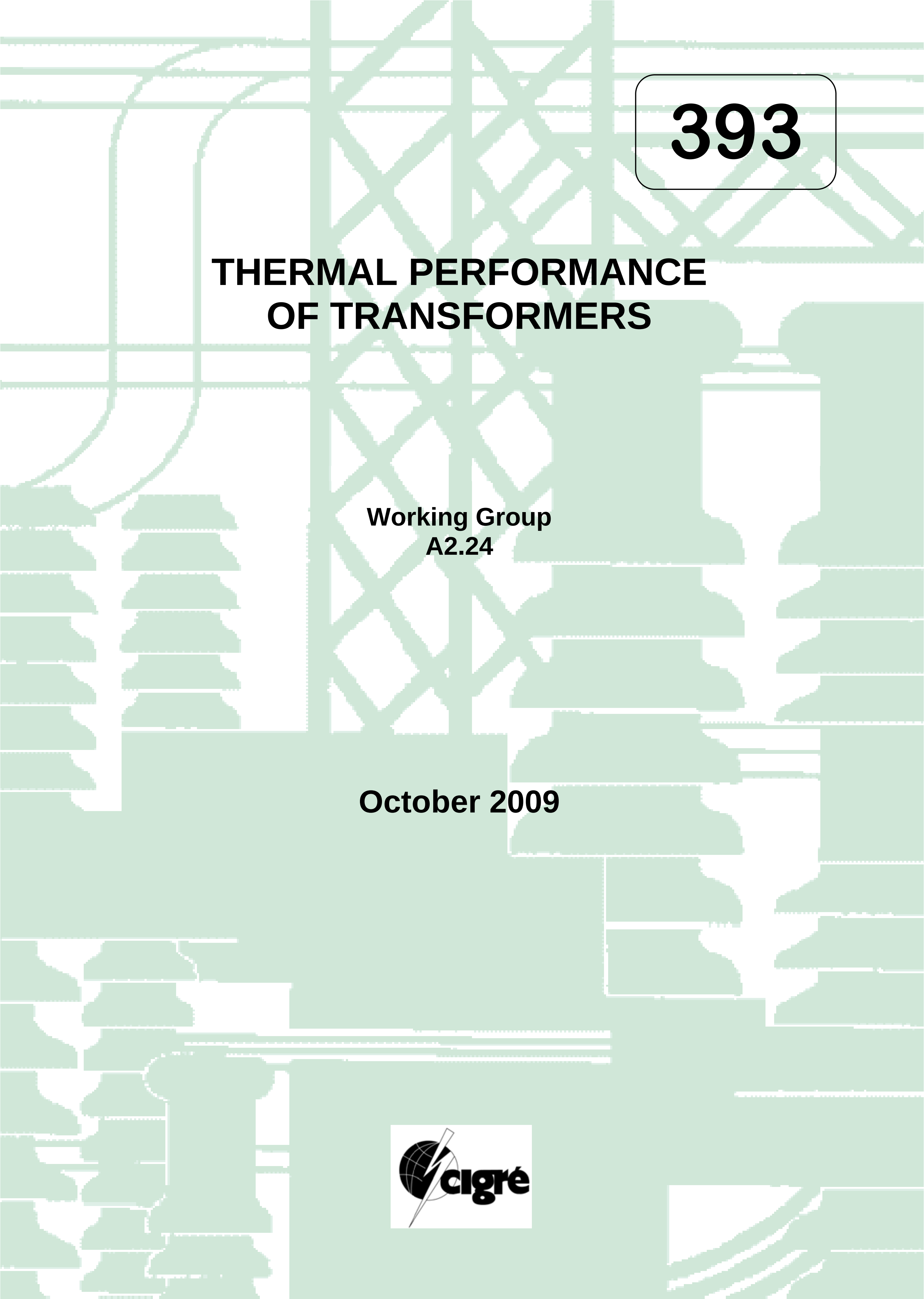

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THERMAL PERFORMANCE OF TRANSFORMERS

Working Group
A2.24

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WG A2.24

Thermal Performance of Transformers

Members

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1. Introduction

1.1. Why Working Group A2.24?

The ability to determine and provide ideas as to how to withstand successfully the stresses that occur in power transformers whether they result from mechanical, electrical, thermal or economic forces has long been the subject of studies and discourse by Cigré. Notable past work by Cigré SC12 and later SC A2 relating to the thermal aspects of transformer design, construction and operation is a matter of record in the many Session papers published by Cigré over some fifty years, in Working Group reports in Electra and more recently Cigré Brochures. Understanding the fundamentals of heat generation, accumulation and dissipation in transformers and the measures needed to ensure adequate practical margins are properly and efficiently included in the manufacture of transformers are topics of long-standing awareness and endeavour by Cigré.

Throughout the whole period of transformer engineering design and construction developments Cigré has kept pace with the step-changes in system voltages and ratings. The first Working Group review by Cigré of the “modern” aspects of transformer thermal performance was initiated in 1986 with the setting up of WG12.09 led by Jacques Aubin. The results of the WG12.09 studies were presented in some eight reports published in Electra between 1990 and 1995 and in Cigré Brochures. This was in addition to those contributions and reports presented at Cigré Sessions.

The central objective of WG12.09 was to review methods to determine safe operating thermal limits for transformers in service. It included recommended best practices to predict and determine hot-spot temperatures under rated and overload conditions at the design stage, during factory temperature rise tests, and in service. The work involved several related parallel investigations to detect and evaluate gases generated during temperature rise tests and in service; to summarise user transformer overload practices; to evaluate transformer life depletion caused by operating temperatures and time; to assess the emerging development of on-line devices to monitor transformers; and to review temperature limits and safeguards and make recommendations regarding calculation methods, “kick-up” factors and particles in oil, as appropriate. The work opened other later avenues of study by Cigré notably the economics and practicalities of transformer life management, the latter being the remit of Cigré Working Group A2.18 under Dr. Sokolov.

The modern economics of transformer purchase and operation means better information and control measures are needed to utilise transformer resources efficiently. These objectives have led to transformer design and construction innovations and materials that further minimise new transformer losses, mass, volume and cost. The same objectives also apply to ageing transformers by highlighting the need for improved understandings of maintenance needs and diagnostic techniques in order to optimise the condition of transformers, maximise their remnant service life and limit potential unplanned outages.

Cigré A2 Study Committee recognised the evolution of these important developments and the extent to which they affected transformer thermal characteristics and performance and in 2003, inaugurated Working Group A2.24 under Dr. Declercq, to review for the benefit of users and manufacturers alike, present day transformer technologies and new materials to determine how these developments can best influence new transformer thermal design and construction and also better assure the operation of transformers in service generally in particular, the considerations that can arise due to ageing transformer populations, such as overloading, monitoring and minimising unplanned outages due to thermal causes. The remit also includes identifying and providing information in support of transformer related IEC

Standards, in particular IEC 60076-2 (Temperature Rise) and IEC TC60076-7 (Loading Guide), and others published by IEC TC10, for example.

WG A2.24 has comprised some twenty-two members and seventeen countries. Seven meetings have been held since its inception. The first meeting was held in Mexico and the remainder have been held in Europe, including a meeting during the A2 Colloquium in Russia in 2005. The tasks set by SCA2 for WG12.24 were also the foundation of Preferential Subject 1 at the Cigré 2004 A2 Session in Paris in 2004, when fourteen papers addressing transformer thermal issues were presented.

The main areas for study and review assigned by SCA2 and set out in its Scope to the Working Group were:

- Fundamentals of thermal ageing
- Rating of new transformers
- Practical applications of the finding to in-service transformers

The first aim has been to establish the state of the art of transformer thermal ageing. This work follows closely upon that done by WG12.18 but also draws on work done by SC D1 and others relating to the ageing of insulation materials and their temperature, moisture, oxygen and acidity dependencies. The ensuing findings directly assist the latest revision of the IEC Loading Guide (IEC 60076-7, formerly IEC 60354).

The second task, to review and update the issues affecting the thermal performance of transformers was in response to the capability and increasing availability of computer programs to evaluate the dynamic thermal behaviour of windings and cooling methods not only under rated load and overload operating conditions but also under transient load conditions like those that can occur during the operation of wind turbine and traction supply transformers, for example. The findings will again assist the development of IEC standards and be applicable to new and existing transformers. These programs have the additional potential to improve the prediction of temperatures attained during factory temperature rise tests and during service operation. The top oil, top radiator and bottom radiator temperatures that are measured at locations remote from the active winding parts during temperature rise tests could be scrutinised more closely by being compared to computer program derived calculated values at those locations predicted in advance. This will provide greater confidence if not confirmation that the thermal conditions within the transformer during the tests conform to design predictions if satisfactory correlation is found.

The third purpose has been to identify any changes that should be made existing practices to increase the utilisation and reliability of transformers by improving for example, cooling methods, oil preservation systems, overloading and dynamic loading capabilities, test requirements and introducing new and improved materials and design techniques. Wherever possible the application of the findings to existing transformers has been a major consideration.

These three objectives have been summarised in the following report under three general headings:

- Ageing mechanisms of transformers
- Diagnostics
- In service transformers

In addition to this Report, an article describing the work that has been undertaken and its accomplishments will be published in Electra. A tutorial has also been prepared for presentation to Cigré and other audiences. The Report is also to be published by Cigré as a Brochure in a format that will address the Report's five chapters: ageing mechanism in transformers, diagnostics, testing, thermal design, and in service units. Examples of temperature rise tests and overloads will also be included.

1.2. History

In 1913 an AIEE Symposium [58] concluded cellulose insulation can endure a temperature of 90°C continuously without deterioration of mechanical properties; can stand 100°C during several years, and wear out at 125°C within several weeks. A thermal limit of 105°C was standardised as result of consensus. In 1930 the principle of "loading with temperature" was suggested, namely that the rate of deterioration increased with each 8^0C increase in temperature (1930) or by 6°C (today).

To determine insulation end of life, mechanical properties such as tensile and burst strength were chosen. A 50% tensile strength retention was chosen for example by the IEEE Transformer Committee for its Loading Guide life plots.

By the late 1920s and early 1930s Kraft paper insulation began to be used in combination with insulating oil in transformers [40].

In the early 1960's Thermally Upgraded (TU) paper was introduced. This is cellulose-based paper that has been chemically modified to reduce the rate at which the paper decomposes allowing higher insulation operating temperatures [40], [45]. It is considered [40] for example, that at 100°C the life of TU paper is several times longer than life of Kraft paper.

On the basis of numerous studies water and oxygen were found to be the most aggressive factors causing acceleration of the rate of cellulose deterioration. This resulted in the introduction of various oil preservation systems preventing water and oxygen penetration into transformers.

Over the years the main approach to determining transformer thermal performance, namely by specifying the average winding temperature rise, hot-spot rise and top oil temperature rise above ambient, has been to verify transformer thermal performance by means of temperature rise tests with direct measurement of top oil temperature, determination of winding temperature by resistance measurement, and calculation of hot-spot temperatures.

In the 1960-70's, two geographically based trends emerged that affected large transformer populations. In North America - an average winding temperature rise of 55C was adopted for transformers insulated with Kraft paper and a temperature rise limit of 65 °C was adopted for oil-immersed transformers using TU paper. Also the introduction of sealed designs (basically nitrogen gas cushions) greatly improved the prevention of moisture and oxygen ingress in operating transformers.
In European countries- the average winding temperature rise adopted for Kraft paper insulated transformers was 55 °C or 65°C (e.g. in USSR and UK) and the oil preservation system in general was the free breathing conservator system utilising a silica-gel breather. Membrane-sealed constructions appeared occasionally by the mid 1970's and later.

In addition, in the USSR for example, all transformers were specified to have a permanent oil regeneration system by means of absorbing filters filled with large-porous silica-gel to remove ageing by-products in the early stages of oxidation.

The above historical background is important to our understanding these matters at the beginning of 21st century. In fact the 20th century understanding of Thermal End of Life was rather a hypothetical one. It was commonly considered that transformer active life should last for 25-30 years and many manufacturers were surprised to learn that thousands of aged units are still in a good health. Despite the fact that huge transformer populations have already been in service for 25-40 years there is still little information available about the units that have failed primarily due to thermal degradation of insulation material.

Apparently, deterioration of transformer fleets is growing significantly as the years pass and without proper actions it would threaten the reliability of electricity supplies with fatal consequences. What tools and methods are available to mitigate ageing phenomena and prevent snowball mode failures are important questions?
For example, is it true that life of transformer would be determined by mechanical life of paper? Is there a convincing confirmation that life of the North American fleet (TU paper, low oxygen) can be substantially longer than life of the European transformer population? Perhaps the deterioration of tensile strength of paper is not so dangerous as traditionally suggested, as conductor insulation is subjected basically to compressive stresses? Is it possible to continue estimating transformer thermal life by considering only temperature without also taking into account water and ageing by-products? Is it sufficient to consider transformer thermal performance on the basis of winding temperature and top oil mean temperature rise? How is the aged state of an operating transformer to be assessed if hot-spot location is unknown and often inaccessible for sampling and observation?

This Report attempts to discuss some of the above questions. It is based on the current work of Cigré WG D1.01, WG A2.24 and on field experience.

2. Thermally induced ageing and failure mechanism’s

2.1. Introduction

The insulation system of a conventional power transformer consists of cellulose (wood, laminated wood, pressboard, paper) and oil. These materials may be treated to improved performance, as for example thermally upgrading insulating paper or inhibiting mineral oils to obtain better oxidation stability. The quality of raw materials (cellulose and crude oil) and processing will change with time. For example, oil refining has been under restrictions on polyaromatics content due to environmental concerns. Stability of new mineral oils is specified in IEC 1125: “Unused hydrocarbon based insulating liquids - Test methods for evaluating the oxidation stability”. For paper there is no IEC test method.

To improve thermal performance other liquids (e.g. esters and silicones liquids) and solid insulation (polyamidimid, aramids) have been introduced. However, high voltage application of these liquids is very limited. (Ref IEC 60076-14, [22])

All these organic materials age. The ageing rates accelerate with temperature (according to Montsinger’s rule doubling for every 6-8°C). Ageing may occur due to several different mechanisms. Cellulose is affected by oxidation, hydrolysis and pyrolysis resulting in reduced mechanical strength. Oil oxidation mainly produces sludge, polar by-products and acids. Lately, it has become apparent that the interaction between oil, copper and paper can cause conductive substances to form. All these processes are interwoven; ageing by products from oil ageing (i.e. low molecular weight acids) may kick-start hydrolysis of paper, and oxidation of paper can be a precursor for hydrolysis. In fact, the situation is even more complicated as catalytic processes involving metal surfaces of copper conductor, core or tank, or substances from other materials (seals, glue etc.) may contribute to the processes. Contact with metals, peroxides and radicals that are formed may start oxidation.

Figure 2-1 shows an attempt to illustrate the drivers, the processes and finally the end products of the chemical ageing of the insulation system.

Consequences of the material ageing can be:

- Reduced mechanical strength of paper and failure due to short-circuit current forces
- Sludge formation and reduction of cooling/clogging of channels
- Formation of copper sulfide with winding short circuit
- Water, particles and polar by-products may reduce voltage withstand along surfaces.

To reduce ageing means reducing access to some of the substances that accelerate the ageing (i.e. water and/ or oxygen). Open breathing transformers will normally have an oxygen content of over 32 000 ppm.

Normally the ingress of water through the conservator is reduced by using moisture absorbers at the air inlet to the conservator. Cold traps or molecular sieves are used for the same purpose. Recently, small vacuum treatment equipments for degassing and dehumidifying the oil have been advocated for reducing oxidation and hydrolysis. However, if the oxidation process is catalytically governed by interaction with metal ions, then quite possibly the ageing rate is not proportional to the oxygen concentration.

The alternative to the open breathing systems used extensively throughout Europe is to seal the oil mass from the atmosphere by a system like those prevalent in the USA. This can be done either by using diaphragms in the conservator or by designing the transformer with a sealed conservator utilising a nitrogen blanket. Sealed oil preservation systems are required for some of the newer liquids e.g. organic esters, which easily oxidise.

