absence or even total absence of water or oxygen or both [14, 76]. In pyrolysis, the glycosidic bonds (oxygen bridges) will be broken simultaneously with the opening of glucose rings, resulting in the formation of moisture and gases such as carbon monoxide and carbon dioxide [77]. Pyrolysis normally occurs at temperatures greater than 140 ℃ [18].

2.2.2.4 Interaction among Paper Ageing Mechanisms

Considering normal transformer operating temperatures, pyrolysis is argued to be irrelevant if compared with hydrolysis and oxidation as can be interpreted from Figure 2.9 that illustrates the temperature dependence of the three paper ageing mechanisms [14, 18]. Although pyrolysis is out of the context under normal transformer operation, temperature does play a part in the sense that the rate of degradation of paper mechanical properties doubles with every 6 – 8 ℃ increase [64, 78].

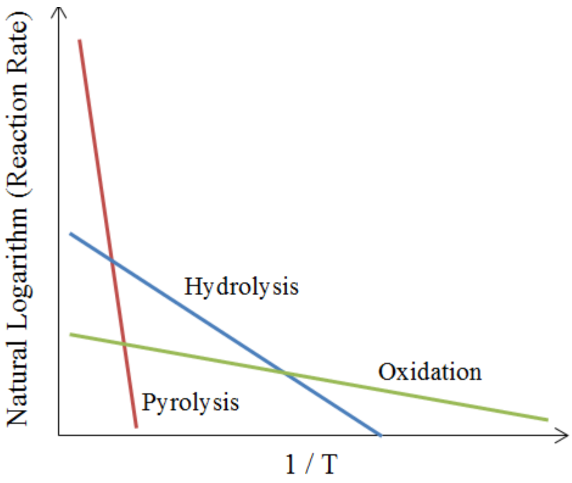

Figure 2.9: Temperature dependence of paper ageing mechanisms [14]

The focus now is on hydrolysis and oxidation. Citing the lower activation energy of oxidation (~70 kJ/mol) if compared with hydrolysis (~110 kJ/mol) and considering initial transformer condition is low in moisture and acidity to initiate hydrolysis, paper deterioration should start with oxidation [13-15]. This paper oxidation (oil oxidation as well) will produce acids that progressively suppress hydroxyl radicals formation [13, 14]. Since hydroxyl radicals function as a catalyst towards oxidation as detailed in Section 2.2.2.2, paper oxidation will be progressively suppressed [13, 14]. This means that paper oxidation is an auto-inhibitory process [13].

Nevertheless, in a simultaneous manner, the acids produced from oil and paper oxidation, along with water will initiate the acid catalysed paper hydrolysis [13]. With the progressive production of acids and water from paper hydrolysis, hydrolytic paper decomposition is ultimately accelerated [13]. Thus, paper hydrolysis is deemed to be auto-acceleratory [13].

2.2.2.5 Retardation of Paper Ageing

From the perspective that oxidation is the initiator of paper ageing, exclusion of oxygen from the insulation system could be a way to prevent paper ageing [13]. Nonetheless, this is only beneficial towards new transformers with low concentration of both water and acidic products [13].

In the context of water and acidity, paper ageing could be hindered through continuous removal of these detrimental species from the transformer insulation system [13, 64]. For that purpose, oil reconditioning or reclamation can be performed apart from adding weak, organic bases such as urea, melamine or dicyanidiamide [13, 64]. These bases will not just neutralise the acids in the insulation system, but also function as organo-chemical drying agents [13]. It is worth noting the difficulty associated with extracting the acids and water in paper if compared with the removal of such species from oil, but the procedures as mentioned, particularly if performed continuously, could extend the lifetime of transformer insulation system [13, 64, 79].

Other than targeting the cause of paper ageing, paper itself could be made more resistant to degradation through addition of nitrogen compounds, resulting in what is customarily called thermally upgraded paper [14, 71]. Typical nitrogen contents used in thermally upgraded papers are 1.8% and 2.7% (currently the highest – Insuldur paper) [71]. It is believed that the ageing rate of thermally upgraded paper is more greatly reduced for paper hydrolysis if compared with paper oxidation but generally a reduction factor to paper ageing between 1.5 and 3 can be expected [14].

2.3 Transformer Oil Test Parameters

With transformer ageing inevitable, there is therefore a need for diagnostic tests to gain information on transformer condition. Considering the ease of accessing oil without intruding or de-energising an operational transformer, transformer oil is commonly sampled and tested for multiple parameters that could connote information on the transformer ageing status or condition [80]. Figure 2.10 illustrates the parameters all grouped into Type I (Routine), Type II (Complementary) and Type III (Special Investigative) based on IEC 60422 [28, 80]. The typical parameters measured by the UK utilities are also shown [80, 81].

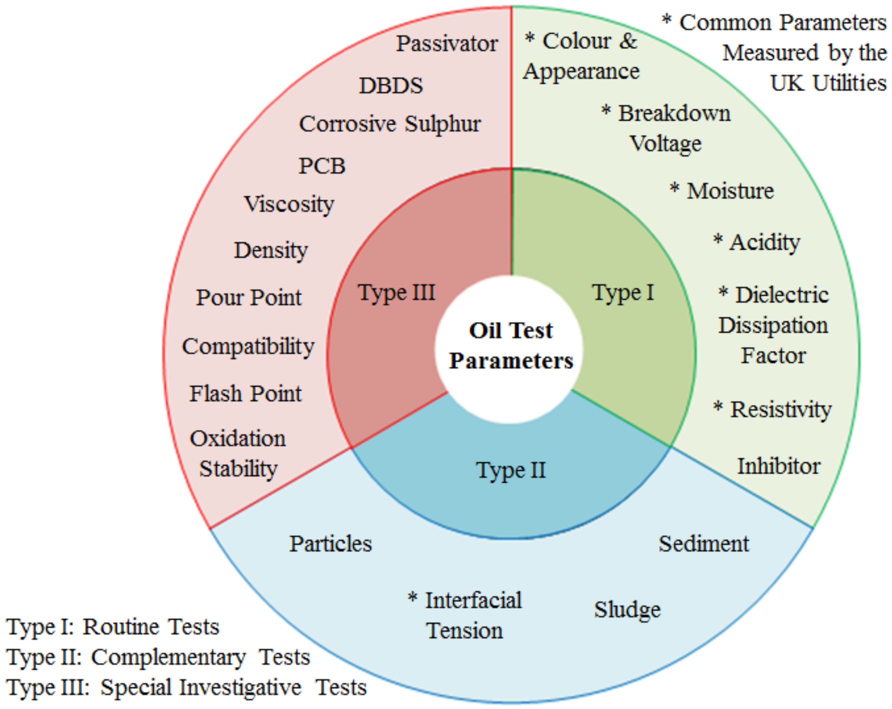

Figure 2.10: Transformer oil test parameters for ageing assessment [28, 80]

Type I represents the minimum tests for monitoring oil to ensure suitability for continued service [28]. Type II on the other hand denotes tests that may be used for acquiring more specific information on the oil quality which may be used to assist evaluation of the oil in terms of suitability for continued service [28]. Finally for Type III, the tests are used mostly for determining whether the oil is suitable for the type of equipment of interest or for ensuring compliance with environmental and operational requirements [28].

In the following sections, the oil test parameters will be introduced, with focus more on the typical parameters measured by the UK utilities as depicted in Figure 2.10. Note that relative permittivity and furans are also typically measured but not shown in Figure 2.10 as they are not included in IEC 60422. Nevertheless, relative permittivity is also a dielectric parameter that is usually acquired together with dielectric dissipation factor or resistivity tests [81]. As for furans, which are related to paper degradation, they are not included in IEC 60422 as the standard concerns only oil [81]. Nonetheless, furans are useful for paper ageing assessment and will also be discussed.

2.3.1 Colour and Appearance

Colour and appearance of the oil sample provides a quick way to assess the insulation condition [10, 28]. Firstly about the appearance, presence of fibres, carbon, dirt, free water, insoluble sludge or any other contaminants can render an oil cloudy [28]. As for a change in colour, the underlying principle could be an increase in the degree of conjugation of the degradation products from progressive insulation ageing [82, 83]. In essence, molecules having more conjugation (alternating double bond – single bond arrangement) have a lower energy difference between the ground states and excited states of the electrons, thus would absorb lower energies of light and reflect what is not absorbed (the complementary colour of what is absorbed) [82, 83].

Thus with ageing, oil that appears initially colourless will change gradually from bright yellow, orange to darker colours through firstly the occurrence of conjugated ageing molecules and progressively more complex and more highly conjugated ageing molecules [82, 83]. For instance, hydroperoxides which are generated in the intermediate stages of oil oxidation will change the oil colour from bright yellow to amber [11]. As a way to record colour changes, visual inspection is an option or more specifically, colour of an oil sample can be expressed numerically from 0.5 to 8.0 (higher numbers for darker colours and more severe ageing) [10, 28, 84, 85].

2.3.2 Moisture

A water molecule is polar due to the formation of a permanent dipole moment (molecular polarisation) arising from the tendency of hydrogen atom to be positive and oxygen atom to be negative [32, 86]. Knowing insulation ageing (both oil and paper) produces moisture and with moisture ingress from atmosphere adequately controlled, moisture measurement is a viable way to assess transformer ageing [13, 14]. In the following discussions, moisture content in oil will be emphasised as measurement of oil samples for ageing assessment is the essence of transformer condition monitoring.

Moisture in oil can generally be categorised into associated moisture, dissociated moisture and moisture droplets [33]. Associated moisture represents the minority of the dissolved water molecules that are bonded to the oil molecules via hydrogen bonding or those water molecules acting as intermolecular bridges between two or more oil molecules [33]. On the other hand, dissociated moisture refers to the majority of dissolved water molecules present in the form of monomers or clusters [33]. Finally, moisture droplets are free water droplets that emerge when the moisture solubility of the oil is exceeded which could occur during a sudden reduction of transformer operating temperature [33, 87, 88].

To measure moisture in oil, coulometric Karl Fischer titration is commonly performed in accordance to IEC 60814 [89]. There are three quantifications of moisture in oil, which are absolute moisture content, corrected moisture content and relative moisture content (relative humidity, RH). Measurements obtained from Karl Fischer titration are indicative of the absolute moisture content and are expressed in mg H_2O/ kg oil or otherwise parts per million (ppm) [28, 32].

Corrected moisture content is an extension of absolute moisture content. By incorporating oil sampling temperature, T_S (in Celsius) into formulating a correction factor, cf as in Equation 2.14, corrected moisture, M_C is obtained through calibrating absolute moisture content, M_A with cf as seen in Equation 2.15 [28].

$$cf = 2.24e^{-0.04T_S}$$ ***Equation 2.14***

$$M_C = M_A \times cf$$ ***Equation 2.15***

As for the third quantification of moisture measurement, relative moisture content or relative humidity (RH), as described in Equation 2.16, is the ratio between absolute moisture content, M_A and moisture solubility of the oil, M_S [28, 32]. Figure 2.11 illustrates the change in moisture solubility with respect to not just temperature, but also oil condition (increased oil acidity due to oil oxidative ageing) [28].

$$RH = M_A / M_S$$ ***Equation 2.16***

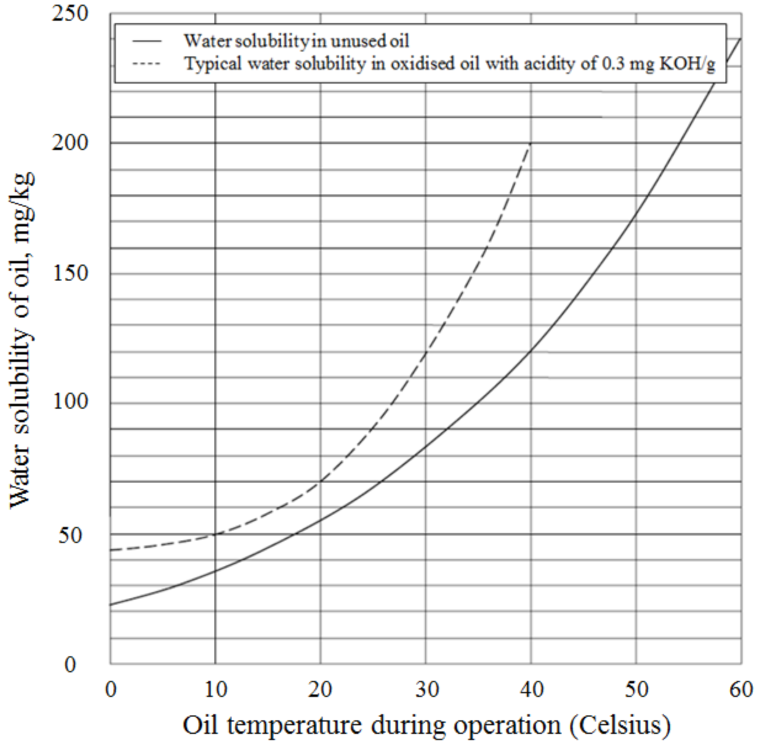

Figure 2.11: Moisture solubility of transformer insulating mineral oil [28]

Although transformer mineral oil is known to be hydrophobic, mineral oil affinity to water increases with temperature which could be attributed to the increase in the size of the solubility window due to an increase in entropy or disorder of the system [90]. As for oil condition, more specifically the presence of acids as depicted from Figure 2.11, the presence of LMA which is polar and hydrophilic could assume the role of emulsifying agents in oil that directly increases moisture solubility [91, 92].

Generally, the higher the moisture solubility, the lower the likelihood to develop free moisture droplets in the oil which are deleterious to the insulation system [93]. Since moisture solubility incorporates not just oil temperature, but also oil condition as well as oil type (different solubilities for mineral oil, natural ester and synthetic ester [93, 94]), RH could potentially be more useful [95, 96]. Typically for in-service transformers, the oil RH ranges from 5% to 25% which amount to a range from 2.75 ppm to 13.75 ppm if the moisture solubility of the oil is 55 ppm (room temperature and assuming unused oil) [33, 93].

Unlike oil, paper is hydrophilic and hence majority of the moisture in an oil-paper insulation would be in paper [32, 97]. Due to the intrusive and destructive nature of paper sampling, moisture in paper could be estimated based on the moisture in oil [32]. This is done via reference to Oommen curves where moisture in paper is expressed in terms of the ratio of the mass of the water to the mass of a dry oil-free paper [33, 70, 98]. Generally, paper in new transformers has a 0.5% of moisture whereas for in-service transformers, it could range from 2% to 5% [1, 14, 28, 99].

2.3.3 AC Breakdown Voltage

Breakdown voltage (BDV) tests performed under the application of power frequency AC voltages are used commonly as an oil quality check. Standards available for the measurement of BDV are IEC 60156 and ASTM D1816, with measurements results recorded in kilovolt (kV) [100, 101]. Although not capable of showing exactly what the species are that undermine a liquid’s dielectric properties, BDV is useful for representing the total deteriorating effects with a lower BDV indicating a higher concentration of undesirable species [34, 102]. Notable mentions of these species are particles and moisture [33, 36].

By being a polar species, moisture is known to adversely affect the oil dielectric strength. Figure 2.12 shows BDV with respect to relative humidity (RH). Focusing on the curve of clean Gemini X (a type of mineral oil), BDV generally tends to remain constant up to around 20% of RH before recording a sharper decrease [34, 103, 104]. Ultimately, free water droplets form when the moisture is increased beyond the oil moisture solubility, rendering a relatively constant and low oil BDV as the dielectric strength is now governed mostly by the presence of free water [103, 105, 106].

Combining the effect of particles, with increasing moisture, an even greater reduction in BDV is expected in the presence of particles [33, 107]. This is depicted by the curve in Figure 2.12 corresponding to dirty Gemini X. With particle contamination level of about 24,000 based on particle size of > 5 μm per 100 ml sample, the relatively dirty oil has a greater BDV reduction compared with the clean one [33].

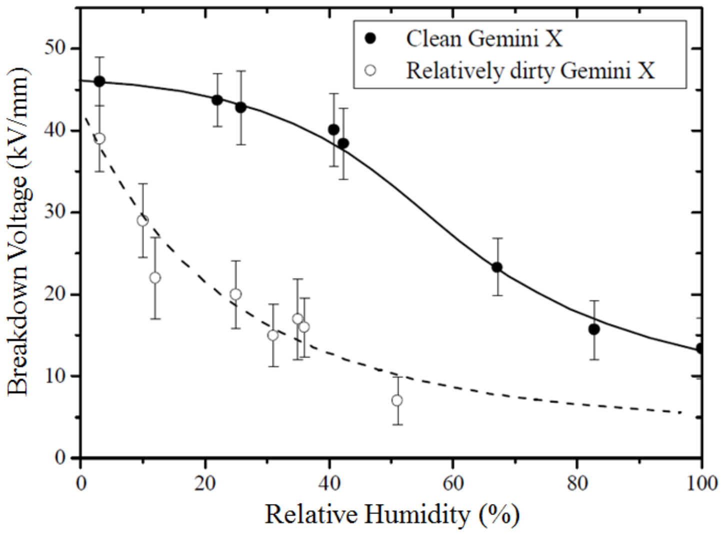

Figure 2.12: Effect of moisture and particles on BDV [33]

2.3.4 Acidity

Ageing of transformer insulation system produces acidic products and hence measurement of acidity could be a representative indicator to reflect the ageing status of insulation. Acidity in transformer oil samples is commonly measured through potentiometric titration according to IEC 62021 with measurements expressed as total acid number (TAN) [55, 108]. TAN has a unit of mg KOH/g which means the amount of potassium hydroxide for neutralising the acids found in one gram of the sample [109]. Figure 2.13 illustrates a typical trend of acidity with transformer age [110].

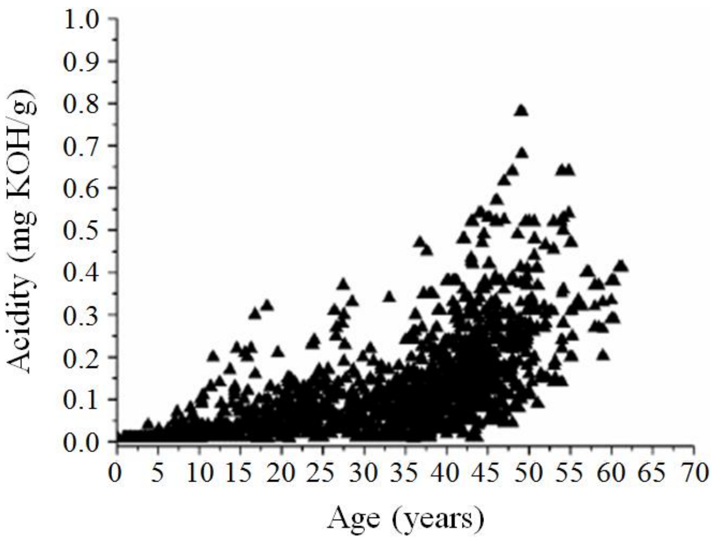

Figure 2.13: Trend of acidity with age [110]

In general, acids present in transformer insulation system are carboxylic or phenolic with carboxylic acids the major species [14, 111]. This type of acids can be further subdivided into low molecular weight acid (LMA) and high molecular weight acid (HMA) [92]. Table 2.1 shows the two categories with the associated acids as well as some of their main characteristics.

Table 2.1: Properties of carboxylic acids [14, 58, 92]

Acid Class	Acid Name	Main Origin	Molar Weight, M_r (g/mol)	Acid Constant (pKa)	Water Affinity
LMA	Formic	Paper Ageing	46	3.8	Hydrophilic
	Acetic		60	4.8	
	Levulinic		116	4.6	
HMA	Naphthenic	Oil Ageing	240	5.5	Hydrophobic
	Stearic		285	4.9	

From Table 2.1, LMAs have lower molar weights and hence the name. Typically, LMAs originate from paper ageing whereas HMAs from oil ageing [14, 58, 92]. Acid constant indicates the acid dissociative tendency with a lower number representing a higher tendency to dissociate [55, 92].

By comparing LMAs and HMAs, research has indicated that LMAs have a more pronounced effect on paper hydrolytic degradation as more hydrogen ions can be produced through acid dissociation [14, 92]. Moreover, paper hydrolysis is also aided by LMAs' propensity to bind water to paper due to their hydrophilic nature [112]. In addition to their more significant effects on paper, research has also suggested that LMAs could be more detrimental to an oil dielectric strength [55].

Considering the partitioning between oil and paper, LMAs are observed to be more readily absorbed by paper than HMAs [92]. This implies that LMAs tend to reside in paper whereas HMAs tend to stay in oil [92]. Although higher temperatures can encourage migration of the LMAs from paper to oil, most LMAs will still be found in paper [92]. Typically for in-service transformers, LMAs percentage in oil is around 18.4% to 33.6%, whereas for HMAs percentage, it is about 64.9% to 81.6% [55].

2.3.5 Dielectric Dissipation Factor, Resistivity and Relative Permittivity

Ideal insulating oil can be represented by a capacitor with a relative permittivity (dielectric constant) of around 2.2 for mineral oil [33, 63, 113]. This ideal case is only when all current through the insulation is solely for charging purposes, contributing to only quadrature or reactive out-of-phase loss [48, 113]. Real insulating medium or dielectric will have an in-phase loss component that is caused by either conductivity or polarisation [48, 51]. Figure 2.14 depicts a possible representation of a real insulating medium by the parallel combination of a capacitor that accounts for reactive out-of-phase loss and a resistor that characterises the in-phase loss.

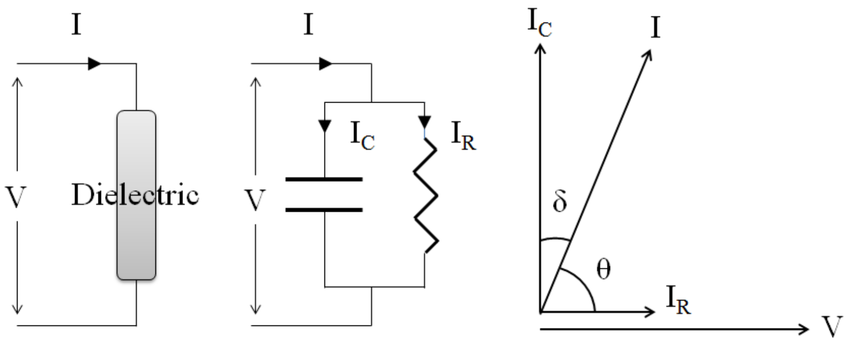

Figure 2.14: Representation of an insulating medium and phasor diagram

Briefly on the conduction and polarisation that contribute to the in-phase loss current, conduction is caused by the energy dissipated due to the finite average velocity of the flow of charge through the insulation whereas polarisation is contributed by the energy dissipated due to the finite displacement of charges where material entities struggle to reorient themselves under an alternating electric field [114, 115]. More about polarisation, the relative shift of positive and negative charges as well as the inability of the electric field in forcing the escape of the charges from the matter will cause polarisation in the form of electronic, ionic, dipolar, interfacial or hopping charge carriers that contribute towards another form of in-phase loss [86, 116].

In the context of transformer insulating oil, this in-phase loss current component, represented by the resistor in Figure 2.14, could be attributed to the presence of soluble polar contaminants and degradation products such as acids, water, aldehydes, ketones, alcohol and so forth [28, 51, 69]. As a mean to monitor this insulating oil in-phase loss which is also temperature dependent, dielectric dissipation factor (DDF) and resistivity are two related parameters that are commonly measured [28, 36, 48, 117]. It is noteworthy that these two parameters do not specifically represent the type of undesirable species present in oil, i.e. acids, furans or water, but are sensitive in general to the presence of contaminants or insulation degradation products.

There are two available standards concerning the measurements of both parameters. They are IEC 60247 and IEC 61620 [118, 119]. Firstly on IEC 60247, measurement is performed through the application of an input sinusoidal voltage signal with frequency of 40 Hz – 62 Hz and amplitude of 0.03 kV – 1 kV across 1 mm distance [119]. On the other hand for IEC 61620, a highly stable quasi-rectangular voltage signal is used as an input [118]. The characteristics of such a signal are as follows: frequency of 0.1 Hz – 1 Hz, amplitude of 10 V – 100 V, ripple of < 1% and rise time of 1 ms – 100 ms [118]. Both standards advise against application of too high a voltage stress or too long a voltage application to avoid dielectric heating, discharges and even charge migration [118, 119].

More about the measurements of these two parameters, DDF is dimensionless whereas resistivity is often expressed in terms of GΩm. With respect to increasing transformer age which can also be reflected by increasing amount of soluble polar contaminants or insulation degradation products, DDF will increase whereas resistivity will decrease [28, 38].

2.3.6 Interfacial Tension

It is of interest to clarify the distinctions between interface and surface. An interface represents the boundary between two immiscible or non-mixable phases whereas a surface denotes the interface between two phases of which one is gas (typically air) [120]. Figure 2.15 provides the illustration.

For a particular liquid, the inward cohesive forces exerted by the bulk molecules on the surface molecules cause surface contraction [121, 122]. This is illustrated by Figure 2.15 particularly between Liquid 1 and air. Surface tension is hence the amount of work applied to increase the liquid surface by a unit area [121]. Instead of a liquidvapour boundary and cohesive forces, interfacial tension is associated with a liquid-liquid boundary (Liquid 1 and Liquid 2) and the adhesive forces existing between two immiscible liquids (non-zero net force on molecules at the interface), indicating the work needed to increase the interface by a unit area [120, 122, 123].

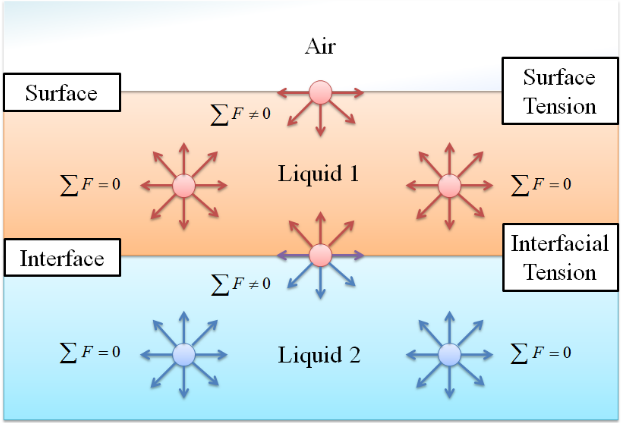

Figure 2.15: Notations for surface and interface

For the purpose of transformer insulation condition monitoring, interfacial tension measurements are performed according to ASTM D971 with the measurement representing the tension needed for rupturing the interface between an oil-water medium and values expressed in dyne/cm or mN/m [36, 124]. Henceforth in this thesis, the measurement of interfacial tension between a transformer oil-water medium will be just called as interfacial tension for simplicity. Interfacial tension is generally lowered by the presence of contaminants or degradation products from progressive degradation of insulating oil and paper [28, 36, 125].

2.3.7 Furans

As furan compounds are only generated from paper ageing and as these compounds are soluble in oil, measurement of these compounds from transformer oil samples presents a non-intrusive way for monitoring the condition of transformer solid insulation [62, 126, 127]. Measurement of furan compounds is achieved via High Performance Liquid Chromatography (HPLC) in accordance to either IEC 61198 or ASTM D5837 standards [128, 129]. Units of measurements are normally expressed in terms of parts per million (ppm) or parts per billion (ppb). Figure 2.16 illustrates six types of furan compounds [62].

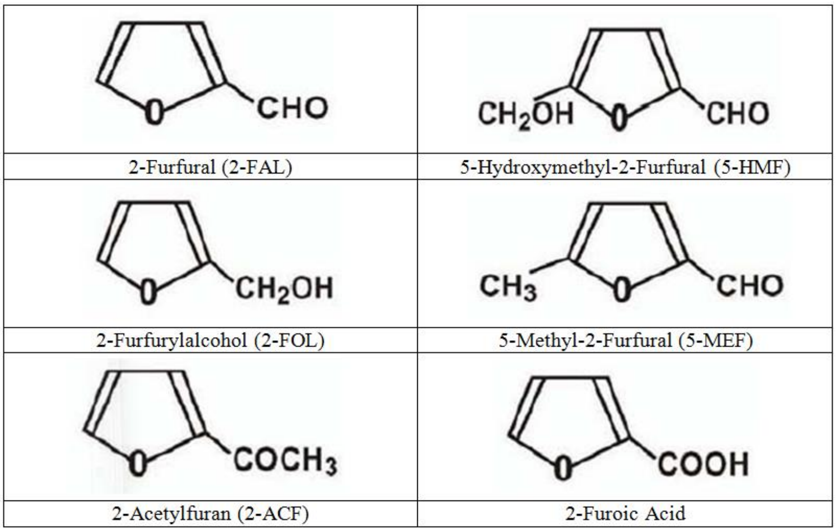

Figure 2.16: Six types of furanic compounds [62]

Customarily for transformer condition monitoring, 2-furfural (2-FAL) receives the greatest attention among the six furan compounds as 2-FAL is significantly more stable and hence is the most abundant type of furan compound [77, 112, 130, 131]. With common consensus that paper reaches its end-of-life when degree of polymerisation (DP) of paper has dropped to 200, 2-FAL measurements are typically interpreted into the corresponding DP values through the different models available such as Burton, Chendong, De Pablo, Morais and Vuarchex models [13, 62, 67].

2.3.8 Inhibitor and Passivator

From Section 2.1.3.2, synthetic inhibitors or antioxidants can be added to enhance the oil oxidation stability with 2,6-Di-Tert-Butyl-Paracresol (DBPC) and 2,6 Di-Tert-Butyl-Phenol (DBP) the two most commonly added compounds [4, 28]. As for passivator, in addition to counteracting corrosion and suppressing electrification, it can also be added to mineral insulating oil to suppress the activity of catalytic metallic ions that promote oil oxidation as mentioned in Section 2.1.3.2 [41, 53]. The typical compound used is Irgamet 39 which is a toluyltriazole derivative [28]. With both inhibitor and passivator subduing oxidation of oil, little oil degradation product can be expected but concentration of these added compounds will be gradually reduced [28, 51]. The trend or the evolution of the concentration of these compounds could be of interest particularly for early ageing assessment of transformers.

2.3.9 Sediment and Sludge

Insoluble materials present in transformer oil are collectively known as sediment [28]. In addition to fibre, carbon, dirt or any other foreign matters, these insoluble materials could be from long chain molecules or varnishes from insulation ageing, metal as well as metallic oxides originating from magnetic core and electrical windings [28, 132, 133]. On the other hand for sludge, it is formed even later in the ageing stages than acidic products, rendering their presence a sign of terminal stages of insulation ageing [4]. Sludge is formed by polymerisation or combination of components with large molecular weight arising from insulation degradation which if the solubility limit is exceeded, sludge will precipitate and contribute as an additional element of sediment [28]. Presence of both sediment and sludge is deleterious to a transformer operation not just in terms of promoting electrical breakdown, but also hindering adequate heat transfer processes caused by insulation shrinkage [4, 28, 48].

2.3.10 Other Parameters

With reference to Figure 2.10, other parameters that can be measured in transformer condition assessment are particle count, viscosity, fire point, flash point, pour point, polychlorinated biphenyls (PCBs) and corrosive sulphur. As they are less recorded from the UK perspective [81], the following provides a brief description of each parameter. More information can be obtained from IEC 60422 [28].

Particle count addresses the number of particles that could arise from manufacturing, storage or handling, as well as operation related sources like metal wear, operation of on-load tap changer (OLTC), localised overheating and insulation ageing [28, 33, 134]. Progressive insulation ageing can also cause an increase in oil viscosity that will hamper oil circulation which directly affects effective heat dissipation [28, 135, 136].

Fire point and flash point are useful to test for volatility considering the risks of fire from transformer operation [137]. On the other hand, pour point provides information on the ability of the oil to flow at low temperatures which is important for transformers in cold climate [137]. As for PCBs, they are generally measured in consideration of environmental pollution caused by PCBs resistance to biodegradation [28]. Finally for corrosive sulphur like dibenzyl disulphide (DBDS), it is measured in consideration of corrosive sulphur issues that have been a cause of premature transformer failures [28].

2.4 Classification of Transformer Oil Condition

Notwithstanding the possibility of measuring for multiple parameters from oil samples, there is a need for adequately interpreting the measurement results to reflect the status or the condition of the transformer oil. Table 2.2 shows condition classification of the more widely measured parameters by utilities into Good, Fair and Poor conditions based on IEC 60422 [28]. These parameters are colour and appearance, moisture, breakdown voltage (BDV), acidity, dielectric dissipation factor (DDF), resistivity and interfacial tension (IFT).

As referred from Table 2.2, the primary voltage at which a particular transformer is operating is also a factor in interpreting the oil condition. A Good condition suggests a normal oil condition for which recommended action is just to continue normal oil sampling and testing practices [28]. If the condition is Fair, it indicates detectable oil deterioration which may prompt more frequent oil testing [28]. As for a Poor condition, oil deterioration is deemed to be abnormal and remedial actions like oil reconditioning or reclamation could most likely be implemented [28]. In essence, interpretation of condition based on standardised values is a fundamental approach towards guiding actions on asset management of transformer fleets.

It is noteworthy that colour does not have clear explicit ranges for interpretation into the three conditions [81]. Besides that, the recommended value ranges for 2-furfural (2-FAL) and permittivity are not shown in Table 2.2 as both parameters are not included in IEC 60422. Specifically for 2-FAL, even though it is regularly measured, reference values for condition classification are still unclear and remain an ongoing research interest in the field of transformer ageing assessment [62, 110, 131].

Table 2.2: IEC 60422 condition classification [28]

Parameter	**Voltage (kV)**	**Condition Classification**		
		Good	**Fair**	**Poor**
Colour and appearance	All	Clear and without visible contamination	Not Applicable	Dark and/or turbid
Moisture (ppm at operating temperature)	>170	< 15	15 – 20	> 20
	72.5 – 170	< 20	20 – 30	> 30
	≤ 72.5	< 30	30 – 40	> 40
BDV (kV, 2.5 mm gap)	>170	> 60	50 – 60	< 50
	72.5 – 170	> 50	40 – 50	< 40
	≤ 72.5	> 40	30 – 40	< 30
Acidity (mg KOH/g oil)	>170	< 0.1	0.1 – 0.15	> 0.15
	72.5 – 170	< 0.1	0.1 – 0.2	> 0.2
	≤ 72.5	< 0.15	0.15 – 0.3	> 0.3
DDF (40 Hz – 60 Hz at 90 ℃)	>170	< 0.1	0.1 – 0.2	> 0.2
	≤ 170	< 0.1	0.1 – 0.5	> 0.5
Resistivity (GΩm, at 90 °C)	>170	> 10	3 – 10	< 3
	≤ 170	> 3	0.2 – 3	< 0.2
IFT (mN/m, uninhibited)	All	> 25	20 – 25	< 20

The recommended value ranges, condition classification and suggested actions as described in IEC 60422 are possible through progressive accumulation of operational experience over the years by electrical utilities and authorities worldwide. As a matter of fact, there have been three past versions of IEC 60422, in 1973, 1989 and 2005 before the current 2013 edition [28, 138-140].

Throughout the years, coverage on interpretation of oil measurements and recommended actions have progressively been more comprehensive; for instance the coverage on more parameters, more condition classes, more distinct classifications for different voltage level transformers, changes to recommended value ranges and changes to test frequencies [28, 138-140].

With IEC 60422 serving as a guideline for utilities, knowledge on a relatively local or regional transformer fleets, in addition to consideration of capital expenditure as well as technical capabilities and limitations are also indispensable towards ageing assessment and asset management of large in-service transformer fleets. Thus, careful incorporation from not just recommendations from an international standard, but also information extracted from utilities own transformer oil test databases is needed.

2.5 Asset Management and Health Index

As discussed in the past section, information extraction from transformer oil test databases is an indispensable step towards facilitating asset management decisions. Revisiting Section 1.1, asset management can be defined as the coordinated activity of an organisation to realise value from assets over their lifetimes while ensuring fulfilment or conformance to service, regulatory or security requirements [24-27].

2.5.1 Asset Management Strategy Evolution

Figure 2.17 illustrates the different asset management strategies that can be implemented. Traditionally, operate-till-failure approach (OTFA) was used where simply equipment was operated until failure upon which decisions were made on whether to repair or replace that particular unit [25]. This approach can be suitable for equipment which is not critical or failure of which will not cause dire consequences [25]. Some examples include equipment operating at lower voltage levels, particularly in remote areas.

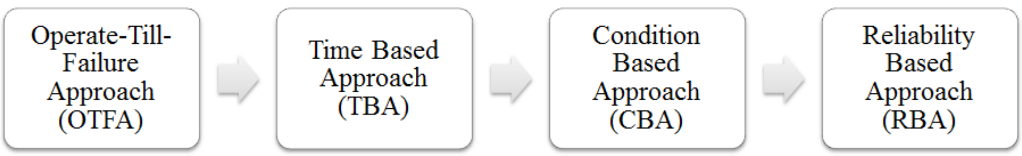

Figure 2.17: Evolution of asset management strategies

In order to prevent catastrophic failures that could seriously affect system security and incur huge penalties, time based approach (TBA) was widely adopted in the past in power systems particularly for managing transformer fleets where regular testing and routine preventative maintenance schemes were a norm [25, 141]. In addition, to ensure system reliability is upheld, transformers were also replaced at a pre-defined age regardless of their potential to operate for a longer period of time [142].

Time based approach however is impractical and particularly wasteful in the current economic climate as field experience has revealed that even after exceeding their design usable lifetimes, transformer failure rates remain low [22, 143]. Furthermore, with deregulation and increased competition of the energy sector, the need for a more economic operation has culminated in a reduction in spare transformer capacity as well as a higher utilisation of existing infrastructure that is also ageing, [20]. All these, together with regulatory constraints have necessitated the migration to condition based approach (CBA) to transformer asset management where more technical and economic justifications are required for engineering decisions and expenditure plans [20, 25, 141, 144, 145].

It is noteworthy that an extension to condition based approach is a reliability based approach (RBA) or otherwise also known as risk based approach which incorporates not just the condition assessment part on the individual system components, but also the importance of those components to and their impacts on the performance of the system [25]. In this work, focus will be more on condition based approach as analysis is to be done on oil test databases pertaining to in-service transformers.

2.5.2 Population versus Individual Perspectives

In terms of the approach towards extracting information from databases for condition monitoring or ageing assessment of transformers, there are generally two perspectives. As depicted in Figure 2.18, the first is the study on the whole transformer population and the second involves the study on individual transformers [96, 146].

Population analysis is customarily the first step in ageing assessment for understanding a particular generic trend that could describe the expected behaviour of all transformers in a population [146]. This information can be a useful reference or guide towards for instance projecting the health of transformers in the future, formulation of precautionary or remedial strategies, capacity and budgeting planning as well as for studies on individual transformers [96].

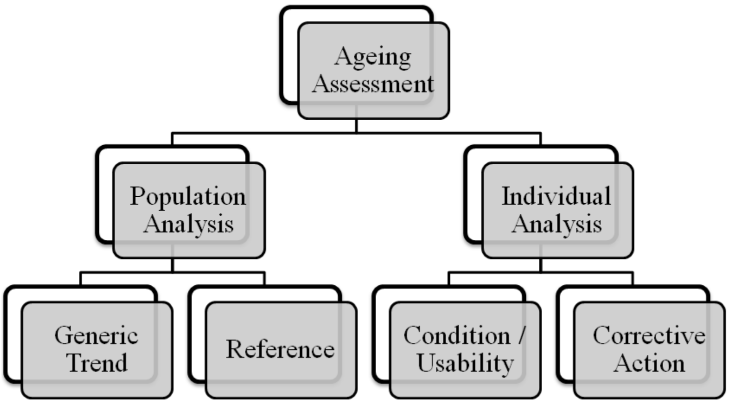

Figure 2.18: Perspectives to ageing assessment: population and individual [96]

As for individual analysis, assessment is typically done on the condition of each unit based on a specific point in time or evolution over a period of time, with reference to observations from a population viewpoint or the Good, Fair and Poor condition criteria as stipulated in an international standard such as IEC 60422 [96]. This information can then be relayed towards the suitability of implementing any corrective actions such as maintaining or prolonging a particular transformer's usability as well as the priority of such actions on that particular transformer [146].

Notwithstanding the availability of two general perspectives to database analysis, ageing assessment of large in-service transformer fleets requires the synergistic and complementary incorporation of both perspectives [147].

2.5.3 Health Index Formulation

Regardless of either population or individual analysis, health index is commonly used as a tool for condition based approach towards transformer asset management. Health index is defined as a single overall score from the aggregation of information consisting of field inspection data, site and laboratory testing records, operational condition and so forth that can be used to indicate the condition of a transformer or the proximity to end of life [145, 148-150]. A brief overview will be provided on the potential approaches available towards health index formulation.

2.5.3.1 Empirical Formula

Empirical formula or expert knowledge based approach has traditionally been one of the most practical ways to formulate health index. Generally, the main procedure employed particularly in terms of transformer insulation condition is the allocation of weightings to a list of oil test parameters, subsequent conversion of the test measurements to scores from a predefined grade range, before aggregating them into a single quantitative value [22, 150-152].

As from [22], with different oil test parameters available, one way of aggregating information related to oil condition and paper condition respectively is to evaluate an oil quality factor (OQF) as defined in Equation 2.17 [22] and a furan factor (FF) as expressed in Equation 2.18 [22].

$$OQF = \left(\sum_{i=1}^{n_{oil}} S_i \times W_i \right) \Bigg/ \sum_{i=1}^{n_{oil}} W_i \qquad \textbf{\textit{Equation 2.17}}$$

$$FF = \left(\sum_{i=1}^{n_{furan}} S_i \times W_i \right) \Bigg/ \sum_{i=1}^{n_{furan}} W_i \qquad \textbf{\textit{Equation 2.18}}$$

where n_{oil} is the number of oil test parameters indicating oil condition and n_{furan} is the number of furan compounds measured. Expert knowledge or empirical experience is considered in evaluating S_i which is the score for each parameter based on comparing its measured value with standardised or reference values [22]. Examples of scores could be from integer values of 1 to 3 with higher values indicating poorer insulation condition. As for W_i, it denotes the weighting for each parameter based on its user perceived relative relevance or significance to OQF or FF [22]. Example weightings could be from integer values of 1 to 5 with higher values meaning greater relevance of that particular parameter to the component health index factor (OQF or FF).

Similar constructions can be made for other factors if data are available or if it is of user’s interest to incorporate other aspects such as dissolved gas analysis (DGA) for fault diagnostics and frequency response analysis (FRA) for winding deformation [22].

The use of such health index formulation method has since been commonplace in utilities but one of the criticisms on such a formulation is their lack of mathematical or statistical justification [150, 151, 153]. In other words, they could be too subjective [154]. In addition, the formulation of a health index that can be adequately applied to a fleet of in-service transformers may be heavily dependent on expert knowledge or empirical experience that may take substantial time to foster [150, 151, 154].

2.5.3.2 Fuzzy Logic

Fuzzy logic is an approach that accounts for possible fuzzy regions in diagnostics which is more realistic, instead of relying rigidly on crisp numerical thresholds [150, 154, 155]. From [150], fuzziness entails firstly membership functions which were designed for each parameter. The parameters considered in [150] are moisture, acidity, breakdown voltage (BDV), dielectric dissipation factor (DDF), total dissolved combustible gases (TDCG) and 2-furfural (2-FAL). Figure 2.19 illustrates the membership functions [150].

Essentially, the membership functions convert numerical values into linguistic or descriptive expressions, much like reference to standardised values but now with incorporation of probability [150]. The descriptive expressions will then be used as an input for activating a set of user predefined fuzzy logic rules [150]. An example of rules predefined in [150] is “If 2-FAL is high moderate and TDCG is not bad and moisture is not bad and acidity is not bad, then the health index is moderate”. In essence, the rules relate the input descriptive expressions to an output health index that has been predefined into five conditions in [150] to Very Good, Good, Moderate, Bad and Very Bad. Similarly, the output health index is also expressed in terms of a membership function depicted in Figure 2.20 [150].

Note that each of the rule that is activated would have an associated output health index whose degree of membership can be evaluated through the Mamdani maximum-minimum fuzzy interfacing method that considers the input degrees of membership from the parameters [150]. Finally, the degree of memberships of the output health indices arising from the activation of more than one rules will be aggregated into a single health index score by using the centroid method [150].

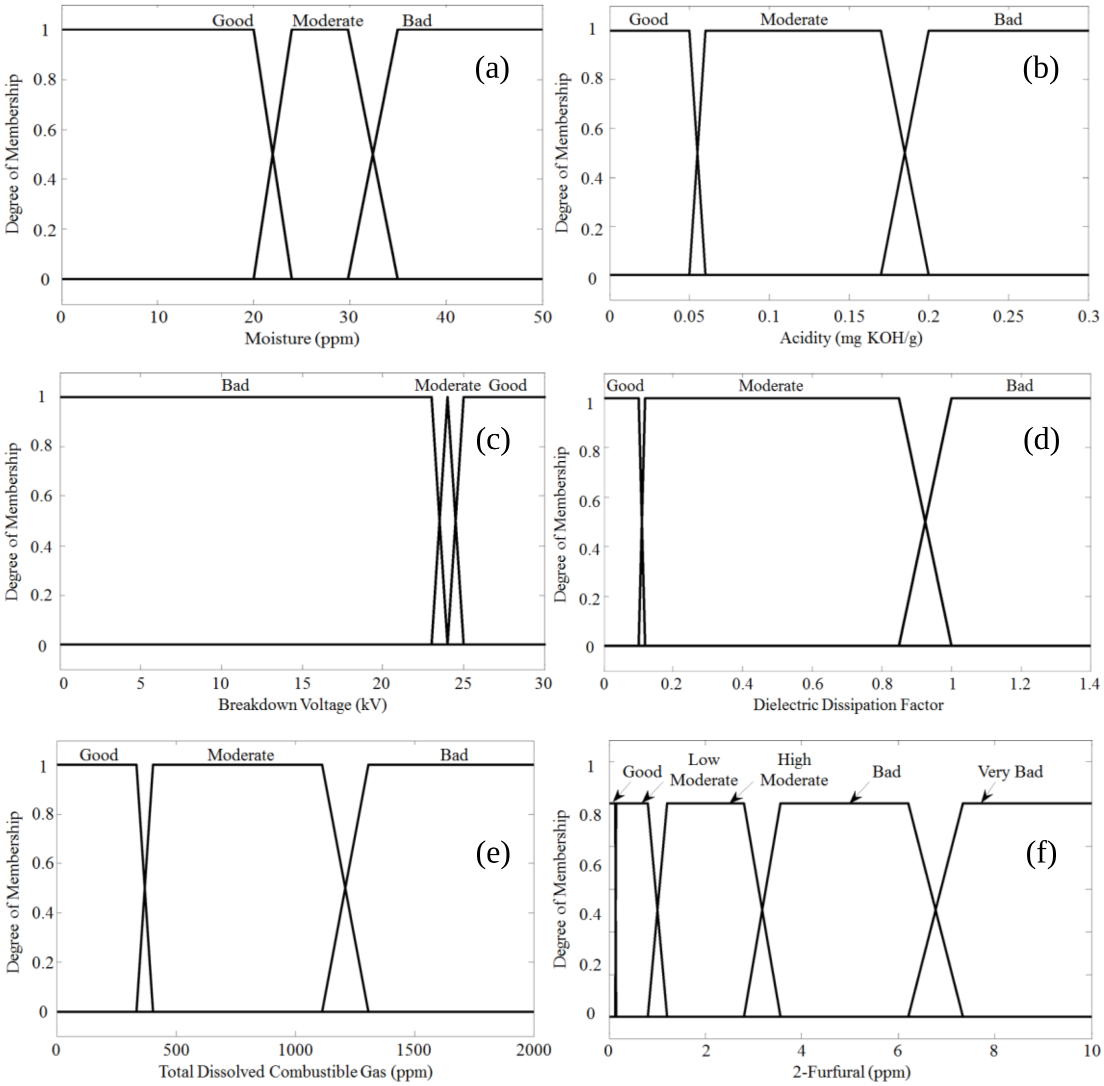

Figure 2.19: Membership functions from [150], (a) moisture, (b) acidity, (c) BDV, (d) DDF, (e) TDCG, (f) 2-FAL

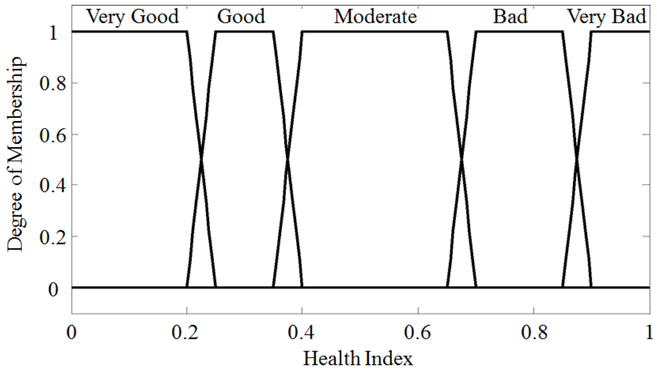

Figure 2.20: Membership function for the output health index adapted from [150]

One of the major limitations of a fuzzy logic approach is that the completeness of the predefined knowledge base highly influences the performances of the intended diagnosis [154, 155]. Besides that, it could lack the flexibility in automatically adjusting the system parameters (the set of fuzzy logic rules) when new information or knowledge is acquired [154, 155].

2.5.3.3 Artificial Neural Network

Artificial neural network (ANN) is a paradigm that is inspired by biological neural networks for information processing, pattern recognition and forecasting [156, 157]. Owing to its flexibility, its ability to analyse complicated, large amount and even incomplete data as well as its excellent interpolation and extrapolation capabilities, it has been explored intensively in recent years in the field of transformer condition diagnostics, predominantly in terms of fault diagnostics incorporating dissolved gas analysis (DGA) data [154-162].

The fundamental building block of an ANN is a node or a neuron [157, 163]. As illustrated in Figure 2.21, a neuron is a computational unit that effectively sums the products of individual inputs and weightings [157, 163]. The summation will then be propagated through an activation function that could be any of the threshold function, piecewise linear function, sigmoid function or Gaussian function; before producing a corresponding output that feeds to other neurons [148, 157].

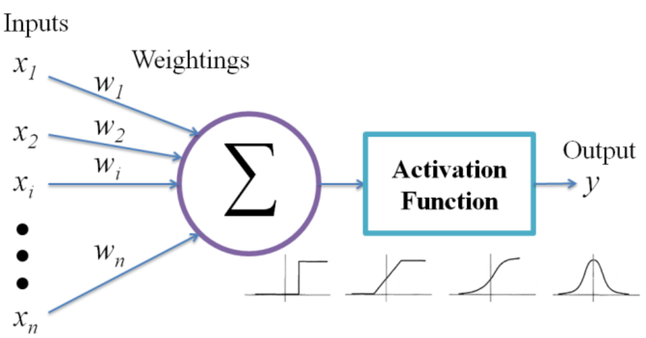

Figure 2.21: Model of a neuron [157]

An ANN hence is basically a network of neurons with interconnections among them governing the type of network architecture [157, 163]. For each different network architecture, a different learning algorithm is needed [157, 163, 164]. In essence, an

ANN is similar to a black box that learns the underlying relationships between inputs and outputs through iterative updates on weightings connected to the multiple neurons [148, 157, 163].

One of the most widely used network architecture is feedforward multilayer perceptron, with back propagation the corresponding learning algorithm [157, 163]. Briefly, with designated inputs and output(s), the input values will be first propagated through the structure to arrive at a set of calculated output(s) where the error(s) between the calculated and designated output(s) will dictate the number of iterative processes needed to update the weightings in the structure [157, 163]. Figure 2.22 depicts an example adapted from [156] in health index calculation.

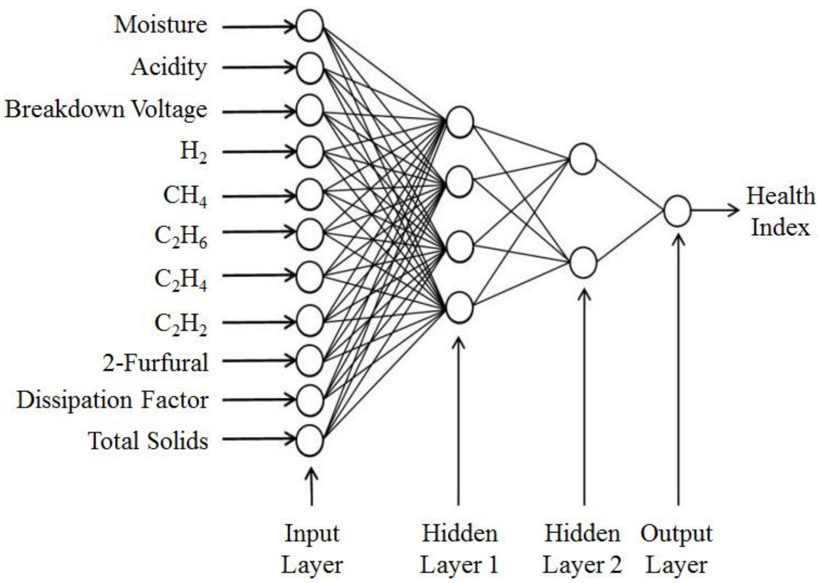

Figure 2.22: ANN configuration for health index formulation from [156]

With the advances in computational resources, ANN formulation can be relatively quick but there are still inherent drawbacks with its application. One major limitation is the absence of explanations to the trained network [148, 154, 155]. In addition, there is known difficulty in determining the network architecture and the number of hidden layer neurons [154, 155]. A large amount of historical data is also required for training the network to achieve high confidence in data forecasting [148, 154, 155]. Furthermore, in addition to the inputs, known outputs are required to train the network which might not be readily available.

2.5.3.4 Principal Component Analysis

Multivariate analysis techniques, such as principal component analysis (PCA) are useful towards detecting correlations between related datasets, learning the interaction patterns among variables and subsequently offer not just dimension reduction but also data interpretation [148, 165, 166]. PCA has been applied in many fields, including transformer partial discharge (PD) monitoring [166-169].

As adapted from [167], the original data consist of 5000 PD records with each containing 5000 samples in the time domain. This is shown by the first row in Figure 2.23. After transforming the time domain signals into the frequency domain, the dimension of the problem reduced to (5000×2500) [167]. This dimension reduction is due to the Nyquist-Shannon sampling theorem which will not be discussed here [167]. Ultimately, PCA was applied to reduce the dimension of the data to (5000×6) before clustering was performed [167].

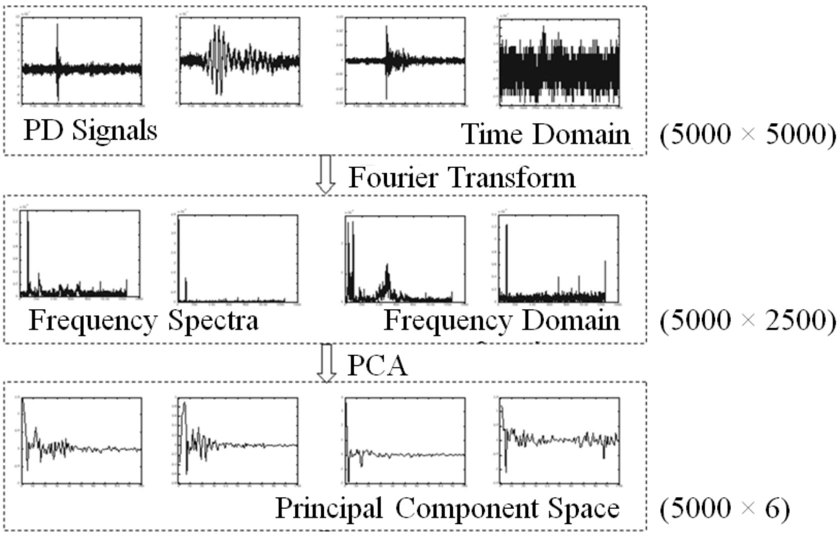

Figure 2.23: Dimension reduction achieved through PCA in [167]

In this thesis, PCA which is new in the field of insulation condition ranking will be applied on oil test data of multiple in-service transformers with the measurements of several parameters as an alternative way to traditional used empirical formula in health index formulation. This will be discussed in more detail in Chapter 7.

2.5.3.5 Analytic Hierarchy Process

The need for evaluating transformer health index based on information from multiple oil test parameters can be perceived as a multiple criteria decision making (MCDM) problem [154]. One technique capable of performing that is called analytic hierarchy process (AHP) [170]. It involves formulating a hierarchy for evaluating a set of alternatives in a pairwise comparison manner pertaining to a certain aim [151, 170]. Following its introduction, AHP has been widely applied in other fields [170, 171] but with only recent applications in power system particularly from the perspective of assessing substation condition [172-176].

As adapted from [172], the condition of 74 substations was evaluated based on records corresponding to 7 aspects. They are the age of main transformer, loading of main transformer, number of obsolete equipment, number of equipment showing symptoms of failure, number of equipment that is of the same type as those that have failed, noise level and the concentration of polychlorinated biphenyls (PCB) [172]. Pairwise comparisons between each pair of the 7 aspects were performed (21 total comparisons as n number of items to be compared will result in $n(n-1)/2$ of pairwise comparisons). Weightings were then assigned to each of them which will be subsequently used in conjunction with normalised measured values of each of the criteria to arrive at a health index value [172].

In this thesis, AHP which is new in insulation condition ranking will be applied on oil test data of multiple parameters for evaluating the health index of transformers. This could serve as an alternative to traditionally used health index formula. More details will be covered extensively in Chapter 7.

2.6 Chapter Summary

This chapter provided a succinct review firstly on transformer insulation system, which is composed of liquid insulation (typically mineral oil) and solid insulation (customarily Kraft paper). Insulation ageing processes were described, with oxidation the key oil ageing mechanism and hydrolysis the main paper ageing mechanism.

Through ageing of both oil and paper, properties of the insulation will change in addition to generation of miscellaneous degradation products such as but not limited to peroxides, hydroperoxides, alcohols, aldehydes, ketones, carbon oxides, moisture, acids and furans. Due to the accessibility of transformer oil, measurement of oil has become a common practice for transformer condition monitoring.

There are multiple parameters that that can be measured from oil, such as moisture, breakdown voltage, acidity and so forth. IEC 60422 presents a guideline to compare the oil test results with specified recommended value ranges for interpretation of transformer oil condition (Good, Fair or Poor conditions). This information can then be useful towards planning and facilitating asset management decisions, such as continuation of normal sampling or the need for implementing remedial actions.

Ageing assessment and asset management of in-service transformer fleets are still a sophisticated task. It would require not just consideration of recommendations from an international standard, but also as much information one could extract or learn from a transformer fleet at hand through analysis on transformer oil test databases and potentially the use of representative health indices for efficient condition based asset management. This paves the way for the research involving oil test database analysis.

CHAPTER 3: DATABASES AND ANALYSIS METHODOLOGY

This research is based on the analysis on databases pertaining to in-service transformers. In this chapter, an introduction is provided on the databases acquired in terms of the type of data or information available. Subsequently, the chapter will include database processing, cleaning and analysis approaches which were employed in the study of the databases.

3.1 Introduction to Databases Acquired

The in-service transformer databases were gathered from three UK utilities, namely National Grid (NG), Scottish Power (SP) and UK Power Networks (UKPN). Apart from a small number of transformers that are equipped with a rubber bag in the conservator, most of the transformers are free breathing with silica gel breathers. Besides that, the transformers to be studied are mineral oil filled and mostly insulated with non-thermally upgraded Kraft paper. As for their operating voltage levels, the primary voltages are 33 kV, 132 kV, 275 kV and 400 kV.

Referring to the databases, they can be categorised into two types which are oil test databases and transformer reference databases. From Figure 3.1, oil test databases contain information of transformer identifier, sampling date, records of multiple parameters and so forth, updated to the year of 2012. As for transformer reference databases, they include not just transformer identifier, but also design and operational information such as operating voltage level, rating, manufacturer, manufacturing year and etc. The presence of transformer asset identifier information in both databases allows combining both types of databases in enriching data analysis and interpretation.

Table 3.1 shows the composition of the number of transformers and number of entries associated with each of the three utilities. Note that the oil test entries from all the databases are all corresponding to oil test results on oil samples obtained from the bottom sampling point of a transformer main tank.

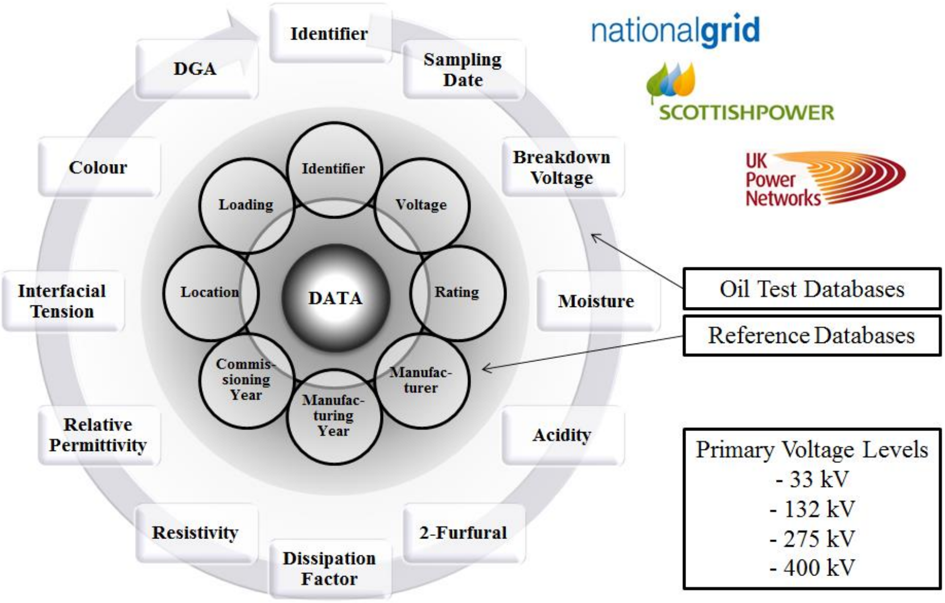

Figure 3.1: General overview of the data available for research

Table 3.1: General composition of databases

Utilities	Number of Transformers	Number of Entries
Company I	750	44,449
Company II	1,646	13,710
Company III	2,180	6,778

Other than the oil test records and individual transformer reference details, extra information in the form of online loading level and online relative humidity data were obtained for specific types of analysis which will be discussed more in detail in Section 5.4.3 and Section 6.1.4.

In order to deal efficiently with large number of data streaming from various database sources, MATLAB 2013a was used predominantly for programming general steps related to database processing, cleaning and analysis. More on the detailed steps of database processing, cleaning and analysis will be discussed in the following sections. In addition, EXCEL 2010 and ACCESS 2010 were used mainly as a platform for viewing both inputs and outputs from MATLAB 2013a programming work. As a complement and support, ORIGINPRO 9.0 was also used to input data and perform specific analysis.

3.2 Database Processing Approach

Before any analysis can be performed, all databases need to be pre-processed to enable extraction of information from databases of widely different formats. Five of the database processing steps that were performed in this work will be discussed in the following paragraphs. All these processing steps seem trivial but need to be addressed and performed for accurate analysis of large databases.

3.2.1 Linking of Databases

How transformers are identified in each of the databases does differ and care needs to be exercised particularly when linking oil test databases with reference databases. In addition to that, other fields of information like manufacturer, manufacturing year, operating voltage level, rating and even oil test parameters might be called different names across different databases. For instance, 2-furfural could be named just "2-furfural", or "Furfuraldehyde", "FFA" and "2FAL".

3.2.2 In-Service Transformer Age Calculation

In terms of understanding the in-service age of transformers from which oil samples were obtained, manufacturing year or commissioning year information will be used in conjunction with oil sampling dates. The use of commissioning year information will be given a higher priority than manufacturing year information as it would reflect more on the in-service duration of a transformer. Most transformers would however have manufacturing year information recorded or erroneous commissioning year information recorded (for instance manufacturing year of 1962 but commissioning year of 1929). Hence, in-service age is to be calculated either by using commissioning year (CY) or manufacturing year (MY) based on Equation 3.1 with SY denoting oil sampling year, SM oil sampling month, SD oil sampling day.

Note that all oil test entries would have oil sampling dates showing explicitly the day, month and year of sampling but only the year of commissioning or manufacturing is typically available. To have a conservative assessment of the in-service transformer age, it is assumed that the transformers would be either commissioned or manufactured on the first of January, as reflected by Equation 3.1. However for cases where not just commissioning year (CY), but also the commissioning month (CM) and commissioning day (CD) are available, Equation 3.2 is used.

$$\text{in-service age} = \frac{(SY - CY \text{ or } MY) * 365 + (SM - 1) * 30 + (SD - 1)}{365} \qquad \textbf{\textit{Equation 3.1}}$$

$$\text{in-service age} = \frac{(SY - CY) * 365 + (SM - CM) * 30 + (SD - CD)}{365} \qquad \textbf{\textit{Equation 3.2}}$$

3.2.3 Addressing of Non-Numerical Records

Non-numerical records like colour (in terms of descriptive records) will be pre-processed or mapped into an arbitrary scale from 100 – 650 for ease of statistical analysis as well as graph plotting. Table 3.2 provides the details on how the arbitrary scale with steps of 50 was used to represent descriptive colour records. This choice of arbitrary scale was also influenced by some of the later colour records expressed in terms of the colour scale of 0.5 – 8.0 (step size of 0.5) as described in Section 2.3.1.

The later colour measurements expressed based on the standardised colour scale spanned from 2007 to 2012 whereas the older descriptive colour measurements spanned from 1992 to 2006. As there was no mapping of the earlier descriptive colour records to the newer 0.5 – 8.0 records, the arbitrary choice of 100 – 650 was necessary to prevent cross-contamination between the earlier and the later colour records.

Table 3.2: Arbitrary numerical scale for descriptive colour records

Numerical	Descriptive	Numerical	Descriptive
100	New	150	New-Light
200	Light	250	Light-Golden
300	Golden	350	Golden-Amber
400	Amber	450	Amber-Dark
500	Dark	550	Dark-Very Dark
550	Dark-Very Dark	600	Very Dark

3.2.4 Addressing of Inequalities

Besides that, inequalities will be converted into numerical values for easing statistical analysis and graph plotting. The presence of inequalities could most probably be due to the detection limit of the equipment used. With conservative assessment in mind, this conversion is done by simply replacing an inequality by the value itself after the inequality sign. For instance, acidity of < 0.01 mg KOH/g will be converted to 0.01 mg KOH/g whereas a breakdown voltage of > 75 kV will be converted to 75 kV.

3.2.5 Addressing of Slight Variations

Other than that, pertaining to entries within the same database (same format), the processing steps undertaken would also include identification and subsequent addressing of slight variations in any of the fields of information contained in either a particular oil test database or a reference database. For instance, colour measurement could be entered as “L. 7.0” instead of just the number 7.0 itself or a manufacturing year of 1972 for a particular transformer could be recorded as “1972 EST”.

3.3 Database Cleaning Approach

Apart from initial processing of the databases, cleaning procedures need to be implemented to remove any inadvertent irregularities and errors in the values recorded. Figure 3.2 illustrates the five database cleaning steps employed in this work. The following sections provide more details on each of the steps employed.

Figure 3.2: Database cleaning approaches employed

3.3.1 Addressing of Abnormal Records

Values exceeding practical limits will be omitted. Examples are rare occurrences of outrageously high breakdown voltage values like 632 kV, 710 kV and 765 kV as well as moisture values that could even reach 1500 ppm. These could most likely be due to human mistake in data entry and will need to be omitted from analysis to prevent misinterpretation of data.

Besides extremely high values, zero values and negative values do occur in the oil test records found in the databases. Note zero values could indicate the absence of testing records for a particular parameter (absence of testing records is normally indicated by a blank space). It depends on the personnel who performed the data entry steps which can be difficult to trace. Nevertheless, efforts arising from discussion with utilities have helped decision making into neglecting zero values for all other oil test parameters like moisture, but not for acidity and 2-furfural. Measurements of acidity and 2-furfural could be really low (in the region of three decimal points) which could have led to data entry personnel marking them as zero.

Therefore, understanding of the measurements particularly for acidity and 2-furfural has led to alteration of the zero values recorded for these two oil test parameters. Zero values will be altered to 0.003 mg KOH/g and 0.01 ppm for acidity and 2-furfural, respectively, based on their measurement detection limits.

Negative values on the other hand could happen for acidity records and this could occur if acidity of the oil sample is really low such that during the acidity measurement procedure, the measured acidity of the oil sample plus solvent is lower than the acidity of the solvent by itself. Similarly to the treatment of zero acidity values, negative acidity values will be altered to 0.003 mg KOH/g.

In addition to addressing and correcting for values associated with oil test parameters, entries having a negative in-service age will also be omitted. A negative in-service age is illogical but could happen if an older transformer at a particular site is replaced by a newer transformer which is given the same asset name or identifier. In this case, the sampling date of the oil test entry would evidently be earlier than either the manufacturing or the commissioning year of the newer transformer, resulting in a negative in-service age.

3.3.2 Consideration of Out-of-Service Information

If information on transformer out-of-service duration is available, such as the starting date and ending date of the out-of-service duration, transformer in-service age can be re-evaluated for better representation. However, the out-of-service duration available for this project (only for one of the many databases acquired) records only the number of years a particular unit has been out-of-service. So, in-service age revaluation is not possible. Nevertheless, if the out-of-service duration is less than 5 years, then the transformer in-service age evaluated based on Equation 3.1 or Equation 3.2 in the preceding Section 3.2 is still valid. More importantly, if a transformer has been out of service longer than or equal to 5 years, it will be omitted.

3.3.3 Oil Contamination Issue

Interpretation of oil test records can be adversely affected if the oil is contaminated. This is particularly serious if the contaminant is also an ageing indicator. Focus of this section will be on 2-furfural (2-FAL) contamination, which by itself is widely known to be a paper degradation product and hence a paper ageing indicator.

Pertaining to the databases acquired, confirmation was obtained from the utilities that some of the UK in-service transformers indeed are filled with 2-FAL contaminated oil. Apart from potential causes of residual 2-FAL in oil like transformer drying or incomplete solvent removal [10, 40, 127], the cause of 2-FAL contamination afflicting some of the UK transformers was widely recognised to be the reusing of oil from a common national oil storage farm for oil in new as well as treated (reclaimed or regenerated) transformers [96]. Figure 3.3 shows the difference in the plot of 2-FAL with age for transformers following a normal ageing pattern and transformers identified with 2-FAL contamination through reference to additional industry records.

Clearly from Figure 3.3, high 2-FAL values are observed for the contaminated population irrespective of the transformer in-service age. The identification of the contaminated population represents one of the key database cleaning steps as separation of these contaminated transformers can prevent misleading interpretation of the condition of not just the individual transformers, but also how 2-FAL behaves generically for a transformer population [96]. Therefore in this work, the contaminated population will be separated from all the ensuing analyses.

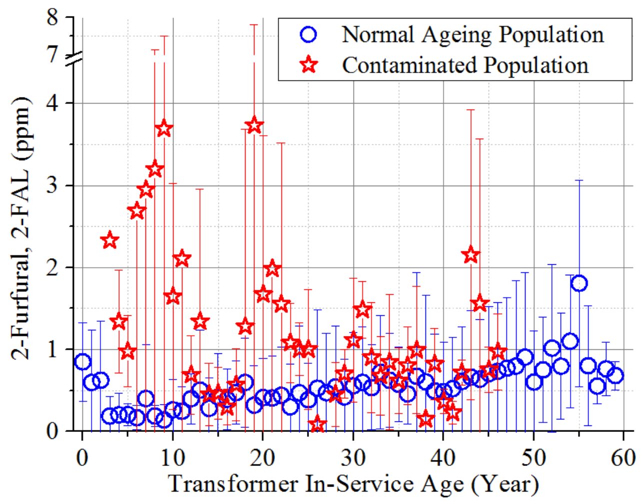

Figure 3.3: Normal ageing and 2-FAL contaminated populations [96]

3.3.4 Change in Measurement Procedure

To ensure correct interpretation of oil test records, a consistently applied measurement procedure should be adopted. For instance, acidity measurements should be performed in accordance to an international standard such as IEC 62021 [108]. Notwithstanding the need for conformance to standardised procedure, changes administered at a local level for instance the choice of laboratory or a change in personnel could invariably cause discrepancies in the values measured [96].

Figure 3.4(a) depicts the acidity with age for four in-service units of a particular database. Acidity is known to increase monotonically over time but noticeably from Figure 3.4(a), spikes do appear. Note that the same observation applies to other transformers but the use of four cases here is to avoid overcrowding of the figure.

After the spikes, the acidities in the four cases, seem to fall into regions where the original increasing trends would be. This is particularly evident for TxC and TxD where the exponential relationship between acidity and age is clearer in the later ageing stages. Delving into this odd behaviour of acidity trend, further analyses revealed all the spikes were contributed by measurements from 2003 to 2006.

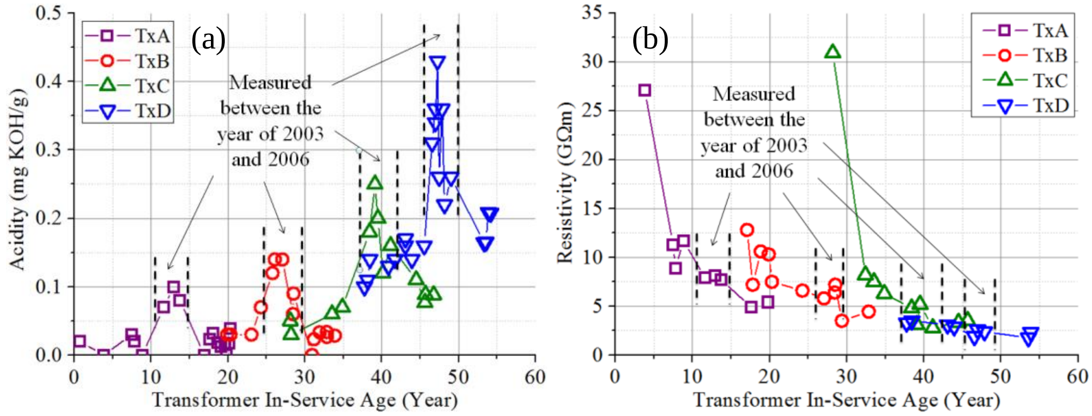

Figure 3.4: Trends with age, (a) spikes in acidity due to a measurement procedure change, (b) resistivity trends indicating normal insulation ageing [96]

These observations could suggest abnormal or sudden insulation deterioration during that period of time before the insulation condition seemingly reverted to what would be expected of it. This notion however seems unconvincing, which is supported by the normal ageing trends of resistivity depicted by Figure 3.4(b). Resistivity is known to decrease with ageing and if the sudden insulation condition change suggested by the spikes in acidity in Figure 3.4(a) was valid, then the corresponding resistivity values for the same four transformers would have recorded a sudden drop too.

The preceding paragraph suggests that the acidity spikes could most probably be due to other reasons than a sudden insulation change. After confirmation with database owner, there was indeed a slight change in the measurement procedure between 2003 and 2006 [96]. Details of the change are confidential but it has since been confirmed the acidity measurements were indeed higher during that period [96]. This is also demonstrated by plotting acidity measurements with respect to measurement dates as in Figure 3.5 where the measurements from 2003 to 2006 were evidently higher.

Hence, to uphold the reliability of the results interpreted from large number of oil test records, a consistent measurement procedure needs to be applied. In this work, for the acidity records of this particular utility, analysis will only be focusing on records from 2007 and henceforth to avoid misleading interpretation of acidity trend.

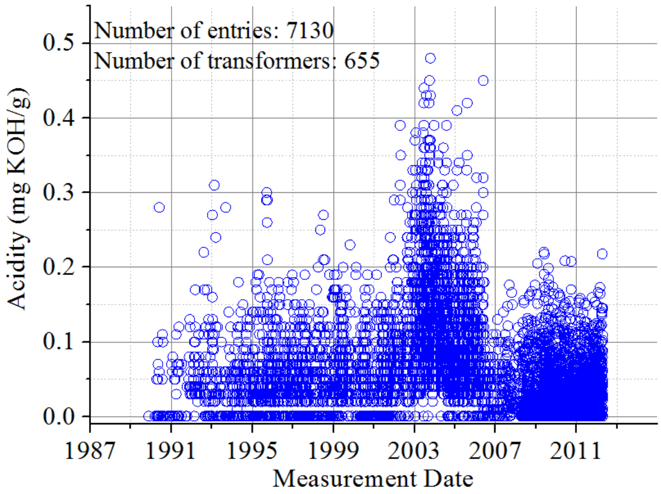

Figure 3.5: Trend of acidity with measurement date

3.3.5 Consideration of Oil Treatment Implementation

Oil treatment processes (oil purification and oil reclamation) are becoming increasingly popular for in-service transformers to extend their usability [177-179]. Briefly, oil purification is a process performed by physical or mechanical means to reduce or remove gasses, moisture and particle contaminations whereas oil reclamation includes chemical means as well in reducing or removing acidic products, sludge or other chemical undesirable compounds [28, 179, 180].

Determination of the in-service transformers that have undergone oil treatment from large databases is needed. Citing poor availability of records of treatment history and the precision of such information if available, a methodology was developed. The key steps in this methodology are shown in Figure 3.6.

Firstly, pertaining to a particular oil test parameter, for instance acidity, consecutive entries from the same transformer will be considered. If for example the acidity measurement of a particular unit at the age of 21 years is 0.01 mg KOH/g, which is smaller than the acidity recorded at the age of 20 years of 0.1 mg KOH/g, this would be regarded as a contradictory or counter-intuitive behaviour as acidity is known to increase with age. Next, the age range of the contradictory behaviour is first identified with a step size of 5 years (for the example, age range of 20 – 24 years). The magnitude of the contradictory behaviour in percentage, e.g. $((0.1 - 0.01)/0.1 \times 100\%)$

will be subsequently stored corresponding to that particular age range and for that specific oil test parameter.

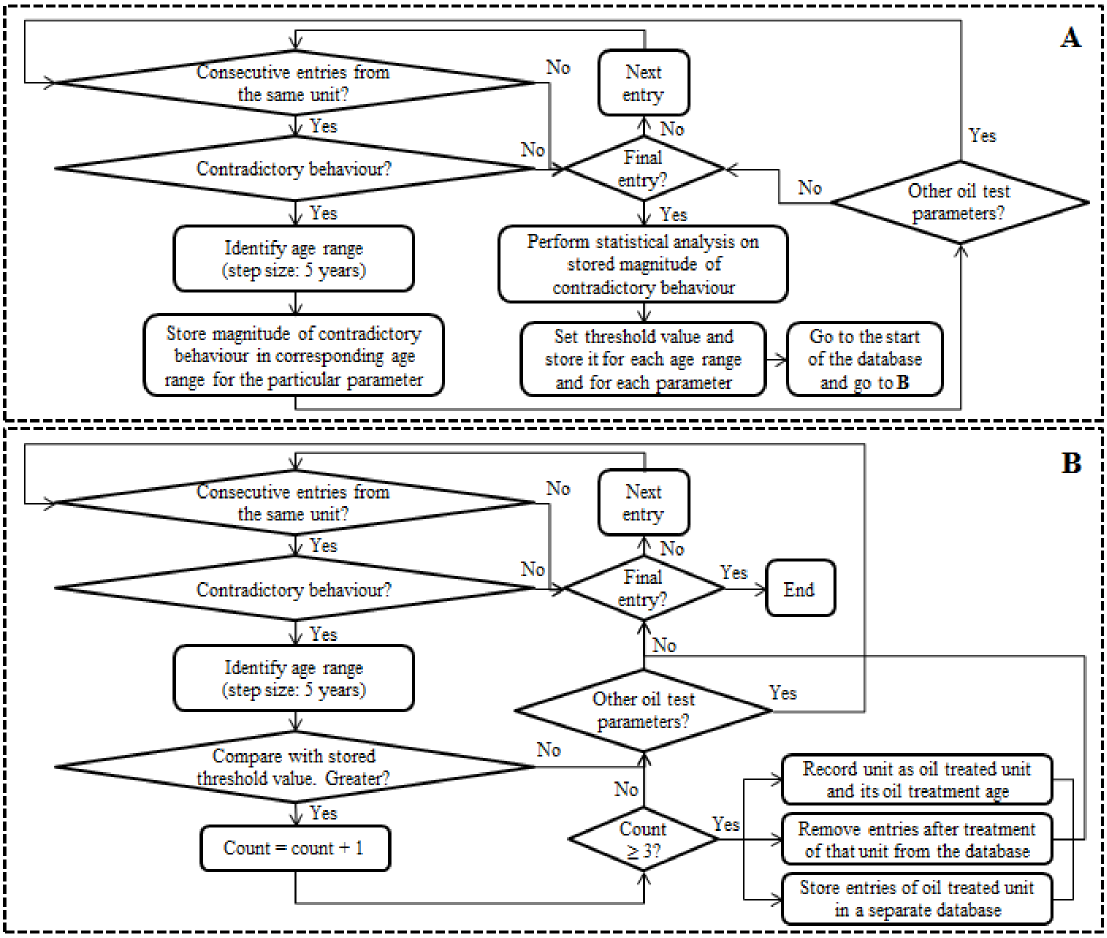

Figure 3.6: Methodology for identifying oil treatment transformer records

The same procedure is repeated for other oil test parameters like dielectric dissipation factor, resistivity and so forth before moving on to other entries in the database. At the end of the database, there will be a set of contradictory behaviour magnitudes corresponding to different age ranges for each of the oil test parameters. Subsequently, statistical analysis will be performed on each set of the contradictory behaviour magnitudes through firstly the identification of an 80th percentile value as a threshold. The choice of an 80th percentile is arbitrary but the essence of selecting a threshold is to guard against some inevitable fluctuations in oil test measurements. What is of interest would be magnitude of contradictory behaviour that is big enough to justify the presence of an oil treatment process instead of inherent measurement fluctuations. In addition to the simple non-parametric selection of an 80th percentile value from the dataset, if the particular dataset can be represented by the parametric Weibull distribution (Kolmogorov-Smirnov test for Weibull suitability), then the threshold value would be taken as the average of the 80th percentile from the dataset and the 80th percentile from the Weibull model.

That marks the end of the **A** part seen in Figure 3.6 where there would be a set of threshold values for each of the age range for each of the oil test parameter. Subsequently, the original database will be revisited for the **B** part in Figure 3.6. Similarly to the **A** part, the **B** part starts with evaluation of consecutive entries from the same transformer in terms of a presence of a contradictory behaviour. Knowing the age range of that particular entry, the magnitude of the contradictory behaviour is compared with the stored threshold value evaluated in the **A** part. If the magnitude of the contradictory behaviour is greater than the threshold value, for three or more than three oil test parameters for a particular transformer, then this transformer would be identified as a transformer that underwent oil treatment processes.

Then, in addition to recording the transformer along with its oil treatment age, the entries after treatment will be removed from the database to reduce the variability in assessing normal ageing transformer populations. This is because oil treatment naturally culminates in discontinuities in the oil test parameter records. These discontinuities are seen in Figure 3.7 showing resistivity and 2-FAL ageing trends of an in-service transformer treated at an age of 18 years.

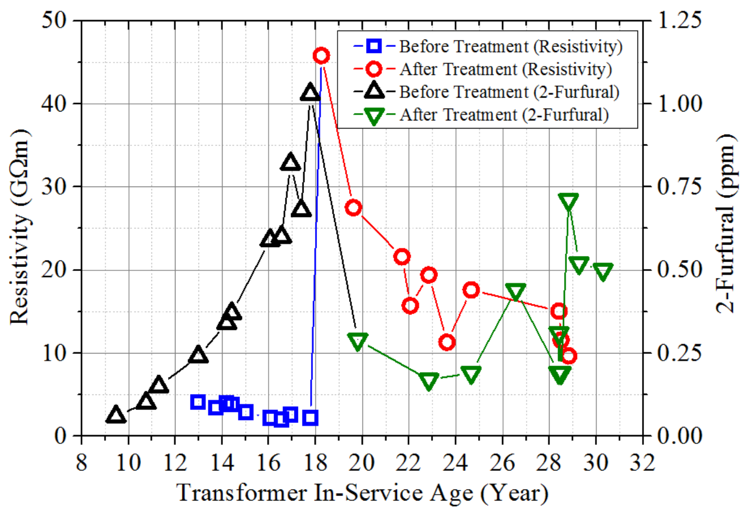

Figure 3.7: Resistivity and 2-FAL trends of an oil treated transformer [96]

Besides removing the entries after treatment, all the entries pertaining to an oil treated transformer (before and after treatment) will be separately copied and stored in a separate database. This information will be used for further analysis that could include assessing the performance of these units after treatment. More details of this portion of the work can be found in Section 6.4.

Note that programming is needed not only due to the sheer number of data, but also to cater for consecutively dated entries that might not have all the oil test parameters recorded. This implies the need for looking further up previous oil test records of the same transformer to enable evaluation of contradictory behaviour. In addition, some transformers can have consecutive entries that are dated the same but with the records of the oil test parameters split among them (for instance, furans are sometimes recorded separately).

Apart from the use of the algorithm developed, industry documents with details on oil treated transformers were also referred to. Although the information can be scarce, the documents can serve as a mean to supplement and consolidate the analysis.

3.4 Database Analysis Approach

With proper understanding of the databases and the information they contain, informed decisions can be made to appropriately prepare the databases for subsequent studies and analyses. Figure 3.8 shows the database analysis approaches employed in this work which can be generally categorised into graphical and statistical analyses. More details on each category will be discussed in the following sections.