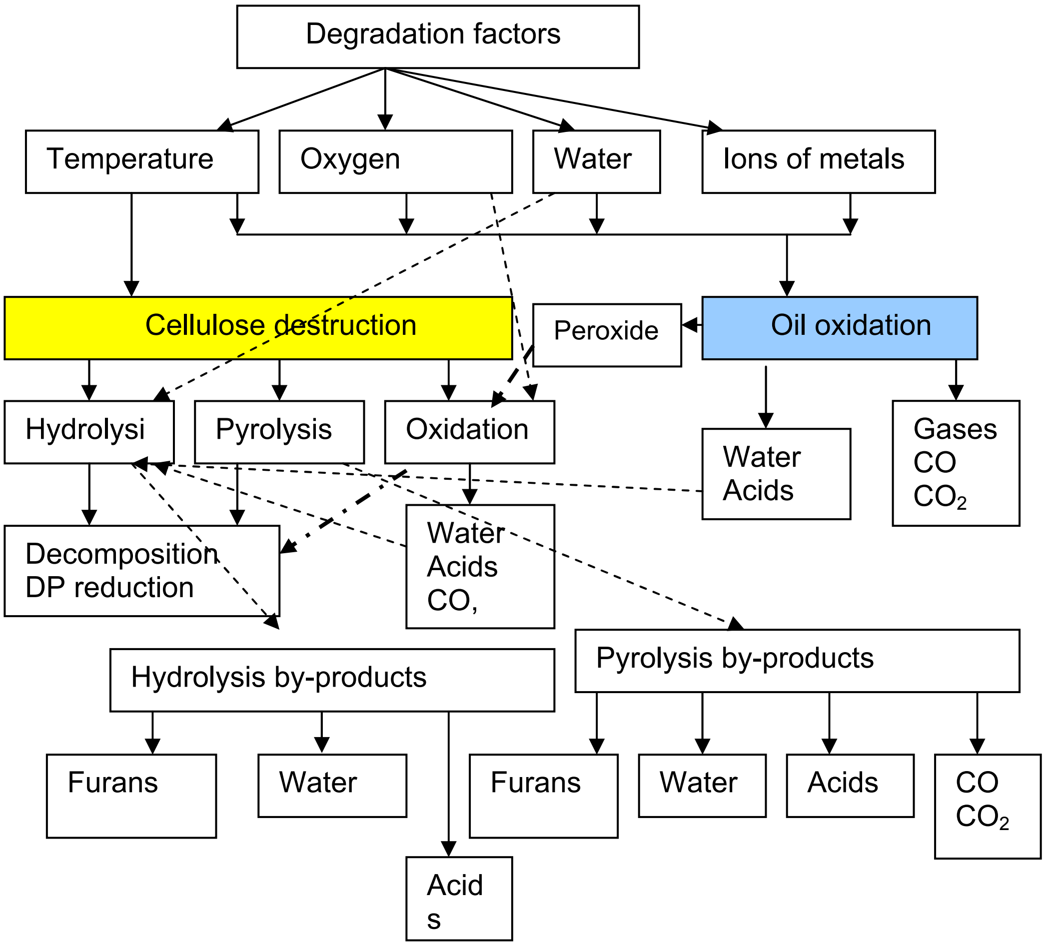


Figure 2-1: Processes involving ageing deterioration [1].

2.2. Thermal ageing of Cellulose

Cellulose materials in form of paper, pressboard and wood are used in transformers. These materials in a transformer serve two purposes:

- Together with the oil they act as electrical insulators for inter-turn insulation (paper), inter-disc insulation and inter-winding insulation (paper, pressboard spaces and barriers). The electrical withstand voltage is not reduced by thermal ageing, but may be reduced by contaminants. In particular, surface contaminants may reduce impulse withstand voltages and PD inception voltages.
- Because the materials are used to provide mechanical support for turns, coils and assembled windings they must be capable of withstanding without failure the stresses that arise from system short-circuit faults, earth quakes and shocks imposed during transport. It is the tensile strength of paper within the clamped winding that prevents a conductor from moving and initiating damaging the insulation. The paper is considered a weak point for shear stresses occurring at winding ends during short circuit. Cellulose ageing is an irreversible process, during which the long cellulose molecules shorten and the tensile strength of paper is progressively reduced. Also, because cellulose has thermoplastic properties it may shrink and deform with time resulting in loosening of winding clamping pressure.

Recently CIGRE WG D1.01.10 published a brochure “Ageing of cellulose in mineral-oil insulated transformers” [6]. The following recapitulates some of the most important D1.01.10 concerns and conclusions.

Mainly unbleached softwood Kraft pulp is used to manufacturing paper and pressboard for electrical insulation. The cellulose is refined from pulped timber by the so-called "sulphate" or "Kraft" process. After processing the typical composition of unbleached Kraft pulp is 78-80% cellulose, 10-20 % hemi cellulose and 2-6 % lignin. Cellulose is a linear condensation polymer consisting of anhydroglucose joined together by glycosidic bonds, Figure 5-2. The cellulose molecules will organize in crystalline and in amorphous regions. The degree of polymerisation (DP) is a number that represents the average number (n) of glycosidic rings in a cellulose macromolecule. It is of the order of 1200 for new unbleached soft wood Kraft. The drying process of the transformer during manufacture will further reduce the DP to around 1000.

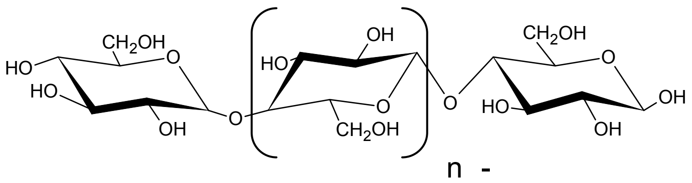


Figure 2-2: Structural formula of cellulose.

Various types of paper and pressboard - having varying density - are made from Kraft pulp. By adding certain nitrogen containing compounds the ageing characteristics of the cellulose may be improved. This is called thermal upgrading.

The purpose of "thermally upgrading" (TU) or "thermally uprating" is to reduce the rate at which the paper decomposes over the lifetime of the transformer. Ageing effects are reduced either by partial neutralization of water forming agents (melamine, dicyandiamide, polyacrylamide) or by inhibiting the formation of water through the use of stabilizing agents (cyanoethylation). The latter method requires modification of the cellulose at the pulp stage and is thus a complicated process and is not used anymore. All processes result in an increased content of nitrogen in the solid insulation, but the treatment is by no means standardised, and the concentration of additives may vary. For the same operating temperature the TU paper shows a lower ageing rate compared to Kraft paper, at least at temperatures above 100ºC, when the same initial conditions, same temperatures, same conditions and laboratory tests are applied. [6].

In a transformer context it is the mechanical strength (usually tensile strength) of the paper that is the essential status indicator, together with freedom from contaminants. A mechanical strength reduction as low as 50% is considered to indicate the paper end of life. Standardised tests can be found in National and International Standards [23], [25] and [57]. They may be of direct or indirect interest for power transformers.

The IEC loading guide [21] accords with Montsinger's equation to determine the life of a transformer, namely,

$$\textit{Life duration} \approx e^{-p\cdot\theta} \qquad (1)$$

where p is a constant (a value 6 is suggested in the range 80-140ºC) and θ the temperature is in degrees Celsius. Here θ for 1 p.u. life is normally taken to be 98ºC at the hot-spot region, and life is supposed to halve/double for every 6ºC increment above or below 98ºC.

This is a simplified version of the Arrhenius law used in IEEE's loading guide [24] which states the per unit life (PUL) can be expressed as:

$$PUL = A \cdot e^{\left(\frac{B}{\theta_H + 273}\right)} \qquad (2)$$

where A and B are constants, θ_H is the hottest-spot temperature, which at design hot-spot gives PUL equal to one. Note: in this case the reference temperature is 110ºC, reflecting the USA practice of using upgraded paper.

As no end-of-life criterion for a transformer is available presently, both guides advocate an approach where ageing rates are considered instead. In the IEC guide this is expressed as:

$$\textit{Rate of ageing} = \textit{constant} \cdot e^{p.\theta} \qquad (3)$$

When this is taken further in a relativistic analysis, in which the ageing rate at a given temperature is compared to that occurring at the actual design hot-spot temperature, then:

$$V = \textit{Ageing rate at } \theta_H \textit{ /Ageing rate at } 98^0C = 2^{\frac{(\theta_H - 98)}{6}} \qquad (4)$$

In IEC 60076-2, 'Temperature Rise' [20], the maximum average winding temperature rise (for ON/OF cooling mode transformers) is 65ºC. With a yearly average ambient temperature of 20ºC, the rated average winding temperature is 85ºC. The IEC Standard assumes normal Kraft paper. It does not give limits for hot-spot as suggested by the IEC loading guide [21]. Users should be aware that loading guides are not Standards, they only provide advice. In IEEE Standard C57.12.00 (2006), [25], the corresponding temperature rise values are 65ºC for the average winding rise and 95ºC for the rated average winding temperature, at a maximum average ambient temperature of 30ºC during any 24 hours period.

It is not easy to measure the tensile strength of service-aged conductor insulating paper of a transformer in service. Furthermore, as it is impossible to take samples from the critical hot-spot region therefore intelligent estimates have to be made using other ageing assessment methods. The measurement of the degree of polymerisation (DP) of paper has become more frequently used than mechanical strength. Figure 2-3 shows a typical correlation between tensile strength and DP value.

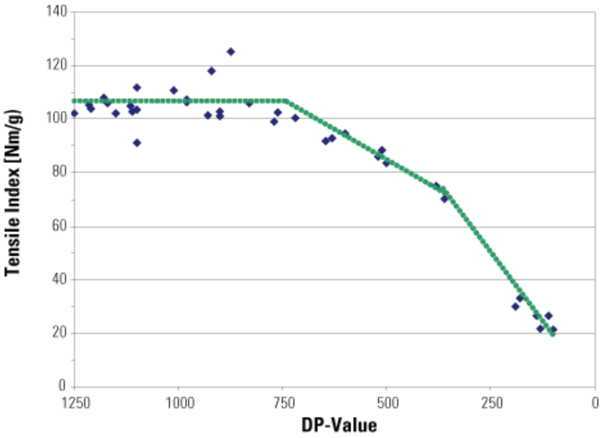


Figure 2-3: Correlation between tensile strength and DP value for Kraft paper [36].

The chain length and DP value of the cellulose is reduced from its starting value (DP_0) due to molecular cellulose chains breaking. The relation between the number of chain scissions (η) and measured DP value after a certain ageing (DP_t) is:

$$\eta = \frac{DP_0}{DP_t} - 1 \qquad (5)$$

The chain scissions may be used as an ageing factor. As an example, if $\eta=5$ the residual DP_t value will be 200, assuming a starting value of $DP_0=1200$.

Another way of looking at this is proposed by Emsley et al. [12]. They show that for limited ageing the tensile index should be proportional with 1/DP. Now 1/DP is proportional to the number of chain scissions η, as shown above. This way of plotting was attempted on the same dataset as shown in Figure 2-3, and showed a fairly linear relationship between ageing and functionality of the paper. This way of plotting serves as a good illustration of the importance of DP and chain scissions. The number of chain scissions is proportional to ageing rate and elapsed time as explained below.

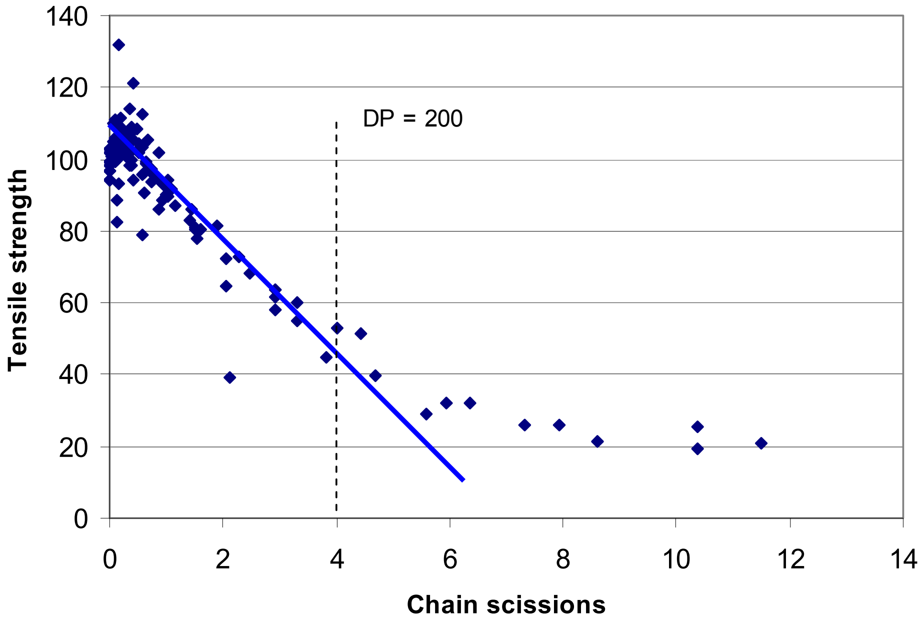


Figure 2-4: Tensile index versus number of chain scissions.

Change of polymerisation of paper is often described by the following Arrhenius relation [11]:

$$\frac{1}{DP_t} - \frac{1}{DP_0} = \frac{\mu}{DP_0} = A \cdot e^{\frac{-E_A}{RT}} \cdot t \qquad (6)$$

Here, R is the molar gas constant (8,314 J/mol/K); T the absolute temperature in Kelvin and E_A is the activation energy in kilojoules per mole. The ageing rate of the cellulose is expressed as k = A•*exp* (-E_A/(R•T)). The pre-exponent value A is a constant depending on the chemical environment. In an Arrhenius plot, the natural logarithm of the ageing rate (In k) is plotted against the inverse absolute temperature (1/T) and a straight line is obtained as shown in Figure 2-5 – illustrating how the ageing rate depends on temperature. The condition for achieving a straight line is that it is the same ageing process over the whole temperature range. The activation energy describes how much the reaction rates depend on temperature; if the ageing process is independent of temperature the activation energy is zero and the line becomes parallel with the X-axis, while if it increases fast with increasing temperature the line falls quickly. One should bare in mind that A and E_A values comes in pairs. In principle E_A is the slope of the line in Figure 2-5, and the A-value is the value of interception with the Y-axis, occurring for 1/T equal to 0 (which of course is an impossible value that would occur for infinitely high temperatures). The point is that a small change in slope will influence the A-value a lot.

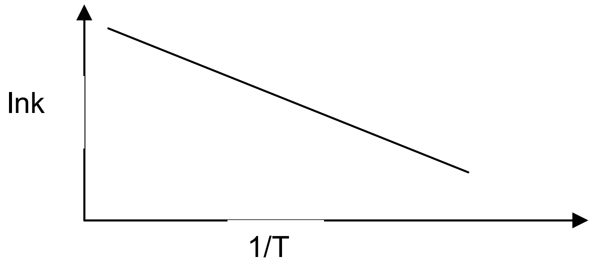


Figure 2-5: Arrhenius plot

It is now commonly accepted that cellulose ageing may be described by the following processes:

- Oxidation
- Hydrolysis
- Pyrolysis

As all these processes have different activation energies acting simultaneously, the Arrhenius plots often ends up non-linear. Furthermore, in real life there will often be synergetic effects between the different mechanisms.

Care should be taken that any accelerated laboratory test replicates service conditions. Tests performed at elevated temperatures (e.g. 140°C) to accelerate ageing can result in misleading results. For example, liquids will have increased water solubility at high temperature and will dry out cellulose to an unrealistic low levels thereby reducing hydrolysis, compared to ageing at service conditions e.g. at 70-80°C, where in almost all cases most of the water will remain in the cellulose.

The following sections examine further the issues governing the three main cellulose-ageing mechanisms – oxidation, hydrolysis and pyrolysis. Even if the mechanisms in practice are interconnected it can facilitate an easier understanding when treating them separately.

2.2.1. Oxidation of Cellulose

Oxidation is one of major mechanisms of paper ageing. The oxidizing agent in this environment is oxygen from air ingress. The ultimate end products of oxidation are much the same as for combustion, i.e. water and carbon dioxide. The mechanism of low temperature oxidation is quite different from that of combustion, though, and a larger variety of formed substances must be considered. The oxygen concentration is of course an important parameter in determining the rate of oxidation. However, most experimental studies show that the ageing rate is not so strongly influenced by oxygen content. Oxidation is suggested to be catalysed by hydroxyl radicals (HO^*), which are produced by decomposition of hydrogen peroxide (H_2O_2) and of organic hydro peroxides (ROOH). As oxygen is needed to form peroxides it is important, but probably not the rate controlling substance. Hydrogen peroxide can for example be formed from oxygen and water though a reaction catalysed by transition metal ions (such as $Cu^+/Cu^{2+}/Fe^{2+}/Fe^{3+}$). Hydroxyl radicals are formed from peroxides by reactions catalysed by small amounts (or traces) of auto-oxidisable compounds like phenols, aromatic amines and thiols.