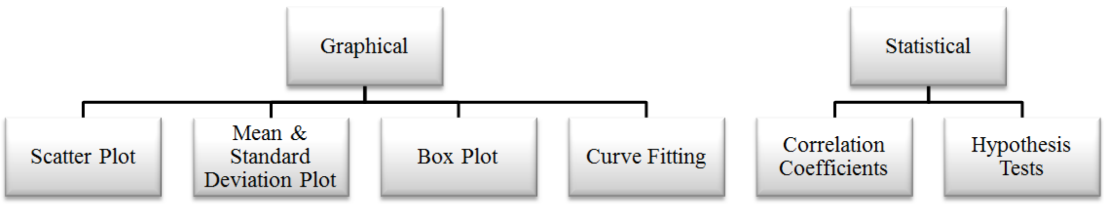

Figure 3.8: Database analysis approaches employed

3.4.1 Graphical Analysis

One essential aspect of extracting useful information out of the databases is visual portrayal or graphical representation of the data. Proper data representation could aid faster interpretation of the essence or the underlying message of huge amount of data in terms of identifying any trends, patterns, structures, relationships or even anomalies if compared with manual scans through numerical or text summaries [181, 182]. Thus, this section introduces and describes several data representation techniques. The trend of acidity with in-service age of transformers of a particular database will be used as an example for demonstrating the different data techniques.

3.4.1.1 Scatter Plot

A scatter plot is also known as a point, dot or symbol graph and is one of the most widely used graphical visualisation of original data points [183, 184]. A scatter plot is essentially a graph illustrating point variations chosen for visualising paired numerical data with the dependent variable capable of having one or more observations for each value of the independent variable [184, 185]. Figure 3.9 shows a scatter plot of acidity measurements with respect to age.

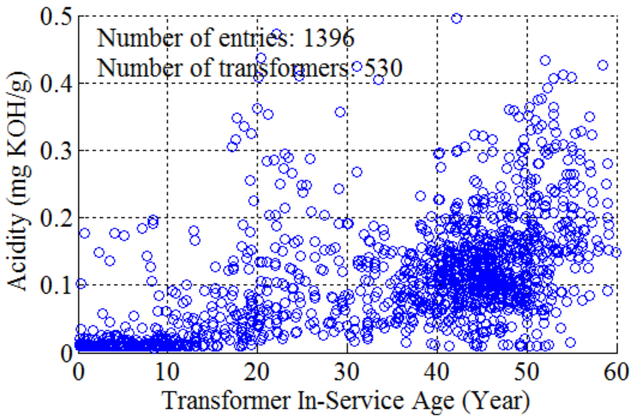

Figure 3.9: Scatter plot representation of acidity with age

Without any form of processing and hence without losing data originality, the large number of data entries are now more easily interpretable in a graphical sense. Besides that, visual inspection of the plot can also enable user to spot trends, patterns, clusters, gaps or even outliers more easily [186].

Nonetheless, plotting data without any form of processing or numerical summaries could be effective for small data size, but with increasing data size, clarity of data representation will inevitably be adversely affected with overlapping or overcrowding of dense data regions [182, 183, 186]. Besides that, its relatively original data representation might hinder efforts of analysing and comparing data from a statistical perspective particularly when difference among age groups is of interest [186].

3.4.1.2 Mean and Standard Deviation Plot

Mean and standard deviation plot is one of the parametric ways of representing original data. Mean is simply the average of a particular dataset whereas standard deviation can be expressed either by Equation 3.3 or Equation 3.4. S_S symbolises the standard deviation for a sample, S_P means the standard deviation of a population, x_i is an individual observation and $\bar{x}$ is the mean of the dataset (sample or population) with n the number of samples [187].

$$S_S = \sqrt{\left[\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2\right] \Big/ (n-1)} \qquad \textbf{\textit{Equation 3.3}}$$

$$S_P = \sqrt{\left[\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2\right] \Big/ n} \qquad \textbf{\textit{Equation 3.4}}$$

For database analysis, Equation 3.3 is preferable as the data available might not be totally or wholly representative of the whole population for a particular time period of interest (there might be more transformers having the same in-service age but not measured) [187]. Moreover, the misuse of Equation 3.4 in cases pertaining to samples instead of populations would yield consistently smaller standard deviations, which might not be truly representative [187]. Hence in this work, Equation 3.3 will be used. Figure 3.10 depicts the mean and standard deviation plot of the same acidity measurements as considered in Section 3.4.1.1.

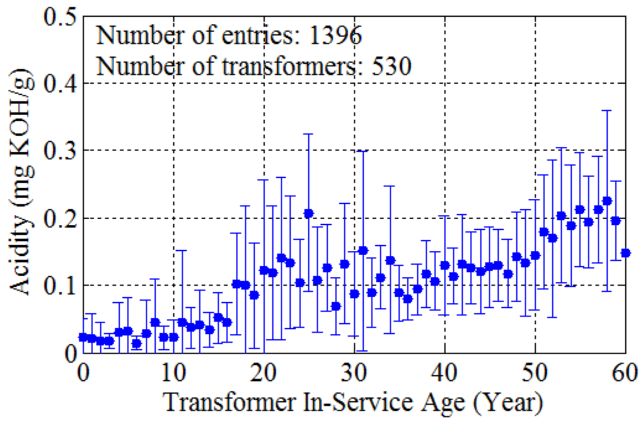

Figure 3.10: Mean and standard deviation representation of acidity with age

The use of mean and standard deviation in representing data has the merit of being readily understandable and easy as they are widely used. Particularly if reliability of the data is upheld, mean and standard deviation plot is useful towards understanding the centre and the spread of the data [184, 188].

However, mean and standard deviation are not statistically robust. Briefly, a statistic is robust when it has a high statistical breakdown point [189]. A statistical breakdown point means the smallest proportion of a dataset which when changed would change the value of that particular statistic [189]. For mean and standard deviation, both of them have 0% breakdown point which suggests their susceptibility towards the presence of even one false or extreme value [190]. Apart from that, since mean and standard deviation is a parametric way of representing data, this suggests the data need to be approximated by a normal or Gaussian distribution which might not be the case [184]. Also, such a derivative plot from original data would have a drawback of masking original data information.

3.4.1.3 Box Plot

Box plot, as shown in Figure 3.11, is a non-parametric (distribution free) representation capable of conveying several fields of statistical information about a dataset [184, 187]. A box plot is usually rectangular with median of a dataset depicted within the rectangle in addition to the representation of both 25th and 75th percentiles by the lower and upper boundaries of the rectangle respectively [187]. The difference between the 25th and 75th percentiles is interquartile range (IQR) [182, 187]. This term is used as a basis on which the lines protruding from the rectangle are drawn. The ends of these two lines (bottom and top) represent values within 1.5 times the IQR [187]. Any values outside these lines are outliers [182, 187]. Figure 3.12 illustrates the box plot representation of the trend of acidity with age used in previous data representation techniques.

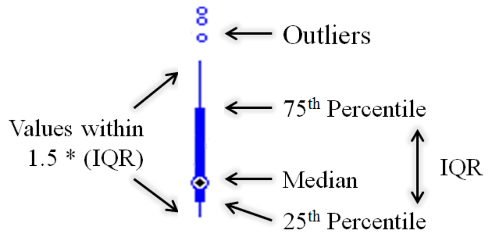

Figure 3.11: An individual box plot representation

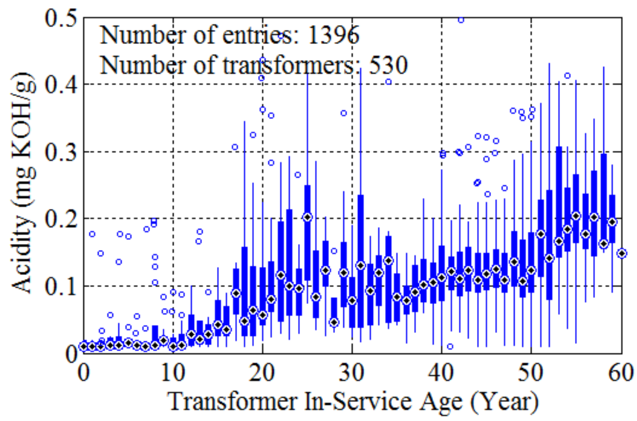

Figure 3.12: Box plot representation of acidity with age

Box plot is particularly useful if summary values representing the original data would be sufficient or detailed individual features of the original data are less of an interest [182]. Besides the benefits of a graphical summary of statistical information, the median and IQR in box plot representation are deemed statistically more robust than their counterparts of mean and standard deviation [190, 191]. Median has the highest possible breakdown point at 50% which means that half of a particular dataset needs to be changed or contaminated to cause an unreliable median value representation [190]. As for IQR, it has a 25% breakdown point [190].

In terms of potential drawbacks, box plot representation could mask original information for instance the number of points contributing to a particular box plot

[186]. Apart from this, different box plot formats are available such as the possibility of 20% and 80% percentile values (instead of 25% and 75%) which could manifest as a problem for comparing work from different sources [184].

3.4.1.4 Curve Fitting

Curve fitting is another parametric way of representing data. It is used for expressing the relationship between two variables by superimposing a curve derived from estimating the behaviour of original data corresponding to both variables [184, 192]. Figure 3.13 illustrates the use of exponential curve fitting on the acidity measurement data that have been used for demonstration thus far.

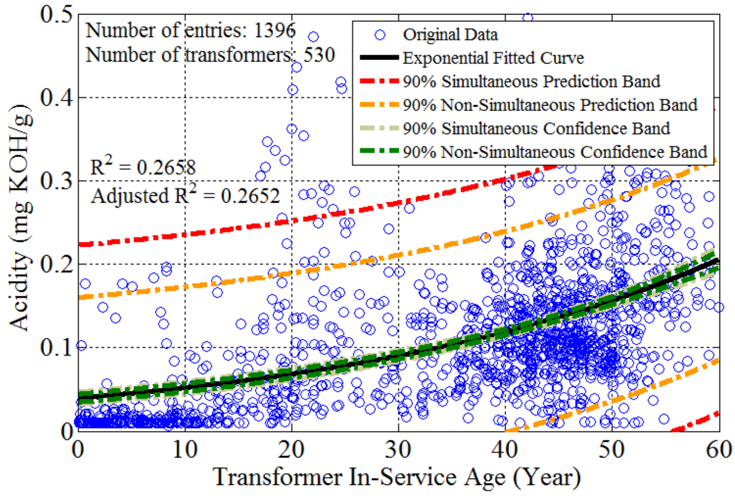

Figure 3.13: Exponential fitting of acidity with age

In addition to the fitted curve, prediction and confidence bands are also used in curve fitting graphical representation. A prediction band denotes a region where future observations are most probable based on typically 90% or 95% of certainty [184, 187]. As for a confidence band, it bounds a region where 90% or 95% of the time, this region would include the true fitted curve [184, 187]. There could be an additional description of non-simultaneous and simultaneous which refers to the consideration of whether the bands are obtained based on a point-wise manner (non-simultaneous) or based on all points (simultaneous) [193, 194]. When a non-simultaneous band is used, it is also alternatively called as an interval, for instance prediction interval and confidence interval [194].

Other than the graphical representations following a typical curve fitting procedure, the adequacy of the fitting procedure is also of interest. Apart from analysing residuals which are the distances between the fitted curve and the original data points, the most widely used measure of fitting adequacy is called the coefficient of determination or more familiarly known as R^2 [194]. This term describes the amount of original data variability that has been accounted for by the fitted curve with values closer to one indicating higher fitting adequacy [194]. Equation 3.5 and Equation 3.6 show how R^2 is evaluated [187].

$$R^2 = 1 - SS_E / SS_T$$ ***Equation 3.5***

$$SS_E = \sum_{i=1}^{n} \left(y_i - \hat{y}_i \right)^2 \quad SS_T = \sum_{i=1}^{n} \left(y_i - \bar{y} \right)^2$$ ***Equation 3.6***

SS_E is the error sum of squares whereas SS_T is the total sum of squares [187]. Considering n data points, y_i is the original observation at x_i, $\hat{y}_i$ is the computed value based on the fitted curve at that point x_i and $\bar{y}$ represents the mean [187]. Interestingly, R^2 can be negative if the model does not have any constant term [195]. Since R^2 describes the amount of original data variability explained by the fitted curve, the R^2 value would be negative if the fitting process is worse than just fitting a horizontal line [195].

In terms of curve fitting, overfitting is always something to be avoided. Adding more variables to a model increases the R^2, but the new variables added might not be meaningful at all [187, 195]. With that in consideration, adjusted R^2 is more representative of a fitting procedure. Equation 3.7 shows the formula for computing adjusted R^2 with p denoting the number of variables added to the model [187].

$$R_{adj}{}^2 = 1 - \frac{SS_E / (n-p)}{SS_T / (n-1)}$$ ***Equation 3.7***

From Equation 3.7, the term $(n-p)$ is the degrees of freedom associated with the error sum of squares and $(n-1)$ is the degrees of freedom for the total sum of squares

[187]. Briefly on degrees of freedom, particularly in curve fitting, they refer to the effective sample sizes for evaluating the respective terms [196]. $SS_E/(n-p)$ can also be collectively known as the mean square error [187]. Pertaining to this mean square error, only if the addition of new variables reduces the mean square error, the adjusted R^2 will increase [187]. In other words, arbitrary addition of variables into the model which might not be useful for the fitting will be penalised [187].

Similarly to R^2, an adjusted R^2 that is unity means a perfect fitting whereas a zero value indicates no representation of the data. On the other hand, a negative value indicates the presence of variables in the model that do not aid prediction of the response [195].

Briefly about the advantages and limitations of a curve fitting process, apart from a compact representation of the underlying trend of the original data, appropriate curve fitting process facilitates forecasting or future value prediction [184, 192]. Nonetheless, care needs to be exercised as analysis based on the fitted curve alone will mask the vast information in the original data particularly if the fitting adequacy is low [184]. Furthermore, fitted models that are representative of the current data might not be that representative of future data which inevitably affects understanding on future projection that could lead to confusing or misleading interpretations [184]. Moreover, different models that are concurrently sufficient for representing the same dataset could also add to wide ranging interpretations [184].

3.4.2 Statistical Analysis

Often the analysis on the databases entails graphically analysing trends of a certain parameter with respect to age as detailed in Section 3.4.1. This section will provide insights into statistical perspectives or approaches that could supplement and complement the graphical analysis. It is understood that there are more statistical techniques as well as more in-depth explanations available in the literature. This section is aimed at providing a succinct overview on the statistical techniques that are used in this work.

3.4.2.1 Correlation Coefficients

A measure of relationship between two variables or in other words how two variables vary with one another can be described by a single quantitative value called as a correlation coefficient [187]. Pearson's correlation coefficient is one that has been widely used in miscellaneous fields [197]. Other correlation coefficients are Spearman's and Kendall's [197]. The definitions of the three correlation coefficients are shown respectively in Equation 3.8, Equation 3.9 and Equation 3.10 [197, 198].

$$P = \frac{\sum_{i=1}^{n}\left[\left(x_i - \overline{X}\right)\left(y_i - \overline{Y}\right)\right]}{\sqrt{\sum_{i=1}^{n}\left(x_i - \overline{X}\right)^2 \sum_{i=1}^{n}\left(y_i - \overline{Y}\right)^2}} \qquad \textbf{\textit{Equation 3.8}}$$

$$S = \frac{\sum_{i=1}^{n}\left[\left(rank\left(x_i\right) - \overline{rank\left(X\right)}\right)\left(rank\left(y_i\right) - \overline{rank\left(Y\right)}\right)\right]}{\sqrt{\sum_{i=1}^{n}\left(rank\left(x_i\right) - \overline{rank\left(X\right)}\right)^2 \sum_{i=1}^{n}\left(rank\left(y_i\right) - \overline{rank\left(Y\right)}\right)^2}} \qquad \textbf{\textit{Equation 3.9}}$$

$$K = \frac{\sum_{i=1}^{n}\sum_{j=1}^{n} sign\left(x_i - x_j\right) sign\left(y_i - y_j\right)}{n\left(n-1\right)} \qquad \textbf{\textit{Equation 3.10}}$$

$$sign\left(x_i - x_j\right) = \begin{cases} 1 & if\left(x_i - x_j\right) > 0 \\ 0 & if\left(x_i - x_j\right) = 0 \\ -1 & if\left(x_i - x_j\right) < 0 \end{cases} ; \quad sign\left(y_i - y_j\right) = \begin{cases} 1 & if\left(y_i - y_j\right) > 0 \\ 0 & if\left(y_i - y_j\right) = 0 \\ -1 & if\left(y_i - y_j\right) < 0 \end{cases} \qquad \textbf{\textit{Equation 3.11}}$$

where $\overline{X}$ and $\overline{Y}$ are the sample averages of data pairs X and Y, each consisting of n number of observations (x_i and y_i with i = 1 to n). Notice the similar forms between the Pearson's correlation coefficient in Equation 3.8 and the Spearman's correlation coefficient in Equation 3.9. The difference is the conversion of the original data into ranks based on the original data magnitudes for Spearman's correlation coefficient [197, 198]. As for Kendall's correlation coefficient in Equation 3.10, it uses the signs from the (x_i - x_j) and (y_i - y_j) pairs as defined in Equation 3.11 to quantify the discrepancy between the number of concordant $(x_i - x_j)(y_i - y_j) > 0$ and discordant $(x_i - x_j)(y_i - y_j) < 0$ pairs [197, 198].

Generally, all correlation coefficients range from -1 to +1 with the magnitude denoting the strength of the relationship between the two variables and the sign representing a directly or inversely proportional relationship [197, 198].

Pearson's correlation coefficient is the most widely used due to its long history and optimality particularly in the case of complete populations that are also normally distributed [197]. Nonetheless, it has limitations such as the need for both variables to be either interval or ratio variables, an assumption of normal distribution for the bivariate data, provision for only a linear relationship and a high susceptibility to noise [197-200]. In the light of that, Spearman's and Kendall's correlation coefficients are more applicable as they are non-parametric (distribution free) and more statistically robust [197, 200]. In this work, Spearman's correlation coefficient will be preferred over Kendall's due to its better performance with smaller sample sizes, data of varying levels of correlation and lower time complexity [197].

3.4.2.2 Hypothesis Tests

With large amount of information available from databases, interest on comparing subsets of the data can be fulfilled through implementation of hypothesis tests which revolves around testing a null hypothesis H_0 for its tenability or otherwise (the opposite of H_0, the alternative hypothesis H_1). An example is to test whether the mean from sample 1, $\bar{X}_1$ and the mean from sample 2, $\bar{X}_2$ are equal. The hypothesis statements are shown in Equation 3.12 and Equation 3.13.

$$H_0 : \bar{X}_1 - \bar{X}_2 = 0$$ ***Equation 3.12***

$$H_1 : \bar{X}_1 - \bar{X}_2 \neq 0$$ ***Equation 3.13***

Pertaining to this particular example, *z* test and *t* test are the most appropriate [187]. In both cases, normal distribution is assumed as the statistic compared is mean which inherently is borne out of the assumption of normally distributed data as discussed in Section 3.4.1.2. The test statistics of these tests are shown in Equation 3.14 and Equation 3.15 with the degree of freedom for the *t* test, *v* also displayed [187].

$$Z = \frac{\bar{X}_1 - \bar{X}_2 - 0}{\sqrt{\frac{\sigma_1^2}{n_1} + \frac{\sigma_2^2}{n_2}}}$$ ***Equation 3.14***

$$T = \frac{\bar{X}_1 - \bar{X}_2 - 0}{\sqrt{\frac{S_1^2}{n_1} + \frac{S_2^2}{n_2}}} \quad ; \quad v = \frac{\left(\frac{S_1^2}{n_1} + \frac{S_2^2}{n_2}\right)^2}{\frac{\left(S_1^2/n_1\right)^2}{n_1 - 1} + \frac{\left(S_2^2/n_2\right)^2}{n_2 - 1}}$$ ***Equation 3.15***

where σ is the population variance, S is the sample variance and n is the sample size. Together with a predetermined significance level (usually 0.05 or 5%) as well as a set of statistical tables containing percentage points for a standard normal distribution and a t distribution, the null hypothesis is rejected only when either the positive valued statistic (it can be z or t statistic) exceeds the positive valued tabulated percentage point; or the negative valued statistic is lower than the negative valued tabulated percentage point [187]. Note that for t test, degree of freedom calculation is needed as another input for facilitating the judgement process [187].

In essence, t test is very similar to z test but unlike z test, it is not suitable for large sample sizes (customarily greater than 40 for both samples to be compared) and when only sample variances (instead of population variances) are known [187]. In this work, t test will be used when dealing with comparisons of means between samples which could be of smaller sizes and without known population variances.

Apart from comparing the mean values, median values of two samples ($\tilde{X}_1$ and $\tilde{X}_2$) can also be compared, particularly when the assumption of normally distributed data is to be avoided [187]. For this purpose, Wilcoxon rank-sum test is performed for median comparison [187]. The hypotheses to be tested are shown in Equation 3.16 and Equation 3.17 where the only difference between the ones discussed for mean comparison is the use of median.

$$H_0 : \tilde{X}_1 - \tilde{X}_2 = 0$$ ***Equation 3.16***

$$H_1 : \tilde{X}_1 - \tilde{X}_2 \neq 0$$ ***Equation 3.17***

Wilcoxon rank sum test starts by sorting the two data samples altogether in an ascending order of magnitude before ranks are assigned to the individual entries [187]. Tied entries (entries with the same magnitude) are assigned the mean of the ranks that would have been allocated if the entries were different [187]. Then, if W_1 is the sum of the ranks in the smaller sample, W_2 is then evaluated from Equation 3.18 [187].

$$W_2 = \frac{(n_1 + n_2)(n_1 + n_2 + 1)}{2} - W_1 \qquad \textbf{\textit{Equation 3.18}}$$

Together with a predetermined significance level (customarily 0.05 or 5%) as well as a table containing the critical values for Wilcoxon rank sum test, the null hypothesis is rejected in favour of the alternative hypothesis only if any of W_1 and W_2 is less than or equal to the referred critical value [187].

3.5 Chapter Summary

This chapter firstly introduced the databases available for this research. Generally the databases are from National Grid (NG), Scottish Power (SP) and UK Power Networks (UKPN) pertaining to in-service power transformers in the UK.

With the databases, processing needs to be done. Database processing approaches discussed include correct extraction of information out of databases of varying formats, treatment of numerical inequalities and non-numerical records, calculation of transformer in-service age and addressing of small inevitable variations in the records within a particular database.

Apart from database processing, databases need to be cleaned to remove any irregularities and errors that could affect subsequent analysis. The oil test parameter records were screened for any abnormalities. Other than that, issues possibly arising from human actions need to be considered in database cleaning. In this work, consideration was given for 2-FAL contamination issue, a change in measurement procedure and discontinuities arising from oil treatment implementation on in-service transformers.

Finally in this chapter, some of the approaches to graphically and statistically analyse the databases were covered. They include the use of scatter plot, mean and standard deviation plot, box plot and curve fitting as graphical approaches. On the other hand for statistical approaches, correlation coefficients like Spearman's correlation coefficient and hypothesis tests such as *t* test and Wilcoxon rank sum test could be used as a tool to supplement and complement the graphical approaches.

CHAPTER 4: EARLY DEGRADATION PHENOMENON

This chapter reports one of the main findings in this work which is the discovery of an early degradation phenomenon. As will be seen, some of the young transformers appear to age abnormally fast, reflected by for instance high acidity values around an in-service age of 20 years old. This will be covered in the first detection section of the chapter. The cause of the early degradation phenomenon will then be identified through exploring manufacturer, loading level and oil chemistry perspectives. Finally, the impacts of such an early degradation phenomenon will be discussed which hopefully can provide insights into better asset management of transformer fleets.

4.1 Detection of Early Degradation Phenomenon

With databases processed and cleaned, one of the main findings from analysing the oil test databases is an early degradation phenomenon. Figure 4.1 shows the trends of two commonly tested parameters, acidity (oil ageing indicator) and 2-FAL (paper ageing indicator) with in-service age for 33 kV transformers from a particular utility. Note that the IEC 60422 recommended value for transitioning from a Good to a Fair condition based on acidity is also shown.

Owing to the large number of entries, some degree of scattering is expected in the ageing trends. Nevertheless, a clear early peak at around an in-service age of 20 years can be seen in both subfigures of Figure 4.1.

The early peak observed is unusual judging by how both parameters are generally known to increase continuously with ageing and with high values generally recorded after an in-service age of 40 years. Considering the IEC 60422 recommended value for condition classification, the acidity trend in Figure 4.1(a) noticeably depicts that the transformers even at around an in-service age of 20 years old are starting to transition into a Fair condition. With these observations, the early peak observed could allude to an unusual early degradation phenomenon [201].

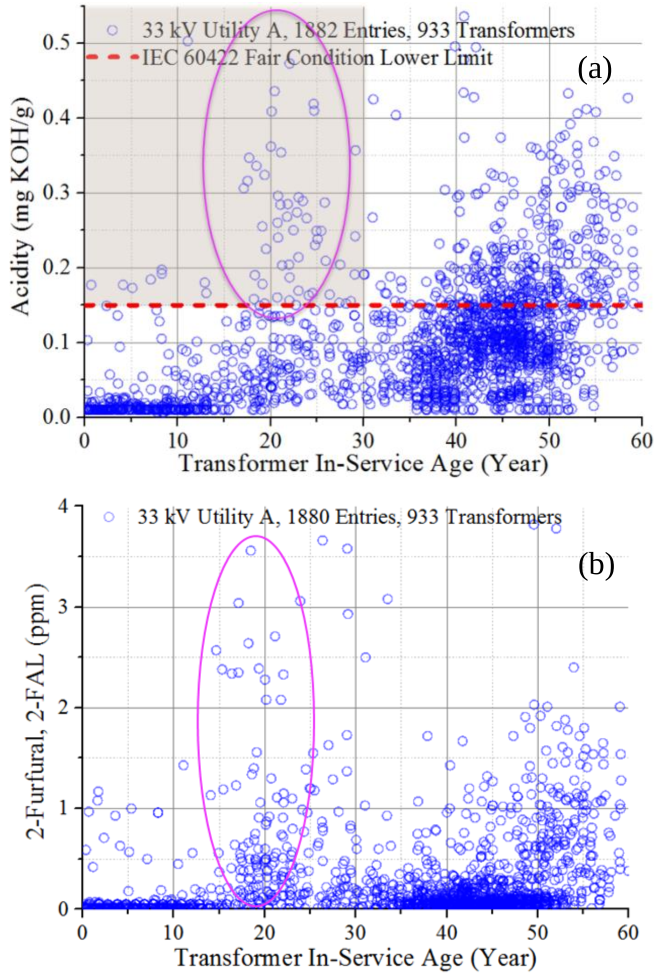

Figure 4.1: Early peak in trends with in-service age for Utility A 33 kV transformers, (a) acidity, (b) 2-FAL [201]

Although not shown here to avoid repetition, the early degradation phenomenon was also reflected by early peaks in acidity and 2-FAL from other utility databases associated with transformers operating at not just 33 kV, but also other voltage levels such as 132 kV, 275 kV and 400 kV in addition to the ones represented in Figure 4.1 [201]. Moreover, this early degradation phenomenon was also detected from other oil test parameters such as dielectric dissipation factor. These suggest that the early degradation phenomenon was not only an issue affecting a certain voltage level or a specific utility, but could most likely be an issue affecting all the UK utilities [201].

4.2 Cause Identification of Early Degradation Phenomenon

In the light of the potential impacts on asset management that the early degradation phenomenon could pose, the cause of such a phenomenon needs to be identified after which remedial actions can be planned. Focusing firstly on the cause identification of the phenomenon, subpopulations of transformers that are most likely affected by the early degradation phenomenon need to be extracted.

A set of criteria as seen in Table 4.1 was developed for subpopulation extraction across all the databases. The first part of the criteria involves selecting transformers whose oil test entries were obtained when the transformers have an in-service age of up to 30 years. The second part of the criteria is based on the value for transitioning from a Good condition to a Fair condition according to acidity measurements as stipulated in IEC 60422 [201]. Note that as IEC 60422 specifies the same recommended value ranges for condition classification and the same recommended actions for both 275 kV and 400 kV transformers, they will be grouped as one [201].

Table 4.1: Criteria for early degradation subpopulation extraction [201]

<table>
<tr><th>Primary Voltage</th><th>In-Service Age</th><th colspan="2">Acidity (mg KOH/g)</th></tr>
<tr><td>33 kV</td><td rowspan="3">≤ 30 Years</td><td>≥ 0.15</td><td rowspan="2">IEC 60422 Fair Condition Lower Limit</td></tr>
<tr><td>132 kV</td><td>≥ 0.10</td></tr>
<tr><td>275 kV & 400 kV</td><td>≥ 0.05</td><td>Set for Greater Detection</td></tr>
</table>

Only acidity is used as part of the criteria for extracting the early degradation subpopulations as it is a parameter with great correlation with transformer age that is also commonly measured by utilities for transformers operating at different voltage levels [81, 201]. Furthermore, recommended value ranges for condition classification based on acidity are also readily available, with IEC 60422 standardised values providing the necessary reference [201].

Note that a lower acidity value of 0.05 mg KOH/g as compared with the standardised value of 0.1 mg KOH/g was used for subpopulation extraction of 275 kV and 400 kV transformers. This measure was to account for the much lower acidity values recorded for these transformers probably due to greater care, maintenance, attention or stricter design requirements [81, 201]. With the subpopulations now established, further analyses will be undertaken to identify the cause of the early degradation phenomenon.

It is noteworthy that as detailed in Section 3.2 and Section 3.3, the databases obtained would have been processed and cleaned. Thus, the early degradation phenomenon detected here would not have been contributed by data entry errors, oil contamination issues, change in measurement procedure, oil treatment implementation or any other human mistakes in data entry. Hence, the following analyses for identifying the cause of the early degradation phenomenon will be approached from manufacturer, loading and oil chemistry perspectives [201].

4.2.1 Manufacturer Perspective

The motivation behind approaching the cause of early degradation phenomenon from a manufacturer perspective is the potential influence different designs could have imparted on varying ageing performance of transformers. Figure 4.2 illustrates the manufacturing year distributions pertaining specifically to the extracted subpopulations based on the criteria discussed in Table 4.1. The compositions of different manufacturers are also displayed. Note that the manufacturing year periods are presented in the form of half decades, for instance, "Early 1970s" for 1970 – 1974, "Late 1970s" for 1975 – 1979 and so forth [201].

Due to confidentiality issues, the exact names of the transformer manufacturers are not shown but as seen from Figure 4.2, there are 25 manufacturers contributing to the units linked to the subpopulations of 33 kV, 132 kV as well as 275 kV and 400 kV. It is noteworthy that the number of manufacturers could be slightly overestimated as certain manufacturers have changed their names or ownerships over the years. However, such information is difficult to obtain and is not considered in this thesis.

Another telling observation is that there is no dominant manufacturer(s) that contributed to transformers in the subpopulations. This implies that the early degradation phenomenon is most likely not attributed to potentially poorer designs or flaws from a specific manufacturer(s) [201]. In addition, Figure 4.2 depicts the high contribution of transformers manufactured in the late 1980s and the early 1990s to the subpopulations across all the transformer voltage categories. It means the early degradation phenomenon is most probably culminated by transformers manufactured during these two periods in time [201].

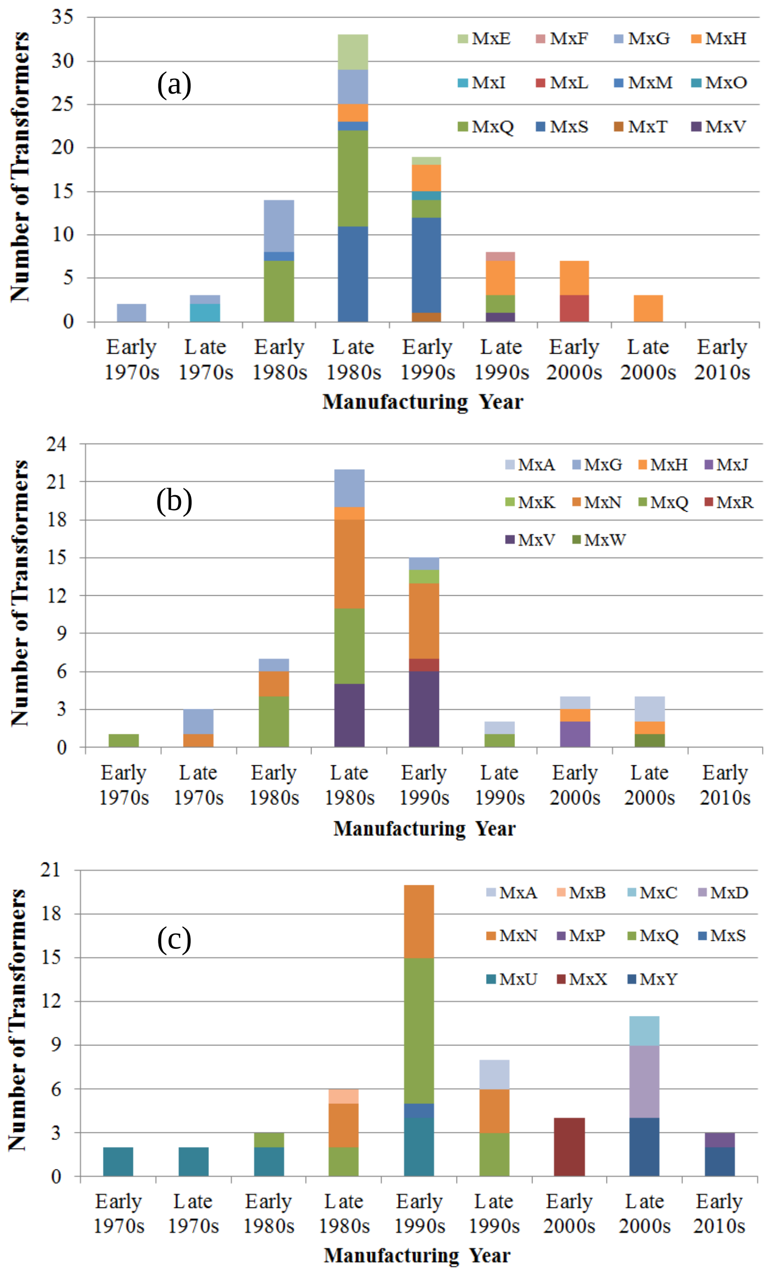

Figure 4.2: Manufacturing year distributions, (a) 33 kV subpopulation, (b) 132 kV subpopulation, (c) 275 kV and 400 kV subpopulation [201]

By focusing on transformers manufactured in those two periods (the late 1980s and the early 1990s), Figure 4.3 illustrates the manufacturer distributions of unaffected transformers (UT) and affected transformers (AT) from the transformer manufacturers that are deemed to be linked with the early degradation phenomenon [201]. Note that UT refers to the transformers that have an in-service age of up to 30 years and an acidity value that is less than the designated limits as seen in Table 4.1. On the other hand, AT represents the transformers considered in the subpopulations.

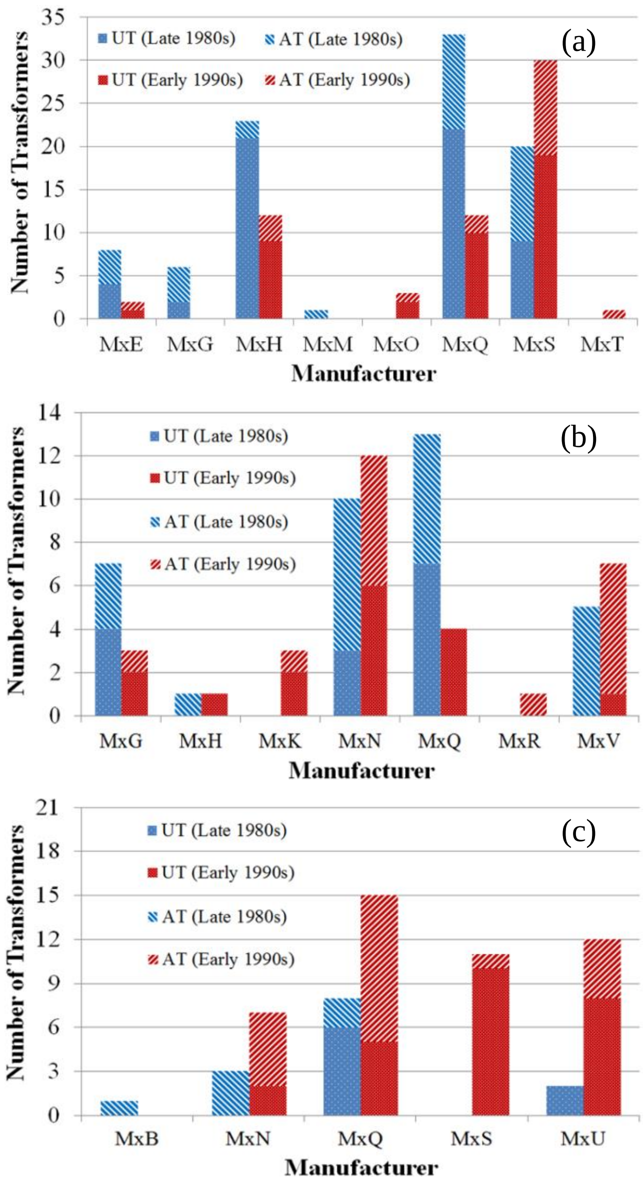

Figure 4.3: Manufacturer distributions of unaffected transformers (UT) and affected transformers (AT) from the late 1980s and the early 1990s, (a) 33 kV, (b) 132 kV, (c) 275 kV and 400 kV [201]

Figure 4.3 illustrates and further consolidates that the early degradation phenomenon is not attributed to manufacturers. This is vindicated by noticing that not only AT units are contributed by different manufacturers, the manufacturers with AT units generally have UT units as well regardless of the manufacturing year period [201]. Furthermore, in the light of the marked increase in adoption of computerised designs reported in the 1980s, the presence of both UT units and AT units for the manufacturers also suggests that the early degradation phenomenon was not due to this shift to computerised designs [201].

Continuing from the distributions of transformers across different manufacturing year periods and manufacturers, the scope of analysis is now narrowed to a particular manufacturer, namely MxQ.

This manufacturer had made transformers spanning a long period of time (from the early 1970s to the early 2000s) [201]. This timespan also includes the late 1980s and the early 1990s that were known from previous analyses as the half decades from which transformers are most likely linked to early degradation phenomenon [201]. In addition to that, MxQ was known from previous analyses seen in Figure 4.2 and Figure 4.3 as a manufacturer that has both UT and AT units regardless of the voltage classes and utilities [201].

To understand the behaviour of transformers from the same manufacturer or the same design family that were manufactured from different periods in time, trends of acidity with respect to in-service age pertaining to MxQ transformers for the three voltage classes are shown in Figure 4.4 [201]. Note that the standard definition of box plot as discussed in Section 3.4.1.3 applies to Figure 4.4. Different colours are used to represent the different half decade groups. Besides that, the width of each half decade box plot is designed according to how wide a particular half decade group covers in terms of the in-service age span [201].

From Figure 4.4, the early peak in acidity can be observed for the bulk of data corresponding to an in-service age of around 20 years. It is also noteworthy that the early 1980s transformers seem to also contribute towards the early high acidity for 33 kV and 132 kV populations. This could be due to an earlier acceptance of the change that triggered early degradation phenomenon by this particular MxQ manufacturer for lower voltage transformers (possibly due to their lower criticality if compared with higher voltage counterparts). This can also be seen from Figure 4.2 where MxQ also contributes to the early 1980s group.

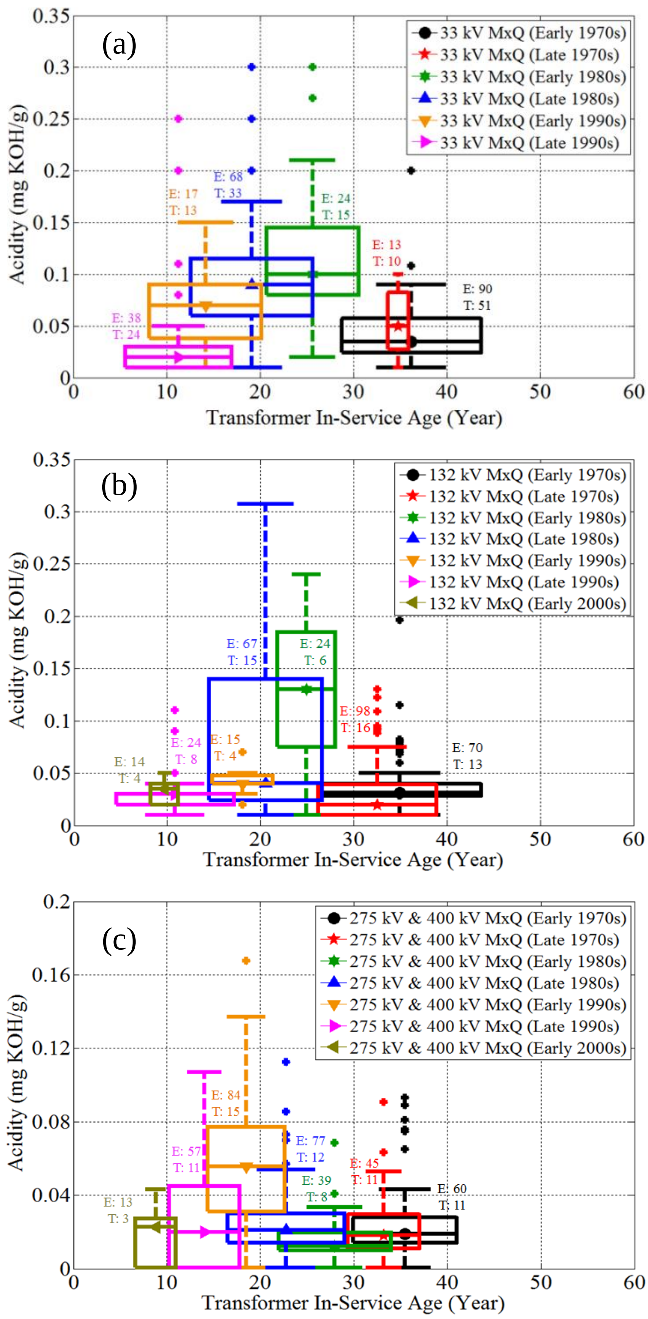

Figure 4.4: Trends of acidity with age for units from manufacturer MxQ, (a) 33 kV, (b) 132 kV, (c) 275 kV and 400 kV E: number of entries, T: number of transformers [201]

More importantly from Figure 4.4, the high acidity seen in the early ageing stages for units from only a single manufacturer (MxQ), where the high acidity is contributed consistently by the late 1980s and the early 1990s groups for all voltages, is similar to what was initially observed in the whole population (including all manufacturers) in Figure 4.1. Therefore, individual manufacturer analysis again consolidated that the early degradation phenomenon is not a manufacturer specific issue and could most probably be attributed to the presence of transformers manufactured in the late 1980s and the early 1990s [201].

4.2.2 Loading Perspective

With early degradation phenomenon adjudged to be independent from transformer manufacturers, the focus of analysis is now shifted to investigating the possible influence of transformer loading levels. From all the databases available in this work, loading information is generally not well recorded or inadequate. Working within the limited data, loading information obtained could be in the form of actual loading records spanning a specified duration or just the peak loading record.

Experience has led to preference of actual loading information as the peak loading is not representative. Actual loading level information spanning a period of time can be converted into an equivalent loading, L_{eq} of a transformer based on the following Equation 4.1 stipulated in IEEE C57.91 – 2011 [202].

$$L_{eq} = \left[\frac{L_1^{\,2} t_1 + L_2^{\,2} t_2 + \ldots + L_N^{\,2} t_N}{t_1 + t_2 + \ldots + t_N} \right]^{0.5} \qquad \textbf{\textit{Equation 4.1}}$$

where L_1, L_2 ... L_N represent the actual loading level in per unit; N denotes the total number of loading steps considered and finally t_1, t_2 ... t_N symbolise respective durations of each of those loading steps [202].

With the focus on actual loading level information, only a particular utility database (Utility E) has records of actual loading for 529 of its in-service transformers [201]. The actual loading information is in the form of half hourly records of the individual transformers from 1 January 2009 to 31 December 2010.

In the context of early degradation phenomenon, there are 23 transformers with such information [201]. On the other hand for transformers considered to undergo normal ageing (with early degradation transformers extracted), actual loading information is available for 506 transformers [201]. Figure 4.5 illustrates the distributions of the equivalent loadings for normal ageing transformer population and transformers regarded with early degradation phenomenon [201].

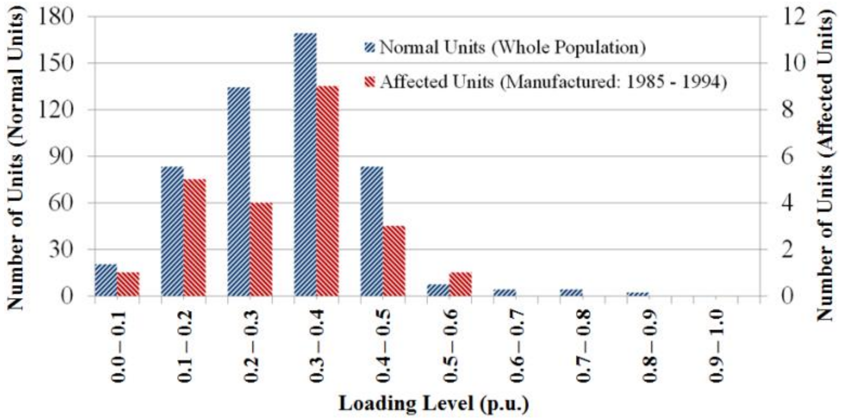

Figure 4.5: Loading distributions of Utility E normal and affected transformers [201]

Focusing on the manufacturing year periods of the late 1980s and the early 1990s, what can be observed from Figure 4.5 is that the early degradation transformers portray a similar loading distribution to that of the normal ageing transformer population. In other words, the early degradation transformers are actually not loaded towards the higher loading level region if compared with their normal ageing transformer counterparts. This observation is important in suggesting that transformer loading level is not the cause of the early degradation phenomenon [201].

4.2.3 Oil Chemistry Perspective

So far, transformer manufacturer and loading level have both been dismissed as potential causes of early degradation phenomenon. This section shifts the focus of investigation to oil chemistry change, with consideration of the different oil refining techniques hitherto adopted in producing mineral insulating oil. This is because the different techniques adopted throughout the long history of mineral oil usage could have affected how units made from different points in time behave or age [201].

More details on the oil refining techniques are found in Section 2.1.2. Generally, the distillation products or distillates from fractionated distillation of crude oil are propagated to one of the main refining techniques as seen in a chronological order in Figure 4.6 [201].

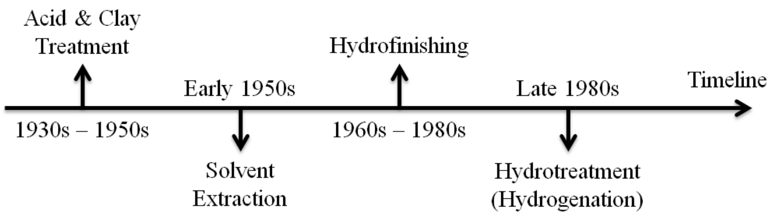

Figure 4.6: Brief chronology of refining techniques for mineral oil [201]

From the 1930s to the 1950s, acid and clay treatment had been widely adopted before solvent extraction became prominent from the early 1950s, with typical solvents of 2-furfural (2-FAL) and phenol used [10, 40]. In the 1960s, hydrotreatment was introduced and was initially implemented as a finishing process for other techniques like solvent extraction [10, 40]. This combinatory oil refining technique is collectively called as hydrofinishing and had been popular from the 1960s to the 1980s.

In the late 1980s, hydrotreatment (hydrogenation) started to be widely used as a complete refining technique on its own citing developments in the science of catalysts as well as the progressive use of higher temperatures and pressure in oil refining [40]. Such a technique is efficient in not just being capable of greatly reducing both aromatic and polar compounds in oil, but also cost effective and providing higher yields with lower toxic sludge [40, 43, 46]. In addition, shortfall in fuel oil demand, refinery downsizing, closure as well as increased emphasis on the relative quantity and quality of refined oil have all further contributed to the worldwide preference of hydrotreatment from the late 1980s [43-45].

More on hydrotreatment, with its involvement of high temperatures and pressure, the intensity of refining is known to be severe [201]. Figure 4.7 depicts how intensity of refining affects the resulting refined oil properties [10, 201]. In the context of ageing, a higher refining intensity increases the oxidation stability of the oil which is preferable [10]. Nonetheless, when the refining intensity is too high, the oxidation stability eventually reduces as naturally existing antioxidants which are useful towards retarding oil oxidation are also removed in addition to the undesirable compounds [10, 40]. Such oil (for instance oil from hydrotreatment) will respond well with synthetic antioxidants or inhibitors, characterised by superior oxidation stability that is based on the synthetic inhibitor induction period [10, 40].

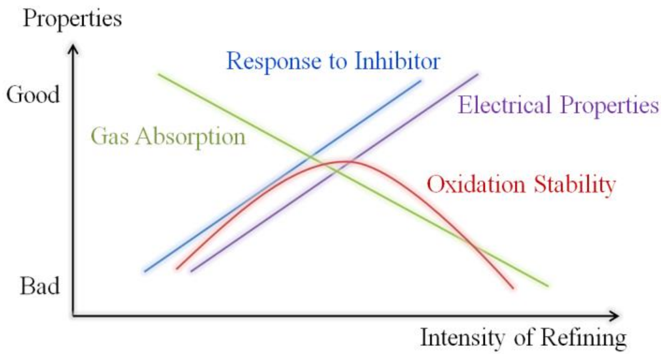

Figure 4.7: Influence of refining intensity on oil properties [10, 201]

Pertaining to the addition of synthetic inhibitors to produce inhibited oil, it was not until the late 2000s that some UK utilities began using inhibited mineral oil in newly manufactured transformers [201]. Hence, with hydrotreatment introduced in the late 1980s and becoming a prominent oil refining technique, the units manufactured around that period of time would not have synthetic inhibitors added to their oil [201].

This is most likely why the early degradation phenomenon observed from analysing the in-service UK transformers is contributed by transformers manufactured around the late 1980s [201]. This finding correspond well with the observations in Figure 4.2, Figure 4.3 and Figure 4.4 where the early degradation phenomenon was most probably contributed by units manufactured in the late 1980s and the early 1990s.

Proper control of the intensity of the refining could help maintain the oil at a desirable oxidation stability, but the early stages of hydrotreatment implementation in the late 1980s and the early 1990s could most likely have resulted in oil that is low in inherent oxidation stability. Transformers manufactured in these periods of time would have then been filled with uninhibited hydrotreated oil that is more susceptible to oxidation, explaining why some transformers are already aged (for instance indicated by high acidity values) even at around the relatively young age of 20 years old [201].

It is noteworthy that even though hydrotreatment was the dominant oil refining technique from the late 1980s, some proportion of oil in the market was still refined using hydrofinishing [10]. This could be the reason why not all transformers that were manufactured in the late 1980s or the early 1990s are associated with the early degradation phenomenon [201].

4.3 Impacts on Asset Management

Through a series of investigations, evidence so far has indicated that the early degradation phenomenon discovered is caused by an oil chemistry change associated with the adoption of early hydrotreatment oil refining technique back in the late 1980s [201]. With cognisance of this early degradation phenomenon, asset managers need to perhaps revise current asset management strategies to accommodate the affected transformers [201]. A 33 kV database from a utility will be used for demonstration with both acidity and 2-FAL projected ageing trends shown in Figure 4.8 [201].

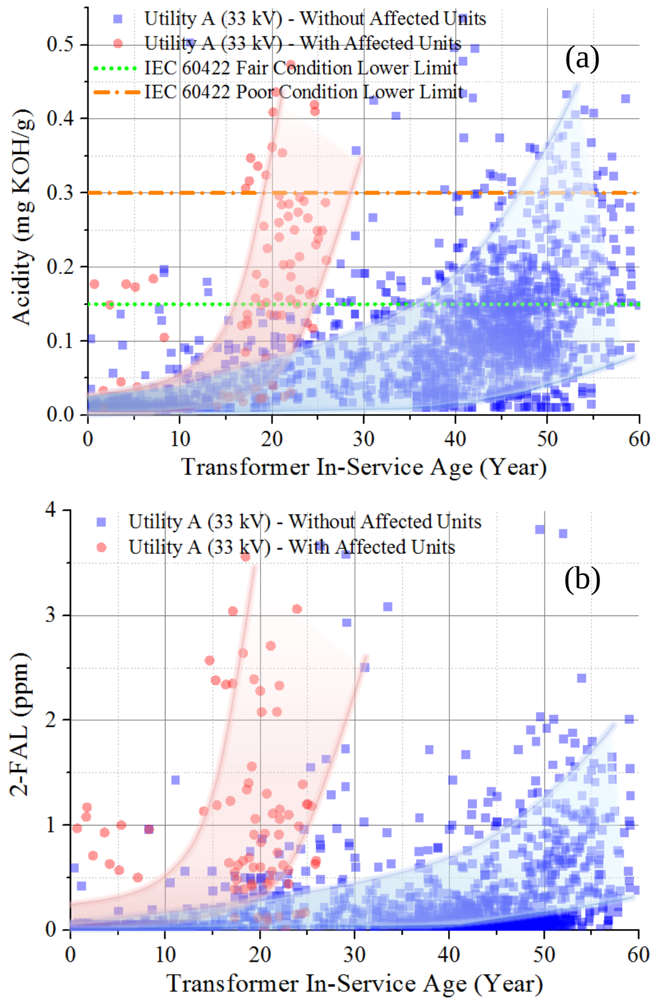

Figure 4.8: Projected ageing trends between populations with and without early degradation transformers, (a) acidity, (b) 2-FAL [201]

From Figure 4.8(a), normal ageing transformers would typically start having acidity values that are interpreted as a Fair condition (based on IEC 60422) around an in-service age of 35 years but the affected early degradation transformers clearly age faster and would start having acidity values that are interpretable as a Fair condition even at about an in-service age of 15 years [201]. Not just for oil ageing commonly represented by acidity, this faster rate of degradation also applies to paper ageing as can be interpreted from the difference in the 2-FAL projected ageing trends depicted in Figure 4.8(b) [201].

This difference in the projected ageing trends for both acidity and 2-FAL highlights the need for revising current asset management strategies to uphold reliability of the transformer fleets and the power system as a whole. From a population perspective, the faster rate of degradation of the affected transformers could be considered into restructuring any existing framework for capital investment, expenditure or any long term replacement policies [201]. Other than that, from individual transformer viewpoint, the affected transformers could be monitored more frequently, with oil regeneration (reclamation) or even oil replacement perhaps prioritised or scheduled earlier for these units to retard further degradation of the insulation system [201].

Extending from what was observed in this work which involves in-service transformers from three UK utilities; early degradation phenomenon was also detected from another UK utility and may actually be also seen in other countries around the world as well [201]. Considering that the early degradation phenomenon is most likely due to the early stage adoption of hydrotreatment and knowing that hydrotreatment was the worldwide choice of oil refining technique from the late 1980s, asset managers not just in the UK but perhaps also around the world might need to investigate the occurrence of such a phenomenon in their respective transformer fleets and subsequently plan counter actions if necessary [201].

With knowledge on how well hydrotreated oil responds with synthetic inhibitors, it is however interesting to note that perhaps the US utilities might not see such an early degradation phenomenon as the US transformers are known to be filled with oil with synthetic inhibitors [201]. As for other countries where uninhibited oil is customarily used, it could be worthwhile to check for this early degradation phenomenon [201].

The ageing of transformers manufactured after the 1990s might be of interest as well [201]. With the late 1980s and the early 1990s deemed to be the time periods when oil chemistry was changed due to hydrotreatment, attention should be also given to the transformers manufactured after these specific periods, particularly when they age to about 20 years [201]. It would be interesting to see whether these transformers behave similarly to the affected or the unaffected transformers [201].

Early speculations suggest that these transformers which are manufactured after the 1990s could be free from the early degradation phenomenon due to the addition of dibenzyl disulphide (DBDS) which acts as an inhibitor. This addition of DBDS, on the other hand, could be the reason why utilities are observing premature transformer failures attributed to the corrosive sulphur issue as mentioned briefly in Section 2.3.10. Nonetheless, the ageing of the post 1990s transformers remains an interesting direction for future work, from the perspectives of whether they would age normally and if they do, the mechanisms or the reasons behind that.

4.4 Chapter Summary

In this chapter, early degradation phenomenon was first demonstrated through the ageing trends of both acidity and 2-FAL for 33 kV transformers from a utility. High values of acidity and 2-FAL were observed even in the early ageing stages. This phenomenon can also be observed for other utilities and for transformers operating at various voltage levels.

Proceeding from the detection of the early degradation phenomenon, a series of investigative studies were performed to identify the potential cause. The studies were performed from the perspectives of manufacturer, loading level and a change in oil chemistry. Evidence so far has suggested the oil chemistry change due to the early stage adoption of hydrotreatment oil refining technique in the late 1980s as the cause of the early degradation phenomenon.

With early degradation phenomenon detected, some recommendations to asset management include revising existing framework for long term capital or replacement plans as well as monitoring more frequently and prioritising oil treatment procedures for the affected transformers. In addition, other utilities in the UK, perhaps even around the world might need to investigate the occurrence of this early degradation phenomenon in their respective fleets and plan counter actions if necessary.

CHAPTER 5: POPULATION ANALYSES

Population analyses are one of the most important steps in approaching databases particularly for understanding generic trends or behaviours of huge transformer fleets. With databases processed and cleaned based on Section 3.2 and Section 3.3, as well as with separation of units with early degradation phenomenon (in Chapter 4), this chapter focuses on databases more representative of normal ageing transformers.

From analysing the databases acquired, the oil test parameters that are considered are breakdown voltage (BDV), moisture, acidity, 2-furfural (2-FAL), dielectric dissipation factor (DDF), resistivity, interfacial tension (IFT), colour and permittivity. The testing frequency and correlation with transformer age of the different parameters will be discussed, before the sensitivity study on the length of testing year period is explored. Finally, study will be performed on the influence of voltage, manufacturer and loading on population ageing trends.

5.1 Testing Frequency

Figure 5.1 shows the testing year periods of the multiple parameters for each of the eight databases. Note that the databases are named with an alphabet and the primary voltage level at which the transformers operate. The testing year periods are represented by the vertical length of the corresponding bars. In addition, each bar is also accompanied by a fraction that shows the number of data entries on the numerator and the number of transformers on the denominator. For example, the 479/397 appearing for BDV of Database A_33kV in Figure 5.1(a) indicates there are in total 479 data entries with BDV records associated with 397 transformers. This means that there are just greater than one BDV measurement per transformer within the two years' period of oil test data records (2009 – 2010).

As can be perceived from Figure 5.1, different databases have different testing year periods and within the same database itself, different parameters are also recorded for different time spans. Note the colour measurements for database G_275kV_400kV in

Figure 5.1(c) recorded from 1992 to 2006 were descriptive in nature. Starting from 2007 to 2012, the colour measurements were in numerical form but due to their lower number of records, they will be omitted from further analysis.

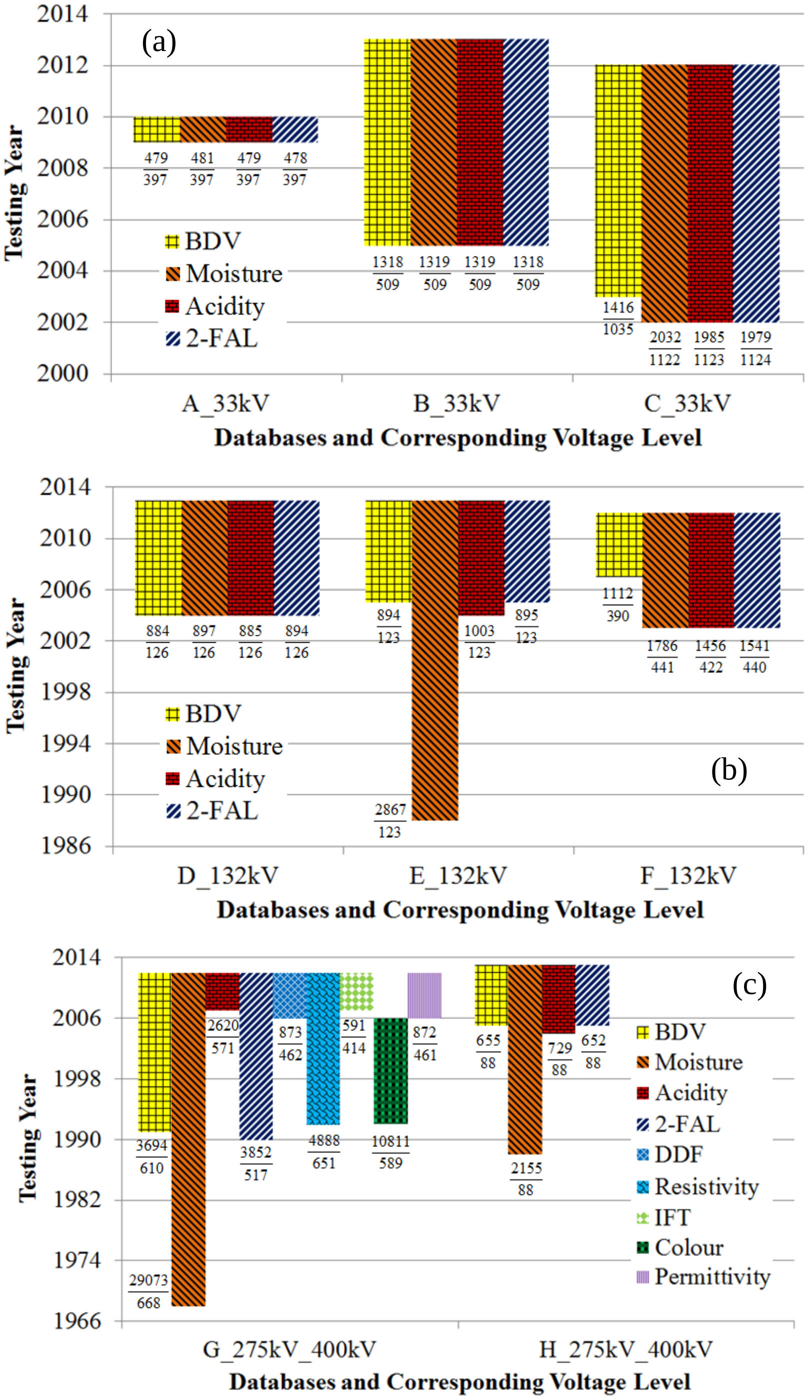

Figure 5.1: Testing year periods of oil test parameters across multiple databases, (a) 33 kV, (b) 132 kV, (c) 275 kV and 400 kV

In general, the common parameters that are recorded in all databases, regardless of the transformer operating voltages and utilities are BDV, moisture, acidity and 2-FAL. To aggregate all the information presented in Figure 5.1, particularly to understand how frequently the parameters are tested, a form of derivative term, known arbitrarily as an aggregated average testing frequency, F_{aat} was evaluated based on Equation 5.1.

$$F_{aat} = \left[\sum_{i=1}^{n} \frac{\left(N_t / N_{tx} \right)}{T_p} \right] \Big/ n \qquad \textbf{\textit{Equation 5.1}}$$

where n represents the number of contributing databases with reference to each of the voltage classes, N_t denotes the number of tests, N_{tx} symbolises the number of transformers and T_p indicates the testing year period. Table 5.1 shows the calculated values for each voltage class [81]. In essence, they represent the number of tests performed on each transformer per year, aggregated from the relevant databases of a particular voltage class [81]. For instance, a value of 0.5 means there is an average of 1 measurement per transformer per 2 years [80].

Table 5.1: Aggregated average testing frequencies from multiple databases [81]

Parameter	**Aggregated Average Testing Frequency**		
	33 kV	**132 kV**	**275 kV & 400 kV**
	3 Databases	**3 Databases**	**2 Databases**
BDV	0.35	0.69	0.55
Moisture	0.36	0.69	0.95
Acidity	0.35	0.65	0.80
2-FAL	0.35	0.65	0.57
DDF	X	X	0.27*
Resistivity	X	X	0.35*
IFT	X	X	0.24*
Colour	X	X	1.20*
Permittivity	X	X	0.27*

* from one database

By studying Table 5.1, regardless of the lower individual values associated with BDV and 2-FAL for 275 kV and 400 kV transformers, a higher frequency of testing is generally observed for transformers operating at higher voltage levels [81]. This implies that higher voltage transformers tend to receive greater attention and care from electrical utilities [81]. Note that IEC 60422 does recommend more frequent oil tests for higher voltage or more critical transformers [28].

The greater attention and care on higher voltage transformers can also be interpreted from Figure 5.1 and Table 5.1 by observing that 275 kV and 400 kV transformers from a particular database are measured for more parameters [81]. Besides the common parameters of BDV, moisture, acidity and 2-FAL, these transformers are measured for DDF, resistivity, IFT, colour and permittivity too [81]. It is interesting to note that even though DDF and resistivity (as well as colour) are categorised in IEC 60422 as routine tests like acidity, they are tested less frequently [28]. Nonetheless, even with a lower testing frequency, the drive behind the measurement of more parameters could be the need for more comprehensive and diverse information on higher voltage transformer condition [81].

Owing to the greater importance of higher voltage transformers in the network, the higher testing frequency would definitely be valuable towards helping asset managers to understand the evolution of certain parameters over time in more detail which could provide timely indications of abnormal conditions, preventing potential catastrophic failures [81]. On the other hand for the measurement of more parameters, asset managers could make decisions with more confidence based on consistent indications from a set of different oil test parameters, for instance high acidity accompanied by high DDF, low resistivity, low IFT and so forth.

5.2 Correlation with Transformer Age

With multiple oil test parameters available to indicate transformer ageing, this section reports findings on the correlation of these parameters with respect to transformer in-service age from two perspectives. The first being a graphical perspective and the second being a statistical perspective.

5.2.1 Graphical Perspective

The graphical perspective will be explored from a visual inspection on trends of the parameters with respect to age. The following figures (Figure 5.2 to Figure 5.9) show box plot yearly data representation pertaining to the eight databases. More details on box plot are found in Section 3.4.1.3. Box plot is particularly suitable here not just its comprehensive information and its capability of representing ordinal variables like colour which has a subjective colour measurement scale, but also its ability to be less susceptible to noise or extreme data.

For parameters that have recommended value ranges for condition classification as in IEC 60422, the Good-Fair and Fair-Poor transition criteria are also shown by the light green and magenta lines respectively. These standardised values can be referred from Table 2.2 found in Section 2.4.

Focusing on the common parameters tested by all databases, population ageing trends indicate quite consistently a clear increasing trend for acidity, to be followed by moisture in terms of representation of in-service age. 2-FAL generally stays low before depicting more of a drastic increase at the later stages of ageing. Database B_33kV seems to have a small peak close to around 30 years of age which could be due to undetected units with oil contamination. As for BDV, it generally stays flat with ageing with a hint of decreasing towards the later stages of ageing based on the current small sample size in the later ageing stages.

As for the additional parameters seen only in Figure 5.8, permittivity evidently stays constant throughout ageing. DDF seems to be increasing slowly but steadily with ageing. As for resistivity, IFT and colour, these three parameters change drastically in the early ageing stages before stabilising after late ageing periods. Note the colour measurements are non-numerical and are represented in terms of New (N), Light (L), Gold (G), Amber (A), Dark (D) and Very Dark (VD). A value between two adjacent steps would just mean an intermediate level [81].

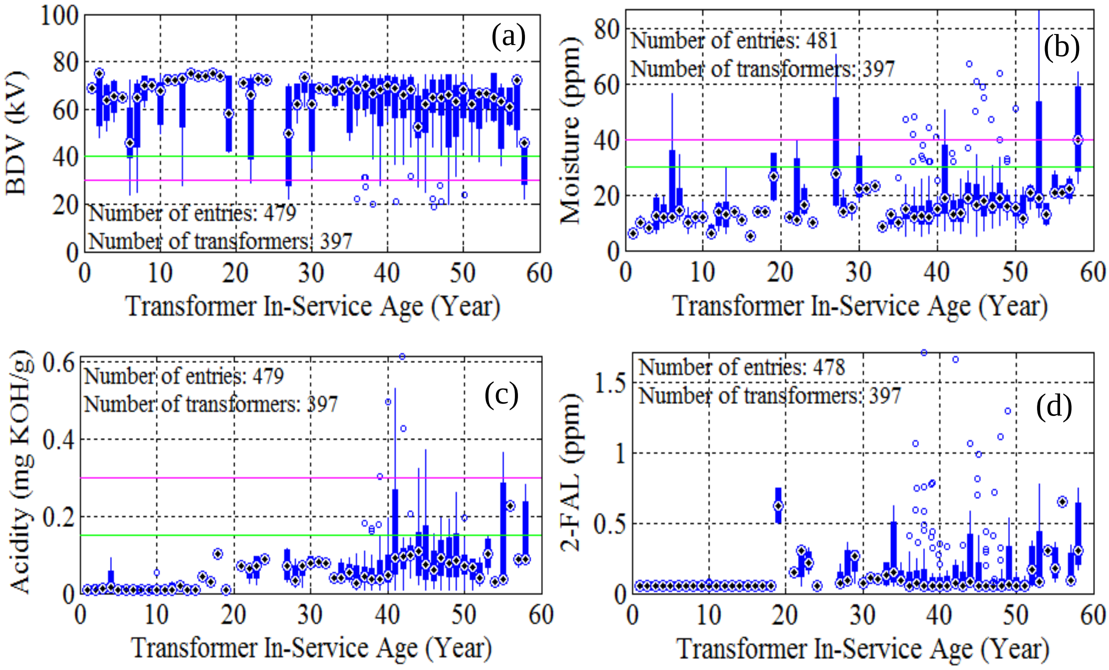

Figure 5.2: Database A_33kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

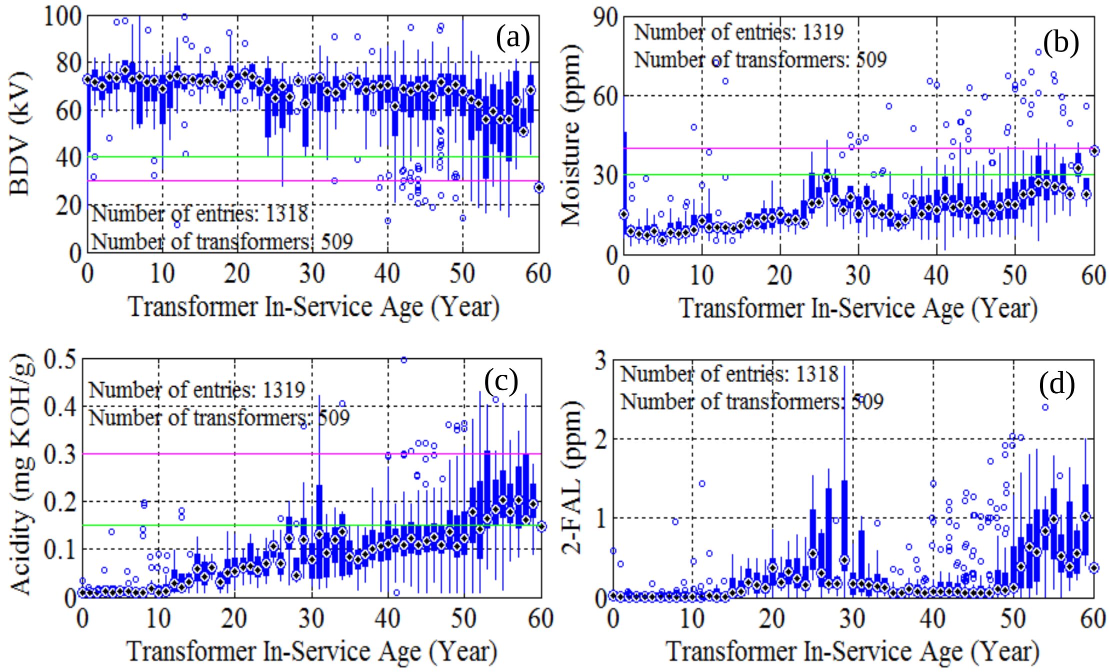

Figure 5.3: Database B_33kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

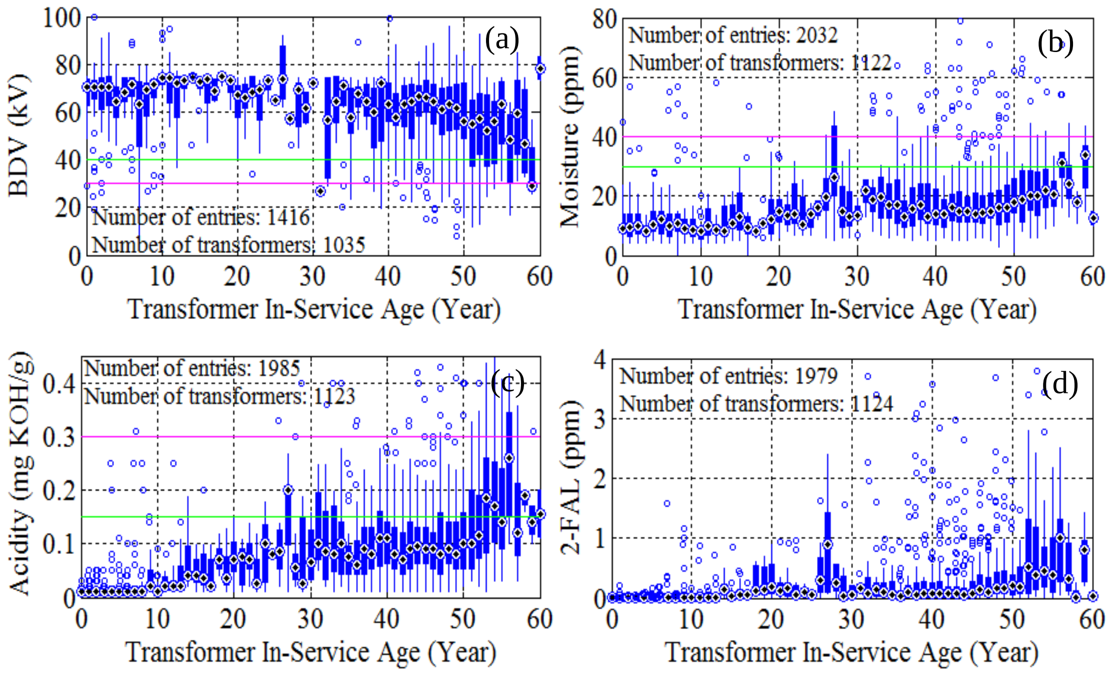

Figure 5.4: Database C_33kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

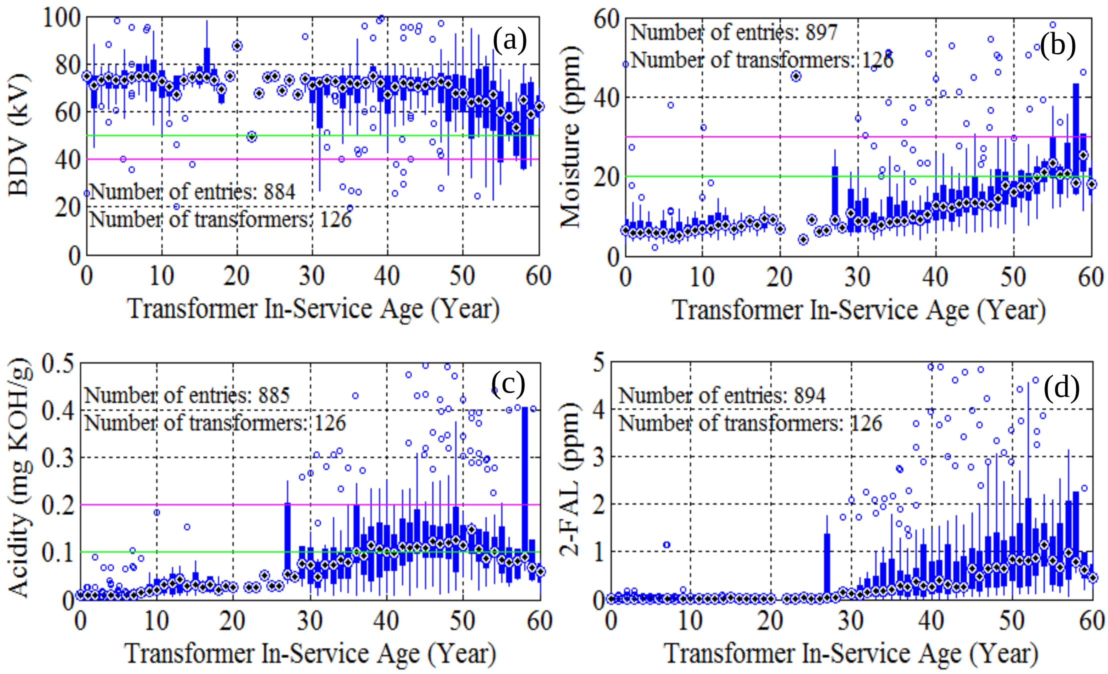

Figure 5.5: Database D_132kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

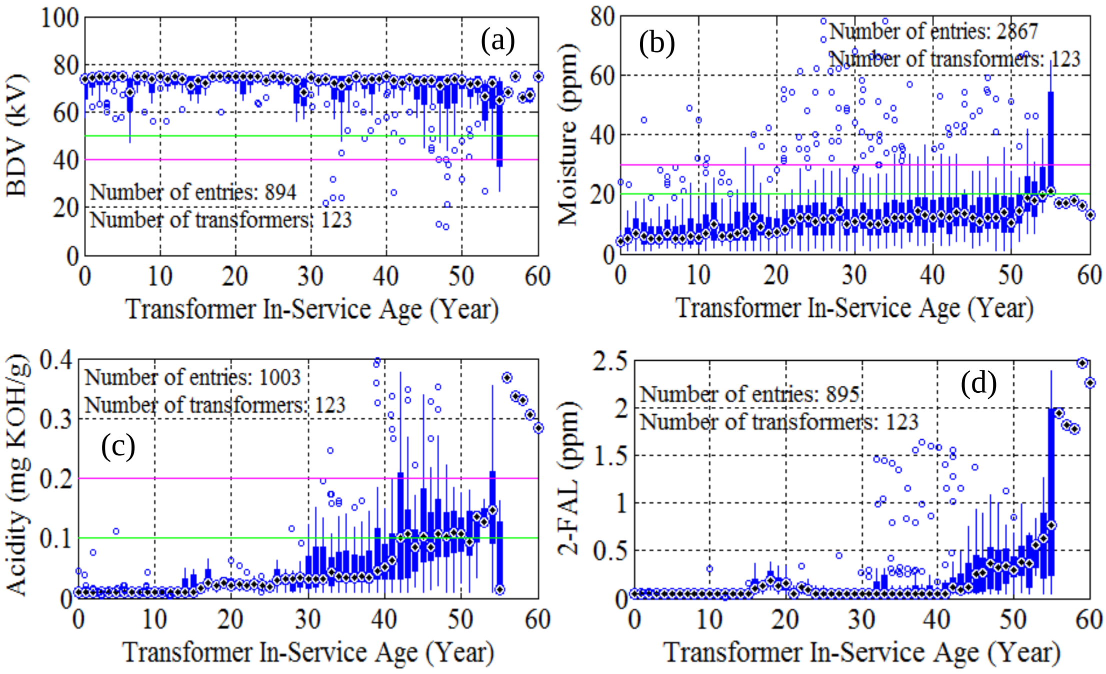

Figure 5.6: Database E_132kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

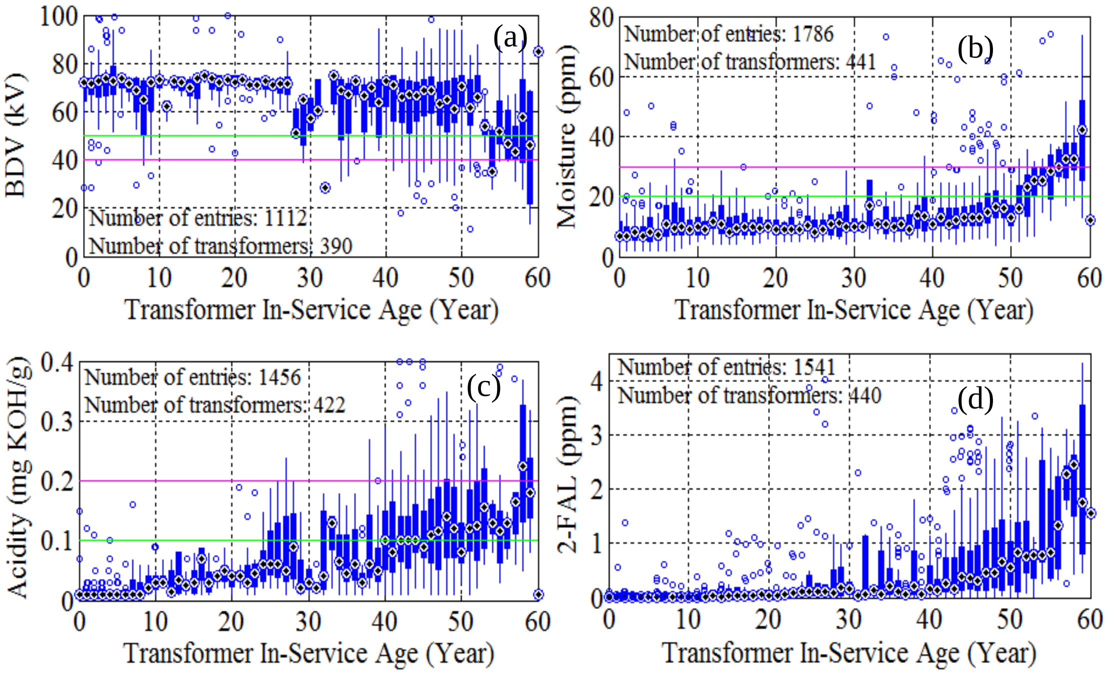

Figure 5.7: Database F_132kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

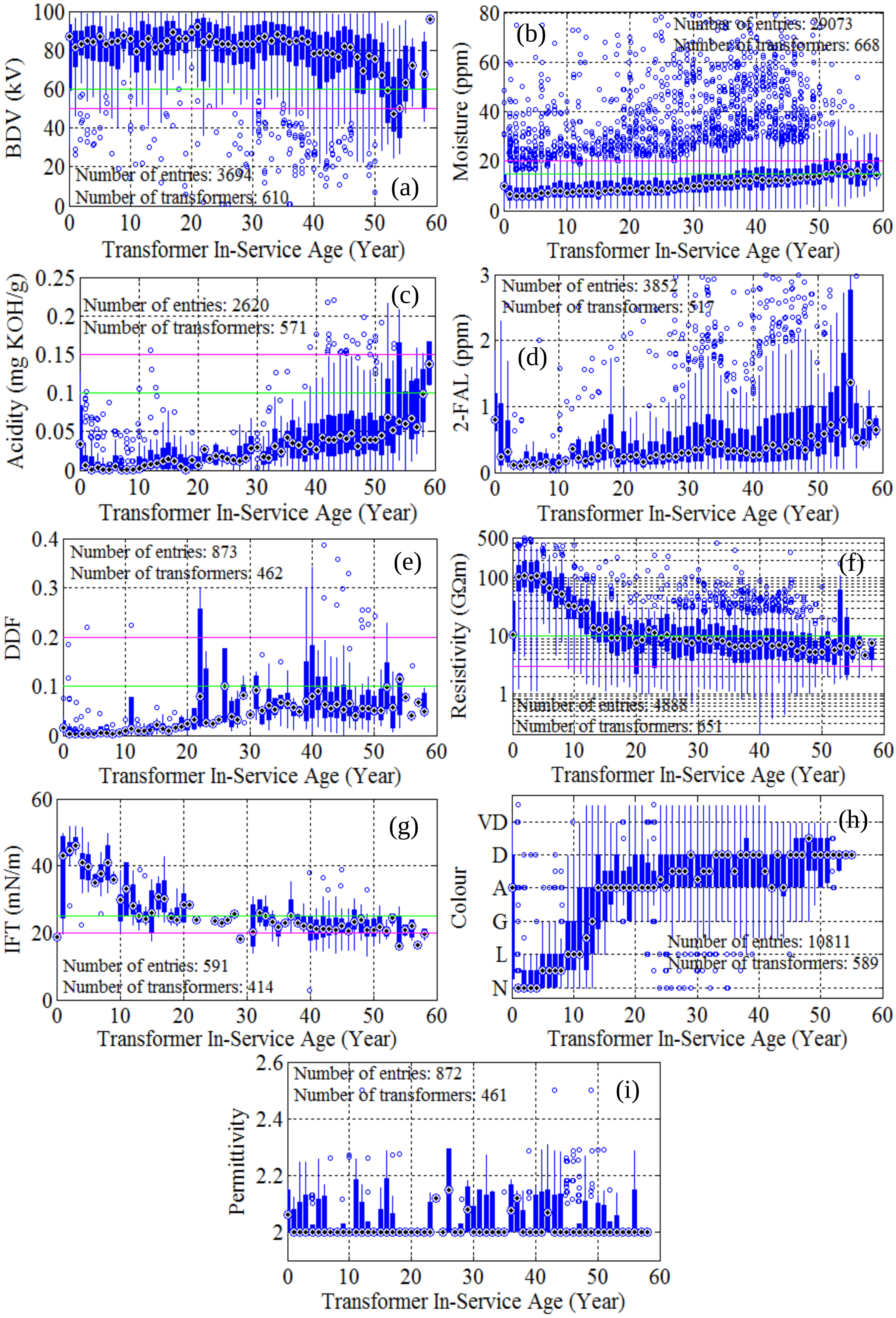

Figure 5.8: Database G_275kV_400kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL, (e) DDF, (f) resistivity, (g) IFT, (h) colour, (i) permittivity

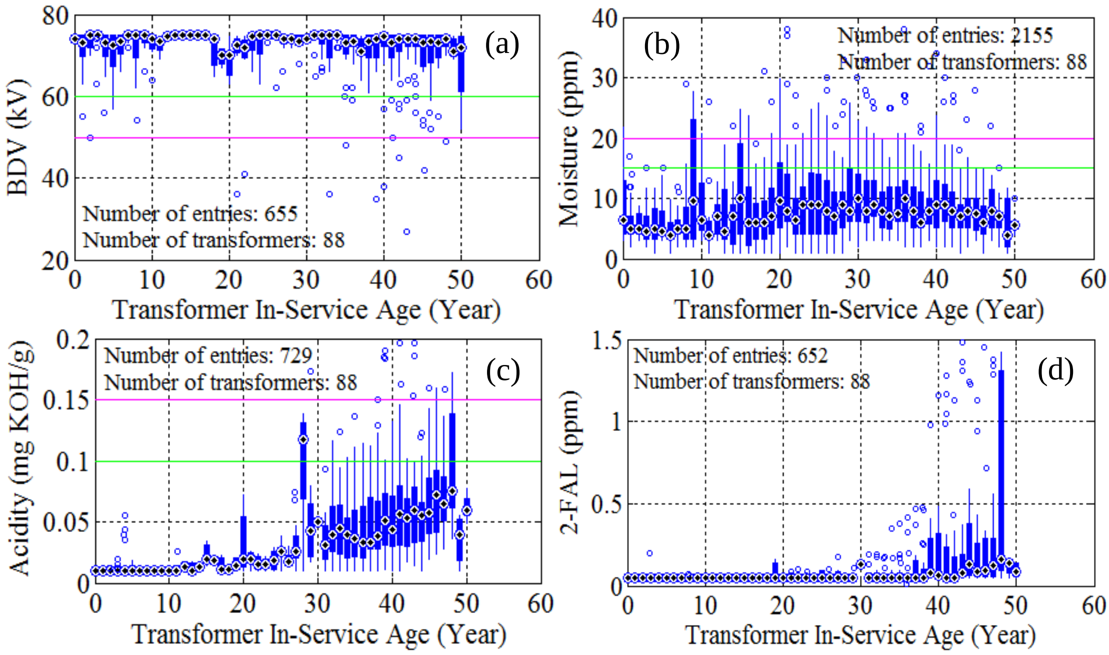

Figure 5.9: Database H_275kV_400kV trends with transformer in-service age, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL

5.2.2 Statistical Perspective

The statistical perspective of analysing the correlation of parameters with age was done based on Spearman's correlation coefficient. More details on Spearman's correlation coefficient are found in Section 3.4.2.1. Figure 5.10 shows the magnitude of Spearman's correlation with age for the parameters tested across all the databases [81]. The increasing or decreasing tendency with age is also reflected by the sign enclosed by the bracket above each bar.