In laboratory experiments, typically, the overall degradation rate from oxidation will be no more than double in experiments with oxygen present, compared to experiments where oxygen is totally excluded. We can therefore assume that the importance of oxygen is limited in the temperature range relevant for service operation. In general oxidation will show lower activation energy than hydrolysis. Values in the range of 80 – 90kJ/mol can be calculated from early experiments performed with and without oxygen [32]. In later experiments where copper dust has been added to facilitate radical formation more easily, values around 50kJ/mol have been found [30]. As the activation energy is low then the ageing rate does not fall so quickly with reduced temperatures and at low temperatures oxidation may therefore become dominating. It is assumed this could be the case in the temperature range below 60ºC. Oxidation is promoted in an alkaline environment, and as this process also produces carboxylic acids, it will attenuate with time. The details of the oxidation process are less understood than for the hydrolysis.

For oxidation, thermally upgraded cellulose based papers showed no big advantages compared to normal Kraft paper [32].

Oxidation of cellulose through dissolved oxygen

4 steps of oxidation are proposed:

- Oxidation of a primary OH group to aldehyde and one water molecule;
- Oxidation of a secondary OH group to carboxyl and acid with no additional water;
- Oxidation of a secondary OH group to Cetogroups + two water molecules;
- Unanimous oxidation of secondary OH groups to aldehyde + one water molecule that may follow with the scission of a ring. This is the least probable case.

This type of oxidation is not considered to directly cause de-polymerisation of cellulose, but contributes significantly to acceleration of hydrolytic destruction.

2.2.2. Hydrolysis of Cellulose

The hydrolysis of cellulose is a catalytic process where the reaction rate depends on acidity; that is H^+-ions (or rather H_3O^+, because the proton immediately is associated to a water molecule) from carboxylic acids dissociated by surrounding water molecules. These H^+-ions can easily get into the amorphous zones of the cellulose. The process of decomposition needs both water and acids. The activation energy of hydrolysis is found to be in the range of 110kJ/mol by many research groups. Apparently, hydrolysis is the dominant mechanism in the upper range of transformer operating temperatures. The environmental factor (A) depends on the dissociation constant for main acids, the amount of acids (q), and water content (α). It is also shown that the lower the molecular weight of the carboxylic acids is the more detrimental it is [34]. As hydrolytic degradation of cellulose produce water and low molecular acids this process is auto-accelerating.

For pure Kraft paper it is found that an activation energy in the range E=95-111kJ/mol shows the best correlation with laboratory experimental data. As explained, for hydrolysis the A factor will depend on several factors. How it depends on the water concentration in paper is shown in Figure 2-6a. The effects of acids are more uncertain. Figure 2-6b shows that large oil-like carboxylic acids as stearic and naphthenic acids hardly change the ageing, while the low molecular weight acids, which also are easily water soluble, accelerate ageing. From Figure 2-6a, it appears that reduced water content in the cellulose will reduce ageing. This is found due to a reduced dissociation of low molecular acids. From this one could search for the water free transformer. However, this is impossible in practice. For new transformers a good and low water content is in the 0.5% range.

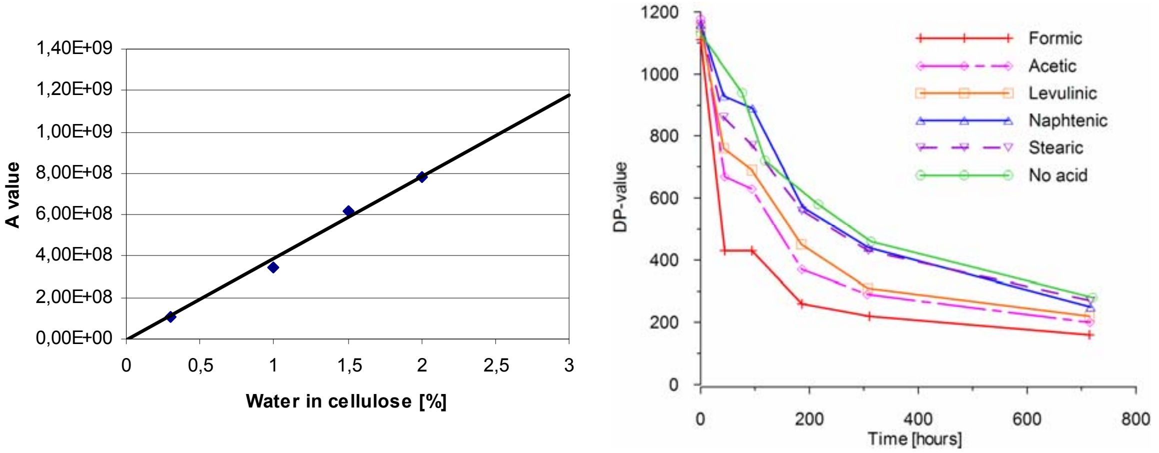


Figure 2-6: (Left) A value dependence on water in paper for activation energy 111 kJ/mol [13], [36]. – (Right) Acid influence on DP-reduction from hydrolysis [37].

Still there are no valid formulae for including acidity into the A-value. However, it appears that the synergetic effect of water and acids can be seen as largely multiplicative and depending on the molecular weight of the acids, being worse the smaller they are. When comparing the effects the three acids have over the range 70-130ºC one gets factors as shown in Table 2-1. In this case the concentrations of acids in paper was in the range of 6mg KOH/g paper, which is quite high - but not extremely high - compared to what is expected for older aged transformers. Furthermore, we know that these acids are found in aged transformers. However, it must be stressed that further work is needed to identify relevant acids types and concentrations for field aged materials. From Table 2-1 we can see that by increasing water content from 0.75% to 2.5% the ageing rate increased by a factor of two, while a factor of three would have been expected from Figure 2-6a.

Table 2-1: Acceleration factor A for low molecular weight acids compared to conditions without acids [56].

Acid type	**Formic**	**Acetic**	**Laevulinic**
Dry cond. (0,75%)	5,6	2,6	1,6
Wet cond. (2,5%)	11,6	4,4	3,0

Present Standards for measuring acidity of oils and paper do not appreciate the importance of the molecular weight of the carboxylic acids measured in an oil sample. The acid number or neutralisation value sums the effects of all acids. One can obtain an idea of the concentration of the low molecular weight acids by first measuring the acidity in a conventional way and thereafter “clean the oil with water” and repeat the measurement on the oil after the water has sedimented out. Only high molecular weight acids will remain and the difference is due to the low molecular weight acids. Such measurements have a potential to serve as a diagnostic indicator of the state of the cellulose insulation.

Thermally upgrading of paper may reduce the ageing rate by a factor between 1.5 and 3. The ageing acceleration from the presence of water is seen to be strongly reduced for the upgraded paper. There is still some uncertainty about the activation energies, and which process dominates ageing for these paper qualities. The reduced sensitivity for hydrolysis is in line with theories presented by Bauer et al. [3], and is supported by two larger investigations performed by Shroff [53] and Lundgaard [32]. In these investigations paper from two different manufacturers (processes) were used.

2.2.3. Pyrolysis of Cellulose

Thermal destruction causes the breakage between rings directly. This is a process that can take place without access to water and/or oxygen, or any other agent to initiate the decomposition. Pyrolysis requires high activation energy – usually over 250kJ/mol and can dominate at high temperatures – usually over 150°C. It is not associated with ageing in a normal sense, but rather what may result from thermal defects like poor soldering, stray losses at bolts etc.

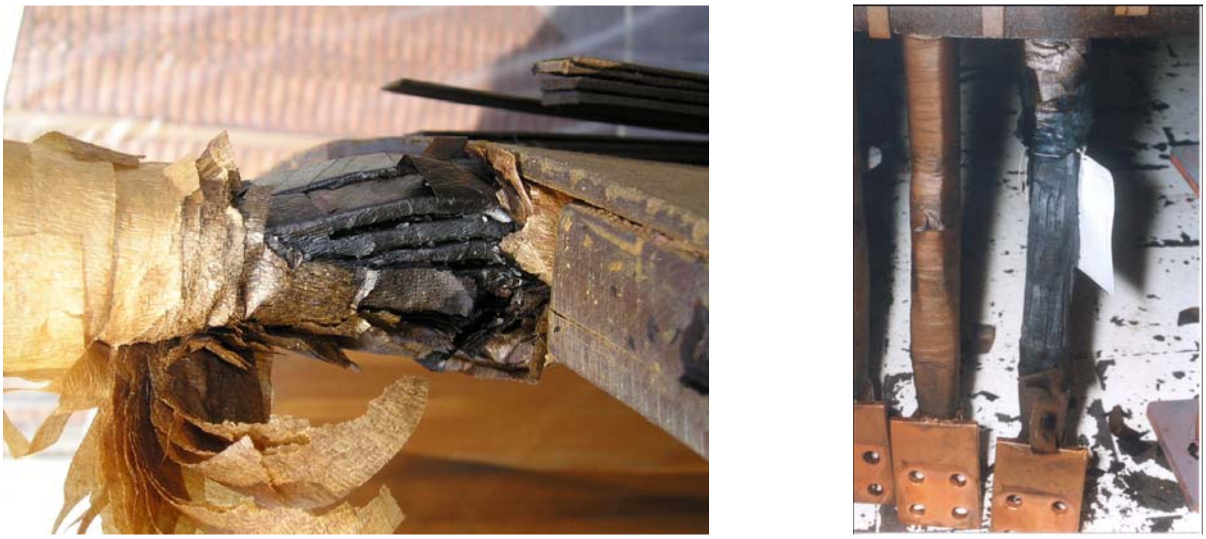


Figure 2-7: Predominantly pyrolytic destruction of overheated leads insulation.

2.2.4. Interaction of cellulose ageing processes

In a real transformer all these processes – hydrolysis, oxidation and pyrolysis act simultaneously, resulting in a non-linear Arrhenius plot that hampers simple application of one single activation energy and description of the full complexity of the degradation processes. Which process will dominate depends on temperature and conditions. Probably also synergetic effects take place between the different reactions; e.g. oxidation may activate hydrolysis. However, for illustrative purposes here independent processes will be assumed. The total degradation can then be described as the sum of degradation from each process:

$$\eta_{Tot} = DP_0 \left(A_{Oxi}\, e^{\frac{-E_{Oxi}}{R \cdot T}} + A_{Hyd}\, e^{\frac{-E_{Hyd}}{R \cdot T}} + A_{Pyr}\, e^{\frac{-E_{Pyr}}{R \cdot T}} \right) \cdot t \qquad (7)$$

where O*xi*, H*yd* and P*yr* are used as subscripts to identify the activation energy E and the environment factor A for the singular processes mentioned above. Somewhat simplified, one can say the degradation rates from these reactions will depend on activation energy and the environmental for each process at the given temperature. The ageing rates dependence on temperature will vary depending on which process dominates in the specific region as suggested in Figure 2-8.

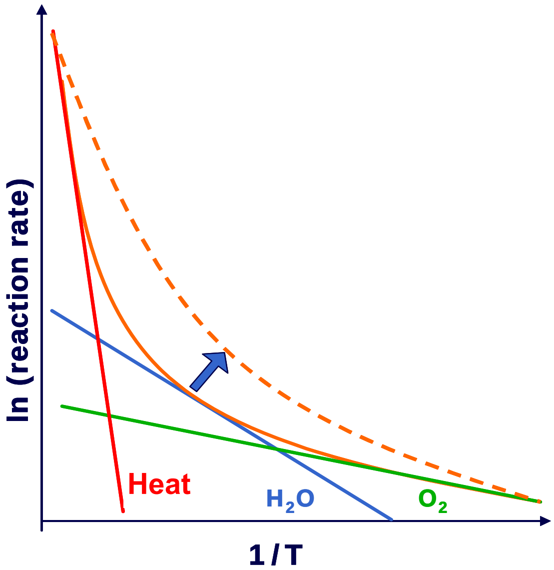


Figure 2-8: Sketch of ageing rates due to different ageing mechanisms. The arrow shows the effect of increased water content increasing the A-factor for hydrolysis.

We have indicated activation energy around 50kJ/mol for oxidation in presence of metals, 80-90kJ/mol for oxidation without, 110kJ/mol for hydrolysis and 250kJ/mol for pyrolysis, where only the first two are of technical interest for long-term ageing. In Table 2-2 we compare this with Montsinger's suggested temperature changes for doubling of the ageing rate. One should be very aware that the E values discussed above are very dependent on the activation energy as shown in the equation above.

Table 2-2: Correlation between activation energy and temperature shift for halving of life. This is only valid in a limited temperature range around maximum operating temperature.

Activation energy [kJ/mol]	50	70	90	110	130	150
ΔT (50%) [°C] at 98 °C ref.	16,2	11,4	8,8	7,2	6,1	5,2

In general the overall picture is largely as follows:

- For new well-dried transformers with Kraft paper, ageing doubles for every 7,5ºC. If the transformer has access to oxygen life may be halved. If water accumulates in the insulation, life may be reduced significantly. 2% water reduces life about a factor of 8. Low molecular acids will further amplify this. Removing water and acids will slow down the ageing rate.
- Upgraded paper seems to extend insulation life by a factor of 3 at least at higher temperatures. This paper quality seems to have better resistance towards hydrolysis, but does not give any significant reductions for oxidation.

When assessing the "thermal life span" of a transformer under normal operation conditions one should consider hot-spot temperatures and time of operation, as well as moisture and acids content.

Life assessment considerations based only on the effects of temperature leads to substantial overestimation of inherent life. On the other hand, using average conditions of insulation contamination may result in an underestimation of end-of-life because conditions at the hottest spot will be less severe than the average: Elevated temperature in oil cooling ducts maintains lower relative moisture content of oil in contacting with conductor insulation, leading to drier cellulose here. For example, in a transformer with moisture content of 20µg/g at average conditions of 60°C, the moisture in paper will in average be around 2% (by weight), while at a hotspot being at 90°C the water concentration in the paper would be only 1% (by weight). This is due to partitioning shifting with temperature.

It is considered the Arrhenius correlation shown in equation (6) is advantageous compared to the IEC approach of life halving, because it reflects also the condition of the materials. As explained earlier: the left side of this equation is proportional to the average number of chain scissions that determines the mechanical strength of the paper. The left side expression is the product of the ageing rate and the elapsed time. The ageing rate is determined by the A factor that depends on the contamination level, by the activation energy for a specific ageing process for a specific material, and by the temperature. The only sources for determination of these parameters are laboratory experiments, and giving figures for service ageing is a hazardous project, even more so as the processes are synergetic. Below, as an example, some values are suggested that can be used for comparison with evidence from service-aged units, and also for appreciating the importance of the chemical condition of the insulation system.

In the early 1990's Emsley et al. [13] reviewed existing literature and suggested that E_A was the about the same for all the processes (111 ± 6 kJ/mol), but that the contamination factor A varied as shown in Table 2-3. These data can be used for assessing the influence of environmental factors. One problem with these data is that they describe an average ageing rate found from experiments with varying progress of ageing and often at quite elevated temperatures compared with service conditions. It is known that ageing rates tend to fall off with increasing number of chain scissions of the cellulose molecules.

Table 2-3: A values from Emsley et al [13].

Insulation condition	A – values [hour $^{-1}$]	95% confidence on a values	
Upgraded paper in oil	$3.65 \cdot 10^7$	$7.93 \cdot 10^6$	$1.68 \cdot 10^8$
Dry paper in oil	$1.07 \cdot 10^8$	$2.41 \cdot 10^7$	$4.71 \cdot 10^8$
Kraft paper with 1% water in oil	$3.50 \cdot 10^8$	$8.41 \cdot 10^7$	$1.46 \cdot 10^9$
Kraft paper with 2% water in oil / Paper in air	$7.78 \cdot 10^8$	$1.83 \cdot 10^8$	$3.30 \cdot 10^9$
Kraft paper with 4 % water in oil / Paper in oxygen	$3.47 \cdot 10^9$	$7.68 \cdot 10^8$	$1.57 \cdot 10^{10}$

Later research at SINTEF has revealed that the temperature dependence is different for oxidation and hydrolysis [14], [33], [34] and [35]. The experiment reported in [33] after two years was continued a further three years. The data has now been further processed and reaction rates for the different conditions calculated from the initial ageing up to around one chain scission (DP going from 1250 to 600) when that was possible. For some of the experiments at lower temperatures ageing could be lower. From the ageing rates the average activation energy over the range from 70 to 130°C was calculated and A-values estimated for each single case based on 1st order ageing models. Then the average A-value for each specific contamination condition was calculated. Figure 2-9 shows Arrhenius plots of how the experimental values fit with the 1st order ageing model during the initial ageing period.