The information interpreted from Figure 5.10 corresponds to the observations from a graphical perspective in Section 5.2.1. One example is the information indicated by the sign of the Spearman's correlation coefficient. As represented by their negative signs, BDV, resistivity and IFT are seen to decrease with ageing which was also observed in Section 5.2.1. More importantly, Figure 5.10 provides information to guide asset managers on how to quantify the representativeness of the different parameters in terms of representing ageing.

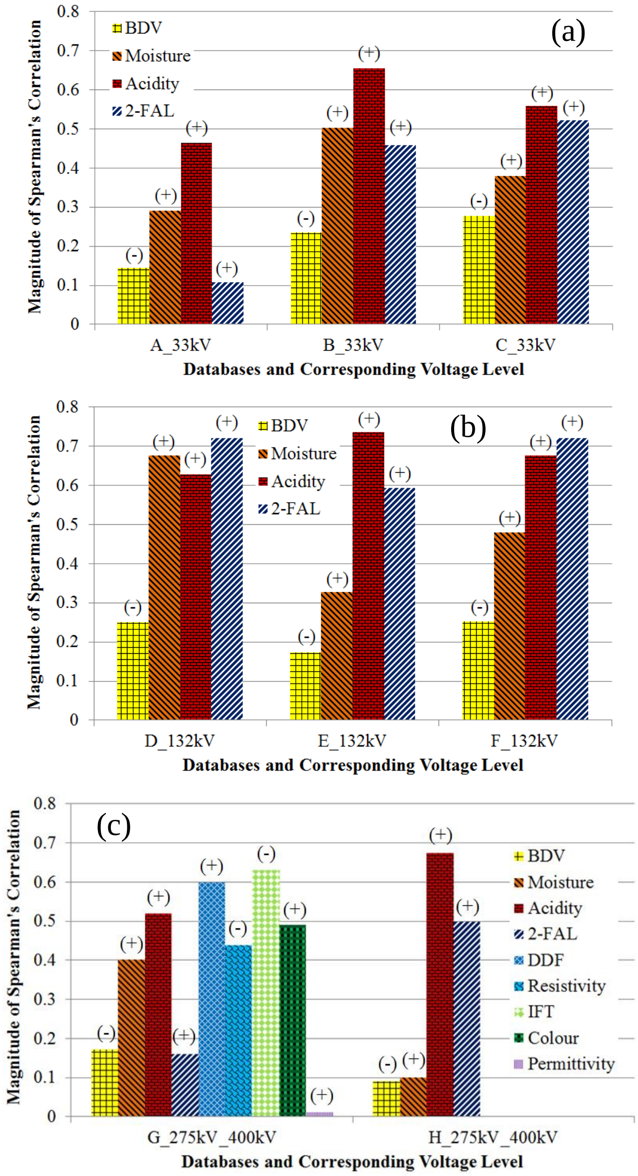

Figure 5.10: Magnitude of Spearman's correlation with age ("+" indicates increasing with age and "-" indicates decreasing with age), (a) 33kV, (b) 132 kV, (c) 275 kV and 400 kV [81]

Firstly on the common parameters and particularly on the only paper ageing indicator, 2-FAL, it has an average magnitude of Spearman's correlation of about 0.47 aggregated from the eight databases [81]. More interestingly for potential oil ageing indicators, acidity consistently outperforms moisture and BDV, with an average magnitude of 0.61, followed by 0.39 and 0.20 for moisture and BDV respectively [81]. As for the additional parameters, relative permittivity has a near zero magnitude of Spearman's correlation. Besides that, DDF, resistivity, IFT and colour in general have high magnitudes of Spearman's correlation with age, with IFT and DDF having similar magnitudes to acidity [81].

5.2.3 Implications

By studying both the ageing trends and Spearman's correlation with age for all the parameters involved in the databases, some insights can be gained on which parameters might be more reflective of the ageing status of transformers.

5.2.3.1 Essential Ageing Indicators

As only the direct paper ageing indicator currently recorded in oil test databases, 2-FAL appears to have quite a moderate Spearman's correlation with age. Care must be particularly taken when 2-FAL is high as the transformer is most likely already in the late ageing stages since 2-FAL increases exponentially and drastically only after mid ageing period as perceived from the graphical perspective in Section 5.2.1. With its low sensitivity towards the early stage of ageing, methanol could be a welcome addition to the list of oil test parameters that are tested for in-service transformers, particularly to indicate early paper ageing or condition [19, 81, 203, 204].

Shifting from paper ageing indication to oil ageing indication, acidity is the best parameter judging from its clear increasing trend with respect to transformer in-service age as well as its high magnitude of Spearman's correlation with age [81]. Another merit of acidity is its wide measurement by all databases and utilities thus enabling not just reliable monitoring of transformer condition within a database itself, but also reliable comparison of transformer ageing behaviours among different databases, different operating voltages and different utilities.

5.2.3.2 Synergistic Combination of Parameters

Particularly for indicating oil ageing, if resources and time are available, or if more information is required on insulation condition, the measurements of DDF, resistivity, IFT and colour are useful as supplementary or complementary ageing indicators [81]. This can be seen from their clear trends with age from a graphical perspective as well as high Spearman's correlations with age from a statistical perspective.

For some of these parameters, such as IFT, resistivity and colour, it is interesting to note they have different sensitivities to different stages of ageing. As seen in Figure 5.8(g), IFT portrays an early sensitivity to ageing. When placed in an oil-water arrangement for IFT measurement as mentioned in Section 2.3.6, the surfactants (surface active agents that generally represent both contaminants and ageing products) will move towards the interface with their hydrophilic groups oriented towards the water and hydrophobic groups towards the oil [120, 205]. This preferential movement or diffusion of surfactants towards the interface is called adsorption, different from absorption that represents actual physical penetration of one phase into another [121].

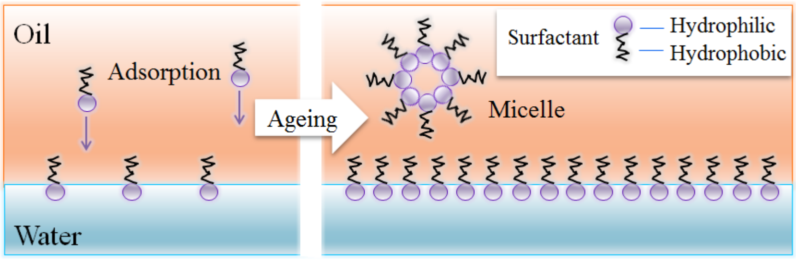

Figure 5.11: Illustration of influence of surfactants on IFT [95]

With the surfactants oriented at the interface, the greater similarity in the nature of both the oil and water at the interface will result in a reduction in IFT [120]. The early reduction in IFT could be attributed to the high production of intermediate ageing products such as peroxides, alcohols, aldehydes ketones and so forth which contribute to a surfactant concentration increase [14, 28, 49, 50]. As these intermediate ageing products are not acidic, acidity tends to stay low during the early ageing stages [95].

As transformers continue to age, more ageing products, including acids are produced but IFT appears to stabilise from mid ageing period onwards due most likely to the formation of micelles [121]. Such a phenomenon can be explained in terms of critical micelle concentration (CMC) where any further increase in surfactants would cause agglomeration of the surfactants in the oil itself instead of adsorbing towards the crowded interface [121, 205, 206]. Figure 5.11 provides the illustration where the hydrophilic heads of the surfactants in a micelle would be oriented towards one another with hydrophobic heads oriented towards the hydrophobic oil. From this point onwards, the oil becomes cloudier but the IFT effectively stays constant [121, 206].

Similarly to IFT, resistivity seems to be more sensitive towards the early ageing changes as perceived by the early drastic drop and subsequent stabilisation of resistivity measurements in Figure 5.8(f). This drastic drop in resistivity in the early ageing stages could be attributed to what is known as a percolation concentration which explains the sudden increase in conductivity (sudden drop in resistivity) at a certain concentration of conductive components [207].

When the concentration of the ageing products (such as moisture and acids which are more conductive than the oil [208, 209]) starts to increase, these species start to agglomerate and form networks of conducting phase within the insulating oil, drastically increasing the conductivity of the system [207]. Subsequently after the formation of these conductive networks, the continuously increasing ageing products will only slightly improve the quality of the conductive networks and hence the stabilisation of the oil resistivity measurements towards the later ageing stages [207].

Shifting to colour measurement, it does have a good magnitude of Spearman's correlation coefficient with age, but perhaps better at indicating early ageing just like resistivity and IFT. This is perceived from the rapidly increasing colour index in Figure 5.8(h). One possible explanation could be the high generation of intermediate ageing products as depicted by Figure 5.12 seen particularly after the induction period which is applicable to uninhibited oil. As in Section 2.3.1, hydroperoxides can change the colour of the oil from bright yellow to amber. The large amount of these intermediate ageing products thus changes the colour index drastically, before the colour index increases though more slowly from the mid ageing period onwards.

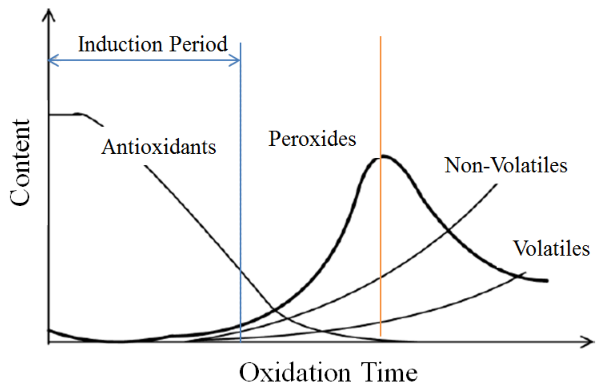

Figure 5.12: Evolution of oil ageing products [51]

From identifying and understanding the different sensitivities to different ageing stages of certain parameters, synergistic combination of parameters may be needed [80, 81, 95]. For instance, resistivity, IFT and colour which portray high sensitivity to early ageing can be used first to indicate more clearly the changes in condition of the transformers in the early stages of ageing. Once these parameters start to lose their sensitivities to ageing, other parameters such as acidity, DDF and 2-FAL can then be used to indicate the later stages of ageing.

5.3 Sensitivity Study on Testing Year Period

Understanding population ageing trends is one of the targets of database analysis. With databases of varying lengths of testing period not just across different databases for transformers at different voltage levels, but also for the different parameters measured, the question arises on whether varying lengths of test records would cause any significant difference in the evaluated population ageing trends.

5.3.1 Study on 33 kV Acidity Database

Figure 5.13 depicts the testing year period sensitivity study for a 33 kV database based on acidity. As a brief description towards how this part of the work was conducted, the whole testing year period (2005 – 2013) of acidity measurements for this particular database was first known. Ageing trends were then plotted from each length of the testing year period with the length increased in a one-year step size manner from 2013 progressively to 2005, i.e. from 2013 – 2013 to 2012 – 2013 progressively to 2005 – 2013 when it will be the full length. The ageing trends of different lengths of testing year periods are shown in Figure 5.13(a).

From Figure 5.13(a), the mean and standard deviation representations of the ageing trends associated with different testing year periods appear similar. This suggests that even a short testing year period or a short testing history could produce a representative population ageing trend.

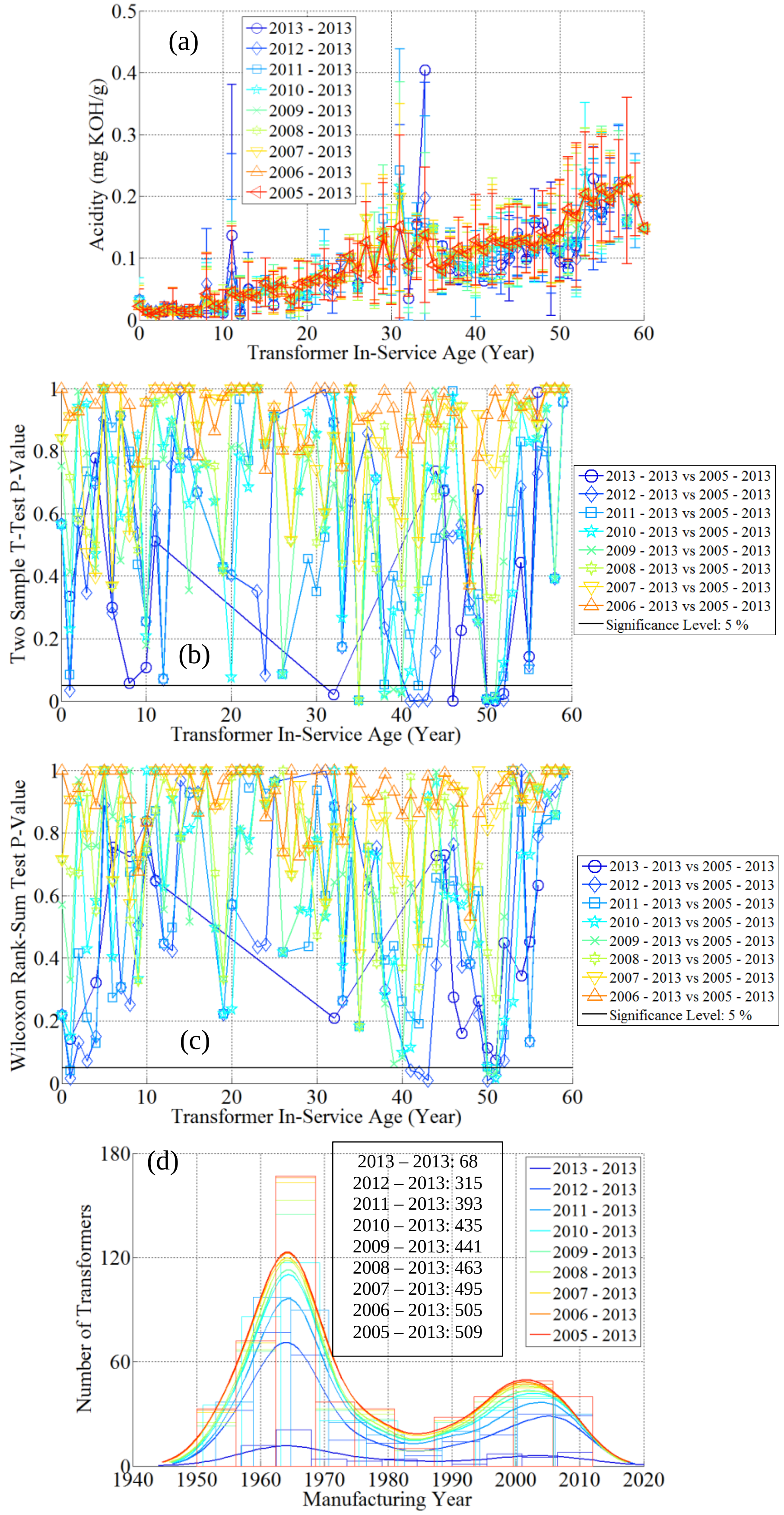

Figure 5.13: Testing period sensitivity – 33 kV based on acidity (a) ageing trend, (b) t-test, (c) Wilcoxon rank-sum test, (d) manufacturing year distribution

Apart from a graphical approach, the observations can be complemented from a statistical approach in the form of two sample t-test and Wilcoxon rank-sum test. Essentially a t-test focuses on the difference in mean which involves an underlying assumption of a normal distribution. Wilcoxon rank-sum test on the other hand focuses on the difference in median and hence is non-parametric. More details can be found in Section 3.4.2.2. In this work, the two tests were performed between samples from any other testing year periods and the full length testing year period itself. In other words, the full length testing year period was used as the reference.

Figure 5.13(b) and Figure 5.13(c) illustrate the t-test and Wilcoxon rank sum test p-values. A standard 5% statistical significance level was chosen. It can be seen in both figures that the longer the testing year periods, the higher the p-values. In accordance to Section 3.4.2.2, this means the greater the evidence towards supporting similarity between the means and the medians of the acidities from different testing year periods with the reference testing year period (the longest).

More interestingly, it can also be perceived that almost all the p-values across different ages and from varying lengths of testing year periods are actually above the 5% threshold value, below which two samples are adjudged to be dissimilar. This suggests that even with a short testing year period (for instance 2012 – 2013), the population ageing trends evaluated would still be reasonably close to the ones obtained from a full length of testing period available. Such an observation consolidates the message interpreted from the graphical analysis which implies that there is actually little difference across the population ageing trends obtained from shorter testing year periods.

Enriching the message interpreted from both graphical and statistical comparisons, manufacturing year distributions pertaining to all lengths of the testing year periods were plotted as shown in Figure 5.13(d). Number of transformers associated with each testing year period is also displayed. A noticeable feature in Figure 5.13(d) is that regardless of the length of the testing year period, the overall profile of the transformer manufacturing year stays stable. In other words, despite having different lengths, the testing year periods covered similar ranges of transformer in-service age.

Aggregating the observations from the graphical ageing trends, the statistical hypothesis tests and the manufacturing year distributions, a short testing year period is actually sufficient for understanding a population ageing trend.

Although not shown here to avoid repetition, the same findings were also observed for acidity databases pertaining to 132 kV as well as the combination of 275 kV and 400 kV transformer populations. In addition, studies on other parameters like dielectric dissipation factor that could indicate oil ageing, also reported the same findings. All these further consolidate the messages interpreted from the study on the 33 kV acidity database in Figure 5.13.

Nevertheless, there should be a large enough sample size that has a sufficient number of transformers as a small sample size (such as the 68 units in the first testing year period in Figure 5.13(d)) could render observations close to statistical rejection from the hypothesis tests. Another condition is that the transformer age profile tested needs to be representative of the whole population available. In this case, the transformer age profile resembles double peaks at around the 1960s and the 2000s which are also reflected by a generic UK manufacturing year distribution to be seen in Section 5.4.2 for the multiple databases studied.

5.3.2 Study on 132 kV 2-FAL Database

Shifting from an oil ageing perspective as indicated by acidity in the previous Section 5.3.1, this section serves as an extension particularly on paper ageing perspective through study on 2-FAL measurements from a 132 kV database.

Regardless of the parameter under study, similar observations can be made. Essentially a short testing year period (also 2 years in this case, i.e. 2011 – 2012) is sufficient for constructing a representative population ageing trend as long as the transformer age covered is representative of how the population is and the sample size of consideration is large enough in relative to the whole population.

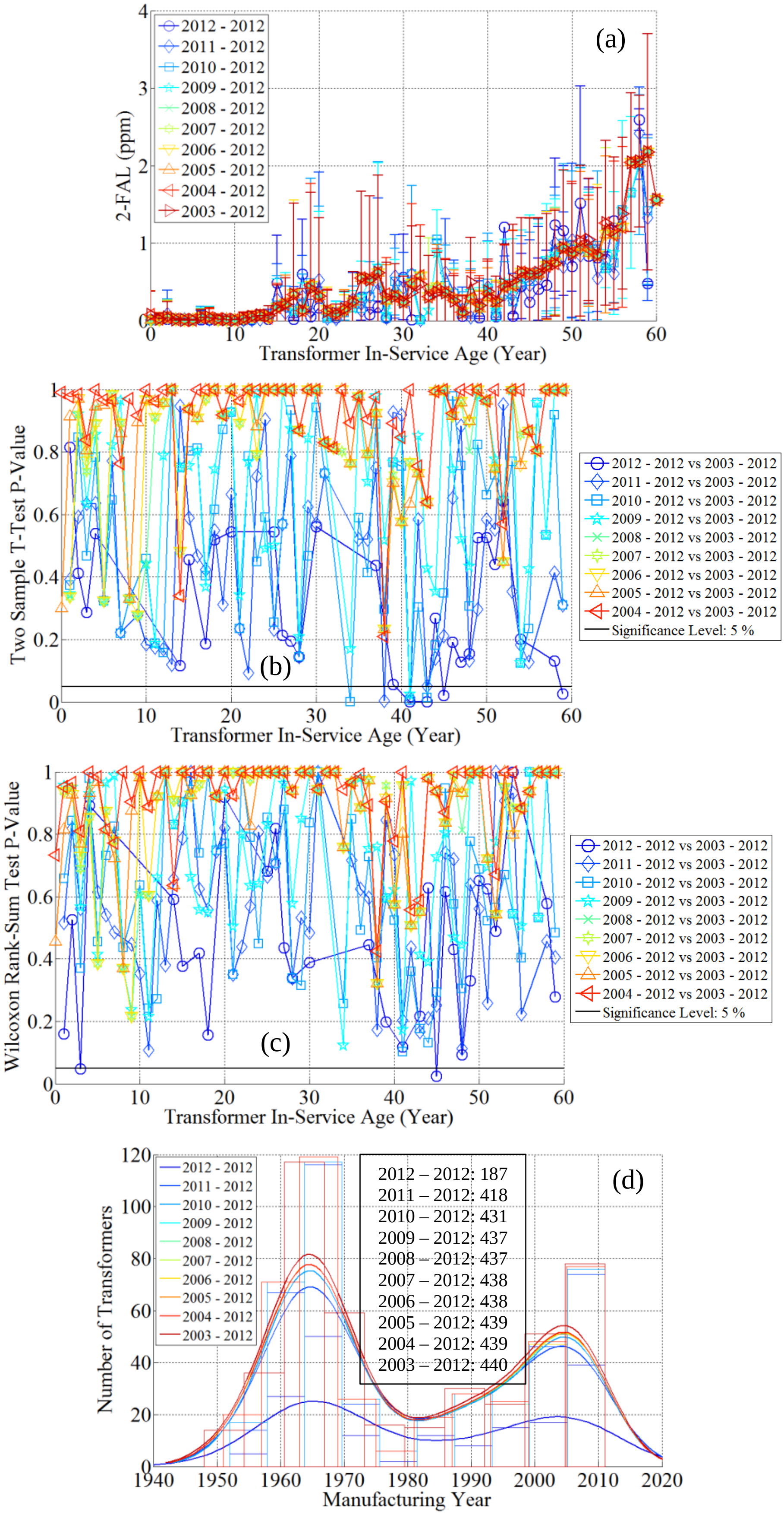

Figure 5.14: Testing period sensitivity – 132 kV based on 2-FAL (a) ageing trend, (b) t-test, (c) Wilcoxon rank-sum test, (d) manufacturing year distribution

From this sensitivity study on testing year periods, the key message obtained could be encouraging for utilities relatively new to accumulating oil test records of their in-service unit populations. For them, as long as the records span a representative transformer age profile and with sufficient number of transformers considered, a short period of the oil test records would already be sufficient to understand a generic population ageing trend. This generic trend could be further used for facilitating asset management strategies. Similarly, the key message obtained from sensitivity study could also be meaningful towards motivating the measurements of new parameters, like methanol and subsequent need for understanding their population ageing trends.

5.4 Influence of Voltage, Manufacturer and Loading

5.4.1 Influence of Voltage Level

With transformers operating at different voltage levels, any potential differences in terms of their ageing performances would always be of interest. Focusing on acidity, Figure 5.15 shows median value representations aggregated individually from the eight databases studied in Section 5.2. The choice of median is to enable tidier representation of the different databases with consideration of a statistic that is more resilient towards noisy datasets.

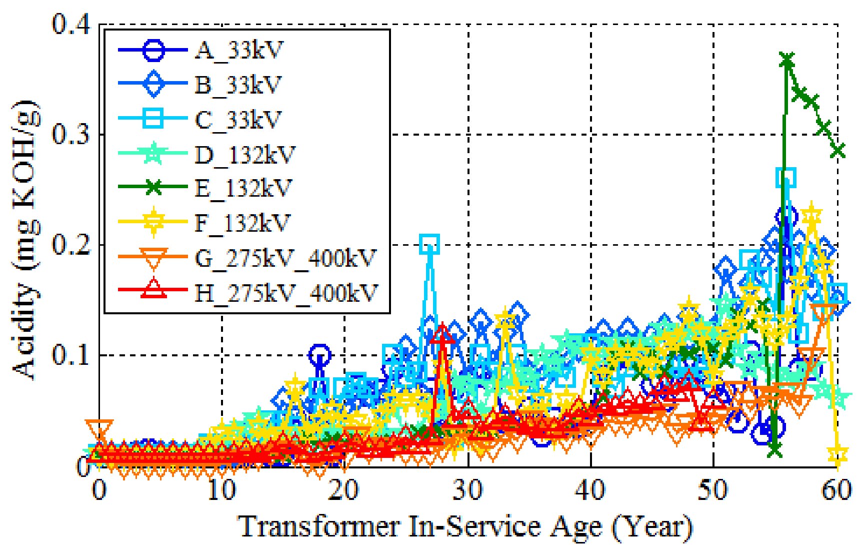

Figure 5.15: Median representation of acidity ageing trends from multiple databases

From Figure 5.15, 33kV and 132 kV transformers in general appear to have similar levels of acidity throughout the whole ageing span. This suggests a similar ageing performance for 33 kV and 132 kV transformers. Notwithstanding the similar ageing tendency, the IEC 60422 condition classification criteria based on acidity are stricter for 132 kV transformers if compared with 33 kV transformers if perceived from Table 2.2. This indicates that perhaps higher voltage transformers tend to receive a more conservative or a more cautious approach from asset managers [81].

The more cautious approach on higher voltage units is also reflected by the visibly lower acidity values portrayed by 275 kV and 400 kV units if compared with both 33 kV and 132 kV units as seen in Figure 5.15. Besides perhaps a stricter design requirement, higher voltage units tend to receive more care or maintenance, rendering lower acidity values [81]. Such an observation is again in tandem with previous findings that higher voltage units are tested more frequently and tested for more oil test parameters (from Section 5.1), all suggesting greater attention by utilities [81].

5.4.2 Manufacturer Influence

Transformers come in different designs by different manufacturers. A large population of transformers were manufactured around the 1960s as seen from Figure 5.16 regardless of the voltage level of the databases. This is most probably due to the start of industrialisation. Around the 2000s, another noticeable spike in transformers manufactured is observed, most likely due to a combination of the need for replacing older units and meeting increasing energy demands through network expansions.

In general, the transformers analysed in this work were manufactured by about 60 manufacturers as illustrated from the different colours and the legends in Figure 5.16. Note the number of manufacturers could be slightly overestimated as certain manufacturers have changed their names or ownerships over the years. Due to confidentiality reasons, the manufacturer names are not disclosed and will be just simply shown as M1, M2 and so forth. It can be seen from Figure 5.16 that the contribution of manufacturers to the transformer populations differed across different time periods in history. In other words, there were new manufacturers across different times. For instance, M29 only contributed to transformers around the 1960s.

Another clear observation from Figure 5.16 is that different manufacturers contribute to the in-service transformer populations regardless of the operating voltage categories. It is often a widely accepted practice among utilities to adopt diversity in transformers purchased (transformers from different manufacturers). This is borne out of economic considerations as well as the notion of minimising the risks of having transformers from only a particular manufacturer which after years of operation, could be identified to contribute to units with defects or high susceptibility to faults.

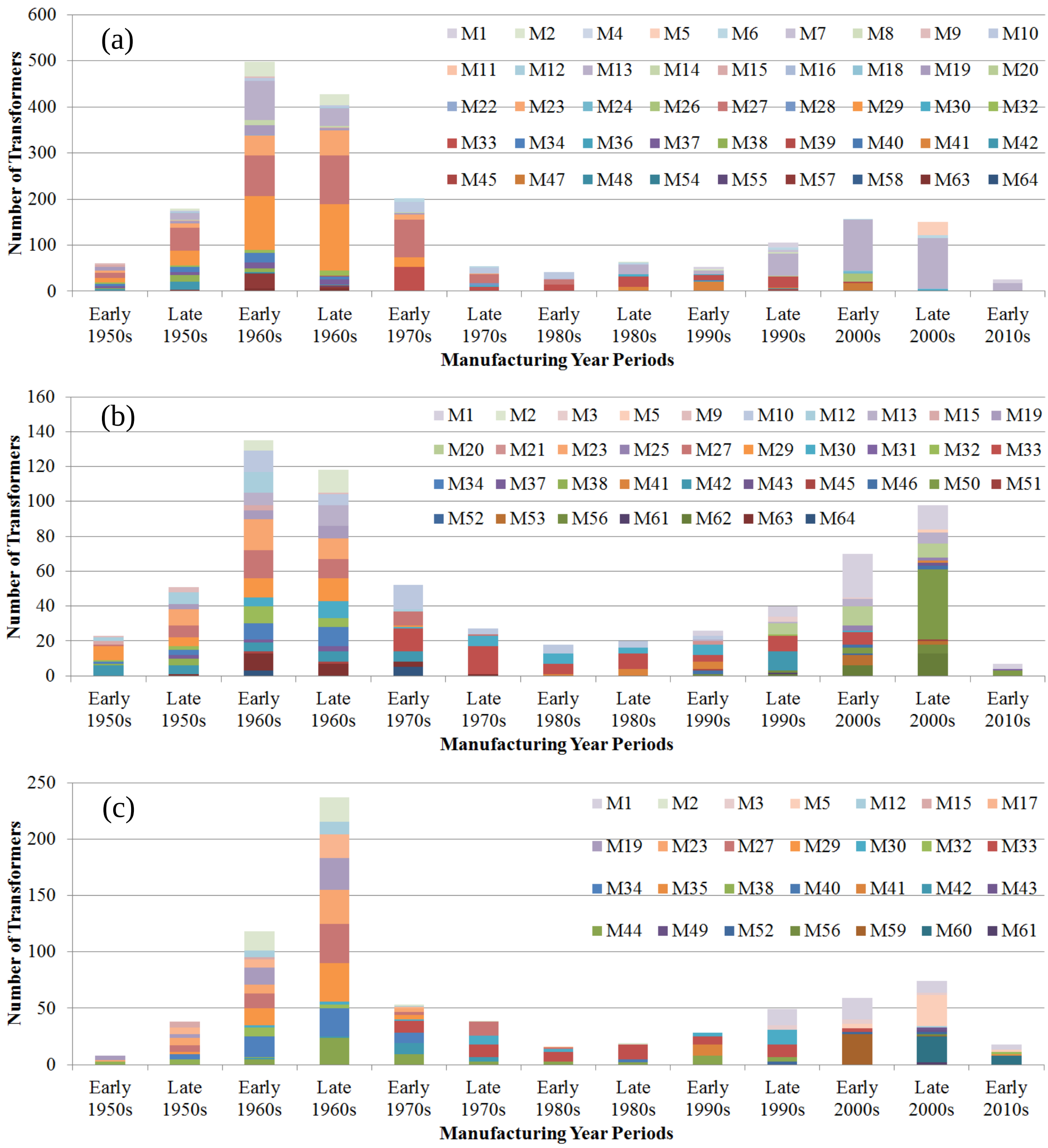

Figure 5.16: Manufacturing year periods, (a) 33 kV databases, (b) 132 kV databases, (c) 275 kV and 400 kV databases

Through database analysis, preliminary work was performed on comparing the ageing tendencies of units from different manufacturers. Figure 5.17 shows the trend of acidity with in-service age for transformers from different manufacturers across several databases. Mean and standard deviation representation is used to allow compact visualisation of the spread of the individual datasets and the difference among the datasets associated with different manufacturers.

Regardless of the voltage level, Figure 5.17 illustrates that transformers from M19, M29 and M33 have lower acidity values. Acknowledging acidity as one of the essential ageing indicators, this suggests better design or better ageing performance for M19, M29 and M33 units. This is also resonated from analysing other parameters. From Figure 5.18, M19, M29 and M33 units have lower DDF, higher resistivity and lower colour index.

Through analysing subpopulations pertaining to different manufacturers, it has shown that if the design variations within a particular company are assumed to be less significant, then there are certain manufacturers that perhaps contribute to transformers that could remain in favourable conditions longer than the others. Asset managers could consider such information in tailoring specific asset management strategies, for instance lowering the need for frequent monitoring of units from manufacturers of known better performance. The converse is also true in terms of monitoring more frequently transformers with known design family issues.

It is however still a challenge to perform more comprehensive studies on the influence of manufacturers. Apart from the great number of manufacturers, detailed design information of transformers is still confidential. Some manufacturers could have already been no longer in the market. In addition, subdividing the whole population into smaller manufacturer specific subpopulations could render subpopulations of small sample size that could affect statistical confidence in data interpretation. Moreover, loading level of the transformers could differ among transformers of the same design family or manufacturer.

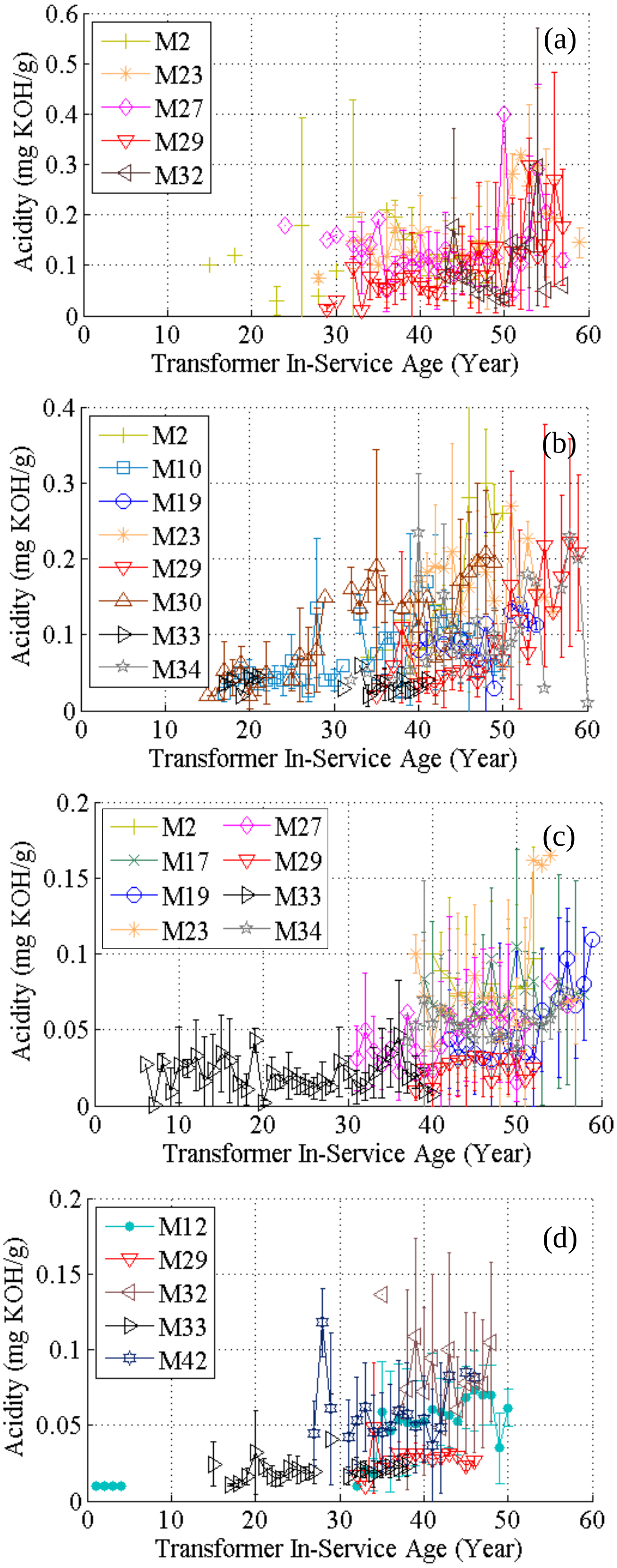

Figure 5.17: Ageing trends of acidity for different manufacturers, (a) C_33kV, (b) F_33kV, (c) G_275kV_400kV, (d) H_275kV_400kV

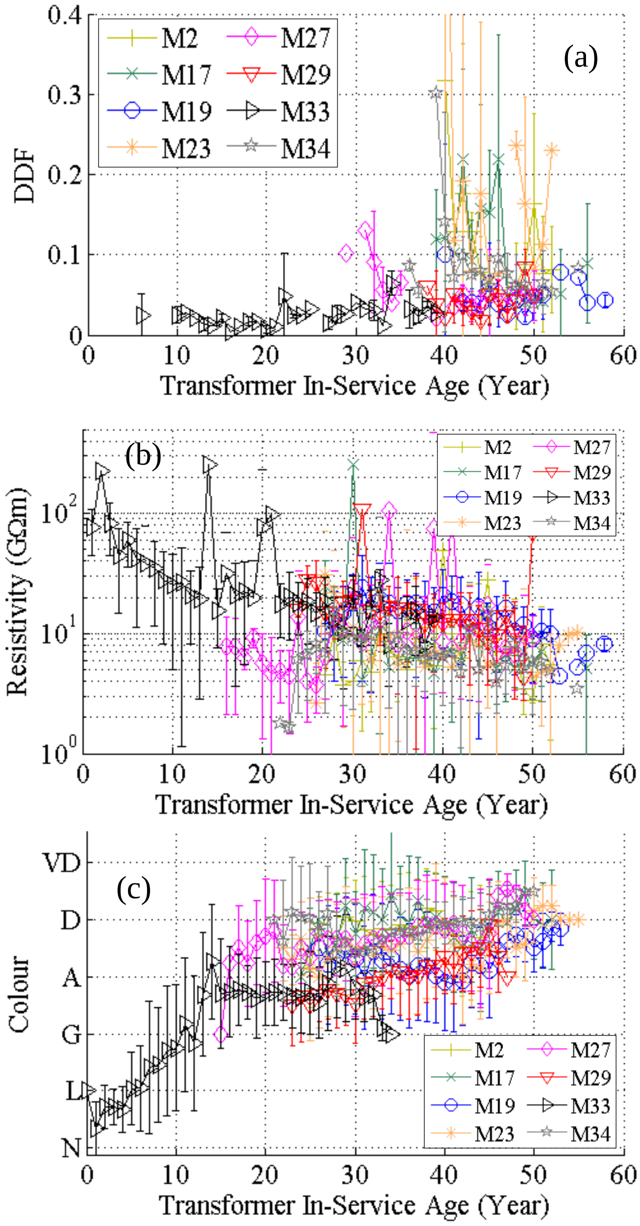

Figure 5.18: Ageing trends for different manufacturers pertaining to G_275kV_400kV, (a) DDF, (b) resistivity, (c) colour

<u>5.4.3 Loading Influence</u>

Leading from Section 5.4.2, preliminary study of loading influence on ageing tendencies of transformers will be performed. From the understanding on ageing, temperature plays a role in expediting the ageing of both insulating oil and paper. With transformers undergoing different loading, the temperature of the insulation system will therefore be different. Interest would therefore be on how transformers experiencing different loading levels would age.

As discussed in Section 4.2.2, loading information is not comprehensive. More so considering that peak loading information is not as representative as actual loading information. Based on the actual half hourly loading level information from 2009 to 2010 that is available for 506 transformers from Database G_275kV_400kV only, IEEE C57.91 – 2011 was used to calculate the equivalent loading for each of the transformers [202]. The equivalent loading equation can be found in Equation 4.1 in Section 4.2.2. Figure 5.19 illustrates the loading level distribution.

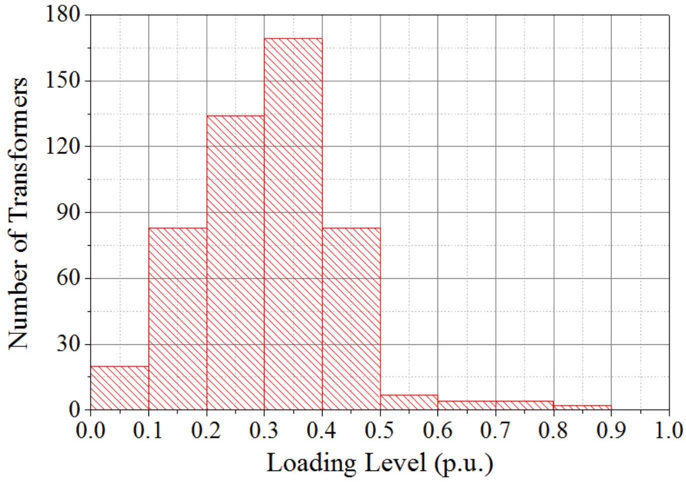

Figure 5.19: Loading level distribution of Database G_275kV_400kV transformers

Based on the loading level distribution in Figure 5.19, preliminary work was done on comparing the ageing trends of different parameters associated with four loading level ranges. They are 0.1 – 0.2 pu, 0.2 – 0.3 pu, 0.3 – 0.4 pu and 0.4 – 0.5 pu judging by their significantly greater number of transformers if compared with the rest of the loading level ranges. Figure 5.20 shows the mean and standard deviation representation of the ageing trends for the four loading ranges.

From Figure 5.20, the differences in ageing trends for transformers loaded in four different ranges seem to be less apparent than expected. This is not just observed from parameters that are less representative of ageing like BDV and moisture, but also from parameters that were discussed to better represent ageing, like acidity, 2-FAL, DDF and IFT. Only resistivity and colour show noticeable differences among the differently loaded transformers. From Figure 5.20(f) and Figure 5.20(h), higher loaded transformers tend to have a lower resistivity and a higher colour index.

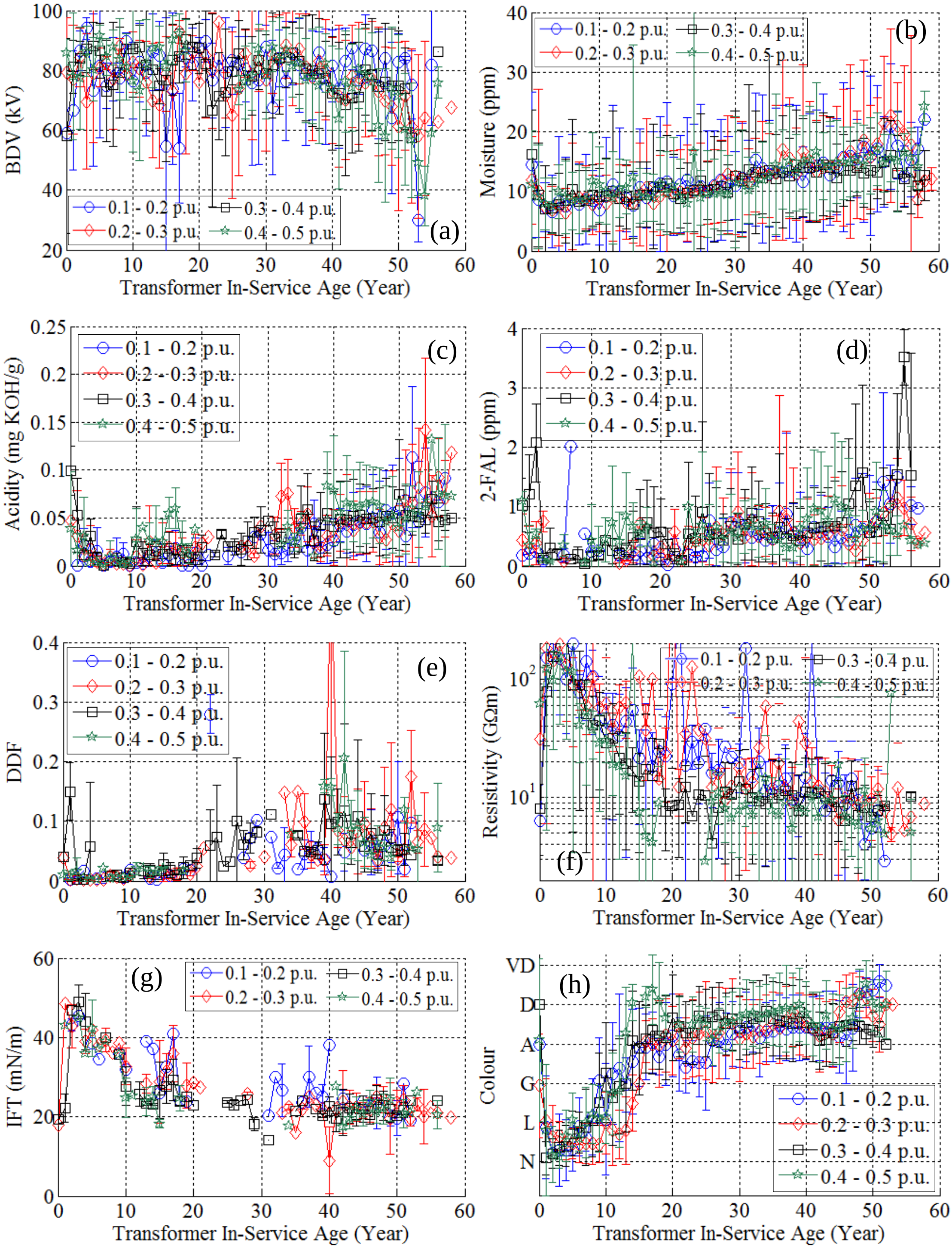

Figure 5.20: Ageing trends for different loading level ranges, (a) BDV, (b) moisture, (c) acidity, (d) 2-FAL, (e) DDF, (f) resistivity, (g) IFT, (h) colour

Considering that manufacturer could also influence the ageing tendencies as seen in the preliminary work reported in Section 5.4.2, the rather indiscernible difference among loading level ranges is again observed if the focus is on specific manufacturers instead of the whole population. Figure 5.21 and Figure 5.22 show the ageing trends for different loading ranges pertaining to transformers manufactured by M23 and M27. Note the loading level ranges were selected in consideration of similar number of transformers from the respective loading level profiles for the two manufacturers. What can be interpreted is again the rather inconclusive influence loading level has even after focusing on specific transformer manufacturer subpopulations.

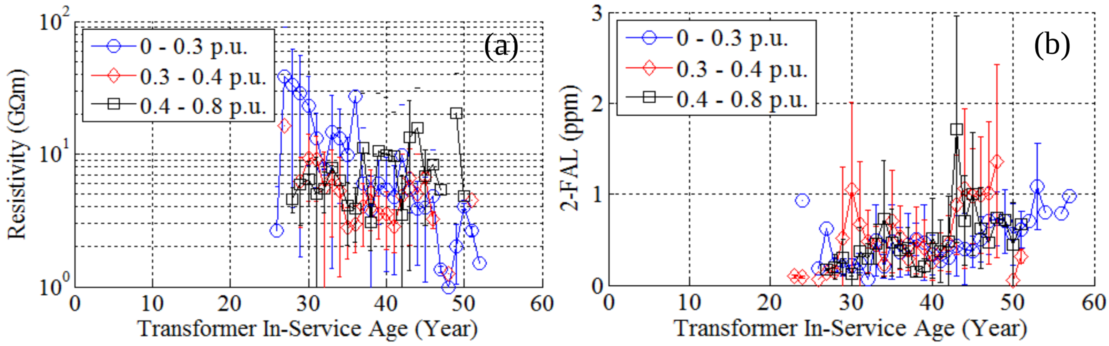

Figure 5.21: M23 ageing trends for different loadings, (a) resistivity, (b) 2-FAL

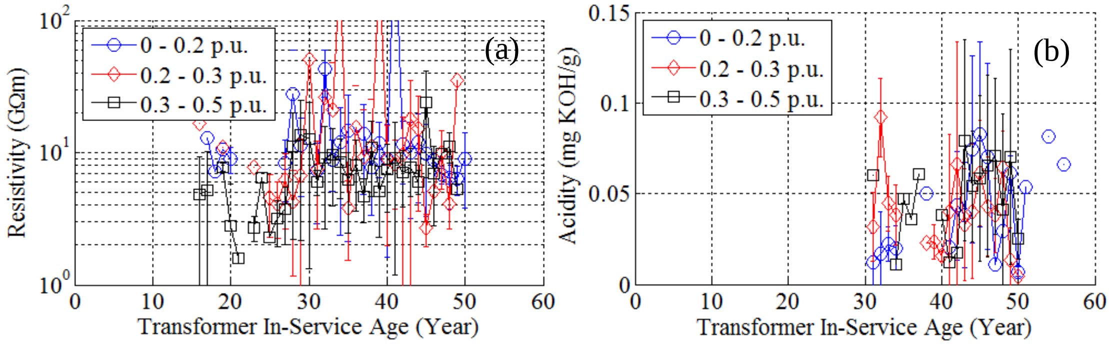

Figure 5.22: M27 ageing trends for different loadings, (a) resistivity, (b) acidity

The uncertain observations from analysing the difference among transformers of different loading levels reveal the need for more loading records not just for more transformers, but also stretching longer time periods. Current underlying assumption in using the two-year worth of loading data (2009 – 2010) is that the equivalent loading calculated is representative of what a particular transformer would experience throughout its lifetime. In other words, the half hourly loading profiles of the transformers are assumed similar for different years in the history. Other than that, it would be worthwhile to have actual loading records for transformers at other voltages as well. Note that the current actual loading level records are only available for a portion of transformers in Database G_275kV_400kV.

Apart from that, due to different transformer cooling settings, the interpretation of the loading records might not be straightforward as transformers might be fitted with two cooling modes. Using a 240 MVA unit as an example, before a loading of 120 MVA (half of the rating), an “oil natural” ON cooling mode could be operational. Once the loading exceeds that of 120 MVA, an “oil forced” OF cooling mode might be enforced. This could affect the effective temperature experienced by the transformers.

In brief, pertaining to the influence of loading on population ageing tendencies, preliminary work done so far has not indicated any effect of loading on ageing performance. Along with more detailed actual loading records over smaller time steps and for more transformers as well as with better understanding on the cooling performance of individual transformers, future analysis into this particular area could yield different views and more conclusive observations.

5.5 Chapter Summary

This chapter reported findings from analysing processed and cleaned transformer populations. The chapter started with an overview of the oil test parameters that are tested and recorded by different databases. Common parameters are breakdown voltage (BDV), moisture, acidity and 2-furfural (2-FAL). Testing frequencies of the parameters were also seen. Generally, higher voltage level transformers are tested more frequently and for more parameters like dielectric dissipation factor (DDF), resistivity, interfacial tension (IFT), colour and relative permittivity.

Through the study on correlation with transformer age, there is a need for combining both graphical and statistical perspectives in understanding how oil test parameters represent ageing. Pertaining to paper condition, 2-FAL is the current option. As for oil condition representation, acidity is the most important parameter judging by its graphically clear increasing trend and high Spearman’s correlation coefficient with age. If more resources are available, DDF, resistivity, IFT and colour can also be tested. Noting the different ageing sensitivity, synergistic combination of parameters could be feasible with perhaps acidity or DDF indicating the later stages of ageing once resistivity, IFT and colour start to stabilise from mid-ageing period onwards.

The next part of the chapter involved sensitivity study on testing year period. Through comparing different lengths of testing year period, graphical analysis on ageing trends and statistical analysis on hypothesis tests revealed that a short testing year period is actually adequate for constructing a population ageing trend as long as the transformer age profile covered is representative of the whole population and the number of transformers considered is not too low. This finding allows utilities to more confidently establish population ageing trends based on limited data.

The chapter ended with work on investigating the influence of voltage level, manufacturer and loading. From voltage level perspective, 132 kV and 33 kV units exhibited similar acidity values even though IEC 60422 recommends a stricter set of condition criteria for 132 kV units. This shows a more conservative approach towards higher voltage units which could also be reflected from the lower acidity values of 275 kV and 400 kV units. From manufacturer perspective, units from certain manufacturers appeared to stay longer in favourable conditions. Nonetheless, manufacturer specific analysis can still be improved with more information on transformer design from each manufacturer or even consideration of loading level information. As for loading level influence, current work suggested an unclear difference in ageing performance among the different loading levels. More loading information of greater resolution, longer period of time and for more units may be needed. Moreover, it could reflect the need for considering detailed cooling designs of the individual transformers.

CHAPTER 6: DATA INTERPRETATION AND RECOMMENDATIONS

Accurate data interpretation is important towards facilitating asset management decisions. This chapter first investigates the seasonal influence on moisture before discussing better interpretation of moisture records which can also be extended to breakdown voltage records as well. Next, this chapter discusses a mismatch in condition interpreted based on IEC 60422 for dielectric dissipation factor and resistivity which suggests the need for a change in standardised criteria. Finally, the chapter ends with recommendations from work on transformer population that has undergone oil treatment (oil regeneration or reclamation), particularly from the perspective of insulation performance after oil treatment.

6.1 Seasonal Influence on Moisture Interpretation

6.1.1 Monthly Moisture Measurements

It is known that oil temperature affects the moisture solubility of the oil, which could influence the amount of moisture measured in oil. Question then arises whether temperature difference throughout different seasons experienced in a year could influence moisture records.

For that purpose, the moisture in oil was investigated with different months in a year. Figure 6.1 illustrates the mean and standard deviation representation of the monthly variation in moisture measurements pertaining to a database of 275 kV and 400 kV in-service transformers [210]. As can be seen, there is a parabolic tendency of moisture with respect to time with high moisture values generally recorded from June to August [210]. On the other hand, moisture values are generally low in the first and the last few months of the year [210].

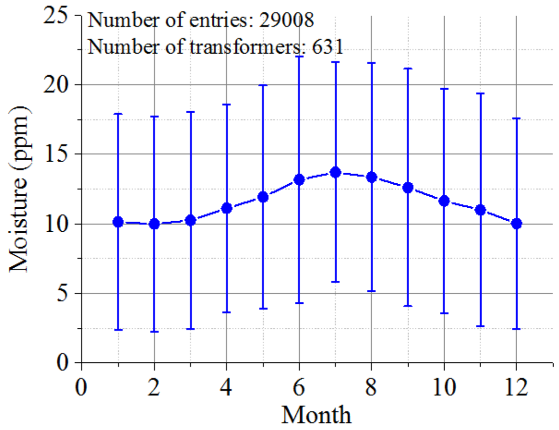

Figure 6.1: Monthly moisture measurements [210]

The same parabolic tendency was also observed for transformers operating at 132 kV and 33 kV as analysed from the corresponding databases. Their monthly moisture trends are not shown here to avoid repetition. In fact, such a moisture parabolic tendency with time was also observed in the in-service transformers in the US and Slovenia [211, 212].

6.1.2 Bottom Oil Temperature and Seasonal Influence

The cause of the parabolic tendency will be investigated. Knowing oil samples are obtained from the bottom drain valve of a transformer main tank, the monthly bottom oil temperature profile was plotted as in Figure 6.2 [210]. Smaller number of entries and transformers can be observed as not all the entries with moisture records have temperature measurements [210]. Interestingly, similar to moisture, the monthly bottom oil temperature profile in Figure 6.2 portrays a parabolic tendency with time.

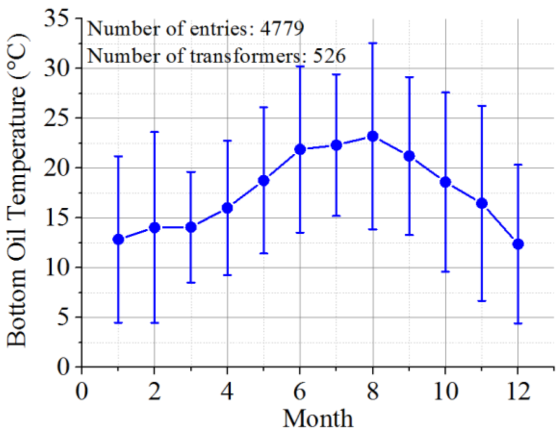

Figure 6.2: Monthly bottom oil temperature measurements [210]

Exploring more on bottom oil temperature, it can be expressed as in Equation 6.1 [213].

$$\theta_{bottom} = \theta_{ambient} + \theta_{flbotr}\left(\frac{L^2 R_{loss} + 1}{R_{loss} + 1}\right)^n \qquad \textbf{\textit{Equation 6.1}}$$

where $\theta_{ambient}$ is the ambient temperature, θ_{flbotr} is the full load bottom oil temperature rise over ambient temperature obtained from off-line testing, L is the ratio of specified load to rated load (or simply transformer loading level), R_{loss} is the ratio of rated load loss to no-load loss and finally n is the cooling state constant [213]. Since θ_{flbotr}, R_{loss} and n are constants, focus will be on the remaining two factors (ambient temperature and loading level) to understand their significance on bottom oil temperature [210].

Focusing firstly on ambient temperature, Figure 6.3(a) depicts the mean and standard deviation representation of the ambient temperature profile of Manchester, UK, based on historical records from 1974 to 2012 [214]. A clear parabolic tendency with time can be seen. Basically, the general UK profile would have a similar shape as the one shown in Figure 6.3. Manchester was chosen as it is geographically in the middle of the UK and could represent collectively the general UK profile [210].

From the loading perspective, Figure 6.3(b) illustrates the actual loading profile of a UK in-service transmission transformer. The loading level was plotted based on the half hourly actual loading level recorded from 1 January 2010 to 31 December 2010. As illustrated, loading level exhibits an inverted parabolic tendency with time.

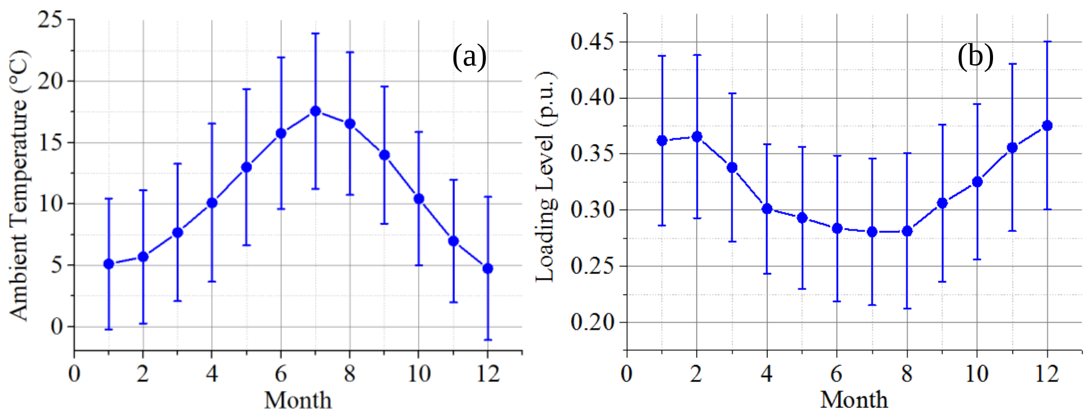

Figure 6.3: Monthly profiles, (a) Manchester ambient temperature, (b) typical transformer loading level [210, 214]

In the UK context, ambient temperature is low during winter that spans the early and the end parts of the year, which causes the need for heating that translates indirectly to higher loading of transformers [210]. The converse is also true during summer when the transformers are more lightly loaded due to a lower demand for heating [210].

Focusing the analysis on the various monthly profiles, bottom oil temperature profile in Figure 6.2 visibly shares the same shape with that of ambient temperature in Figure 6.3(a), albeit with higher values [210]. Loading only affects the bottom oil temperature profile more during winter [210]. These observations reflect the greater significance of ambient temperature or seasonal variation on bottom oil temperature profile [210]. Extending to moisture records, knowing high moisture coincides with high temperature, the moisture parabolic tendency with time is therefore now identified to be influenced by ambient temperature or seasonal variation [210].

6.1.3 Potential Confusion on Moisture Interpretation

The issue with the seasonal influence on moisture is the possibility of interpretation error on the insulation condition. High moisture values recorded in summer could falsely alert asset managers. Table 6.1 provides an example, showing portions of moisture records from a UK in-service transformer that was built in 1958 [210].

In the early ageing stage, moisture changed from 11 ppm to 14 ppm before dropping to 13 ppm in the year of 1993 when the transformer was 35 years old [210]. Note the 14 ppm was measured in June (one of the hottest months in a year). The parabolic tendency exhibited by the moisture records over that one year could most likely be due to seasonal influence [210]. Notwithstanding such a moisture increase, the condition interpreted throughout that year was the same (a Good condition) as moisture generally stays low during early ageing [210].

With ageing, more moisture is produced. In 1995 (37 years old), the condition interpreted throughout the whole year was still Good except for June when it is hot [210]. Moisture increased over time from 11 ppm to 19 ppm in June before decreasing [210]. Similarly in 2011 (53 years old), the same parabolic tendency was observed with moisture peaked at 24 ppm in July (also one of the hottest months), indicating a Poor condition [210]. All these show the seasonal influence on moisture records.

Table 6.1: Portions of moisture records of a UK in-service transformer [210]

Testing Date	Moisture (ppm)	Condition (IEC 60422: 2013)
14/04/1993	11	Good
02/06/1993	14	Good
26/10/1993	13	Good
⋮	⋮	⋮
30/01/1995	11	Good
05/05/1995	14	Good
26/06/1995	19	Fair
13/09/1995	13	Good
13/12/1995	12	Good
⋮	⋮	⋮
17/01/2011	10.5	Good
18/04/2011	14	Good
04/07/2011	24	Poor
25/10/2011	17.5	Fair

From the above, there is a high possibility of condition interpretation difference based on moisture, especially in the late ageing stages [210]. Moisture in the insulation would have already been high and any increase in ambient temperature could further increase the moisture measured in oil, indicating an even poorer condition [210].

It is notable that from asset management perspective, it is unlikely to observe a sudden insulation condition change within the same year itself unless there is a moisture ingress issue [210]. Understanding that moisture solubility of oil changes with oil temperature, instead of a poorer condition, the higher moisture measured when the oil temperature (or ambient temperature) is high could actually indicate a similar condition to that of lower moisture in oil at a lower oil temperature [210]. This suggests the need for incorporating oil temperature for moisture interpretation.

6.1.4 Temperature Incorporation for Moisture Interpretation

Temperature incorporation for moisture interpretation can be achieved via analysing relative moisture content or relative humidity (RH) [210]. It is expressed in percentage (%) and is the ratio of absolute moisture content and the moisture solubility of the oil [28, 32]. Apart from oil condition and oil type, moisture solubility, $W_{\mathrm{solubility}}$ is temperature dependent and this moisture solubility specifically for mineral oil can be expressed in accordance to IEC 60422 as Equation 6.2 [28, 32, 215].

$$W_{\mathrm{solubility}} = 10^{7.0895 - 1567/T_{sampling}} \qquad \textbf{\textit{Equation 6.2}}$$

where $T_{sampling}$ is the oil sampling temperature in Kelvin. Owing to the lack of concrete findings on the influence of oil condition on moisture solubility, the use of Equation 6.2 in evaluating RH is actually the same as employing a correction factor as discussed in the past 2005 version of IEC 60422 [28]. Nevertheless, in this study, moisture solubility and hence RH based on temperature incorporation is used. This is because it could also be implemented for studying the possibility of interpreting breakdown voltage measurements as breakdown voltage is generally linked to RH variation [210].

Figure 6.4 illustrates the RH values evaluated based on entries that have both moisture and oil sampling temperature records [210]. The right vertical axis shows the scale of moisture in ppm, through multiplying the RH values with the moisture solubility at a set temperature, for example a room temperature of 20 ℃ [210]. This essentially is the same as the corrected moisture in IEC 60422:2005 mentioned in the preceding paragraph [28]. Most importantly and noticeably, the parabolic tendency with time previously evident for original moisture measurements has now been mitigated [210].

The flatter trend of RH evaluated through manually incorporating temperature into original moisture records is also reflected through online measurement data [210]. Figure 6.5 illustrates 27203 measurements of both oil temperature and RH from the year of 2012 acquired from an online sensor fitted on an in-service transformer [210]. Bottom oil temperature exhibits the same parabolic tendency as discussed in Section 6.1.2. However, the RH stays constant, more so considering the smaller scale used for RH representation which ranges from just 0% to 6% [210]. This further highlights the need for incorporating temperature information for better moisture interpretation, particularly in the light of seasonal influence on moisture.

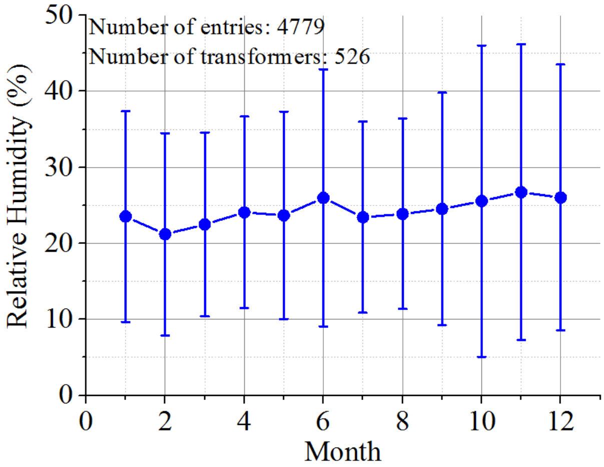

Figure 6.4: Monthly RH and temperature revised moisture [210]

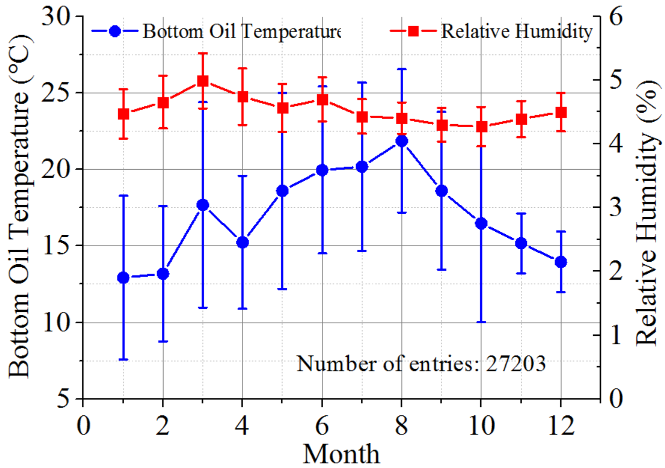

Figure 6.5: Monthly plot of online oil temperature and RH of an in-service unit [210]

6.1.5 Asset Management Practice

Through the analysis on oil test databases, a seasonal influence on moisture was identified. Not just here in the UK, other countries benefit from understanding their own seasonal profiles for addressing any possible moisture variations or fluctuations due to sampling at different months in a year [210]. As an example, the USA has a seasonal profile similar to the UK but with greater temperature difference experienced in summer and in winter [210]. Hence, apart from still portraying a parabolic tendency with time, a bigger magnitude difference in the moisture measured in summer and in winter can be expected [210]. For countries like Australia which experiences summer in months of UK winter, an inverted parabolic tendency of moisture with time can be expected compared with that of the UK [210]. As for tropical countries where ambient temperature stays relatively constant throughout a year, a moisture parabolic tendency with time may not be expected [210]. However, considering potential different loading profiles of transformers, temperature incorporation is still advisable [210].

Apart from the promise of mitigating seasonal influence on moisture interpretation, temperature incorporation helps more representative interpretation or monitoring of insulation condition. Table 6.2 shows the original and interpreted moisture results pertaining to a 1993 built UK in-service 276 MVA transformer operating at 400 kV [95]. The measured moisture was 21.5 ppm which if the interpretation neglected the oil sampling temperature information, the RH evaluated based on a set reference temperature of 20 ℃ is 38.75% (moisture solubility of 55.48 ppm at 20 ℃ based on Equation 6.2) [210]. However, if oil sampling temperature is considered, the moisture solubility at 57 ℃ is 220.38 ppm, resulting in a RH of 9.76% which suggests the oil is actually dryer than initially thought [210].

Table 6.2: Original measurement and interpreted result of moisture [95]

Oil Sampling Temperature of 57 ℃		
Moisture and Relative Humidity (RH)	Measured	21.5 ppm
	RH @ 20 ℃	38.75%
	RH @ 57 ℃	9.76%

The need for oil temperature in oil condition monitoring has actually been discussed in the past and recent versions of IEC 60422 [28, 138-140]. Specifically in IEC 60422:2005, oil condition interpretation was based on moisture corrected to a reference temperature [138]. This practice however has not been widely practiced, at least not from most of the UK databases analysed in this work. It is interesting to note that such a corrected moisture interpretation was discontinued in the latest IEC 60422: 2013, probably due to the lack of oil temperature records in the field and the confusing nature of implementing the corrected moisture interpretation [28]. It was then replaced with interpretation based on just original measurements and such interpretation is only valid for transformer operating temperatures [28]. Nevertheless, from this study, oil temperature records were demonstrated to play an important role in better interpreting moisture records as transformer operating temperatures would vary according to loading level and more importantly ambient temperature (seasonal influence) [210].

Discussing the incorporation of temperature into moisture interpretation in the form of RH, direct record of RH is easily achievable as capacitive or resistive solid state sensors are readily available [210]. Absolute moisture values in ppm are subsequently assessed based on a moisture solubility curve, providing both RH and ppm measurements [210]. Nevertheless, considering that moisture solubility differs with oil type and oil condition, the accuracy in predicting absolute moisture has therefore attracted scepticism, more so considering that current condition interpretation is based on absolute moisture instead of RH [210]. The implementation of RH could therefore be more welcome if condition interpretation based on RH was available [210].

6.2 Breakdown Voltage Interpretation

Leading from the previous section on moisture, temperature incorporation could be extended to breakdown voltage (BDV) as the influence of moisture in oil on BDV is well documented [210]. In addition, BDV is also measured at room temperature at which interpretation might not truly reflect the dielectric strength of the oil at transformer operating temperatures [80, 96].

6.2.1 Generic Breakdown Voltage versus Relative Humidity Relationship

Figure 6.6 illustrates the behaviour of BDV with RH aggregated from literature [34, 99, 105, 216, 217]. For facilitating data aggregation and collation, moisture used in all sources was expressed in RH [95]. Similarly for BDV, recorded values were expressed in per unit (pu) through dividing BDV in kilovolt (kV) by the BDV measured when the RH is at its lowest, so as to address different electrode gap distances (1 – 2.5 mm) used in different sources [95].

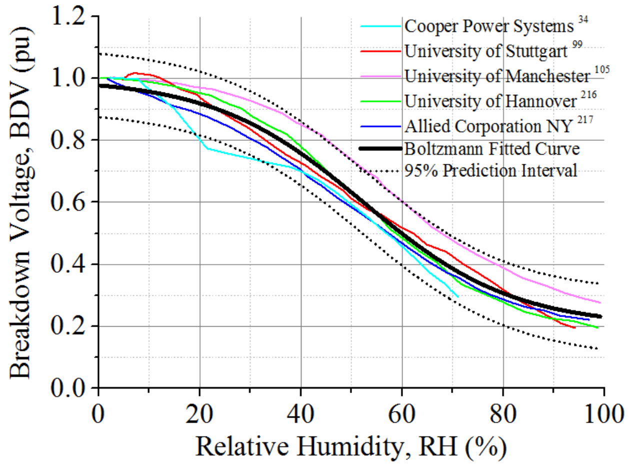

Figure 6.6: Relationship between BDV and RH [34, 99, 105, 216, 217]

From Figure 6.6, the trends of BDV with RH are similar across different sources. As also mentioned in Section 2.3.3, BDV changes little during initial increase in RH due the even dissolution of moisture in oil through hydrogen bonding of the moisture with polar species found in oil [103]. As RH continues to increase (from about 20% RH onwards), due to the limited number of polar species in oil, moisture molecules will start agglomerating to form moisture clusters or combine with particles, manifesting as the weakest links that facilitate oil breakdown [103]. This causes the faster BDV reduction. Ultimately, free moisture droplets appear as moisture increases beyond the solubility limit (RH > 100%), causing a very low BDV [87, 103].

The findings from all the sources were then subsequently fitted with a Boltzmann curve for obtaining a generic relationship between BDV and RH, as shown in Equation 6.3. The adjusted R-square for the fitting process is 0.9623 [210].

$$BDV = BDV_{\min} + \frac{BDV_{\max} - BDV_{\min}}{1 + \exp\dfrac{-(RH_{\text{midspan}} - RH)}{RH_{\text{@timeconstant}}}} \qquad \textbf{\textit{Equation 6.3}}$$

BDV_{max} and BDV_{min} denote the maximum and the lowest BDVs at extremely low and high RHs respectively [210]. Values of 1.00 and 0.20 were obtained for BDV_{max} and BDV_{min} respectively. $RH_{midspan}$ (value of 52.37), is the RH value related to a BDV midway between BDV_{max} and BDV_{min} [210]. $RH_{@timeconstant}$ is similar to a time constant that can be approximated by first evaluating the slope of the curve portion exhibiting an obvious change in BDV, before equating that slope with $((BDV_{max} - BDV_{min})/(4 \times RH_{@timeconstant}))$ [218]. For this case, $RH_{@timeconstant}$ was obtained as 14.82 [210].

6.2.2 Indirect Breakdown Voltage Revision Based on Relative Humidity

Equipped with the generic relationship between BDV and RH, interpretation of BDV measurements with consideration of oil sampling temperature can then be achieved. It will be done in an indirect manner if compared with that of moisture interpretation. Revisiting the same in-service transformer example in Section 6.1.5, the 1993 built UK in-service 276 MVA 400 kV transformer has a measured moisture value of 21.5 ppm (RH of 38.75% at 20 ℃). Here for BDV, the corresponding BDV measured is 57 kV [95]. This BDV is expressed in terms of 0.57 pu as the maximum BDV recorded in the database where the example was taken from is 100 kV [210]. With respect to Figure 6.7 that shows the Boltzmann fitted generic curve, the original measurements are represented by the blue circular dot.

As in Section 6.1.5, after consideration of oil sampling temperature of 57 ℃, the RH was adjudged to be 9.76%. As portrayed by Figure 6.7, there was essentially a RH change due to temperature consideration (green coloured range). This RH change will be reflected to a change in BDV (orange coloured range) before this BDV change was added to the original BDV, resulting in a revised BDV of 0.76 pu [210]. This suggests that the oil actually has a higher dielectric strength than initially thought [210].

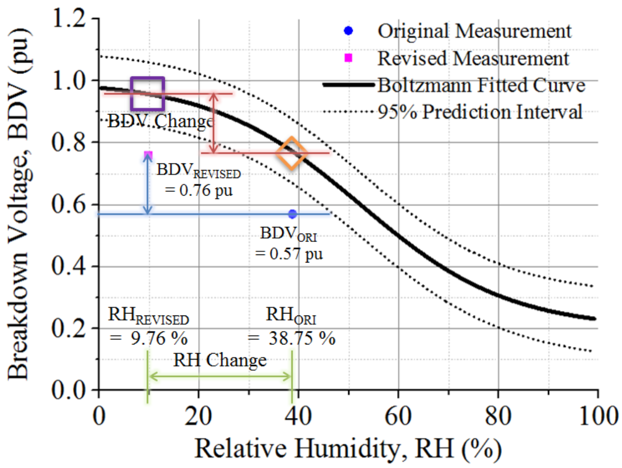

Figure 6.7: BDV revision based on RH revision [210]

6.2.3 Asset Management Practice

Similarly to moisture, the importance of oil sampling temperature is demonstrated. BDV values that are generally obtained in a laboratory setting may need temperature incorporation to better reflect the dielectric strength of the oil in an in-service or operating transformer [210].

Targeting the way BDV is currently measured, there have been propositions on the possibility of heating the oil sample up to the same temperature as recorded from the in-service transformer where the oil sample is taken, and subsequently maintaining the oil at that temperature during the BDV test [210]. In addition to temperature control, there might be a need for controlling the oil condition (such as moisture level) during the BDV test [210].

Nevertheless, with large databases of historical moisture and BDV measurements, provided that oil sampling temperature records are also available, an indirect way of better interpreting BDV measurements can be done via understanding of a generic relationship between BDV and RH [210]. Acknowledging that BDV is not only affected by moisture, a potential further improvement is to incorporate the influence of other factors like particles and acidity into deriving a more representative BDV [99, 105].

6.3 Condition Mismatch

To facilitate decision making on transformer asset management, oil condition is commonly interpreted based on comparing oil test measurements with the recommended value ranges stipulated in standards such as IEC 60422. This section focuses specifically on dielectric dissipation factor (DDF) and resistivity.

6.3.1 Dielectric Dissipation Factor and Resistivity Theoretical Relationship

DDF is defined as the ratio of active power to reactive power that flows through a dielectric, with the active power component contributed by both conduction and polarisation [51]. More on conduction and polarisation can be found in Section 2.3.5.

As resistivity is just the reciprocal of conductivity, DDF is thus expressible as a function of resistivity through the following derivation adapted from [219-221].

Starting with Maxwell-Ampere equation, as shown in Equation 6.4, the curl of the magnetic field strength $\nabla \times \overline{H}$ is equal to the total current density $\overline{J}_{total}$ that consists of conduction and displacement current components [222]. The displacement current component is due to the time-varying effect of an electrical field [222]. Equation 6.5 and Equation 6.6 show the time and frequency domain representations respectively.

σ_{static} is the conductivity of the oil, $\overline{E}$ is the electric field strength and $\overline{D}$ is the electric flux density which is just a scaled version of $\overline{E}$ by the absolute permittivity of free space, ε_0 and the relative permittivity of the oil, ε_r . This ε_r can be more comprehensively represented by both its real part, $\varepsilon_r^{'}$ and its imaginary part, $\varepsilon_r^{"}$ as shown in Equation 6.7. The negative sign is needed for energy conservation and will also become apparent in subsequent derivation steps [221, 223].

The real part concerns the energy stored from an electric field [223, 224]. It has been widely regarded to remain relatively constant even though it does increase with age or increasing contaminants or degradation products, [38, 119, 225, 226]. The imaginary part, $\varepsilon_r^{"}$ represents the losses due to the inability of the dipoles in aligning themselves with the alternating electric field [223, 227]. If compared with $\varepsilon_r^{'}$, $\varepsilon_r^{"}$ has a much smaller magnitude (but always greater than zero) and is sensitive to dissolved or suspended components in the oil that could arise from contaminants or degradation products [224, 227-229]. Thus, $\varepsilon_r^{"}$ is expected to increase with transformer ageing.

With knowledge on the relative permittivity, Equation 6.6 can now be rewritten as Equation 6.8. Understanding that DDF or $\tan\delta$ is the ratio between the real and imaginary components, DDF is now expressed in Equation 6.9 which can be simplified to Equation 6.10 by approximating the imaginary part of relative permittivity, $\varepsilon_r^{"}$ to zero through assuming highly insulating oil with negligible polarisation loss [118].

$$\nabla \times \overline{H} = \overline{J}_{total} = \overline{J}_{conduction} + \overline{J}_{displacement}$$ ***Equation 6.4***

$$\overline{J}_{total} = \sigma \overline{E} + \frac{d\overline{D}}{dt}$$ ***Equation 6.5***

$$\overline{J}_{total} = \sigma \overline{E} + j\omega\varepsilon_0\varepsilon_r \overline{E}$$ ***Equation 6.6***

$$\varepsilon_r = \varepsilon_r^{'} - j\varepsilon_r^{"}$$ ***Equation 6.7***

$$\overline{J}_{total} = \left(\sigma + \omega\varepsilon_0\varepsilon_r^{"}\right)\overline{E} + j\omega\varepsilon_0\varepsilon_r^{'}\overline{E}$$ ***Equation 6.8***

$$DDF_{full} = \frac{\sigma + \omega\varepsilon_0\varepsilon_r^{"}}{\omega\varepsilon_0\varepsilon_r^{'}} = \frac{\sigma}{\omega\varepsilon_0\varepsilon_r^{'}} + \frac{\varepsilon_r^{"}}{\varepsilon_r^{'}} = \frac{1}{\omega\rho\varepsilon_0\varepsilon_r} + \frac{\varepsilon_r^{"}}{\varepsilon_r^{'}}$$ ***Equation 6.9***

$$DDF_{simplified} = \frac{1}{\omega\rho\varepsilon_0\varepsilon_r}$$ ***Equation 6.10***

As discussed in Section 2.3.5, DDF increases while resistivity reduces with increasing soluble polar contaminants or insulation degradation products. Both parameters are measured together and are obtainable through knowing the theoretical relationship between the two. Hence theoretically; condition interpretation based on either one parameter should be similar to the other. However, there is a mismatch in condition interpreted based on DDF and resistivity as identified from database analysis.

6.3.2 In-Service Data Observation and Representation

Table 6.3 illustrates an in-service transformer example. For this 1976 built 400 kV transmission transformer, the DDF and resistivity measured in 2010 are 0.15 and 1.8 GΩm respectively. With reference to the latest (2013) version of IEC 60422 recommended value ranges for condition classification seen in Table 2.2, the condition is Fair based on DDF, whereas it is Poor based on resistivity. There is thus a mismatch in the condition interpreted which could affect asset management decisions.

Table 6.3: In-service transformer condition mismatch example

Parameter	Measurement	IEC 60422: 2013 Condition
DDF	0.15	Fair
Resistivity	1.8 GΩm	Poor

This condition mismatch issue does not just affect a single transformer. Referring to Figure 6.8, DDF and resistivity were plotted on logarithmic scales. The condition criteria based on 2005 and 2013 versions were also plotted in purple and orange lines respectively. With respect to the latest 2013 version, the figure is categorised into different regions according to the interpreted conditions based on the two parameters. The blue dots represent data entries with the same conditions interpreted whereas the red dots represent data entries with condition mismatch issue. More specifically, there are 446 entries corresponding to 241 in-service transformers.