Table 2-4: Activation energy (E_A) and environment factor (A) for oxidation and hydrolysis of Kraft cellulose based on experiment described in [33] and [35].

Parameter	Dry, no oxygen.	1,5%-moisture	3,5%- moisture	Dry, Oxygen. access
E_A-value [kJ/mol]	128	128	128	89
A-value [hour $^{-1}$]	$4{,}1{\cdot}10^{10}$	$1{,}5{\cdot}10^{11}$	$4{,}5{\cdot}10^{11}$	$4{,}6{\cdot}10^{5}$

Table 2-5: Activation energy (E_A) and environment factor (A) for oxidation and hydrolysis of Insuldur upgraded Kraft cellulose based on experiment described in [33] and [35].

Parameter	Clean system	1,5%-moisture	3,5%- moisture	Dry, Oxygen. access
E_A-value [kJ/mol]	86	86	86	82
A-value [hour $^{-1}$]	$1{,}6{\cdot}10^{4}$	$3{,}0{\cdot}10^{4}$	$6{,}1{\cdot}10^{4}$	$3{,}2{\cdot}10^{4}$

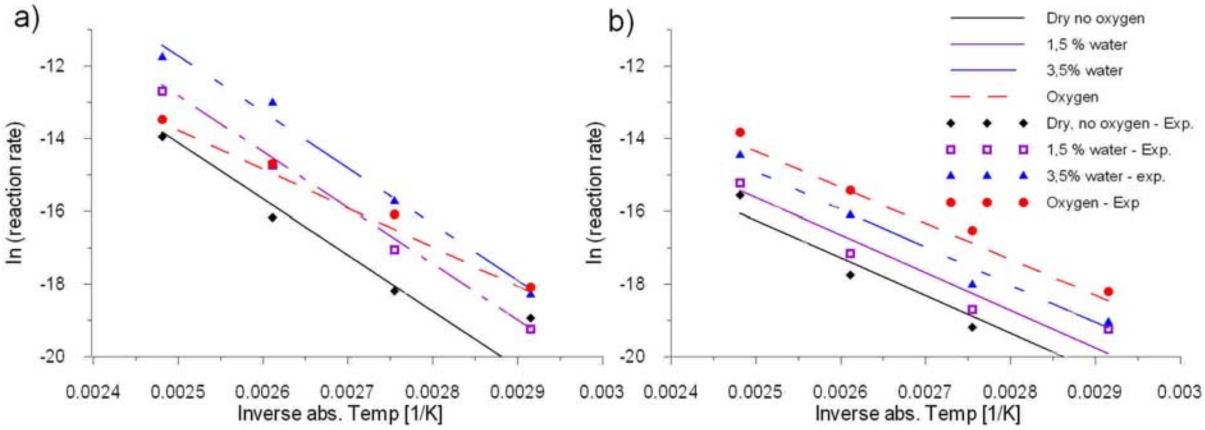


Figure 2-9: Arrhenius plots of ageing of (a) Kraft paper (Munksjø termo 70) and (b) Thermally upgraded paper (Insuldur).

The effects of acids are still under investigation, but there is every reason to believe that the 'A' factor will be proportional to the water concentration and the content of low molecular water-soluble acids. The concept of differentiating between activation energy for hydrolysis and oxidation is supported by CIGRE [6]. The values given in Table 2-4 and Table 2-5 should be considered as unconfirmed and may be disputable. However, the figures give a reader possibility of playing a little with different ageing scenarios. Again one should remember that even for the sake of simplification, if we differentiate between the oxidative and hydrolytic processes, they will in reality occur in a synergetic way. The models fit quite well for Kraft paper, while for upgraded paper the data does not really support one singular model, from the values of the activation energy found for this paper it seems that hydrolysis is suppressed and that oxidation seems to dominate.

Many laboratory studies refer contamination to the initial conditions. In practice conditions will develop with increasing water concentration and acidity. It is still a problem to identify the ageing rate for a certain condition to the specific ageing condition (i.e. DP value). It is known that ageing rates fall off while contamination increases. The expectation would have been that they would increase. The fact that the ageing appears to slow down is explained by consumption of locations that are readily aged (Amorphous regions) leaving less spots for ageing to occur in paper fibres where crystalline regions become dominating.

2.3. Thermal ageing of oil

IEC test methods and maintenance guides for oil involve the following considerations:

- Inhibited vs. uninhibited oil
- Sludge and acidity and interfacial tension, resistivity/loss factor and inhibitor consumption as ageing descriptors
- Checking descriptors vs. temp gives Arrhenius relations (challenge)
- Composition
- Corrosivity
- Change in production giving reduced sulphur and polyaromates
- Radicals – metals

Oil ageing occurs at high temperature under impact of molecular oxygen and the electrical field surrounding transformer materials. The most important aspect of this ageing is the oxidation of hydrocarbons and other components.

2.3.1. Oxidation of Oil

The auto-oxidation of hydrocarbons (like mineral or vegetable oil) is brought about by the combination of heat and exposure to oxygen. The process can be inhibited by different types of anti-oxidants, but it is also catalysed by for example, metal cations. The process is often referred to as peroxidation because it is mediated by hydroperoxides which take part in radical chain reactions to produce different oxidation products.

The process starts with thermal generation of a hydrocarbon radical which quickly reacts with available oxygen to form a peroxy radical. This radical in turn abstracts a hydrogen (generating another radical) to form a hydroperoxide. The formed hydroperoxides can decompose to form new radicals and the first generation of oxidation products such as alcohols, aldehydes and ketones. The decomposition rate is very temperature dependent and also dependent on present catalysts such as metal cations. When the content of metal ions is low, the peroxide decomposition rate is doubled for each rise of 9-10°C in temperature. When the content of metal ions is already high, the reaction is almost independent of temperature.

Further oxidation then leads to the second generation oxidation products which include carboxylic ester and acids as well as carbon dioxide. The mechanisms, although in principle well understood (Denisov, Afanas'ev, 2005), are very complex. There is only one way in which radicals can be destroyed, which is to react with another radical. All other reactions generate new radicals that continue the chain reaction. Sludge (material not soluble in oil) can be formed through various paths including condensation reactions, polymerisation and salt formation.

Dissolved transition metal cations such as those of copper and iron catalyse peroxidation of hydrocarbons. They do so through a mechanism where a metal cation of a lower oxidation state is first oxidised by a hydroperoxide. The result is formation of a metal cation of a higher oxidation state, a hydroxyl anion and a highly reactive hydroxyl radical. At this point the electron rich oxidised metal cation can donate electrons to yet another hydroperoxide molecule that then disproportionates into hydrogensuperoxide (a.k.a. hydroperoxy radical) and a proton. The net reaction is that two hydrogenperoxide molecules have been turned into two radical species and water. The metal cation is not consumed and therefore the reaction is truly catalytic as the oxidation rate increases dramatically even when the metal ion concentration is present in very low concentrations. This process is known as a Fenton-type reaction after H.J.H. Fenton who developed this chemistry for oxidation of various organics in the 1890s.

Molecules that inhibit the chain reaction of peroxidation are called antioxidants. There are two different modes in which these can act. So called hydrogen peroxide decomposers act by reducing hydroperoxides to harmless alcohols. These compounds include various sulfur compounds that can be found in mineral oils. There are also so called chain-breaking antioxidants which react with formed radicals and stabilise the resulting radicals. The result is a much slower, or totally inhibited, oxidation process. This group includes hindered phenols such as DBPC, a synthetic inhibitor that is added to some grades of transformer oil. Both types of antioxidants are eventually consumed, but the time this takes depends on temperature and oxygen availability as well as on chemical composition of the oil.

Simplified oxidation model proposed by Prof. Lipshtein (Figure 2-10). Successful attack of the oxygen results in its combination with at least one free radical R* + * O ® R: O-O, which triggers the process.

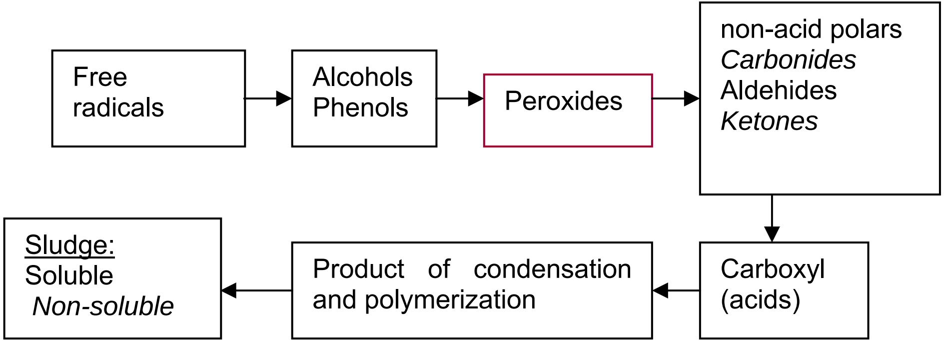


Figure 2-10: Model of oil oxidation based on attack of dissolved oxygen (By Prof. Lipshtein).

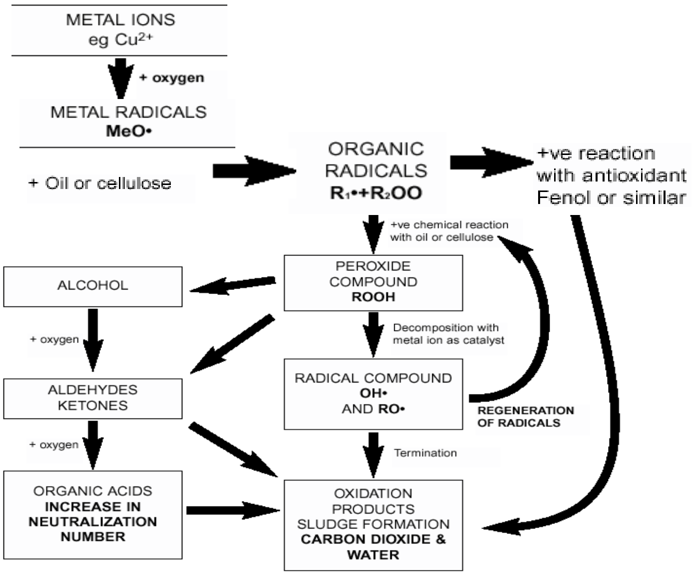


Figure 2-11: Model of oil oxidation based on attack of dissolved oxygen and ions of metal (By Prof. R. Agnemo).

Prof. R. Agnemo found that the dominant processes under the impact of oxygen and metal ions, are reactions which create metal radicals. Metal radicals are the ignition for the degradation of the cellulose and oil. They react very quickly to form ultimately organic radicals and peroxides from oil and cellulose. These organic radicals will, with a few reaction steps degrade the oil or cellulose into a number of products like low molecular acids, carbon dioxide and water.

The antioxidant additives in the oil can react with radicals and reduce the production of new peroxides. The antioxidants are consumed all the time but will last longer in oils with low oxygen levels. Organic peroxides further decompose into organic radicals.

Antioxidants are naturally present and also added to some new oils. They migrate to the cellulose, reduce peroxide formation and protect both oil and possibly also to some degree the cellulose from fast degradation. In spite of antioxidants, oxygen remains the most negative substance in this context. Without dissolved oxygen no oxidation can take place, therefore, the lower the oxygen content the better. However, it is still an open question whether the ageing rate is proportional to the oxygen concentration or not. As the process is catalytic one may expect that such a simple correlation does not exist. If the oil has a high content of heavy metal ions the oxidation rate is higher.

2.3.2. Copper Sulfide Formation in Insulation

Recently failures have occurred in transformers due to formation of copper sulfide, which is conductive. Predominantly non-inhibited oils are involved, but also inhibited oils have shown a tendency to copper sulfide formation. Also oxygen lean conditions using barriers in conservators have been a common denominator. It is a general pattern that the temperature of the failed units has been high, though not exceeding design values. Some further observations on the units with copper sulphide formation are:

- Temperature is the most important influential factor for all chemical reactions, including copper sulfide formation.
- Potentially corrosive sulfur is activated even by moderate ageing of oil (far from fully understood how, though)
- Variations in oil flow may influence not only via temperature, e.g. restricted oil flow may cause local depletion of oxygen and build-up of ageing products
- N.B. Even though temperature is obviously important, it is evident from dissections that temperature is not the only factor to decide location of copper sulfide deposits

Cigré WG A2.32 has worked on methods for identifying potentially corrosive oils, [9]. The method is an extension of earlier copper strip corrosion, where a layer of paper on the copper is introduced and the corrosivity is based on both copper and paper discoloration.

2.3.3. Impact of Inhibitor on Oil

Life of oil might be determined with Induction Period, namely with the time when oil retains resistance to oxidation process considering impact of temperature, oxygen, copper and electrical field until production of acids and sludge reaches an unacceptable rates at the end of induction period. The induction period, which guarantees normal life span might be considered e.g. as a time of oxidation at 120°C to formation of volatile acids of 0.05 mg KOH/g, and end of life –formation of volatile acids of 0.25-0.28 mg KOH/g.

Apparently the oil should not produce substantial amount of conductive by-products during the Induction Period.

Different oils meeting the same specification show different life courses. The presence of a natural inhibitor plays a significant role in retarding oxidation rates. Some inhibited oils start to deteriorate rapidly just after the inhibitor is consumed, Figure 2-12, Oil A).

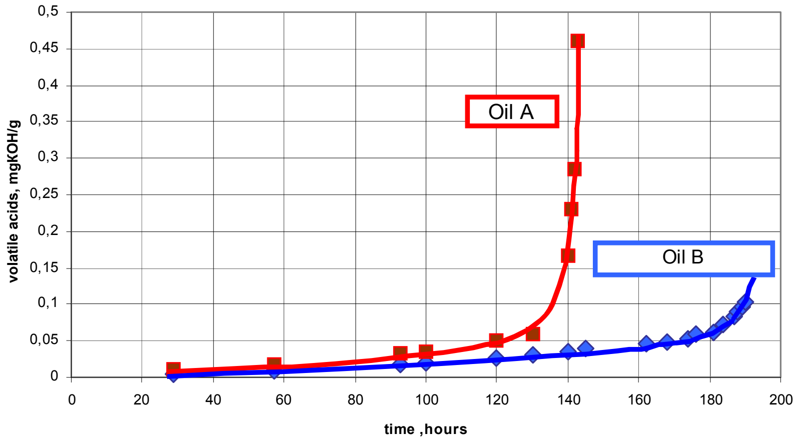


Figure 2-12: Course of life of two inhibited oils that meet IEC 60296.

The particular tested parameter is susceptible to the particular by-product. Different oils form different amount of by-products. For example, oils in service with fairly acceptable interfacial tension and acid numbers may reflect a significant amount of reactive non-acidic polar compounds detected by infrared spectroscopy.

The conditions under which sludge could form are not always readily apparent. Even with low acid numbers (<0.05 mg KOH/g) low stability oil form sludge (Figure 2-13) that under influence of strong electric fields deposit locally.

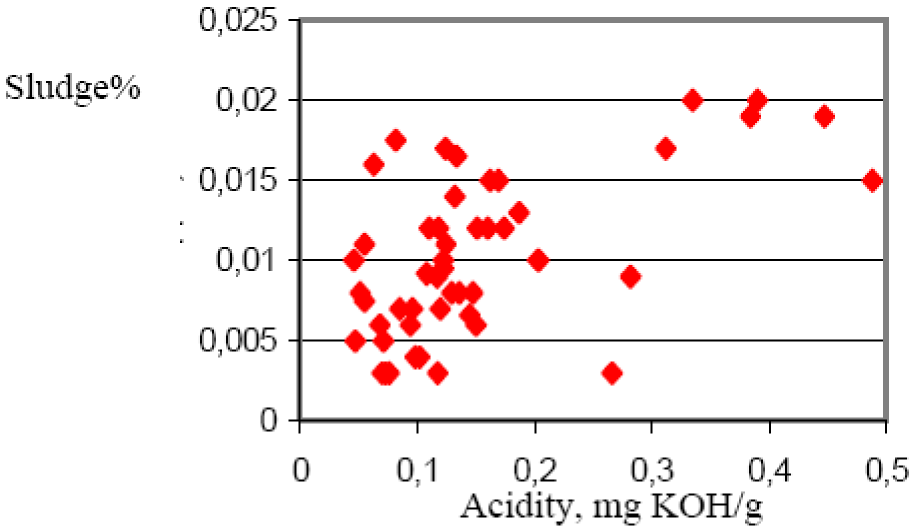


Figure 2-13: Correlation between oil acidity and sludge formation, samples from service-aged transformers.

One should consider that final decay products of a fluid are not the final decay products of the system. It's important to distinguish between at least three groups of oil by-products:

1. Conductive and polar products.
2. Products, which are responsible for accumulation of bound water.
3. By-products, which have an impact on acceleration of cellulose decomposition.

The correlation between traditional ageing characteristics such as colour, acidity, interfacial tension, dissipation factor, resistivity and sludge appearance during oil stability tests may be quite different for different oils. These differences increase significantly when the fluids are ageing in transformers, due to the impact of transformer materials, dielectric stress, limited amount of oxygen and interaction of ageing by-products with cellulose. In fact, the oil stability test model e.g. by IEC 61125 method B, is significantly different from the oxidation process in a real transformer.

Different oils that meet ASTM and IEC Standards show a drastically different picture of how conductive by-products are formed during ageing under the effect of an electrical field (Figure 2-14).

Figure 2-14: Doble Free Life Test Behaviour of different non-inhibited oils under operating temperature 95ºC. Rise of tanδ characterized the rate of producing conductive and polar by-products.

Apparently while selecting non-inhibited oil the products that relate to area (II) should be preferable, and oils that relate to area (I) would produce conductive by-products just after a short time (may be weeks) of operation.

2.4. Synergy between thermal Ageing of Cellulose and Oil

The two insulation components have been discussed. However, the electrical insulation system consists of the solid and liquid insulation in combination. One is aware that certain synergetic effects do exist between cellulose and liquid. This paragraph discusses the interaction between these insulation materials.

In today's Standards, solid and liquid insulation are tested separately, but in real applications, they have to be compatible and perform together.

2.4.1. Influence of Oil Contaminations on Cellulose Decomposition

Hydrolysis may also be influenced by low molecular weight acids from oils. Oxidation of the oil produces both low molecular weight acids and larger acids. Oil testing according to IEC 61125 includes measurement of all types of acids measured in the aged oil and in a water trap connected to the exhaust from the ageing cell. Probably most low molecular acids – being volatile – are found in the water trap. So in principle data on low molecular acids from different oils are available. However, in a real transformer it seems that a significant fraction, or even most, of the low molecular weight acids found are paper degradation products.

Like water, fluid oxidation products are instrumental in the degradation of the insulation system. The oxidation process culminates with the formation of sludge which, as a suspended impurity, reduces the fluid dielectric withstand strength in a manner similar to particles; as semi-conductive sediment, reduces the insulation dielectric withstand strength and may initiate tracking; and will aggressively age both the oil and the cellulose insulation.

There has been a case that sludge formation has been deposited on the winding and increased the probability of partial discharges.

2.4.2. Effect of Oil Quality on Paper Ageing

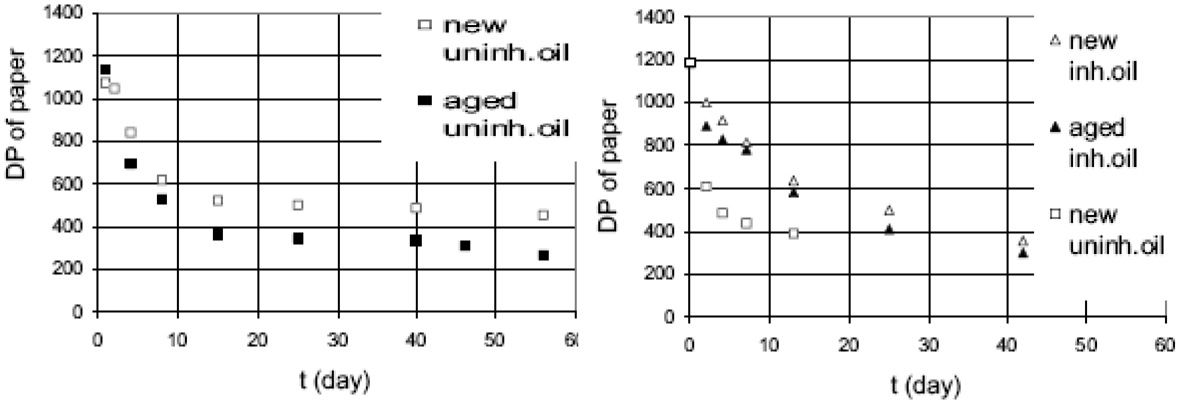


Figure 2-15: Ageing of paper at 120ºC in transformer oils of different types and quality [38]

Left: Change of DP with time in closed system in new and aged non-inhibited oils

Right: Change of DP with time in open system in inhibited and non-inhibited oils.

Ageing experiments performed by the Milan Vidmar Research Institute in Slovenia [38] show clear evidence of impact of oil deterioration on acceleration of paper ageing rate (Figure 2-15).

In new uninhibited oil the degradation of paper was the quickest, since uninhibited oil has considerably lesser resistance to ageing at 120°C than inhibited oil. The paper in aged uninhibited oil in an open system would degrade even quicker than in new uninhibited oil in an air open system. Probably the accelerated paper ageing is connected to formation of carboxylic acids from ageing of the oil.

2.4.3. Influence of Inhibitor on Ageing of Oil and Paper

It was shown in [2] and [51] that improper oil reclaiming is based only on specified parameters (acidity, ITF) for which acidity is conventionally measured as the sum of all acids. It seems promising to differentiate between the high molecular weight oil soluble acids and the low molecular water-soluble acids. The latter ones would reside mainly in the paper while the first would dominate in the oil. Interfacial tension is the interfacial tension between oil and water, usually measured by a so-called ring tensiometer placed just at the interface. Ageing products of oil that will contain polar groups may also form ions, having one hydrophilic and one hydrophobic end. These seek to the water/oil interphase. Interfacial tension is therefore a good indicator of oil ageing. **(**Table 2-6).

Adding an inhibitor to aged oil gives only slight improvement in oil life. Reclaiming aged oil, which does not contain natural inhibitor, cannot improve the life. However, adding inhibitor in thoroughly reclaimed oil allows extending the life significantly (Table 2-7).

Table 2-6: Effect of poor reclaiming oil (residual not-acid polars) on acceleration ageing rate oil and paper. Ageing at 100ºC at open tubes; ratio paper/oil=1/100 [2].

Oil parameters		Oxidation time (hours)							
		0		192		288		384	
		Blank	With paper	Blank	With paper	Blank	With paper	Blank	With paper
1	ITF	42.8	42.8	39.3	37.4	38.3	35.4	36	32.3
	Acidity	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
	IR 1710cm-1*	ND	ND	ND	ND	ND	ND	ND	ND
	DP		1067		855		784		716
2	Acidity	0.02	0.02	0.11	1.05	0.12	1.76	0.18	2.00
	IR 1710cm-1	1.9	1.9	3.7	23	4.7	37.3	5.7	
	DP		1067		289		289		221

*Carbonyl absorbance band

Table 2-7: Impact of oil reclaiming and inhibiting of the Life Span.

Parameters	Colour	Visible spectre	Tanδ % 90C	Acidity mgKOH/g	Induction period at 120C, hours
Service aged oil	6.5	99.9	15	0.12	7.3
Adding 0.2% of DBPC	6.5	99.9	15	0.12	13.8
Thoroughly reclaimed	2.0			0.005	8
Adding 0.2% of DBPC	2.0	82		0.005	34

2.4.4. Influence of Oil By-Products on Dielectric Properties of Insulating Materials

A special study was performed in the field with the goal to study the impact of conductive and polar oil by-products on dielectric properties of insulating materials [55]. Packages of insulating materials were placed into the top oil of 180kVA distribution transformers for 6.5 years. The maximum top oil temperature in the transformers typically did not exceed 60°C, which was too low to cause significant insulation destruction. Table 2-8 presents clear evidence of degradation of dielectric properties of insulation materials.

2.4.5. Influence of Oil By-Products on Ageing Deterioration of Insulation

There have been numerous examples of more severe deterioration of outer layer insulations caused by oil by-products.

Table 2-9 shows the case involving an 800MVA 400/275/22kV, ONAN/ODAF that was in service for 23 years. It was being loaded basically at less than 60% of rating, mostly in ONAN cooling mode. The oil temperature was rather high because the top oil rise in the ONAN mode was 68°C.

It was found that the ageing state of outer layers was significantly more degraded than the average state. It was noted that deterioration of the tertiary winding, which had never been loaded, could have occurred only as a result of the high oil temperature and oil by-products.

Table 2-8: Change of oil and paper parameters after ageing on service condition.

Parameter		Transformer 1		Transformer 2	
		Before	After	Before	After
Acidity		0,06	0,58	0,01	0,10
Water soluble acids [mgKOH/g]		0,01	0,21 / 36 %	0,003	0,04 / 20%
Sludge		ND	0,005	ND	ND
Tan δ at 20°C		0,14	0,71	0,14	0,26
Kraft Paper	**Tan δ [%]**	0,6	14,5	0,6	12,3
	Permittivity	3,3	4,9	3,3	3,7

The temperature of the outer insulation in contact with the oil would have been lower than the insulation average temperature . However, contrary to what should have been expected, the ageing was highest in the coldest layer, which can be explained by the oil having a higher contamination level. Further study of the moisture and contamination distribution within the insulation around conductors is necessary to explain this. Potentially this has to be included in future ageing models.

Table 2-9: Ageing deterioration of insulation of 800MVA autotransformer.

Winding	Temperature rise above oil		Sample	DP in average	DP of outer Layers
	Average	Top			
Tertiary (Not loaded)	11.5	15.2	**Top**	420	391
			Centre		463
			Bottom		491
Common	18.2	43.8	**Top**	500	275
			Centre		484
			Bottom		453
Series	16.9	45.8	**Top**	420	275
			Centre		484
			Bottom	510	453
Tap	16.8	39.6	**Top**	560	294
			Centre		
			Bottom	650	514

2.4.6. Bubbling

A high and fast transformer insulation temperature rise in the presence of high gas or high water content may result in the formation of bubbles. Generally gases which do not dissolve in oil, will result in gas bubbles and water that does not dissolve will form water droplets and possibly water vapour bubbles if the temperature is sufficiently high. This effect increases with increasing relative water content level and increasing total gas pressure in oil. The breakdown strength of the insulation system is reduced dramatically and the transformer will fail when the bubbles or water drops pass high electric fields.

Influence of dissolved gas and water

The impact of water on electric faults in hermetically sealed transformers with nitrogen blanket was recognized a long time ago. Measurements of the water absorption characteristics of transformer insulation materials were collected by John D. Piper 1946 [44]. For additional investigations see [27] and [41]. A first physical description of bubble formation was given in [46]: the total pressure of gas and vapour components dissolved in oil was compared to the local hydrostatic pressure in the oil. This local hydrostatic pressure is the sum of the hydrostatic pressure of the oil column above the actual location plus the atmospheric pressure. If this external pressure is low compared to the total gas and/or vapour pressure, bubbling will occur.

In practice the gas pressure in the oil is determined by the components dissolved in oil – gas (air) and moisture. In case of mineral oil its water vapour pressure is negligible at normal transformer operating temperatures. The long-term level of dissolved air depends on the tank design and temperature dynamics. In any case there is a slight drop of pressure in dissolved air at a fast temperature rise according to the increasing solubility in oil. By "fast" one assumes quick enough to avoid further absorption of air from the atmosphere.

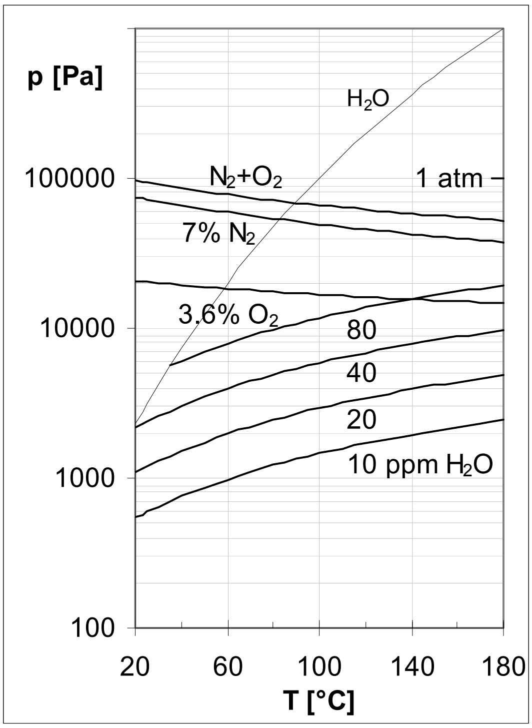


Figure 2-16: Example of partial pressures [35]:

- **Air (N2 + O2) dissolved in mineral oil, saturated at 20°C**
- **Moisture dissolved in mineral oil**
- **Water**

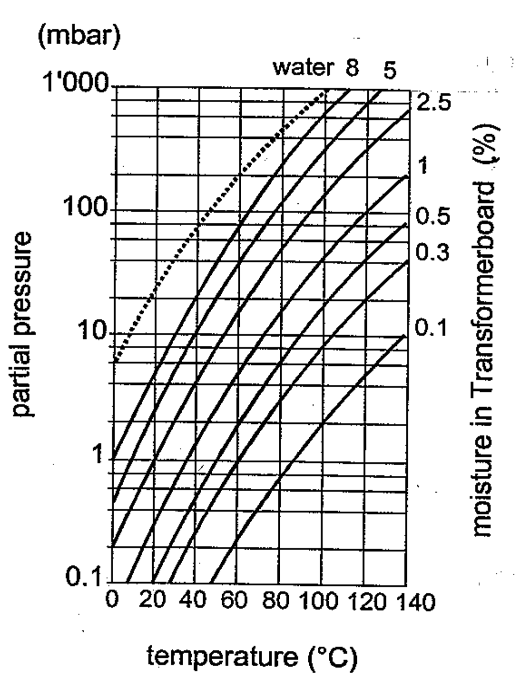


Figure 2-17: Moisture vapour pressure in paper at various water contents.

The water vapour pressure in cellulose was determined by several authors and is shown in Figure 2-17. A mathematical description was presented in [15], [60] and [50].

The long-term total quantity of water in the transformer depends on initial drying, on ageing effects of cellulose and the exchange with atmosphere [7]. The impact of the atmosphere is similar to the absorption of air. In addition the temperature level and environmental humidity determines whether water will be absorbed or desorbed from the insulation system. With increasing temperatures – during daily load increase or overload - the partial water vapour pressure will increase (Figure 2-16) even if the moisture level in oil increases with temperature due to shifting of the moisture equilibrium condition between solid insulation and oil, see Figure 2-18 (Left) for a given moisture content W_c of cellulose. Therefore, the moisture contribution is of increasing importance especially at high temperature levels.

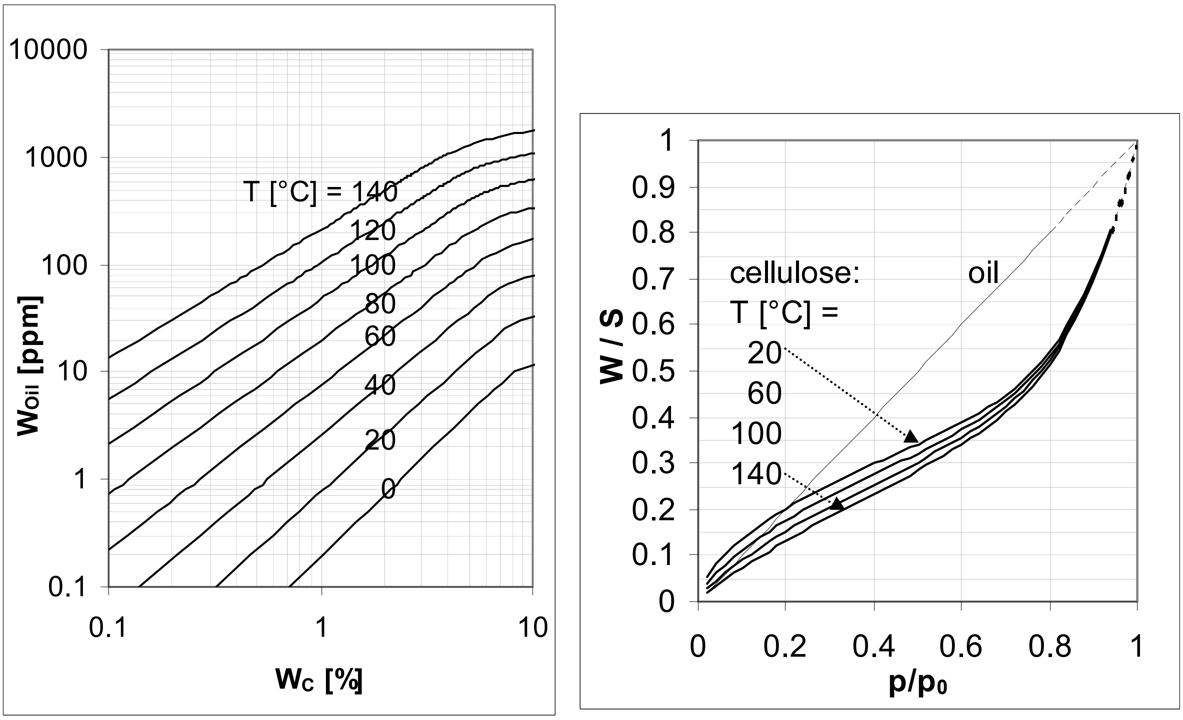


Figure 2-18: Example for equilibrium curves of moisture in paper (cellulose) and mineral oil. In equilibrium the moisture vapour pressure in cellulose is the same as in the surrounding oil.