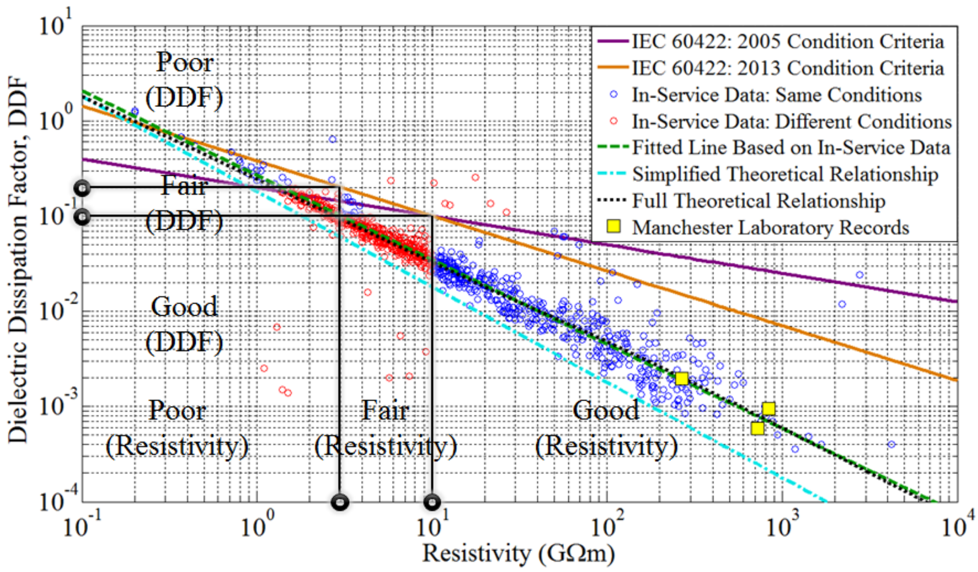

Figure 6.8: In-service data and comparison with IEC 60422 condition criteria

Such a mismatch in condition could be most likely due to how the criteria in the standard were independently established using separate populations of measurements for DDF and resistivity without actually having both of these parameters measured together for the same sets of samples [80]. Through the analysis on a particular UK utility database containing measurements of both parameters, the fitted line that represents the bulk of the data (green line) clearly deviates from the IEC 60422: 2013 line which was used for condition interpretation. With an adjusted R-square value of 0.9630, the fitted line is represented by the following Equation 6.11.

$$DDF_{fitted} = 10^{(-0.5746-0.8846\log\rho)}$$ ***Equation 6.11***

where ρ represents the resistivity in GΩm. Such a fitting process can be substantiated through understanding of the theoretical relationship between the two parameters. Considering firstly the simplified theoretical relationship, it is represented by the cyan line in Figure 6.8. It is based on Equation 6.10 with angular frequency at the power frequency of 50 Hz and the real part of the relative permittivity $\varepsilon_r{}'$ set constantly to 2.0 as it remains relatively constant not just discussed in Section 6.3.1 but also seen in the database analysed (about 70% of data analysed). Such a simplified theoretical relationship does follow most of the variation of the in-service data but consistently estimates lower values. This is attributed to its negligence of the polarisation loss component which is considered by the full theoretical relationship as in Equation 6.9 and represented by the black dashed line in Figure 6.8.

An additional parameter for considering the full theoretical relationship is the imaginary part of the relative permittivity, $\varepsilon_r{}''$. Even though it is known that $\varepsilon_r{}''$ is much smaller than the real part but always greater than zero, there is still a lack of concrete data on typical values of $\varepsilon_r{}''$ [224, 227]. There are also no in-service measurements of this parameter. As an effort to incorporate $\varepsilon_r{}''$ into the full theoretical relationship, arbitrary modelling with respect to resistivity will be performed.

Through findings from literature, the ratio of $\varepsilon_r{}''/\ \varepsilon_r{}'$ can vary from 0.001 to an extreme value of 0.337 [230-232]. Hence, if $\varepsilon_r{}'$ is set as 2.0, $\varepsilon_r{}''$ will then range from 0.002 to 0.674. With this information, $\varepsilon_r{}''$ was modelled as shown in Figure 6.9.

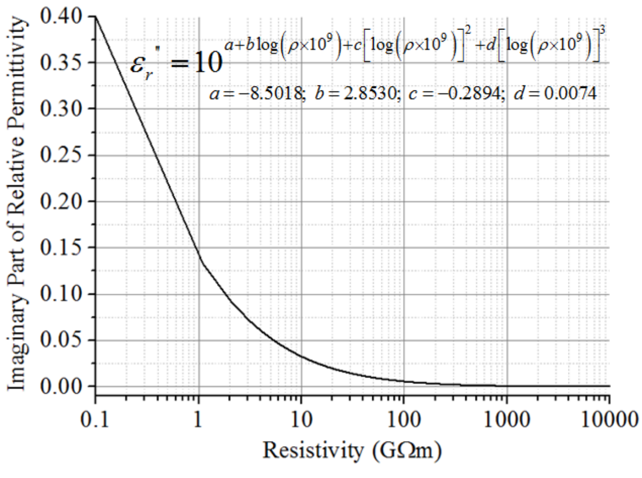

Figure 6.9: Modelling of imaginary part of relative permittivity with resistivity

In essence, lower resistivity values indicate poorer oil condition with more contaminants or degradation products that mean greater space charge polarisation losses, leading to higher ε_r'' values [229]. When the resistivity is high, i.e. for oil with excellent oil quality, polarisation loss is almost negligible, resulting in exceedingly low ε_r'' values. The modelling of ε_r'' allows the representation of the full theoretical relationship (black dashed line in Figure 6.8) which provides a glimpse into why the simplified relationship is consistently lower than the generic data behaviour. More importantly, it provides physical meaning to the fitted curve on the bulk of the data.

6.3.3 Asset Management Practice

The condition mismatch issue discovered in the previous Section 6.3.2, particularly from Figure 6.8 shows the need for revision to current criteria for condition classification for either DDF or resistivity. Interestingly, with reference to Figure 6.8, the criteria were actually changed in 2013 from the previous 2005 version and the trajectory of this change is visibly in the direction of the line representing the bulk of the data. Most likely, there had been awareness in the field on the condition mismatch issue, which had led to efforts to revise the standard. However, perhaps due to the lack of data available at that time, the revision was not adequate.

Now with the support of in-service data and understanding of the theoretical relationship between the two parameters, more informed decisions can be made on the revisions. In fact, some laboratory measurements done on new mineral oil in the University of Manchester, represented by the yellow squares in Figure 6.8 also support the generic behaviour of DDF versus resistivity. These measurements do follow the generic behaviour exhibited by the in-service data.

Using the fitted line based on the in-service data as a point of reference, two options are possible for condition criteria revision as illustrated in Figure 6.10. The first retains the current IEC 60422: 2015 fair condition range for DDF, but alters the resistivity range correspondingly. On the other hand, the second option retains the resistivity fair condition range while altering that of DDF. With these potential adjustments, better interpretation of DDF and resistivity data can be achieved for more accurate condition monitoring of in-service transformers.

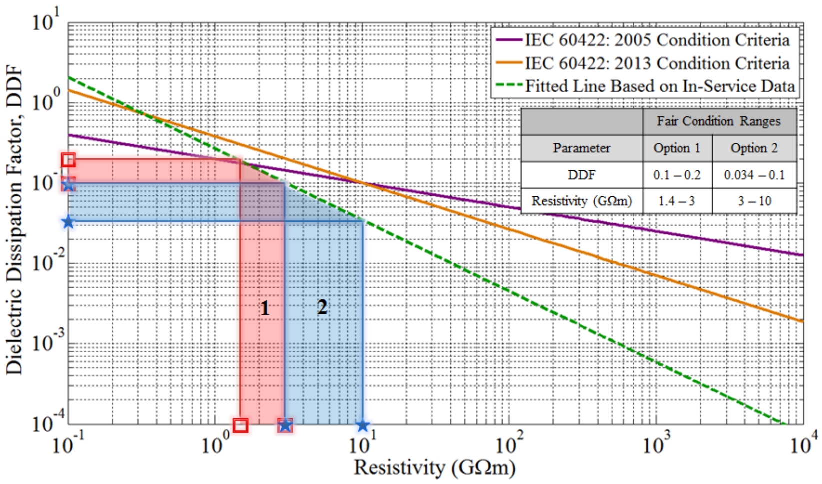

Figure 6.10: Suggestions for condition criteria revision

6.4 Oil Treatment Implementation

Citing the possibility of prolonging transformer usability, oil treatment such as the practice of oil regeneration or reclamation has increasingly gained importance and attention in this economic climate. This section discusses some preliminary findings from analysing a separated population of transformers from a utility that have undergone oil treatment, identified according to the methodology in Section 3.3.5.

The gist of this section will be on the performance of these transformers after treatment where discussions will be based on resistivity and 2-FAL trends. The choice of these two parameters was due to their longer history of measurements. These two parameters can also represent the oil and paper ageing respectively. In addition, both have good representation of transformer age as discussed in Section 5.2.

Besides that, the analysis will be performed by expressing resistivity and 2-FAL with respect to the time elapsed after oil treatment instead of transformer in-service age. Referring to Figure 6.11, let the age when a transformer is treated as oil treatment age (OTA), time elapsed after oil treatment is simply transformer in-service age minus OTA. This expression of the trends with respect to time elapsed after oil treatment can thus allow comparison and investigation into the behaviour of insulation condition specifically after oil treatment for units treated at different in-service times.

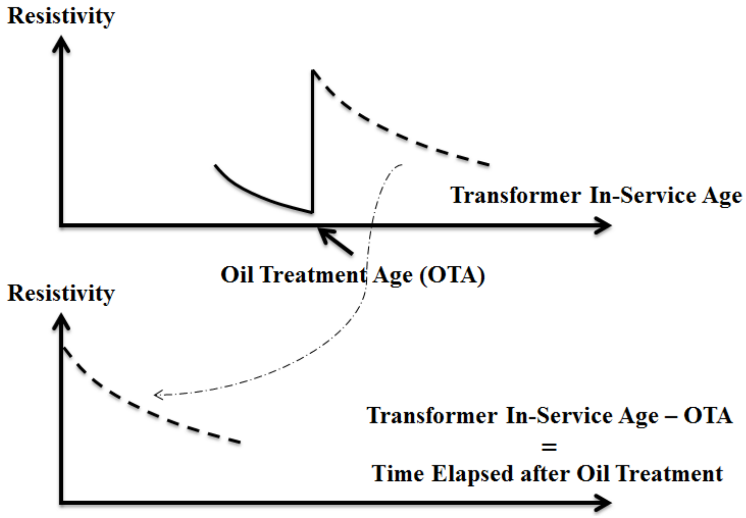

Figure 6.11: Definition of "time elapsed after oil treatment"

6.4.1 Influence of Age on Trends after Treatment

Figure 6.12 illustrates the trends of resistivity and 2-FAL with time elapsed after oil treatment for a subpopulation of treated transformers. The transformers were grouped based on their OTAs, more specifically two groups of ≤ 30 years or > 30 years. In the figure legends, the column directly after the OTA information is either the resistivity (Figure 6.12(a)) or 2-FAL (Figure 6.12(b)) before treatment. The next columns denote the colour before and after treatment. Due to the absence of exact degree of oil treatment, the change in colour before and after treatment was used as estimation. The text description of each of the colour numerical values can be found in Table 3.2.

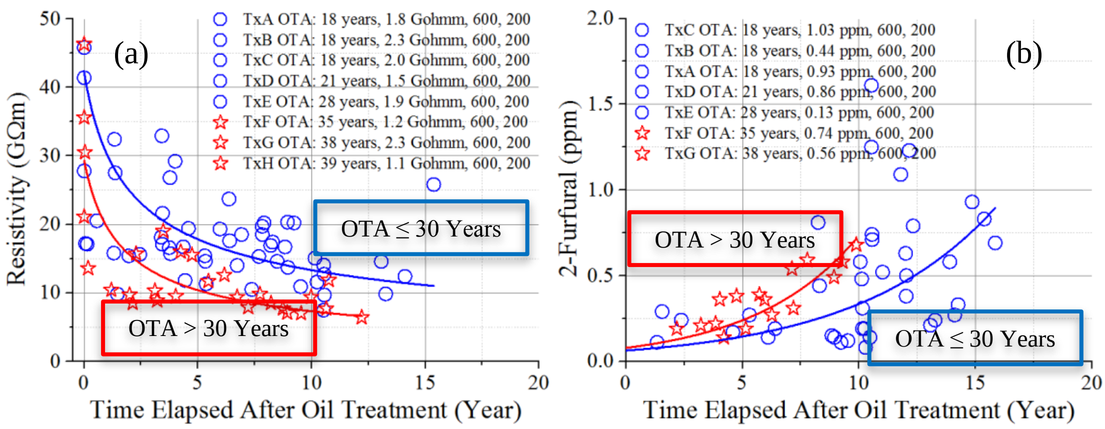

Figure 6.12: Trends with time elapsed after oil treatment, (a) resistivity, (b) 2-FAL

As reflected by a higher resistivity trend in Figure 6.12(a) and a lower 2-FAL trend in Figure 6.12(b) for the blue group (OTA $\leq$ 30 years), transformers that were treated before 30 years old tend to stay in favourable conditions longer than those treated after 30 years old.

For the younger units, there could be a lower consumption of the natural inhibitors present in the oil from insulation ageing prior to treatment, resulting in greater stability against oxidation and hence a higher resistivity value. Another possibility is from the perspective of oil-paper partitioning whereby younger transformers that generally have fewer degradation products will hence experience lower concentration of degradation products (such as moisture, acids and particularly 2-FAL) migrating from the solid insulation to the oil [62]. Such an observation could suggest the preference to treat a transformer when it is younger. Nonetheless, this should always be aligned with sound economic judgement.

6.4.2 Influence of Insulation Condition on Trends after Treatment

One of the reasons for limiting the same range of colour index (particularly the colour index before treatment) in the preceding Section 6.4.1 is that insulation condition prior to treatment could also affect the ageing trends after treatment. This will be discussed in this section with relaxation on particularly the colour index before treatment as it would reflect different insulation conditions before treatment. In addition, to achieve adequate number of sample size, the colour index after treatment was also relaxed from a strict 200 to a range from 100 to 200.

By considering units treated when they were $\leq$ 30 years old, Figure 6.13(a) illustrates that transformers with a higher resistivity prior to treatment tend to have a higher resistivity trend after treatment. As shown, the three groups are categorised according to IEC 60422 condition criteria based on resistivity. The better the condition of the oil before treatment would suggest a lower degree of ageing, implying a better insulation health and also a greater residual concentration of natural inhibitors. Thus, the ageing tendency of these transformers after treatment would have been less drastic or less severe if compared with those treated when their condition is poorer.

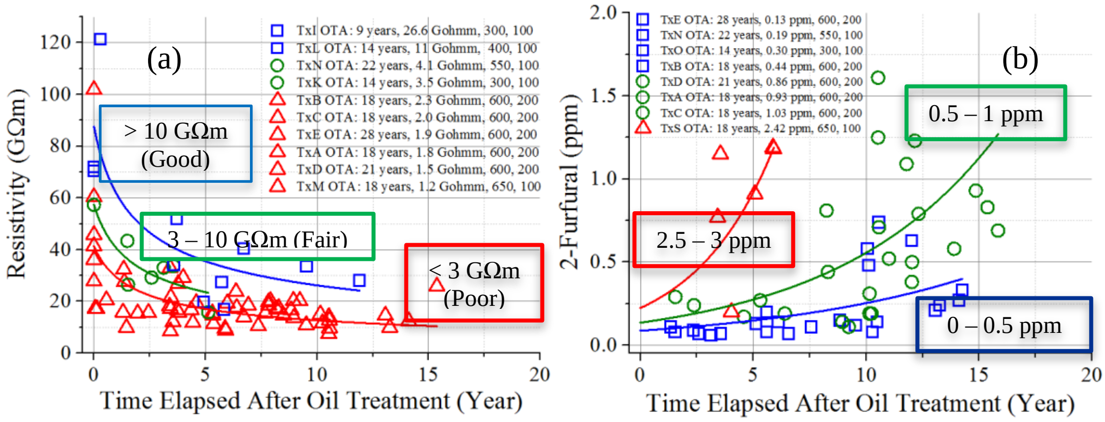

Figure 6.13: Trends with time elapsed after oil treatment for OTA ≤ 30 years, (a) resistivity (b) 2-FAL

This observation from an oil condition perspective as represented by the resistivity measurements is also perceived from analysing a paper condition perspective. Figure 6.13(b) illustrates the 2-FAL trends with transformers having a lower 2-FAL prior to treatment exhibiting greater tendency to record lower 2-FAL trends after treatment. This could again be due to the lower amount of 2-FAL residing in paper before migrating to oil after treatment.

Note that the findings observed for transformers treated when they were ≤ 30 years old are also perceived from those treated after 30 years old. These findings suggest that oil treatment should be performed on units that are not too poor in insulation condition to achieve a longer period of usability after treatment. Again, a tender balance needs to be established between the technical suggestions and economic viabilities of the oil treatment options available for a transformer fleet.

6.4.3 Influence of Inhibitor Usage on Trends after Treatment

With inhibitor known to be useful towards retarding oil oxidation, interest has hence been generated on the prospect of using inhibitor after treating transformers that are traditionally filled with uninhibited oil.

In spite of a lack of exact records, consultation with the utility providing the data analysed in this oil treatment section revealed that the use of inhibitor (most likely dibenzyl disulphide, DBDS) for treated transformers only started from 2007 onwards.

Hence, to understand the influence of inhibitor usage on trends after treatment, two groups will be analysed which are transformers treated before 2007 and after 2007 (inclusive of 2007). Figure 6.14 shows resistivity and 2-FAL with respect to time elapsed after oil treatment of both treated transformer populations.

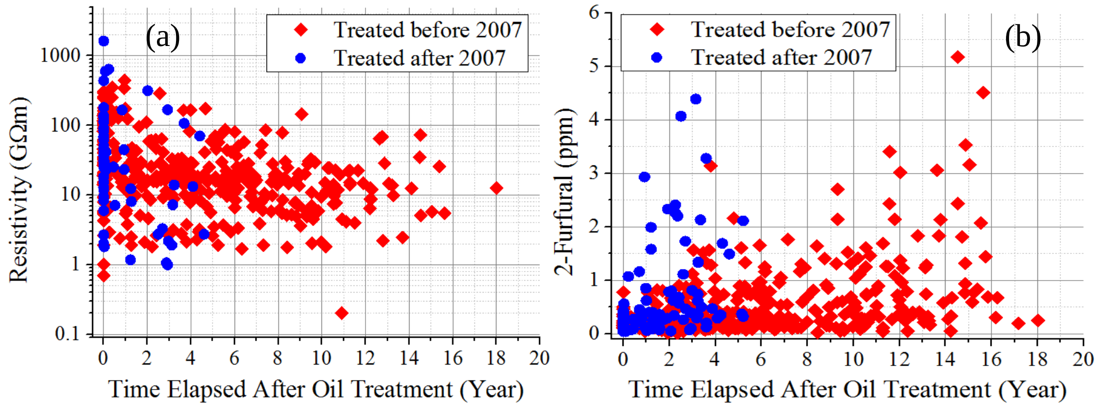

Figure 6.14: Trends with time elapsed after oil treatment, (a) resistivity, (b) 2-FAL, * before 2007 (likely uninhibited) and after 2007 (likely inhibited with DBDS)

As the database acquired from this particular utility has records only up till the year of 2012, the trends represented by the transformers treated after 2007 are visibly shorter than those treated before 2007. Nevertheless, an interesting observation is that from the two different parameters (from both oil and paper condition perspectives), transformers treated after 2007 that are most likely refilled with inhibited oil appear to age similarly if not worse than transformers treated before 2007 that are refilled with uninhibited oil after treatment.

This observation is perhaps surprising as better ageing performance is expected for transformers that are refilled with inhibited oil that has greater oxidation stability. Apart from potential limitation in terms of data and information available, the observation could be due to the way inhibited oil is refilled into treated transformers. In addition, there could be a different interaction involving inhibitor and an already aged insulation system if compared with that for new transformers with a pristine insulation system. More research, potentially from laboratory ageing experiments will need to be performed to further consolidate this observation. Until then, caution should be exercised in the use of inhibitor in oil treated transformers.

6.5 Chapter Summary

This chapter first investigated moisture measurements from a monthly perspective. Studies revealed a seasonal influence on moisture with high values generally in the month of June, July and August corresponding to the summer months. Such a seasonal influence could cause potential confusion on the condition interpreted. The incorporation of oil sampling temperature, through relative humidity (RH) is thus recommended in better interpreting moisture measurements.

Following better interpretation of moisture measurements, since breakdown voltage (BDV) is known to be related to moisture, the next section of the chapter studied an indirect manner of better interpreting BDV measurements. By first aggregating literature findings on BDV versus RH relationship, a generic curve was obtained which was used as a basis for reflecting a change in RH due to temperature incorporation into a change in BDV. This BDV change was then added to the original BDV measured.

The third section of the chapter discussed a mismatch in condition interpreted based on dielectric dissipation factor (DDF) and resistivity measurements. With theoretical relationship existing between the two parameters and knowing that the two parameters are commonly measured together, condition mismatch discovered from in-service database analysis reveals there is a pressing need for revising the current criteria in the IEC 60422 standard.

The chapter closed with studies on oil treatment implementation, particularly focusing on the trends after oil treatment that could reflect the length of transformer longevity after treatment. Studies suggest treating transformers at an earlier age or when insulation condition is not too poor to achieve longer usability after treatment. In addition, based on current database study, the use of inhibitor after treatment might not yield a better performance than uninhibited oil. More work perhaps from an experimental approach needs to be performed to further consolidate all these oil treatment related findings from database analysis.

CHAPTER 7: INSULATION CONDITION RANKING

7.1 Introduction

Oil test data manifest as a rich source of information for aiding and justifying asset management practices. As in Section 2.5.3.1, empirically formulated health index is commonly used for interpreting oil test information into a single condition score. This practice could be subjective and could take time to form as operational experience and forensic experience (scrapping data) are required. In this chapter, two techniques namely principal component analysis (PCA) and analytic hierarchy process (AHP) will be introduced to rank transformers according to their insulation condition.

The two techniques will be demonstrated on oil test data of a total of 39 in-service UK transmission transformers with oil test records in 2012. These free breathing, Kraft paper and mineral oil insulated transformers, without undergoing any oil treatment, were selected because in the latest 2012 entry, they all have records of the following eight parameters: breakdown voltage (BDV), moisture, acidity, 2-furfural (2-FAL), dielectric dissipation factor (DDF), resistivity, interfacial tension (IFT) and colour as seen in Table 7.1. Besides the oil test parameters, the in-service age is also shown. Referring to Figure 7.1, the data are subjected to PCA and AHP in conjunction with a track record proven empirical formula (EF) used by the utility providing the dataset. Comparisons among the condition rankings interpreted will be performed.

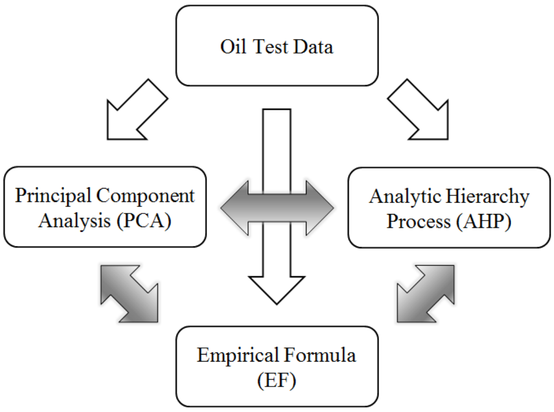

Figure 7.1: General work flowchart of condition ranking using PCA and AHP [151]

Table 7.1: Oil test data for 39 in-service transformers as recorded in 2012

	In-Service Age (Year)	BDV (kV)	Moisture (ppm)	Acidity (mg KOH/g)	2-FAL (ppm)	DDF	Resistivity (GΩm)	IFT (mN/m)	Colour
T1	41	68.6	11.5	0.088	0.38	0.143	2.005	17.0	4.0
T2	44	91.5	14.0	0.036	0.07	0.022	14.995	24.0	2.5
T3	49	78.0	16.0	0.076	2.70	0.108	2.405	18.0	4.0
T4	45	99.0	13.5	0.138	0.62	0.185	1.510	15.0	5.0
T5	19	91.1	18.5	0.049	0.16	0.017	16.180	22.0	2.0
T6	51	89.0	10.5	0.059	0.25	0.025	14.060	26.2	2.5
T7	47	89.6	10.0	0.070	0.51	0.039	9.605	23.0	3.0
T8	44	91.0	9.5	0.019	0.84	0.028	14.900	29.0	2.5
T9	51	83.6	10.0	0.014	0.31	0.020	18.360	28.3	2.0
T10	58	67.5	11.0	0.118	0.56	0.038	8.800	19.7	3.5
T11	43	83.8	14.5	0.035	0.93	0.049	7.685	22.9	4.0
T12	46	98.1	12.0	0.078	0.22	0.031	11.665	22.2	2.5
T13	54	93.2	15.0	0.013	1.52	0.015	31.685	28.0	2.0
T14	49	88.0	9.5	0.086	0.50	0.056	5.275	19.5	3.0
T15	42	98.7	11.0	0.041	0.26	0.080	4.095	22.0	3.5
T16	47	89.0	12.0	0.041	0.45	0.058	6.060	24.3	3.0
T17	44	90.0	13.5	0.040	0.31	0.045	5.850	22.8	3.0
T18	46	90.3	11.0	0.056	0.55	0.026	13.725	25.8	4.0
T19	50	97.0	10.0	0.125	1.31	0.063	5.120	19.7	3.5
T20	46	92.7	22.5	0.104	1.24	0.328	0.925	21.3	6.5
T21	46	93.0	13.5	0.072	0.10	0.043	8.290	23.0	2.5
T22	50	100.0	10.0	0.032	0.35	0.039	10.090	25.7	2.5
T23	46	84.6	13.0	0.074	0.09	0.108	2.955	19.0	4.0
T24	45	92.4	14.5	0.032	0.24	0.033	9.010	25.0	3.0
T25	44	81.2	10.0	0.050	1.26	0.066	4.685	21.0	3.5
T26	45	98.0	13.5	0.096	2.75	0.121	2.460	19.3	5.0
T27	15	80.4	9.5	0.079	1.54	0.021	16.400	19.0	4.0
T28	46	96.9	7.0	0.068	0.32	0.040	8.035	20.3	3.0
T29	46	92.3	10.0	0.059	0.10	0.053	5.500	20.5	3.5
T30	51	87.7	25.0	0.100	1.48	0.127	2.195	17.1	4.5
T31	49	88.0	12.0	0.104	0.41	0.057	5.245	18.7	4.0
T32	42	84.2	17.0	0.068	0.10	0.059	4.970	22.1	3.0
T33	45	91.0	13.5	0.090	0.08	0.157	3.180	20.9	3.0
T34	51	83.0	15.0	0.043	0.37	0.093	4.500	24.0	2.5
T35	51	93.0	15.0	0.048	0.41	0.133	2.500	21.0	3.0
T36	58	90.0	13.0	0.043	0.45	0.048	7.435	21.5	3.5
T37	10	85.0	23.5	0.043	0.08	0.033	8.350	20.2	2.5
T38	45	95.0	10.5	0.014	0.21	0.010	38.850	34.0	1.0
T39	46	78.0	8.0	0.058	2.50	0.117	2.675	18.0	4.0

7.2 Descriptions of the Mathematical Techniques

7.2.1 Principal Component Analysis

As mentioned in Section 2.5.3.4, PCA is a technique capable of dimension reduction for a dataset with a large number of correlated variables [165, 166]. With its long history of usage, PCA has been widely applied in miscellaneous fields, ranging from neuroscience, image processing, chemometrics to partial discharge analysis [166-169]. In this work, PCA will be applied primarily to extract the essence of a set of multi-variable oil test data for insulation condition ranking.

Generally, PCA involves the transformation of original correlated variables into a new set of uncorrelated variables which are collectively known as principal components (PCs), while maintaining the original data variation [165, 166]. For *n* number of original variables, there will be *n* number of PCs as well. Dimension reduction is achieved when the first *k* number (where $k < n$) of PCs are chosen to represent the original data [151].

The following provides a brief description on the steps for PCA computation as adapted from [165, 166, 168]. Let X_{raw} be a set of data of *m* entries associated with *n* original variables (e.g. the oil test data in Table 7.1 has 39 transformers corresponding to 8 parameters). To avoid emphasising on parameter records of a larger scale range, each value in the original dataset is to be mean-centred and scaled based on the mean and standard deviation evaluated for each variable as in Equation 7.1 [151]. The resulting matrix, *X* is displayed in Equation 7.2.

$$\overline{x_{\cdot j,raw}} = \frac{1}{m}\sum_{i=1}^{m} x_{ij,raw};\ \sigma_{\cdot j,raw} = \sqrt{\frac{1}{m-1}\sum_{i=1}^{m}\left(x_{ij,raw} - \overline{x_{\cdot j,raw}}\right)} \qquad \textbf{\textit{Equation 7.1}}$$

$$X = \begin{bmatrix} x_{11} & \cdots & x_{1n} \\ \vdots & \vdots & \vdots \\ x_{m1} & \cdots & x_{mn} \end{bmatrix},\ x_{ij} = \frac{x_{ij,raw} - \overline{x_{\cdot j,raw}}}{\sigma_{\cdot j,raw}} \qquad \textbf{\textit{Equation 7.2}}$$

Subsequently, X is converted into Y which is the PC dataset by linearly combining X with A as in Equation 7.3. Note that Y has the dimension of $m \times k$ where before the first k components are chosen for dimension reduction, $k = n$. In essence, the matrix A has the individual weightings for each of the n original variables [151]. The first column is the set of weightings for linearly combining the n original variables into the first PC, second column for the second PC, up to the kth column for the kth PC [151].

$$Y = XA$$

$$\begin{bmatrix} y_{11} & \cdots & y_{1k} \\ \vdots & \vdots & \vdots \\ y_{m1} & \cdots & y_{mk} \end{bmatrix} = \begin{bmatrix} x_{11} & \cdots & x_{1n} \\ \vdots & \vdots & \vdots \\ x_{m1} & \cdots & x_{mn} \end{bmatrix} \begin{bmatrix} a_{11} & \cdots & a_{1k} \\ \vdots & \vdots & \vdots \\ a_{n1} & \cdots & a_{nk} \end{bmatrix}$$ ***Equation 7.3***

The key to PCA is the evaluation of the elements in A which can be performed by either eigenvector decomposition (EVD) or singular value decomposition (SVD) [165, 168]. SVD is known to be a more general solution than EVD as its application is not just limited to square matrices [168, 233]. Considering its more general nature, SVD will be used in this work for PCA evaluation.

With reference to Equation 7.4, SVD involves the decomposition of the matrix X ($m \times n$) into three components, which are U ($m \times r$ orthogonal matrix), S ($r \times r$ diagonal matrix) and V ($n \times r$ orthogonal matrix) [165, 168, 233]. These three components respectively represent a rotation, a stretch and a secondary rotation [168]. With X previously mean-centred and scaled, the expression of X^TX is symmetric and hence diagonalisable [233]. That means that S and V as expressed in Equation 7.5 are related to the eigenvalue and eigenvector of X^TX [233]. More specifically, S is the square root of the eigenvalue of X^TX while V is simply the eigenvector of X^TX. After evaluating S and V, the other matrix, U can be obtained based on Equation 7.6.

$$X = USV^T$$ ***Equation 7.4***

$$X^T X = VS^T U^T USV^T = VS^T SV^T = VS^2 V^T$$ ***Equation 7.5***

$$U = XVS^{-1}$$ ***Equation 7.6***

The three component matrices, U, S and V are directly related to $Y = XA$ as will be seen in the following. As PCA results in a new set of uncorrelated variables, the covariance matrix of Y, denoted by C_Y, is diagonal with $n \times n$ dimension (before k components are chosen, i.e $k = n$) [151, 168, 233]. By substituting $Y = XA$, C_Y can be expressed as a function of covariance of X as in Equation 7.7. Subsequently, Equation 7.8 is obtained first from substituting Equation 7.5 into Equation 7.7 and knowing V is actually A as C_Y is a diagonal matrix [168, 233].

Hence, the SVD component matrix V is actually the A matrix for PCA evaluation [168, 233]. Note that a sign convention needs to be subsequently enforced on the A matrix by multiplying the sign of the largest coefficient in each column with all the coefficients in that particular column [234, 235]. Covariance of Y is simply the component matrix S^2 divided by *(m-1)* [168, 233]. Finally, the Y matrix is simply the product of X and A or even the product of the component matrices U and S as in Equation 7.9 based on the SVD relation in Equation 7.4 [168, 233].

$$C_Y = \frac{1}{m-1} Y^T Y = A^T \left(\frac{1}{m-1} X^T X \right) A \qquad \textbf{\textit{Equation 7.7}}$$

$$C_Y = \frac{1}{m-1} A^T \left(V S^2 V^T \right) A = \frac{S^2}{m-1} \qquad \textbf{\textit{Equation 7.8}}$$

$$Y = XA = XV = US \qquad \textbf{\textit{Equation 7.9}}$$

7.2.2 Analytic Hierarchy Process

As mentioned in Section 2.5.3.5, AHP is a decision making paradigm that involves formulating a hierarchy to evaluate a set of alternatives pertaining to a certain aim [151, 170, 236]. This technique is coherent, flexible, easy to understand as well as comprehensive in combining insights, intuition and experience with mathematics and data, thereby allowing both qualitative and quantitative evaluations [171, 174, 175, 236, 237]. Applications have since been extensive, ranging from defence, aviation, IT, health, banking, manufacturing and more recently in power system too [170-176]. AHP will be used in this work on devising weightings for the oil test parameters before using them to interpret oil test records for insulation condition ranking.

Figure 7.2 illustrates the AHP concept. The structure and complexity of the hierarchy is up to the discretion of the user and could vary for different scenarios or studies. In general, a set of *p* alternatives are evaluated pertaining to a certain aim based on a set of *q* criteria, which in turn could be assessed with reference to another set of *r* sub-criteria (if required) [170, 171, 236].

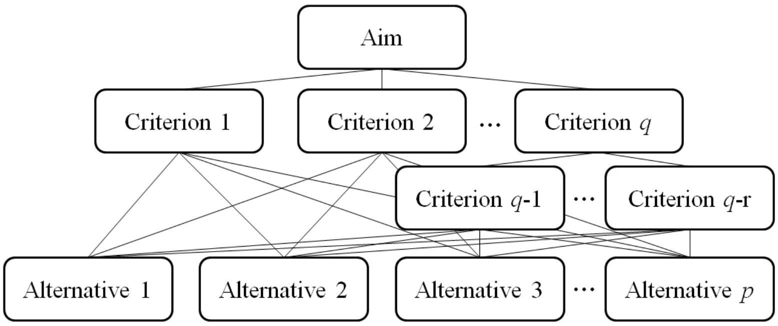

Figure 7.2: AHP concept illustration [151]

After establishing the hierarchy, pairwise comparison of each element pair at each level is performed with reference to the level directly above [170]. As an example at the highest level in Figure 7.2, the preference of Criterion 1 over Criterion 2 with reference to the aim is assessed [151]. This qualitative pairwise comparison requires the use of a scale to convert subjective preference into numbers which can be done via two possible scales as shown in Table 7.2 [170, 171, 237].

Table 7.2: Scales for pairwise comparisons [170, 171, 237]

Definition	**Linear Scale**	**Balanced Scale**
Equal	1	1
Weak	2	1.22
Moderate	3	1.5
Moderate plus	4	1.86
Strong	5	2.33
Strong plus	6	3
Very strong	7	4
Very, very strong	8	5.67
Extreme	9	9
*if an element *i* compared with an element *j* has one of the above non-zero numbers assigned to it, then the reciprocal value is assigned when comparing *j* with *i*		

From Table 7.2, the traditional linear scale originally introduced by Saaty is the most commonly used [170]. Although easy to implement, the linear scale is reported to cause unevenly dispersed local weights that could affect sensitivity when comparing elements that are preferentially close to one another [171, 237]. This can be overcome by using a balanced scale which is also adopted in this work [171, 237].

With the scale, a comparison matrix with a form shown in Equation 7.10 can be used to summarise all the pairwise comparisons of each downstream element pair at a particular reference level [151]. Note that the diagonal values are always unity as they simply mean comparing an element with itself. As for the off-diagonal elements, the values in one of the upper or lower triangular halves are just the reciprocals of the values in another half as the elements under comparison are the same [170].

$$C = \begin{bmatrix} c_{11} = 1 & c_{12} & \cdots & c_{1z} \\ c_{21} = 1/c_{12} & c_{22} = 1 & \cdots & c_{2z} \\ \vdots & \vdots & \vdots & \vdots \\ c_{z1} = 1/c_{1z} & c_{z2} = 1/c_{2z} & \cdots & c_{zz} = 1 \end{bmatrix}$$ ***Equation 7.10***

Each of the comparison matrices formed at each reference level for evaluating the downstream elements is then converted to a set of local weightings [151]. For instance, a $q \times q$ comparison matrix for the first level in Figure 7.2 is converted to q number of local weightings, i.e. one for each of the criteria [151]. Such a conversion is done through either the traditional evaluation of matrix eigenvector or geometric mean evaluation (logarithmic least squares method) [170, 171]. Geometric mean will be used in this work citing potential occurrence of rank reversal issues with the eigenvector evaluation method [171]. Equation 7.11 shows the geometric mean evaluation method. As a comparison matrix is a square matrix, each weighting is evaluated by calculating the z-th root of the product of all elements either in a row or in a column, before normalising it [171].

$$w_i = \sqrt[z]{\prod_{j=1}^{z} c_{ij}} \Bigg/ \left(\sum_{i=1}^{z} \sqrt[z]{\prod_{j=1}^{z} c_{ij}} \right) \text{ or } w_j = \sqrt[z]{\prod_{i=1}^{z} c_{ij}} \Bigg/ \left(\sum_{j=1}^{z} \sqrt[z]{\prod_{i=1}^{z} c_{ij}} \right)$$ ***Equation 7.11***

After calculating the weightings of the elements at each level, the hierarchy as in Figure 7.2 will be filled with local weightings, *w* [151]. The global weighting, *W*, of each element in the hierarchy is then evaluated through additive aggregation. As shown in Equation 7.12, *W* is the sum of the product between the global weighting of a reference on an upper level, $W_{upper\ level}$ and the local weighting of that element on the current level with respect to that certain reference, $w_{current:\ upper\ level}$ [151, 170, 171].

$$W = \sum_{upper\ level} W_{upper\ level} \cdot w_{current:\ upper\ level} \qquad \textbf{\textit{Equation 7.12}}$$

7.3 Implementation Results

The understanding fostered on both PCA and AHP will now be used to demonstrate their implementation on transformer insulation condition ranking, based on the oil test data shown in Table 7.1. Comparisons among the rankings interpreted from both techniques along with that from an empirical formula will also be discussed.

7.3.1 Principal Component Analysis Implementation

Checking for the suitability of implementing PCA is needed before representing the original data in terms of the new set of principal components (PCs). This is done via statistical tests like Kaiser-Meyer-Olkin (KMO) test and Bartlett test [151]. Briefly on KMO test, it is a measure of sampling adequacy with values closer to 1 desirable and values below 0.5 suggesting unsuitability of PCA implementation [238, 239]. As for Bartlett test, it evaluates the presence of correlation among the original variables with test values lower than a standard 0.05 significance level desirable for PCA [239, 240]. From Figure 7.3, both test statistics prove suitability for implementing PCA [151].

As detailed in Section 7.2.1, *n* original variables result in *n* PCs. Hence, referring to Figure 7.3, with eight oil test parameters, there will be eight principal components with each of them explaining different percentages of the variance in the original dataset. Both individual and cumulative percentages of the variance explained by each PC are also shown in Figure 7.3.

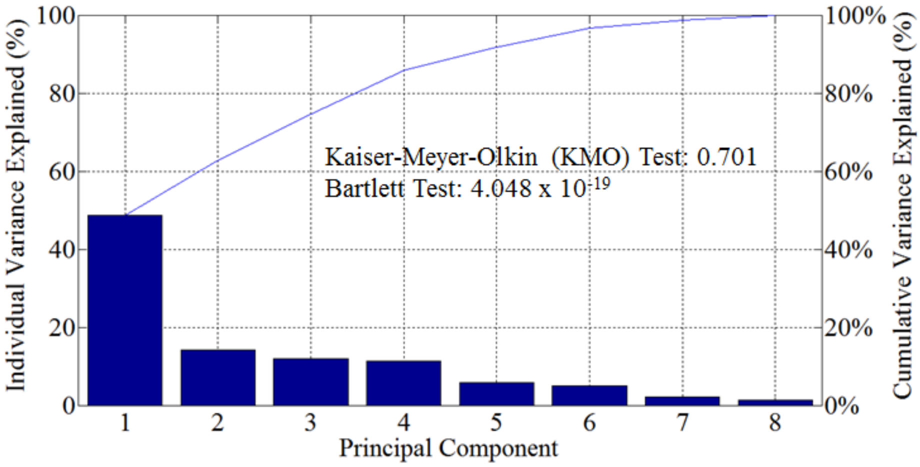

Figure 7.3: KMO test, Bartlett test and variance explained by each PC [151]

One way of interpreting the PCs used is through a bi-plot. For visualisation purposes, dimension reduction will be performed where the first three PCs will be used to represent the original eight dimensional data. Inevitably, there will be a loss of representativeness as the use of three PCs can account for up to 75% of the original data variance as observed from Figure 7.3. Nonetheless, majority of the original data variance is still preserved and the three dimensional bi-plot can allow a fast and direct graphical interpretation of the relative transformer insulation condition.

The three dimensional bi-plot corresponding to the use of three PCs is illustrated by Figure 7.4. This bi-plot was first plotted by plotting the values of the three PCs of the eight original variables (first three columns of the A matrix described in Section 7.2.1) [151]. Then, the values of the three PCs of the 39 individual transformers (first three columns of the Y matrix in in Section 7.2.1) were plotted after they were normalised by the maximum in the three PCs for the 39 transformers and scaled to the maximum length among the eight original variable representations in the three dimensional space [151]. Note that sign convention is enforced for both representations of the original variables and the individual transformers in the three dimensional space [166].

This three dimensional bi-plot therefore does not just allow the interpretation of individual transformer insulation condition based on just three PCs, but also show how these three PCs can relate back to the eight original variables [151, 166].

With reference to Figure 7.4, PC1 represents well colour, IFT, resistivity, acidity and DDF by judging from their PC1 magnitude, to be followed by 2-FAL, moisture and BDV [151]. Considering the signs in PC1 instead of magnitude, interpretation of which reveals that moisture, DDF, colour, acidity and 2-FAL behave in an opposite manner to BDV, IFT and resistivity in terms of representing ageing [151]. These observations are beneficial towards indicating the behaviour of oil test parameters with age as well as providing an estimation of how well they represent ageing [151]. PC2 and PC3 can be similarly interpreted but PC1 will be prioritised as it accounts for most of the original data variance [151].

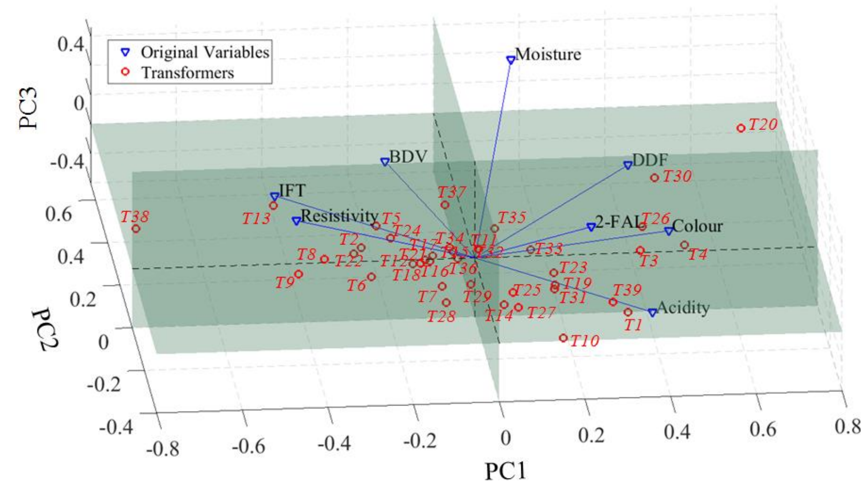

Figure 7.4: Three dimensional bi-plot for interpretation of condition ranking [151]

More importantly, apart from the relation to the original variables, the bi-plot also enables users to identify quickly the transformers that are the best or the worst based on their insulation condition [151]. From Figure 7.4, the origin reflects the average insulation condition, whereas the transformers further away from the origin are in a better or a worse condition [151]. For example, T38 is interpreted to be the transformer with the best insulation condition [151]. On the contrary, T20 is perceived to be the worst condition transformer as it has high positive values of PC1, PC2 and PC3 which can actually be also interpreted if the T20 point is projected orthogonally to each of the lines representing the original variables [151].