- **(Left) For absolute moisture content see [47]; the numbers depend on material properties and ageing conditions of oil [52] and cellulose [28].**
- **(Right) Equilibrium based on relative moisture values; only applicable for T_{oil} = $C_{ellulose}$. In equilibrium oil and cellulose obtain the same relative vapour pressure p/p_0 : W/S : ratio of moisture content W (% weight in cellulose or ppm in oil) to its saturation content S [50].**

The curves above assume unaged materials. It is known that aged oil will dissolve more water than unaged. Therefore it is better to base evaluation on relative moisture content than on absolute moisture content. Modern solid-state sensors detect relative content and may in this respect be advantageous to the conventional Karl Fischer measurement.

It should also be noted aware that moisture content in a transformer will vary with temperature because partitioning is temperature dependent. Assuming equal moisture in the oil the hotter parts have a lower than average water content in the paper. In spite of this distribution the maximum moisture vapour pressure is located at the winding hot-spot [50]. Temperature distribution and dynamic processes require progressive modelling to describe the moisture performance in a transformer.

In addition to overcoming the total hydrostatic pressure bubble formation must also overcome interfacial tension forces [42]. This effect requires an additional internal pressure versus the external static pressure. Interfacial tension therefore hampers bubbling. The general criteria for bubbling become:

$$P_{\text{internal}} > p_{\text{external}} + p_{\text{interfacial tension}} \qquad (8)$$

Neglecting the contribution of the interfacial tension makes results more conservative. The external static pressure also increases the solubility of gas in oil. The same is supposed for moisture in oil. The generation of bubbles is believed to occur at the boundary layer between solid surfaces and oil where the interfacial tension is reduced.

In Figure 2-19 the curves show the variation of the temperature measured at bubbling inception. Aged cellulose seems to require higher water content for bubble initiation, vice verse aged oil accelerates bubbling due to reduced interfacial tension.

The influence of hydrostatic pressure and temperature, or moisture distribution is not considered here. Experiments have revealed that the influence of nitrogen-saturated oil is detected only below 140°C [42]. An empirical formula can be deduced from Oommen's curve (Figure 2-19, right).

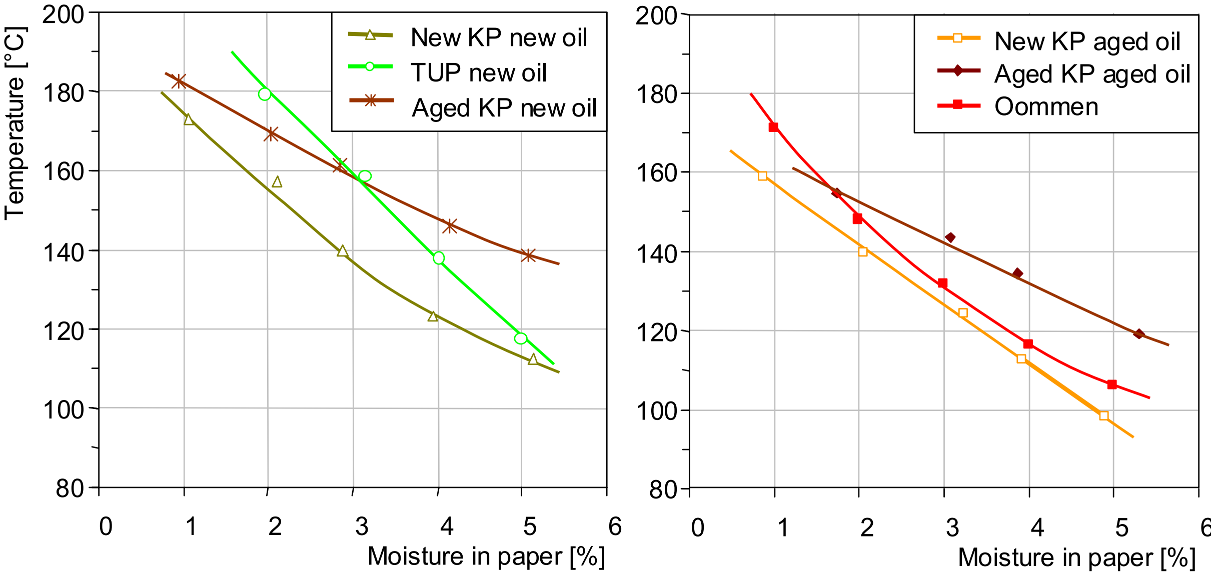


Figure 2-19: Inception Temperature for New Kraft Paper, Thermally Upgraded Paper and Thermally Degraded Kraft Paper in New Shell Diala D (left) and for New Kraft Paper in Service-Aged Oil, Thermally Degraded Kraft Paper in Service-Aged Oil and Data from Oommen (right) [28] or [41].

At least the generation of water droplets at temperatures far above 100°C sounds rare. Two aspects should be borne in mind: in cellulose the moisture saturation level decreases at increasing temperatures; and over saturation can occur principally at rising temperatures!

Generation of water drops was observed at temperatures exceeding those at which bubbling occurs [10]. Further work is needed to better clarify the effects of ageing of oil and cellulose.

Effects in oil

The description above focuses on oil with dissolved gases and moisture and the risk of bubble formation.

When bubbling occurs the water concentration is high and saturation may be close. As subsequent temperatures fall over-saturation may occur, water will precipitate and a water-in-oil emulsion will form. Fast cooling raises the risk of over-saturation. The moisture content in oil depends on the cooling dynamics. In a transformer the moisture cannot transfer back to the cellulose quickly enough to reach the equilibrium condition. Diffusion of moisture from the cellulose surface into the body of the cellulose needs time.

Oil that is exposed to atmospheric air will absorb air until the pressure of dissolved air also reaches the pressure of one atmosphere. Over-saturation would occur if the external pressure were reduced below one atmosphere. Evacuation would be an extreme treatment. On the other hand the internal pressure of air dissolved in oil will gain values exceeding one atmosphere during cooling. In transformers the external pressure caused by the static pressure of oil in windings and the interfacial tension avoid bubbling during cooling to a sufficient extent.

Effects in cellulose

In practice bubbling depends on the thickness of the cellulose insulation. It is not visible from thin insulation [48] and mainly occurs when the temperature increases rapidly. [7], [28], indicating that a certain moisture flow must exist to facilitate bubble formation

At the cellulose surface the bubble must overcome the local interfacial tension between cellulose and oil, which is lower than the surface tension of oil. This effect is still not quantified.

2.5. Thermal Ageing of High Temperature Materials

2.5.1. Introduction

High-temperature transformers are now quite common around the world. Mineral oil immersed transformers are manufactured with average winding temperature rises exceeding the 65K found in the Standards. High-temperature insulations including enamel and tape wrap for conductors, winding spacers and mechanical support materials are commonly used in mobile, locomotive and rectifier transformers. These applications benefit from the lighter weight, improved reliability or longer life offered by the use of higher temperature materials. For many years, these materials have also allowed manufacturers to provide solutions for repair applications and mobile transformers. Traction applications have been produced for many years. More recently, applications in pole-type distribution transformers and wind turbine transformers have become increasingly more important.

In response to this growing market, IEC/TS 60076-14 [22] was published in November 2004. This document was developed to meet the international need for additional guidance in specification and design of liquid-immersed power transformers using either high-temperature insulation or combinations of high-temperature and conventional insulation. Many different dielectric coolants are considered as well.

2.5.2. New Definitions for High Temperature Materials

When using high-temperature insulation, an increased number of choices and options are available to the designer and the user. As new materials have been developed and applied over the years, many new design techniques have emerged. The challenge for the IEC working group was to organize and standardize this broad range of methods and techniques. One of the key accomplishments of the document in meeting this challenge was the definition of new terms, including four new insulation systems. These insulation systems are defined as a means of standardizing the technical content of the document for design guidance and to improve communication between the manufacturer and the user. They are identified as homogenous, mixed, semi-hybrid and hybrid insulation systems.

Homogenous Insulation System

The Homogenous Insulation System is a uniform composite of solid and liquid insulations that all exhibit similar thermal capability. The typical liquid-immersed transformer is composed of cellulose solid insulation and mineral oil liquid insulation. The cellulose may be wood, Kraft paper and/or pressboard and the high voltage winding wire insulation may be enamel coated. However, all of these components have approximately the same thermal capability. For conventional transformers this temperature is a maximum hot-spot temperature requirement of 98°C, corresponding to the 105(A) class. IEC/TS 60076-14 defines the insulation system of this type of transformer as the "conventional" insulation system, consisting of mineral oil as the liquid insulation and non-thermally upgraded insulation as the solid insulation.

By reference then, all other insulations capable of continuous operation at temperatures above that of either mineral oil or non-thermally upgraded cellulose, are considered "high-temperature" insulations. An insulation system composed of high-temperature liquid and high-temperature solid insulation or conventional liquid and high-temperature solid insulation is considered to be a high-temperature insulation system. This approach allows the document to concentrate on only the differences between "conventional" insulations or systems and "high-temperature" insulations or systems.

This approach was also a practical necessity, since there is no generally accepted test method for determining the thermal capability of an insulating liquid. In fact, the stated capabilities of the fluids listed in the document are specifically noted as "generally accepted" values and "Estimated maximum operating temperature (°C)". Accordingly, the liquids were divided into three basic categories that also define the maximum "recognized" thermal capability. In the "conventional" category is mineral oil with a higher capability assigned to ester fluids and the highest classification defined by silicone fluid. Given the lack of definition in the standards the categories and limits were based on application history as a starting point. [22] compares the maximum temperature limits for these three basic combinations.

It is important to note that the average winding temperature rise is defined as a maximum rather than a fixed value. While the 65K average winding temperature rise for the conventional insulation system is also a maximum value, it is generally considered to be a fixed value. Some units are rated at lower temperature rises, but in most cases 65K is adopted as the rise even if the actual temperature rise is somewhat lower. The situation is a bit different for high-temperature insulation systems. Average winding temperature rise increments of 5K are typical and reasonable.

Table 2-10: Example: Maximum temperature limits of homogenous insulation systems Solid is cellulose in Mineral oil, and class 220ºC for ester and silicone liquids.

Insulation Type	Limit Description	Mineral Oil	Ester	Silicone
Liquid	Maximum liquid temperature(°C)	100	130	155
	Maximum liquid temperature rise (K)	60	90	115
Solid with appropriate temperature class	Maximum hot-spot (°C)	118	190	220
	Maximum hot-spot without accelerated ageing (°C)	98	170	200
	Average winding rise (K)	65	115	130

In practice, the maximum temperature limits indicated in Table 2-10 will be lower due to the use of different materials or exceeding the liquid temperature near the hot-spot region.

Operating the liquid at higher than conventional temperatures requires higher temperature gasket material and may also affect the design of the no-load tap switch. Bushings must be addressed, either by over sizing or by specifying equipment with a higher temperature capability. Other accessories such as coolers, temperature indicators, gauges, relays, and even conservators must be analysed for the affects of possible higher temperatures. For example, higher operating temperatures for the liquid may increase the expansion volume needed in conservator tanks. In the windings, tapes, adhesives and epoxy paper coatings are likely to require thermal upgrading.

Preventing the entrance of moisture into the system can be a major concern for these units, since moisture will generally accelerate the natural ageing process of both liquid and solid insulation. The effect also increases as the operating temperature increases. Consequently, the risk in using a free-breathing oil preservation system is much higher when operating close to the maximum temperature limits, compared to only slightly exceeding the conventional temperatures.

The remaining three defined insulation systems are related in that they all use mineral oil or the equivalent as the dielectric coolant and all use a combination of high-temperature and conventional solid insulation. The differences lie in the degree of usage for the high-temperature insulation. Since the dielectric coolant is conventional and operated at normal temperatures, standard bushings, gasket material and most other accessories are generally acceptable. On the other hand, tapes, adhesives and epoxy paper coatings used in the windings may still require thermal upgrading.

Table 2-11 compares the maximum temperature limits for these three insulation systems. The liquid temperature maximums are only shown for emphasis, since conventional temperature limits are never exceeded. Table 2-11 also emphasizes that there are two distinctly different maximum hot-spot temperature limits that must be addressed and mapped in the thermal analysis.

Table 2-11: Maximum temperature limits of mineral oil insulation systems compared to conventional

Insulation Type	Limit Description	Conventional	Mixed	Semi-Hybrid	Hybrid
Liquid	Maximum Top (°C)	100			
	Maximum Top Rise (K)	60			
Conventional Solid	Maximum Hot-spot (°C)	118			
	Maximum Ageing Hot-spot (°C)	98			
High-Temperature Solid	Maximum Hot-spot (°C)	118	150	130	170
	Maximum Ageing Hot-spot (°C)	98	130	110	150
	Average Winding Rise (K)	65	65	75	95

Mixed insulation system

The Mixed Insulation System uses high-temperature solid insulation material adjacent to the winding conductors located in the hotter regions of the winding. It includes all conductor insulation and, if necessary, spacers, strips and cylinders in direct contact with these conductors. Cellulose materials are then used in the rest of the winding and other lower temperature areas where thermal class 105(A) limits are met. This insulation system uses the least amount of high-temperature insulation and is essentially used to augment the capability of the conventional insulation system. This technique is best used when only normal hot-spot temperatures are exceeded, either due to the transformer design or due to the application. The average winding temperature rise does not exceed 65K.

Typical applications are larger power rectifier and furnace transformers. Rectifier transformers typically see harmonic currents that exaggerate the conductor heating at the ends of the windings. Using high-temperature insulation only in these hot areas can reduce the unit size while adding reliability. Furnace transformers often supply very high currents that generate high magnetic fields leading to higher than normal hot-spot temperatures. These units are also operated at very high load factors, often continuously. Higher temperature insulation in the hottest areas of the windings can increase unit life while adding reliability, often at a very reasonable cost.

As an example, with many rectifier transformer designs, it is necessary to reduce the average winding temperature due to excessive hot-spot temperatures. This reduces the average winding temperature rise and also increases the size of the unit. By using a mixed insulation system, it is possible to operate closer to a normal average winding temperature rise and then merely protect the hot-spot locations with higher temperature insulation. The entrance of moisture into the system for this type of unit is less of a concern, since these units only slightly exceed the conventional temperatures.

Semi-hybrid Insulation System

The Semi-hybrid Insulation System uses high-temperature materials only for conductor insulation. This option offers another step higher in the use of high-temperature insulation. When applied to all windings, the goal is usually longer life and better reliability. In some cases, lower cost or reduced losses are the incentive and high-temperature insulation may be used on only one winding.

Generator step-up transformers, furnace transformers and other high load factor applications are all good candidates for a semi-hybrid design. Another suitable application applies to transformers designed for use in high ambient temperature conditions. The higher ambient requirement is usually resolved by reducing the average winding temperature of all windings, similar to the rectifier transformers. Since the high ambient is usually 50°C rather than the standard 40°C, the average winding rises are typically reduced by 10K. An alternative is to use high-temperature insulation on all windings, since the semi-hybrid temperature limit is 75K rather than 65K. Often a standard design may be used with only the addition of extra cooling capacity to maintain the correct top oil temperature.

Hybrid Insulation System

The Hybrid Insulation System uses high-temperature solid insulation material adjacent to all winding conductors, including all conductor insulation, spacers, strips and cylinders in direct contact with the winding. Cellulose materials are used in lower temperature areas where thermal class 105(A) limits are met. The Hybrid Insulation System uses the largest percentage of high-temperature insulation from the three mineral oil systems. Table 2-11 also indicates that this system has the highest thermal limits of the three, which fits well with high overloading, small size and high power density.

There are many design applications using hybrid insulation systems. Historically, medium power mobile transformers used as emergency substation replacements were some of the first applications to take advantage of high-temperature insulations. This technique was an excellent match for the high power densities needed for this type of unit and initially all high-temperature insulation was used. However, the high unit cost quickly became prohibitive for most applications. This high cost led to a technique of blending high-temperature and conventional insulations, which became known as a “hybrid”.

The hybrid insulation system has also been used in the repair industry for many years. This approach often provides additional capacity and quick delivery at an attractive price. More recently, new units have been specified to provide improved reliability, higher overload capacity, or to supply more capacity in the same available space.

2.5.3. DGA on Hybrid Insulation Systems

The hybrid insulation systems behave as conventional systems due to the presence of cellulose and mineral oil. Signs coming from the degradation of the insulation system have to be interpreted. For example, preliminary data [40] on hybrid insulated units (aramid/cellulose/mineral oil) indicate CO, CO2, methane, and ethane values are within the "normal" condition as specified in IEEE C57.104 (condition 1) [45], even though the average winding rise may be higher (up to 95K) than conventional insulation systems (cellulose / mineral oil) (Figure 2-20).

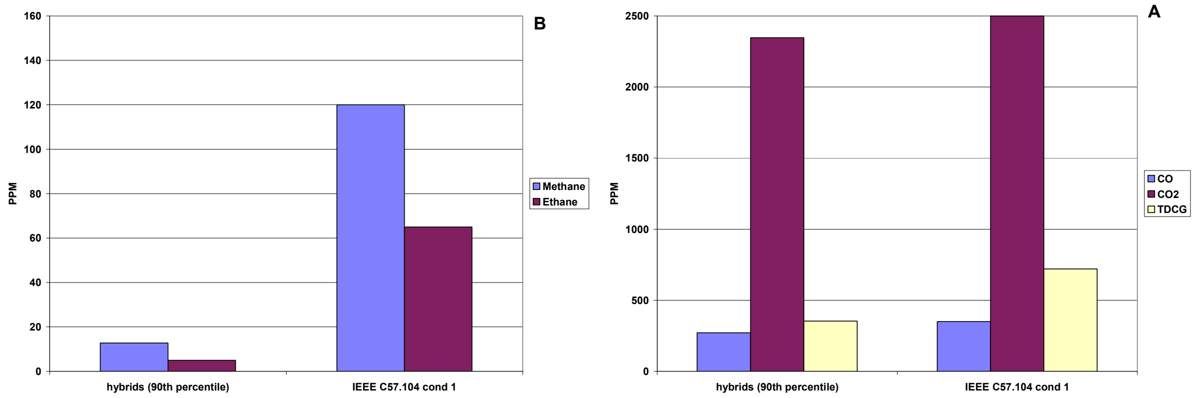


Figure 2-20: A - 90th percentile CO, CO$_2$, TDCG (total dissolved combustible gas content), B - 90th percentile CO, CO$_2$, TDCG (total dissolved combustible gas content), 90th percentile methane and ethane level.

2.5.4. Ageing of Hybrid Insulation Systems

In order to mimic application, thermal evaluation of hybrid insulation systems should be performed such that the fluid and the cellulose are maintained at a typical low temperature while the aramid insulation is aged at an elevated temperature. This type of testing, defined as dual temperature ageing testing, has been previously described and recently was integrated as part of regular testing procedures [45], [56]. It provides a basis for assessment of life characteristics for insulation systems comprised of materials having different thermal capabilities (Figure 2-21).

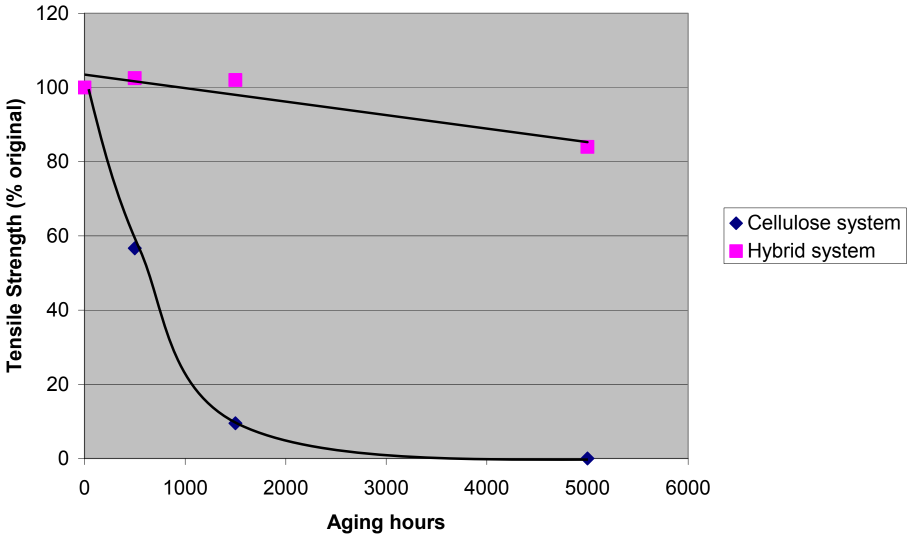


Figure 2-21: Tensile Strength as a Function of Ageing Time.

2.5.5. Comments of use of high temperature liquids

For most of the non-mineral oil liquids, the maximum allowable temperature is higher than for mineral oil. However, other parameters such as breakdown value, compatibility, pour point, viscosity, and thermal expansion can be different.

Additional factors that must be taken into account in the design of the transformer include: esters and silicone have a higher viscosity that will lower cooling performance of the transformer and, some liquids have a pour point of –15ºC which is not as low as in IEC Standards for transformers.

2.6. Thermal Ageing of New Materials

New materials arrive in the market continuously. We will here shortly comment on their characteristics and what is important when being concerned about the thermal performance of a liquid insulated transformer.

2.6.1. Liquids

New liquids must be able to perform at required temperatures without loosing its properties. In a thermal performance perspective this is mainly the oxidation stability. It should also be noted here that metals might play an important catalytic role.

Water absorption will vary from one liquid to another. Several new liquids have high moisture absorption. How the absorption depends on temperature may be important. If the absorption is very temperature dependent, then temperature drops are more prone to result in precipitation than if the absorption is stable over a large temperature range.

Finally, viscosity is an important issue. Several of the new liquids have higher viscosities and a higher pour point than tradition mineral oils. The cooling flow through the winding determines the heat flows, both for static and transient conditions. If the viscosity is high when the transformer is on a low load or being unenergised then a sudden load increase/ energisation will result in a temperature overshoot in the windings. This is because the heating of the conductors is immediate, while it takes time to start the thermal siphon in the windings. The liquid has to be heated and accelerated before cooling is activated. This problem is most likely to occur in countries with low ambient temperatures.

2.6.2. Solids

For thermal performance of solids there are some issues demanding further concern.

Mechanical performance is one such concern. At high temperatures such materials will become softer. The so-called glass transition temperature for a thermoplastic is a parameter describing this. At lower temperatures many plastics become brittle and may crack.

Water absorption for synthetic materials will normally be in the same range as for the liquids, being much lower than for cellulose. From a bubbling pint of view this is an advantage

2.6.3. Solid/liquid synergetic effects

Synergetic effects are an issue that will require specific studies. We can briefly mention:

- Absorption of liquid into solid, acting as a softener
- Deterioration of solids by being dissolved into liquid
- Water partition curves

The list could have been made longer, but this is mainly meant as an indication that compatibility issues are important.

2.7. Conclusions

Some of the most important issues concerning material behaviour in context of thermal performance of transformers can be summarised as follows:

It is obvious that from an asset management point of view, the loading guides come up short on treating the influence of contamination on the ageing rates. The importance of water and acid hydrolysis is clear, as is the effect of oxidation. Still further studies are needed to reveal the details of the oxidation. It is clear that the two processes act together and cannot in real life be separated.

It also now seems clear that the European practice of using open breathing units is inferior to using sealed units where oxygen content may be kept low.

Ageing characteristics of upgraded paper needs further studies. It is a puzzling fact that we have standards for temperature rise of transformers and thermal performance of liquids, while for paper IEC has no specific requirements. Particularly for upgrade paper this is a problem. It is unclear how efficient the various processes are under various conditions, and how dependent the quality of the paper is on concentration of the upgrading agents.

Ageing performance for paper/liquid system with new liquids need investigation. The studies should be done with moisture content in the cellulose that represents realistic conditions for service temperatures.

Bubbling risk needs further studies with materials at service conditions; also the role of interfacial tension is still not clear. Information about the performance of moist transformers under overload conditions is needed. It seems that with synthetic solid insulation at the hot-spot e.g. hybrid systems, the problem of bubbling will be reduced as the amount of water in the solid insulation now is much lower.

Oxidation stability tests are an issue that needs further studies. This is currently being investigated in Cigre TF D1.01.17 headed by Ivanka Höhlein. Also introducing new high viscosity liquids in larger transformers in countries that experience a cold climate (below zero degrees centigrade) should be avoided unless the impact on cooling of the full winding is investigated first.

Compatibility effects between liquids and solids will need further attention.

3. Diagnostics

3.1. Introduction

In the past, diagnostics on transformers were mostly considered as tools to investigate failures and bad operating performance of transformers. During the last years, diagnostics are more and more used as tools to monitor the behaviour and current status of the transformer. Monitoring systems that combine several of the 'standard' diagnostics together with a data logger and analysing system allow following the evolution of the health of the transformer closely.

Care must be taken however, because even the most powerful monitoring system will return the wrong conclusions when the sensors are not placed in the right positions in the transformer. For example, when only top oil temperature is measured, one ignores that the top oil temperature is not the highest or only temperature in the transformer. Temperature drops about the different parts and temperature differences inside of the transformer are also of great informative value and should be monitored too.

This chapter discusses the different diagnostic techniques that can be used inside a transformer: Section 3.2 gives a short overview of diagnostics used to assess the condition of the paper insulation in the windings. Section 3.3 shows different diagnostics to monitor oil condition. And section 3.4 gives different options to measure temperatures occurring in the transformer.

3.2. Diagnostics for Paper Condition [6]

3.2.1. Water

Water is produced by ageing and is also an important ageing accelerator that significantly influences the ageing rate. In order to assess the ageing rate it is therefore important to measure the water content of the cellulose correctly. It is now clear that the indirect scheme using equilibrium curves for assessing moisture in paper via measured water content in oil can give significant errors, due to changes in the water solubility for aged oils. Errors of a factor of two are possible. It appears that this is mainly due to an increased content of low molecular weight acids in the oil that increases the water solubility, thereby changing the partitioning of water between oil and cellulose. Nevertheless, in spite of its shortcomings, this indirect method still has its use. CIGRE WG A2.30 is presently reporting on moisture dynamics of transformers.

3.2.2. Furanic Compound Analysis

Furanic compounds are a group of chemicals formed both by oxidation and hydrolysis of cellulose. A lot of faith has been put in these as chemical markers for assessing the ageing state of the cellulose. However it is now apparent that temperature dependent partitioning between oil and cellulose has to be considered, as have moisture, acidity, stability etc. Also one has to consider that production of furanic compounds will depend on the degree of ageing - being distributed through the winding - and the amount of materials involved. Finally, it appears that thermally upgraded cellulose does not produce furanic compounds to the same extent that normal Kraft paper does. This has all led to a more reluctant attitude towards accepting simple relations between furanic compound concentrations and winding ageing. CIGRE TF D1.01.13 pursues this complex issue.

3.2.3. Dissolved Gas Analysis

Water and carbon oxides are the main by-products from cellulose degradation. However, other degradation processes produce these gases and they may come from the outside atmosphere. Since the cellulose material is the main producer of carbon oxides these gases can be used for a rough assessment of the cellulose ageing. This assessment is based on gas levels, production rates and on ratios. Recently CIGRE joint task force JTF D1-01/A2-11 made an extensive summary of typical absolute values and gas increase rates [4].

3.2.4. Other Markers

Presently work goes on with gas chromatography and HPLC techniques to identify other oil soluble markers suited for diagnostics and many interesting substances are identified (e.g. carbohydrates, alcohols and acids). More work is indeed necessary on the low molecular weight acids, also due to their participation in hydrolytic ageing. Recently a large study focusing on methanol as a cellulose specific ageing marker has been proposed [26].

3.2.5. Dielectric Testing

Dielectric response methods (FDS, PDC and RVM) are promoted for measuring water in cellulose [5]. It appears that ageing by-products like carboxylic acids may act somewhat like water in these measurements. However, the effect on the dielectric response from ageing seems small compared to that of water, and dielectric methods can therefore not be expected to offer an alternative to chemical diagnostics.

3.2.6. Cellulose Diagnosis

Apparently, the most reliable characteristic of ageing state of a transformer would be measurement of cellulose DP [1]. Typically there are two opportunities for sampling of cellulose pieces for testing: during internal inspection after draining oil and after disassembling the active part (e.g. post-mortem inspection). It should also be mentioned that presence of Cu_2S could be detected by e.g. X-ray diffraction.

Internal Inspection

Internal inspection allows sampling a piece of cellulose from leads and pressboard barriers, Some investigators have elected to take very small micro-samples from the winding [16].
In some cases a good correlation has been found between lead insulation and winding insulation condition, however in most cases DP tests of paper from leads have shown either underestimation of insulation condition due to lower temperature or overestimation due to effect of moisture that under influence of temperature gradient is pressing out into surface layers, as well as due to effect of oil by-products.

Micro-samples from the winding affect on accuracy of DP test (due to a small amount) and required subsequent repair of the area where the sample is taken.

Samples of pressboard taken e.g. from top and bottom part of a barrier do not affect insulation reliability. They allow measurement of DP both internal and outer layers however require correction of temperature to that in hot-spot area.

Figure 3-1 shows DP values from 62 service-aged transformers being in operation 15-40 years (one unit that showed DP=160 was in service about 60 years). Samples were taken during internal inspection.

9 units showed minimum DP value below 500. Assuming that ageing rate in a hot-spot area 3 times greater that ageing rate of cellulose operating under oil temperature one can deduce that 15% of observed units may have DP 250 or less.

Apparently investigation of accessible insulation members is not sufficient to understand ageing profile of insulation, however DP of pressboard pieces taken from the top and bottom part considering oil temperature in samples location may allow anticipating ageing rate in hot-spot area.

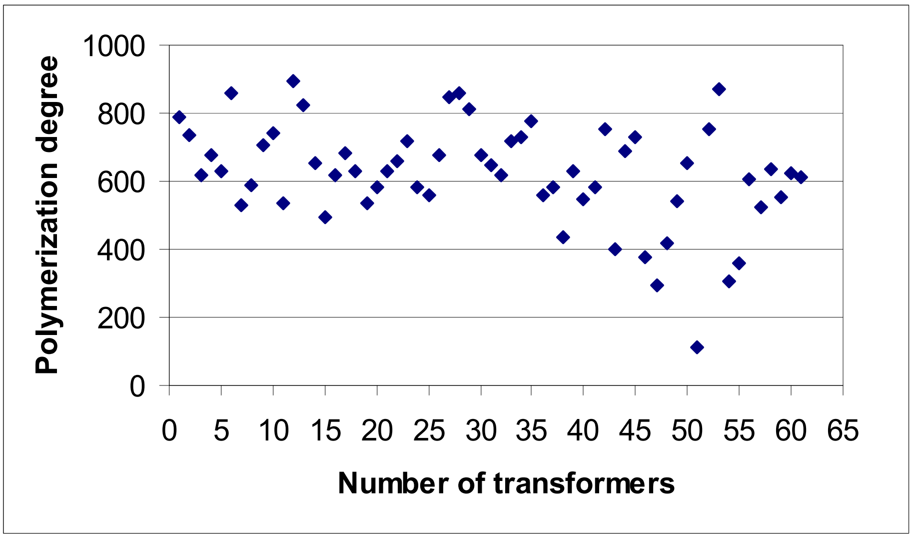


Figure 3-1: DP test of cellulose samples taken during internal inspection (by ZTZ-Service Lab).

Post-mortem inspection has allowed understanding insulation ageing profile

Figure 3-2 summarizes minimum DP values from 16 transformers having Kraft paper insulation and 5 transformers with TU insulation (see Appendix 1). Most of tests were performed by ZTZ-Service Lab, 3 cases that involved Kraft paper were borrowed from [16] and cases that involved TU insulation were borrowed from Doble's case history [60].