As an extension, clustering algorithms such as fuzzy c-means or hierarchical clustering can be applied to the three PCs representations of the 39 transformers if it is of user's interest to group transformers based on their interpreted insulation condition.

Apart from graphical interpreting the bi-plot, a value arbitrarily called as PCA rank was calculated by multiplying the normalised and scaled values of the three PCs with their respective variance explained (VE) as shown in Equation 7.13 [151]. The incorporation of VE hence represents a form of weighting allocation. Note that three PCs were used here (following from the three dimensional bi-plot) but essentially all of the eight PCs could be incorporated. For the data used in this work, the difference between the two is small and the PCA rank based on three PCs will be used in the following discussion.

$$PCA\ Rank = \sum_{i=1}^{3} PC_i * VE_i \qquad \textbf{\textit{Equation 7.13}}$$

The PCA ranks of the 39 in-service transformers are shown in Table 7.3 in an order of decreasing severity of insulation condition [151]. Note Tx ID denotes transformer identifier and higher values of PCA rank indicate a poorer condition. As can be observed, the worst three transformers in terms of insulation condition are T20, T30 and T4, whereas the best three transformers are T38, T9 and T13 [151].

Table 7.3: PCA rank for 39 in-service transformers [151]

Tx ID	PCA Rank	Tx ID	PCA Rank	Tx ID	PCA Rank
T20	0.415	T37	0.016	T7	-0.062
T30	0.271	T32	0.014	T18	-0.066
T4	0.249	T11	0.009	T28	-0.069
T26	0.212	T25	0.007	T12	-0.070
T3	0.182	T27	-0.003	T24	-0.074
T1	0.117	T14	-0.009	T5	-0.079
T39	0.105	T15	-0.015	T2	-0.115
T23	0.075	T36	-0.019	T22	-0.127
T33	0.073	T34	-0.019	T6	-0.131
T19	0.066	T29	-0.027	T8	-0.169
T31	0.061	T17	-0.043	T13	-0.179
T35	0.052	T16	-0.053	T9	-0.212
T10	0.020	T21	-0.054	T38	-0.349

7.3.2 Analytic Hierarchy Process Implementation

In this work, AHP was used firstly to evaluate the ranking or the weightings assigned to each of the different oil test parameters. Then, similarly to the use of a classical empirical formula, the parameter weightings were then applied to the oil test data in Table 7.1 for insulation condition ranking.

Figure 7.5 depicts the AHP setup for parameter ranking consisting of four criteria and eight alternatives (the parameters themselves). The criteria selections and the subsequent subjective pairwise comparisons among the elements in the hierarchy were facilitated by the experience and understanding gained from not just literature [10, 12, 13, 18], but also oil test databases [81, 96, 201, 210].

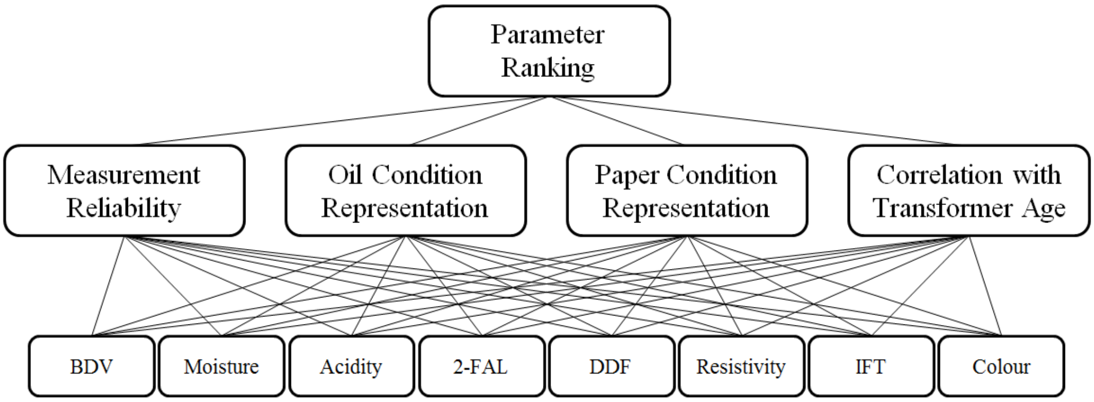

Figure 7.5: AHP setup for parameter ranking [151]

With reference to Figure 7.5, four criteria were selected to aid decision making on parameter ranking. Measurement reliability (MR) covers the confidence on the parameter measurements including measurement principles, history and inherent stability [151]. Oil condition representation (OCR) and paper condition representation (PCR) are straightforward as they respectively reflect how well the parameters represent oil and paper ageing [151]. The final criterion is correlation with transformer age (CTA) which indicates the degree of representation or the sensitivity of the parameters to transformer age [151]. The four criteria will be represented by their initials in the following for simplicity.

Table 7.4 shows the pairwise comparisons among the four criteria. As the aim is about condition ranking of insulation (composed of oil and paper), OCR and PCR were adjudged to be slightly more important than MR [151]. CTA was also deemed more important than MR as CTA could indicate how well the parameters represent ageing [151]. These thoughts are reflected by the second to the fourth entries in the first row or the first column. The comparison matrix was completed by accepting that paper health is more essential than oil health to transformer longevity as oil can be easily replaced or cleaned [151]. Lastly, PCR was regarded as important as CTA [151]. With values determined, the weightings, w_{CR} were evaluated and are shown in the last row.

Table 7.4: Comparison matrix pertaining to criteria ranking (CR) [151]

	MR	OCR	PCR	CTA
MR	1/1	1/1.22	1/1.22	1/1.22
OCR	1.22/1	1/1	1/1.22	1/1.22
PCR	1.22/1	1.22/1	1/1	1/1
CTA	1.22/1	1.22/1	1/1	1/1
w_{CR}	0.214	0.237	0.275	0.275

Proceeding from the evaluation of the criteria to the evaluation of the alternatives (the parameters themselves), the preference of the parameters with respect to each of the four criteria will be evaluated. The evaluation will be aided by any information gathered from previous studies and literature in terms of increasing or reducing the importance or the preference of the parameters with respect to a particular criterion.

Table 7.5 shows the pairwise comparison results of the eight parameters with respect to MR. Acidity and 2-FAL were regarded as the most reliable parameters considering their wide measurements by various utilities if compared with other useful parameters such as DDF, resistivity and IFT that are perhaps less adopted [81, 96, 151]. As for the least reliable parameter, colour was deemed as such due to its inherent subjective value determination [81, 151]. Moisture and BDV were considered more reliable than colour measurement in general but still less preferable due to issues like potential moisture ingress, temperature and seasonal influence on moisture as covered in Section 6.1; as well as the indirect effects these would have on BDV [96, 151, 210].

Table 7.5: Comparison matrix pertaining to MR [151]

	BDV	Moisture	Acidity	2-FAL	DDF	Resistivity	IFT	Colour
BDV	1/1	1/1	1/1.86	1/1.86	1/1.5	1/1.5	1/1.5	1.22/1
Moisture	1/1	1/1	1/1.86	1/1.86	1/1.5	1/1.5	1/1.5	1.22/1
Acidity	1.86/1	1.86/1	1/1	1/1	1.22/1	1.22/1	1.22/1	2.33/1
2-FAL	1.86/1	1.86/1	1/1	1/1	1.22/1	1.22/1	1.22/1	2.33/1
DDF	1.5/1	1.5/1	1/1.22	1/1.22	1/1	1/1	1/1	1.86/1
Resistivity	1.5/1	1.5/1	1/1.22	1/1.22	1/1	1/1	1/1	1.86/1
IFT	1.5/1	1.5/1	1/1.22	1/1.22	1/1	1/1	1/1	1.86/1
Colour	1/1.22	1/1.22	1/2.33	1/2.33	1/1.86	1/1.86	1/1.86	1/1
w_{MR}	0.091	0.091	0.168	0.168	0.137	0.137	0.137	0.073

Table 7.6 shows the pairwise comparisons pertaining to OCR. Acidity was the preferred parameter based on understanding that it is linked directly with oil degradation products and is able to represent the crucial late ageing stages [81, 151]. As for other parameters, as moisture is produced by not just oil oxidation but more predominantly from paper hydrolysis, it would be less preferred, hence indirectly affecting BDV as well [151, 210]. Most importantly, the least preferred parameter in terms of OCR should always be 2-FAL as it is a paper degradation product [13, 151].

Table 7.6: Comparison matrix pertaining to OCR [151]

	BDV	Moisture	Acidity	2-FAL	DDF	Resistivity	IFT	Colour
BDV	1/1	1/1	1/1.5	4/1	1/1.22	1/1.22	1/1.22	1/1.22
Moisture	1/1	1/1	1/1.5	4/1	1/1.22	1/1.22	1/1.22	1/1.22
Acidity	1.5/1	1.5/1	1/1	9/1	1.22/1	1.22/1	1.22/1	1.22/1
2-FAL	1/4	1/4	1/9	1/1	1/5.67	1/5.67	1/5.67	1/5.67
DDF	1.22/1	1.22/1	1/1.22	5.67/1	1/1	1/1	1/1	1/1
Resistivity	1.22/1	1.22/1	1/1.22	5.67/1	1/1	1/1	1/1	1/1
IFT	1.22/1	1.22/1	1/1.22	5.67/1	1/1	1/1	1/1	1/1
Colour	1.22/1	1.22/1	1/1.22	5.67/1	1/1	1/1	1/1	1/1
w_{OCR}	0.114	0.114	0.179	0.025	0.142	0.142	0.142	0.142

In the context of PCR, whose pairwise comparison values are shown in the following Table 7.7, 2-FAL was evidently the preferred parameter as it is linked exclusively to paper degradation [151]. Apart from that, it is noteworthy that even though most would stay in paper, the degradation or the ageing of paper will also produce moisture and acidic products that can be found in oil [13, 151]. Hence, after 2-FAL, the preferable parameters were chosen to be moisture and acidity.

Table 7.7: Comparison matrix pertaining to PCR [151]

	BDV	Moisture	Acidity	2-FAL	DDF	Resistivity	IFT	Colour
BDV	1/1	1/1.86	1/1.86	1/4	1/1	1/1	1/1	1/1
Moisture	1.86/1	1/1	1/1	1/1.5	1.86/1	1.86/1	1.86/1	1.86/1
Acidity	1.86/1	1/1	1/1	1/1.5	1.86/1	1.86/1	1.86/1	1.86/1
2-FAL	4/1	1.5/1	1.5/1	1/1	4/1	4/1	4/1	4/1
DDF	1/1	1/1.86	1/1.86	1/4	1/1	1/1	1/1	1/1
Resistivity	1/1	1/1.86	1/1.86	1/4	1/1	1/1	1/1	1/1
IFT	1/1	1/1.86	1/1.86	1/4	1/1	1/1	1/1	1/1
Colour	1/1	1/1.86	1/1.86	1/4	1/1	1/1	1/1	1/1
w_{PCR}	0.080	0.155	0.155	0.291	0.080	0.080	0.080	0.080

Unlike the previous criteria which involve qualitative pairwise comparisons, the parameters were evaluated with respect to CTA in a quantitative or a statistical manner through Spearman's correlation with transformer in-service age, *S* from population trend analyses as reported in Section 5.2.2. These coefficients are shown in Table 7.8. The weightings, w_{CTA} were then calculated through normalisation [151].

Table 7.8: Spearman's correlation with age and weightings pertaining to CTA [151]

	BDV	Moisture	Acidity	2-FAL	DDF	Resistivity	IFT	Colour
S	0.201	0.395	0.613	0.471	0.590	0.438	0.620	0.502
w_{CTA}	0.052	0.103	0.160	0.123	0.154	0.114	0.162	0.131

With aggregation of the weightings from the CR level in Table 7.4 that dealt with pairwise comparisons among the four criteria, to the MR, OCR, PCR and CTA levels that examined the preference of the parameters with respect to each of the criteria found in Table 7.5 to Table 7.8, the global weightings, *W* of the oil test parameters were evaluated as found in Table 7.9.

Table 7.9: Global weightings of oil test parameters [151]

	BDV	Moisture	Acidity	2-FAL	DDF	Resistivity	IFT	Colour
W	0.201	0.395	0.613	0.471	0.590	0.438	0.620	0.502

Before applying the weightings of the parameters to assess the condition of the 39 in-service transformers, the original data in Table 7.1 were normalised according to the increasing or decreasing nature of the parameter with respect to a change in insulation condition [151]. As an example, acidity measurements were divided by the maximum acidity recorded in the dataset [151]. Table 7.10 shows the condition rankings based on AHP application. The AHP ranks are in decreasing severity of insulation condition where high values represent a poorer condition whereas low values indicate a better condition. It can be observed that T20, T4 and T30 are the worst three transformers, whereas the best three are T38, T9 and T8.

Table 7.10: AHP rank for 39 in-service transformers [151]

Tx ID	**AHP Rank**	**Tx ID**	**AHP Rank**	**Tx ID**	**AHP Rank**
T20	0.802	T35	0.447	T12	0.369
T4	0.674	T25	0.445	T28	0.364
T30	0.669	T14	0.430	T16	0.363
T26	0.664	T32	0.415	T17	0.361
T3	0.651	T11	0.413	T5	0.350
T39	0.579	T37	0.394	T13	0.344
T1	0.551	T34	0.392	T24	0.331
T19	0.529	T7	0.381	T6	0.330
T10	0.490	T36	0.381	T2	0.311
T31	0.479	T29	0.375	T22	0.303
T27	0.478	T15	0.375	T8	0.302
T33	0.474	T18	0.370	T9	0.263
T23	0.467	T21	0.370	T38	0.217

Through these evaluations, the merits of AHP are shown where subjective pairwise comparisons were used from Table 7.4 to Table 7.7 whereas Table 7.8 incorporated objective statistical studies. AHP is also flexible. The pairwise comparison values in the subjective evaluations can be changed; similarly for the overall AHP structure, where more criteria could be added [151]. All these can be done if more information is obtained or if a specific asset management strategy needs to be followed.

7.4 Discussion of Findings

This section discusses the performance of PCA and AHP application in condition rankings with consideration of an empirical formula (EF). This EF has not only been fine-tuned and validated through years of operational and forensic experience (scrapping data) by the utility providing the data, but also used by them for a long period of time in asset management of their in-service transformer fleets [152]. The insulation condition ranks based on this EF are shown in a decreasing order in Table 7.11 with higher values implying a poorer condition.

Table 7.11: Empirical formula (EF) rank for 39 in-service transformers [151]

Tx ID	EF Rank	Tx ID	EF Rank	Tx ID	EF Rank
T20	220	T25	110	T27	80
T1	140	T29	110	T6	70
T4	140	T36	110	T7	70
T26	140	T10	100	T12	70
T30	140	T15	90	T18	70
T33	140	T16	90	T2	60
T3	130	T21	90	T5	60
T23	130	T28	90	T22	60
T35	130	T32	90	T24	60
T39	130	T34	90	T8	50
T14	120	T37	90	T9	40
T19	120	T11	80	T13	40
T31	120	T17	80	T38	30

With the EF rank, Table 7.12 shows transformers in a decreasing severity of insulation condition interpreted based on the three ranking methods. Note that shaded entries for EF rank represent tied ranks as this method can produce transformers that are assigned the same condition score [151].

Table 7.12: Comparison of condition ranks from EF, PCA and AHP [151]

Ranking of Insulation Condition		PCA Rank	EF Rank	AHP Rank
Worst	1	T20	T20	T20
	2	T30	T1, T4, T26, T30, T33	T4
	3	T4		T30
	4	T26		T26
	5	T3		T3
	6	T1		T39
	7	T39	T3, T23, T35, T39	T1
	8	T23		T19
	9	T33		T10
	10	T19		T31
	11	T31	T14, T19, T31	T27
	12	T35		T33
	13	T10		T23
	14	T37	T25, T29, T36	T35
	15	T32		T25
	16	T11		T14
	17	T25	T10	T32
	18	T27	T15, T16, T21, T28, T32, T34, T37	T11
	19	T14		T37
	20	T15		T34
	21	T36		T7
	22	T34		T36
	23	T29		T29
	24	T17		T15
	25	T16	T11, T17, T27	T18
	26	T21		T21
	27	T7		T12
	28	T18	T6, T7, T12, T18	T28
	29	T28		T16
	30	T12		T17
	31	T24		T5
	32	T5	T2, T5, T22, T24	T13
	33	T2		T24
	34	T22		T6
	35	T6		T2
	36	T8	T8	T22
	37	T13	T9, T13	T8
	38	T9		T9
Best	39	T38	T38	T38

By analysing Table 7.12 with consideration of the in-service age information from Table 7.1, age does not necessarily reflect the condition or the status of the insulation condition. For instance, T20 that has the worst condition has been in-service for 46 years whereas T38 that is deemed to have the best condition has been in-service for 45 years. In other words, the good condition transformers are not necessarily the younger ones. This is because, in addition to the in-service age of a transformer, other aspects like the loading history, design and so forth do affect the insulation condition.

In general, regardless of the condition ranking methods employed, the transformers at the two extreme ends of the list are similar [151]. Some difference in condition rankings does exist for transformers in between the two extremes. This difference could be due in essence to the tied ranks by EF where the ranks can be interchanged, as well as the small numerical differences in the PCA and AHP ranks [151]. Therefore, based on this perspective, groups of transformers with similar conditions interpreted are actually similar across the three condition ranking methods [151]. This suggests the promises of PCA and AHP as alternatives or backups to a conventional EF.

A track-record proven EF that is capable of delivering a representative view of insulation condition ranking requires expertise, operational and forensic experience that might not be readily available to all utilities. As demonstrated, PCA and AHP could be reliable and promising alternatives as they offer a similar output to that based on a track-record proven EF. As a matter of fact, the two methods could also be used as a reference or validation for utilities that already have their own EFs.

7.5 Chapter Summary

This chapter explored the use of principal component analysis (PCA) and analytic hierarchy process (AHP) in insulation condition ranking based on oil test data. This information on the interpreted condition can then help subsequent asset maintenance and management decisions. The oil test data used are from 39 in-service transformers measured for eight parameters in the year of 2012. Both techniques demonstrated potentials as alternatives to a conventionally used empirically formula (EF).

For utilities without the necessary resources, expertise or experience in formulating an in-house EF, the techniques demonstrated can be used as they offer a similar output to a track-record proven EF. As for utilities that have already developed their own EFs, the two techniques can be used a point of reference or validation.

PCA has the merits of being objective, data centred and capable of capturing the essence of a set of data of multiple dimensions and considerable size [151]. This would present utilities with or without an in-house developed EF a quick way to explore relations among the original oil test parameters as well as to assess the relative conditions of a large transformer fleet [151]. Users will however need to satisfy tests like KMO and Bartlett tests to ensure their own data are fit for PCA [151]. Furthermore, in terms of visualising the resulting principal components (PCs) through a bi-plot, the choices of the number of PCs to be used needs to be carefully considered to prevent excessive loss of original data representation [151].

As for AHP, it could offer a systematic way of formalising the splitting of a problem [151]. Through incorporation of both subjective and objective considerations, a hierarchy is established that allows evaluations not just in terms of subjective preference in pairwise comparisons, but also quantitative evaluations based on prior statistical studies [151]. Besides that, the concept of AHP is easily comprehended and coherent [151]. It is also flexible as the hierarchy can be updated (e.g. number of branches or value of elements) when more information or knowledge is obtained or when specific asset management strategies need to be tailored to [151].

Considering the promise of PCA and AHP in this demonstration for insulation condition ranking based on oil test data, these two mathematical techniques could be extended to incorporate other transformer aspects such as the inclusion of dissolved gas analysis (DGA) data, frequency response analysis (FRA) data, data from tap changers, bushings or even the cooling system [151].

CHAPTER 8: CONCLUSIONS AND FUTURE WORK

8.1 Conclusions

8.1.1 General Review

In this work, analysis was performed on oil test databases pertaining to in-service transformers to identify patterns, trends and information that can aid transformer ageing assessment. Through analysing databases pertaining to 33 kV, 132 kV, 275 kV and 400 kV transformers operated by three UK utilities, the research objectives were achieved and have resulted in some useful findings.

The research topics covered in this work are:

- Database processing, cleaning and analytical procedures
  - Oil contamination, test procedure change and oil treatment discontinuity
- Early degradation phenomenon
  - Detection through ageing trends
  - Cause identification from manufacturer, loading and oil chemistry
  - Suggestions to asset management
- Population analyses
  - Testing frequency and correlation with transformer age of parameters
  - Sensitivity study on testing year period
  - Influence of voltage, manufacturer and loading
- Data interpretation and recommendations
  - Seasonal influence on moisture interpretation
  - Breakdown voltage interpretation
  - Condition mismatch between dielectric dissipation factor and resistivity
  - Transformer oil treatment
- Insulation condition ranking
  - Implementation of principal component analysis (PCA)
  - Implementation of analytic hierarchy process (AHP)
  - Comparison among PCA, AHP and empirically formulated health index

In brief, through analysing multi-variable oil test data pertaining to in-service transformers in the UK, key findings as discussed in this thesis would not just help advance academic understanding on transformer ageing assessment, but also provide readily practical suggestions to industries, particularly utilities in asset management of large fleet of ageing in-service transformers.

8.1.2 Summary of Results and Main Findings

Database Processing, Cleaning and Analytical Procedures

The steps used and key messages learned in processing, cleaning and subsequently analysing databases could be beneficial for asset managers in approaching large databases. A good database should have information on both oil test records as well as transformer details such as manufacturing date or commissioning date for in-service age evaluation. Other than the usual addressing of data abnormalities, a good database should also be free of issues affecting the integrity of measurements such as oil contamination issue or a change in measurement procedure. A series of programmes was developed on a MATLAB 2013a platform that allowed automation for dealing with large number of data. This incorporated techniques for database processing and cleaning as well as mathematical and statistical analyses.

Early Degradation Phenomenon

One of the key findings in analysing transformer oil test databases from three UK utilities is an early degradation phenomenon. This phenomenon was reflected by an early peak observed in parameters like acidity and 2-FAL for transformers at all voltage levels with an in-service age of around 20 years. Subsequent investigations involving a series of eliminatory based studies revealed that the early degradation phenomenon was neither due to manufacturer nor loading; instead evidence suggested it is caused by the adoption of early hydrotreatment oil refining technique in the late 1980s. This phenomenon could have affected the whole of the UK and perhaps other countries with uninhibited oil usage. Once identified, asset managers should monitor more frequently the subgroup of affected transformers as well as revise long term capital and replacement plans.

Population Analyses

With focus on cleaned databases with early degradation units separated, population analyses indicated that higher voltage units (275 kV and 400 kV) are generally tested more frequently and for more parameters compared with lower voltage units (33 kV and 132 kV), most likely due to their greater criticality in the power system network. Graphical and statistical analyses in understanding the correlation with age of the different oil test parameters suggested acidity and 2-FAL being the essential parameters for representing oil and paper ageing respectively. Apart from that, sensitivity study on different lengths of testing year periods indicated that it is acceptable to construct a representative population ageing trend using a short period of test records (e.g. two years) as long as the transformer age profile is representative of the whole population. This finding is useful towards motivating the measurements of new ageing indicators such as methanol or for utilities wanting to start recording oil test results of their in-service transformer fleets.

Data Interpretation and Recommendations

Leading from population analyses, a seasonal influence on moisture measurements was discovered by expressing moisture measurements with respect to months. This could potentially confuse asset managers on the insulation condition interpreted throughout the same year. Better interpretation can be achieved via oil sampling temperature incorporation through the expression of relative humidity. This could be extended to breakdown voltage measurements. Through aggregating results from literature to obtain a generic relationship between breakdown voltage and relative humidity, a change in relative humidity due to temperature incorporation can be reflected into a change in breakdown voltage to revise the original measured value. All these highlight the importance and the need for oil sampling temperature records, which has been advised in IEC 60422 and hence should be more practiced by utilities.

Through analysing in-service oil test measurements of dielectric dissipation factor and resistivity, a mismatch was identified in the condition interpreted based on IEC 60422 recommended value ranges. This suggests the pressing need for revising the current standard for better data interpretation. Besides that, analysis was also performed on a separated treated transformer population that was identified through a combination of statistics and programming. Analysis so far suggested it is better to treat a transformer when it is not too old or when insulation degradation is not too severe to expect a longer usability after oil treatment. It might still be debatable whether inhibitor usage would further prolong transformer usability after oil treatment.

Insulation Condition Ranking

Heath index formulation has always been an interest for asset managers in terms of aggregating information from multiple oil test parameters to guide judgement on insulation condition. An empirical formula is commonly used by utilities for condition assessment but it could depend on expert knowledge, operational and forensic experience that not all utilities have. Two alternatives were introduced which are principal component analysis and analytic hierarchy process. These two techniques were demonstrated to yield a similar output to that of a track-record proven empirical formula. Therefore, utilities without the necessary expertise or resources could adopt these two techniques. As for those that have their own in-house formula, the two techniques could be useful as a reference.

Principal component analysis implementation was observed to be fast, direct and data centred, allowing utilities with or without in-house developed formula a quick way to understand original parameter relation as well as to assess the condition of a transformer fleet. As for analytic hierarchy process, it is capable of incorporating both subjective and objective senses into evaluating the weightings of different parameters in a hierarchical manner. This approach is coherent, easily understood and flexible by allowing changes to the structure or values when more information is obtained or when there is a need for aligning towards a specific asset management strategy.

8.2 Future Work

The databases analysed in this work were contributed by three utilities in the UK. An expansion to current work done would be to incorporate databases and experiences from other utilities in the UK. Such an attempt to form a national database would be helpful not just for obtaining greater confidence in data interpretation from a statistical perspective, but also useful towards facilitating miscellaneous studies that have perhaps hitherto been lacking of comprehensive data or information.

One example study could be a more comprehensive analysis into the influence of transformer loading levels on ageing trends, taking into account exact loading of transformer over a period of time in addition to transformer cooling design information. Furthermore, with significantly greater sample size contributed by all UK utilities, studies can be performed on failed and scrapped transformer populations which are inherently small in sample size as transformers have been fairly reliable over the years.

As utilities are refrained from making large expenditure, oil treatment is one technically and economically feasible way of prolonging transformer fleet usability. More work, either laboratory experiments or data analysis or both needs to be performed to understand the impacts of for instance transformer age, insulation condition and inhibitor usage on transformer usability after treatment is performed.

With alternative liquids (like esters) increasingly used for power transformers, an extension to current work based on mineral oil filled transformer populations is to incorporate knowledge gained from database analysis to help establish an equivalent IEC 60422 standard for alternative liquid applications.

Apart from that, the current approaches to analysing databases could be extended to incorporate fault diagnostic perspective through interpretation of dissolved gas analysis (DGA) records. Some preliminary results from analysing DGA records can be found in Appendix A. Besides that, experience gained from analysing oil test results from power transformer main tank can be applied to other oil test databases pertaining to cables, circuit breakers, instrument transformers, bushings and so forth.

In terms of the insulation condition ranking approaches proposed, which are principal component analysis and analytic hierarchy process, the techniques demonstrated could be also applied to obtain an overall transformer health index (not just insulation condition) or even facilitate reliability evaluations of other power system assets, for instance generators, overhead lines, cables and switchgears.

APPENDIX A: PRELIMINARY WORK ON DISSOLVED GAS ANALYSIS

This appendix reports preliminary findings on dissolved gas analysis (DGA) records. These DGA records correspond to the databases that have also been processed and cleaned. There will be two sections in this appendix. The first involves the report of general observations particularly on median value representations across multiple databases. As for the second section, 90th percentile values from the databases will be compared with the 90% typical values stipulated in IEC 60599 standard, titled "Mineral oil filled electrical equipment in service – Guidance on the interpretation of dissolved and free gases analysis" [241].

A.1 General Observations from Databases

Figure A.1 shows the median value trends with transformer in-service age of hydrogen (H_2), methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), acetylene (C_2H_2), carbon monoxide (CO) and carbon dioxide (CO_2). Median was selected for compact display of representative values from multiple databases as well as its high statistical robustness. Note that CO and CO_2 are only recorded for six out of the eight databases.

The first observation on all the figures shows that there is no influence of the transformer operating voltage level on the gas concentrations, except for acetylene in Figure A.1(e). The acetylene median values for the lower voltage transformer databases are evidently higher which is actually common considering the use of communicating on load tap changer (OLTC) design for some of these lower voltage transformers [241]. In other words, there is sharing of some oil and/or gas between the OLTC compartment and the transformer main tank [241].

Apart from that, it is noted that hydrogen, methane, ethane, ethylene and acetylene are known to be independent from ageing. This is reflected by the analysis on the in-service transformer DGA records in Figure A.1 as well. Nonetheless, interestingly, methane, ethane and ethylene show consistent increasing trends towards the very late stages of ageing. More work is needed to understand the mechanisms or the reasons behind this noticeable increasing trend, particularly if it is a sign of fault evolution.

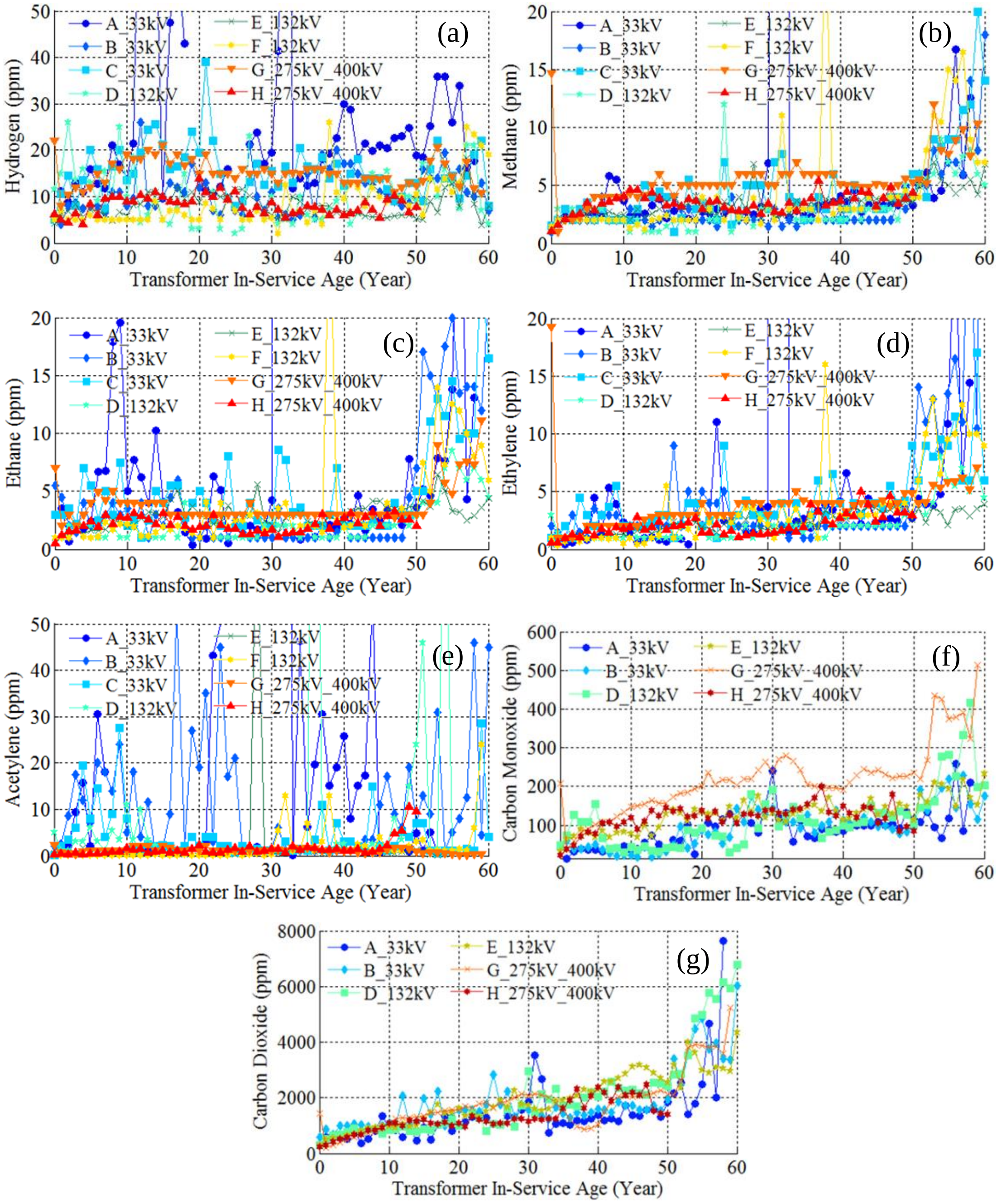

Figure A.1: Median value representation trends with transformer in-service age, (a) hydrogen H_2, (b) methane CH_4, (c) ethane C_2H_6, (d) ethylene C_2H_4, (e) acetylene C_2H_2, (f) carbon monoxide CO, (g) carbon dioxide CO_2

As for the carbon oxide gases, a clear increasing trend can be observed from all the databases. From Section 2.2.2, paper ageing produces carbon monoxide and carbon dioxide gases. Hence, notwithstanding the presence of background gas concentration as transformers analysed are free breathing, the increasing levels of carbon oxide gases observed correspond well to the degradation of solid insulation over time.

A.2 Comparison with IEC 60599 90% Typical Values

In the previous Section A.1, the concentrations of the dissolved gases were represented as median values. Here in this section, as the aim is to compare with the 90% typical values designated in IEC 60599, 90th percentile values will be used in the following study. Table A.1 shows the 90% IEC 60599 typical values [241].

Table A.1: IEC 60599 90% typical value ranges [241]

<table>
<tr><th></th><th>H_2 (ppm)</th><th>CH_4 (ppm)</th><th>C_2H_6 (ppm)</th><th>C_2H_4 (ppm)</th><th>C_2H_2 (ppm)</th><th>CO (ppm)</th><th>CO_2 (ppm)</th></tr>
<tr><td>No Communicating OLTC</td><td rowspan="2">50 – 150</td><td rowspan="2">30 – 130</td><td rowspan="2">20 – 90</td><td rowspan="2">60 – 280</td><td>2 – 20</td><td rowspan="2">400 – 600</td><td rowspan="2">3,800 – 14,000</td></tr>
<tr><td>Communicating OLTC</td><td>60 – 280</td></tr>
</table>

Figure A.2 shows DGA records with transformer in-service age from multiple databases. For each of the gases, IEC 60599 90% typical values range will be enclosed by a black solid horizontal line that represents the lower limit; and a black dashed horizontal line that represents the upper limit.

From Figure A.2, apart from acetylene in Figure A.2(e), the 90% typical values in IEC 60599 are generally too high for the UK in-service transformer DGA experience. For the different gases, the 90th percentile values evaluated at each age for each of the contributing databases are generally lower than the lower limit of the IEC 60599 90% typical value ranges.

This observation is most likely due to how IEC 60599 90% typical value ranges were constructed with the absence of the UK DGA experience. Nevertheless, this is not a major issue in terms of referring to IEC 60599 for condition monitoring. It is mentioned in the standard that utilities are advised or encouraged to evaluate their own sets of typical value ranges [241]. This study based on in-service transformer DGA records contributed by three UK utilities merely serves to consolidate the need for incorporating not just information from international standard but also knowledge on own transformer populations. Table A.2 tabulates the 90th percentile values aggregated from the databases studied.

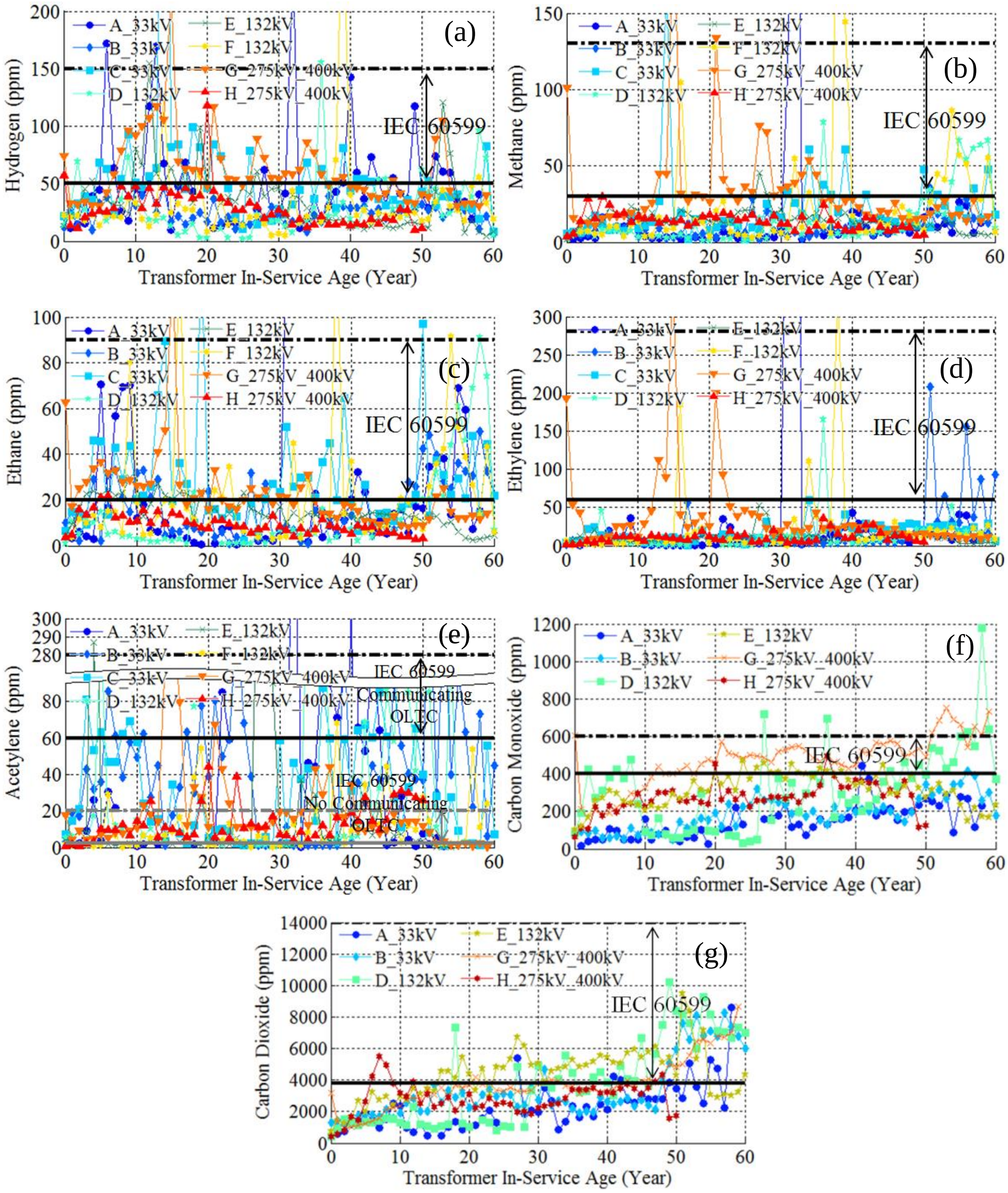

Figure A.2: 90th percentile value representation trends with transformer in-service age, (a) hydrogen, (b) methane, (c) ethane, (d) ethylene, (e) acetylene, (f) carbon monoxide, (g) carbon dioxide

Table A.2: 90th percentile values from databases studied

	H_2 (ppm)	**CH_4 (ppm)**	**C_2H_6 (ppm)**	**C_2H_4 (ppm)**	**C_2H_2 (ppm)**	**CO (ppm)**	**CO_2 (ppm)**
33 kV Databases	38	13	22	17	52	217	3,455
132 kV Databases	30	15	15	10	9	353	4,770
275 kV & 400 kV Databases	56	25	20	25	14	462	3,471

APPENDIX B: LIST OF PUBLICATIONS

Peer-reviewed Journal Papers:

[1] S.J. Tee, Q. Liu, Z.D. Wang, G. Wilson, P. Jarman, R. Hooton, D. Walker and P. Dyer, "An Early Degradation Phenomenon Identified through Transformer Oil Database Analysis," IEEE Trans. Dielectr. Electr. Insul., vol. 23, no. 3, pp. 1435-1443, 2016.

[2] S.J. Tee, Q. Liu, Z.D. Wang, G. Wilson, P. Jarman, R. Hooton, D. Walker and P. Dyer, "Seasonal Influence on Moisture Interpretation for Transformer Ageing Assessment," vol. 32, no. 3, pp. 29-37, 2016.

[3] S. Tee, Q. Liu and Z. Wang, "Condition Ranking of Transformer Insulation through Principal Component Analysis and Analytic Hierarchy Process," IET Generation, Transmission and Distribution, [Under Review], 2016.

International Conference Papers:

[1] S.J. Tee, Q. Liu, Z.D. Wang, G. Wilson, P. Jarman, R. Hooton, P. Dyer and D. Walker, "Practice of IEC 60422 in Ageing Assessment of In-Service Transformers," 19th Int'l. Sympos. High Voltage Eng. (ISH), Pilsen, Czech Republic, Paper 423, 2015.

[2] S.J. Tee, Q. Liu, Z.D. Wang, G. Wilson, P. Jarman, R. Hooton, D. Walker and P. Dyer, "Challenges in Oil Test Database Analysis for Ageing Assessment of In-Service Transformers," 50th Int'l. Universities Power Eng. Conf. (UPEC), Stoke-on-Trent, UK, Paper 110, 2015.

[3] Z.D. Wang, Q. Liu, S.J. Tee, S.Y. Matharage, P. Jarman, G. Wilson, R. Hooton, P. Dyer, D. Walker, Ch. Krause, P.W.R. Smith, P. Mavrommatis and A. Gyore," Ageing Assessment of Transformers through Oil Test Database Analyses and Alternative Diagnostic Techniques," CIGRE SC A2 Colloquium, Shanghai, China, Paper FP0663, 2015.

[4] S.J. Tee, Q. Liu, and Z.D. Wang, "Prognosis of Transformer Health through Oil Data Analysis," TechCon® Euro, 2013, Glasgow, UK, 2013.

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