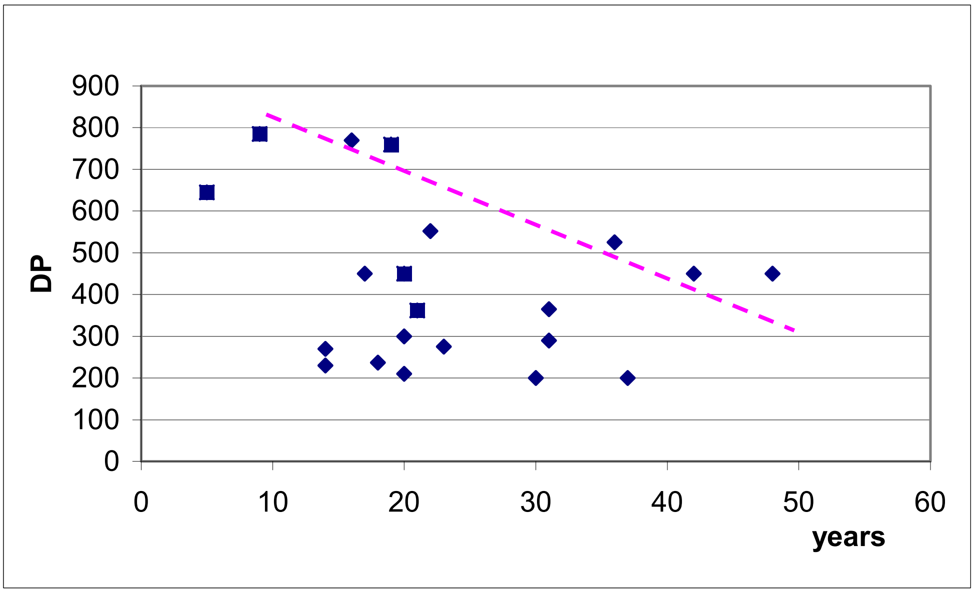


Figure 3-2: Minimum DP values of cellulose insulation from service aged transformers (■ Kraft paper, ♦ Thermally Upgraded paper).

Test data shows that critical state of insulation can be achieved both after 35 and just after 15 years

There was found a clear but poor correlation between DP and service years. Some transformers show an ageing factor less that 2 (60% of residual life) after 40 years however many units were substantially aged after 15-30.

Unexpectedly insulation performed from TU paper showed an ageing trend similar to Kraft paper. A possible explanation of this similarity could be the use of a higher temperature limit for TU paper than for normal Kraft paper. However, the present available data did not allow differentiating between design temperature limits.

3.3. Diagnostics for Oil Condition

3.3.1. Copper Sulfide Contamination

Determination of copper sulfide contamination of oil is difficult on a live transformer. Readily available diagnostic techniques can only detect this post mortem, by analysis of the insulating paper.

More information can be found in the results of Cigré Workgroup 32. The results of this workgroup will be used by IEC TC10 to introduce the findings of WG32 in the international standards.

3.3.2. Water

The moisture content of the oil has a direct influence on the breakdown voltage of the transformer oil. Also, as described in section 3.2.1, the water content in oil can also be used to estimate the moisture content in the insulating paper.

The water content of oil can be measured on-line with moisture sensors available from suppliers.

3.3.3. H_2

H_2 is mainly produced by partial discharges. Therefore the presence of H_2 is a good indication for the existence of partial discharge problems within the transformer. In order to provide a timely discovery of PD problems, an on-line H_2 detector should be installed.

3.3.4. CO

Excessive heating at a local spot in the transformer causes the production of a number of fault gasses. One of these gasses is CO.

The presence of this gas is a good indication for the existence of a to high hot-spot temperature somewhere in the transformer.

On-line CO-sensors are cheaper than a full DGA on-line sensor. Therefore, these CO-sensors are found mostly in the smaller and cheaper monitoring systems that provide only basic monitoring for the transformer.

3.3.5. DGA

In a DGA measurement, the concentration of the 8 fault gasses indicated by IEEE and IEC are measured. The typical gasses produced by thermal breakdown of cellulose are: CO, CO2, H2, C4, C2H4 and C2H2.

On-line measurement tools are readily available for use. The cost of these units is however still quite high. Therefore, these on-line tools are mostly built in, in complete monitoring systems.

Transformers without an on-line measurement system can still be checked for dissolved gasses. However, this will mean Oil samples have to betaken each time

3.3.6. Additives

A lot of additives added to increase performance of the transformer oil are being consumed during the lifetime of the oil. However at the present it is not a custom to check the development of these additives. The effects of depletion of oil additives could prove to be an important factor in the ageing of transformers.

This is an important issue in the thermal modelling of transformers, and more work should first have to be done in this area before conclusions can be made.

3.3.7. Natural inhibitor

Depletion of the natural inhibitors in transformer oil causes destabilisation of the oil and should be monitored. The concentrations of these oil-components are difficult to measure due to their great variety. A work around could be to monitor the amount of oxidation of the oil.

3.3.8. Oxidation

The amount of oxidation of transformer oil is a good indicator for the ageing of the oil itself. The oxidation of the oil also has an influence upon the other ageing processes in the transformer.

Oxidation in oil is at the present not measured directly. Oxidation progress of the oil is mostly monitored indirectly by measuring the concentration of decay products of the oxidation process. These include for example the concentration of CO and CO_2 gasses.

3.4. Diagnostics for Temperature

Measuring the different temperatures inside the transformer has always been an important issue in the construction of a transformer. The excess heat generated in the different parts directly affects the lifespan of the transformer. Therefore it is very important to get a good impression of the different temperatures inside the tank and the windings.

The electrical requirements of a transformer severely limit the possibilities to measure temperatures inside the windings. One can still use optical fibres, however these fibres are quite expensive and cannot be installed in every transformer. Therefore the best practice is to provide an accurate thermal model of the transformer. This model must predict the different temperatures that cannot be measured directly. The values calculated with the model should be checked and supported by the measurements of those temperatures that can be measured directly. Also measurements with optical fibres should be used on a certain number of transformers to validate the thermal model.

The next parts give a short description of the different temperature diagnostics that are commonly use in transformers.

3.4.1. OTI

Oil temperature indicators or OTI’s are among the most common transformer components. A small, separate oil volume inside the transformer tank is connected with a capillary to a mechanical temperature indicator mounted outside of the transformer tank. This simple and robust construction allows getting a good impression of the oil temperature inside of the tank.

Care must be taken to calibrate the temperature indicator correctly. E.g. problems may arise when the sun is shining directly on the capillary. This increases the temperature in the capillary by a small fraction however, due to the long necessary length of the capillary, this give a large measurement error in the temperature indicator. A proper construction and calibration of the OTI however can prevent this from happening.

More modern solutions provide electronic sensors and displays to measure the oil temperature, e.g. a PT100 sensor could also be used to measure the oil temperature. This solution is more accurate and prevents a number of measurement errors occurring with standard mechanical OTI's. On the other hand these electronic sensors have there own problems. Megger tests or electrical impulses occurring in the transformer could damage these sensors and these devices need a separated power supply in order to function.

3.4.2. WTI

A winding temperature indicator or WTI is very similar to an OTI. The difference is the small heating coil that increases the temperature of the separate oil volume of the sensor. A current transformer that measures the current in the winding bushing lead supplies the current to the WTI coil.

When calibrated correctly, this sensor could give a good indication of the winding temperature. However, this measurement remains only an estimation of the real winding temperature. There is also no guarantee that the calibration remains correct over time.

3.4.3. Optical Fibres

Optical fibres contain no conducting materials and their working principle is not based upon electrical or magnetic phenomena. Therefore they are a very useful means by which to measure the real oil temperature inside the winding. However an optical fibre will only be able to measure the temperature in one fixed point. The location of the hot-spot, on the other hand, cannot be predicted accurately enough to place the optical fibre exactly in that spot.

Optical fibres therefore provide a more accurate picture of the temperatures inside the transformer, however they are still not suitable to measure the exact hot-spot temperature the number of measurement points will improve the accuracy of the prediction of the hot-spot, but considering the high cost of these optical fibres this will also have a noticeable impact on the total production cost of the transformer.

Optical fibres can also be used to measure the temperature in metal parts. The same rules as for the windings apply here. The location of the hot-spot is not exactly known in advance, therefore optical fibres will give a good measurement on a particular position of the metal part. However, there is no certainty that the optical fibre is installed exactly at the hot-spot position.

Optical fibres are also highly vulnerable to physical damage. When applying these fibres in production transformers there are some general guidelines that must be followed to obtain a good working measurement system:

1. All optical fibres should be checked visually upon arrival, and their temperature measurement should be checked with the aid of an isothermal bath. The accuracy of the optical fibres is dependent of the suppliers, however ±1°C is a normal value.

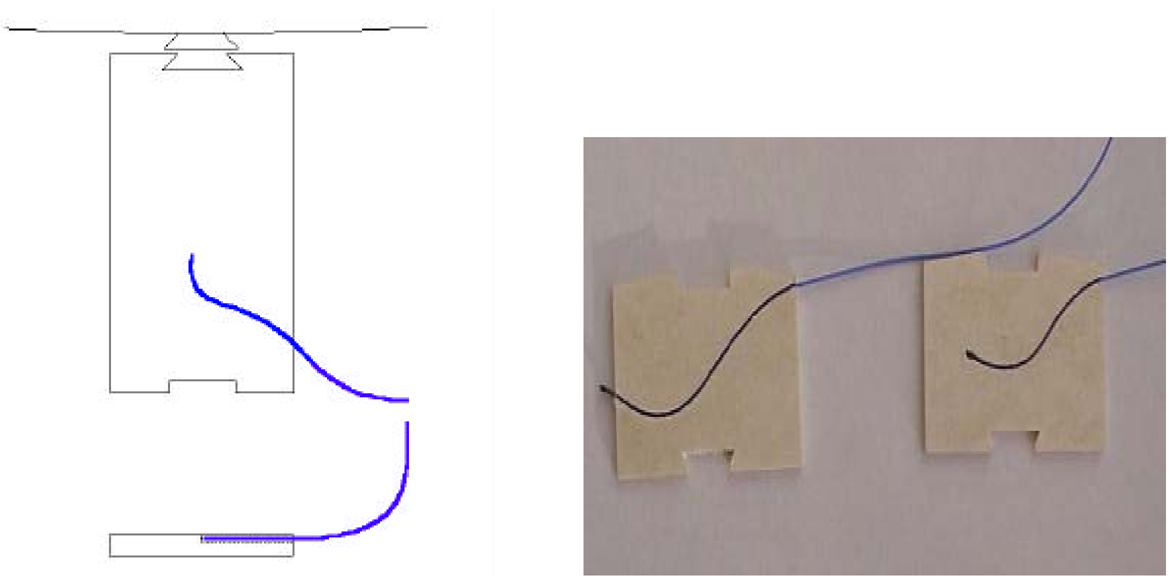


Figure 3-3: Examples of fixation slots for optical fibres inside the windings.

2. Optical fibres are best fixed by using their own stiffness. The fibres need to be placed in an S-shaped slot inside the spacers. This slot must position the end tip of the fibre at the measurement point and allow the fibre to exit the winding radially. Examples of these slots can be seen in Figure 3-3. It should not be possible to pull the fibre out when pulling in the plane of the slot.

3. The spacers who contain the optical fibres are best installed by replacing an existing spacer after the coil has been completed. However, care must be taken in order not to damage the insulation of the conductors when replacing the spacers. There should always be another spacer or a layer of smooth material between the wedges and the conductors. An example of the latter technique can be seen in Figure 3-4.

Figure 3-4: Left: Using a wedge and 2 layers of smooth material to replace a spacer.

Right: Guiding the fibres to the top of the winding.

4. When guiding the fibres to the top of the windings, care must be taken to make broad turns with the fibres and not to pull the fibres tightly against the winding. This will allow the windings to move a little bit without damaging the optical fibres. The fibres should be fixed with the same materials used in the construction of the windings: Paper and wood glue. No new materials should be introduced inside the transformer.

5. When the fibres are outside the windings, enclose them in hard paper tubes to protect them against physical damage. Soft paper tubes can still give a limited protection when hard paper tubes cannot be used. The fibres have first to be inserted in the tubes. Afterwards the tubes must be secured against the other parts of the transformer.

6. The primary use of optical connectors as displayed in Figure 3-5 is to lead the optical fibres outside of the tank. However, these connectors can also be use to end the optical fibres at the top of the active part. This will allow making the connection between active part and cover with a separate piece of optical fibre at the end of the production process. This will reduce the risk of physical damage of this last part of the optical fibre.

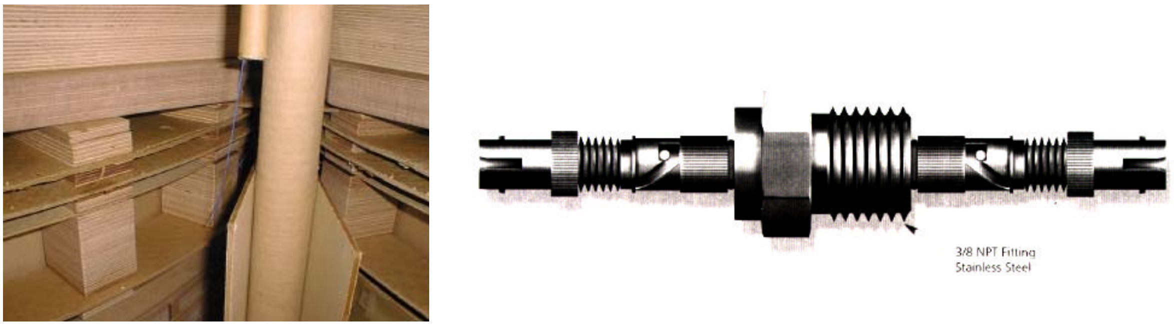


Figure 3-5: **Left: The start of a hard paper protective tube around the optical fibre.**

Right: An optical connector used to lead the optical fibre outside of the tank.

7. Since these fibres are so vulnerable for wrong treatments, it is extremely important to give all necessary information to the people of production. This includes not only those workers who need to install the system, but also those people who have to work in the neighbourhood of the optical fibres.

3.4.4. Infrared Thermography

Infrared thermography is a quick an easy method to get the temperature profile of the exterior of the transformer tank. The technique is however only feasible for one time only measurements to validate calculations or to investigate heat problems in a critical transformer.

3.4.5. Thermocouples

Thermocouples can be used in several places of the transformer. Care must only be taken that the thermocouples and the connecting wires do not cause electrical problems in the transformer. Possible usages of thermocouples are the temperature of clamping beams, tie rods, the transformer tank and other metal components.

3.5. Conclusions

Diagnostic techniques for transformers are available in great variety. Each technique has its strong and weak points and it is up to the designer and customer to work together and define which diagnostic tools are feasible to install and use on a particular transformer.

The major factors in this discussion will be the cost of the diagnostic tools, the increase in reliability of the transformer and the cost of a failure of the particular unit.

Also in recent transformers an increasing use of monitoring systems can be noticed. These systems are composed out of a number of the diagnostic techniques described in this chapter, combined with data logging and analysing tools. The most advanced of these systems provide a continuous assessment of values that in the past could only be measured in a laboratory.

4. Testing of Thermal Performance of Transformers

4.1. Introduction

Guidance for testing to verify thermal performance at rated load is provided in IEC 60076-2 (1993-04) however is currently being revised and a much improved second draft of the proposed revision has been circulated to National committees for comment. It is expected the new and significantly improved version of 60076-2 will have been issued by the time this report is published. It is strongly recommended that the latest version of 60076-2 be read in conjunction with this report when considering and specifying tests to verify thermal rating and overload capability of transformers.

The following additional requirements should also be considered for large transformers.

- Hot spot temperatures rise limits be specified and determined in each winding by direct measurement by optical fibres imbedded in each loaded winding of each phase as well as by calculation from average winding and top oil temperatures determined from conventional temperature rise test and with winding hot-spot factors determined from design calculations. The new version of 60076-2 will provided guidance on the installation of fibre optic probes and determination of winding hot-spot by calculation.
- Average temperature rise by resistance to be measured only in the phase with highest winding hot-spot temperatures, if hot-spot temperatures for same windings are within ± 3 degrees of average for the three phases, otherwise in all three phases.
- Maximum tank, bushing turrets and cable box temperatures (if applicable) to be determined from infra scans.
- Core, tie-rods, flitch-plates and flux shunt temperatures be verified as not excessive by thermocouples or from result of DGA on oil samples taken before, during and after temperature rise tests.
- The importance of these determinations increases with increasing MVA rating, increasing impedance and core flux values.

4.2. Temperature Rise Test to verify Overloading Capability of Transformers

Large transformers generally operate at higher loss density per kg of active material and at much higher leakage flux/reactive power than smaller transformers. This creates losses and heating effects, which are more difficult to calculate than heating arising from conventional no load losses in the cores and I^2R losses in the windings. Cooling calculation for large multi-winding transformers is therefore much more complex than for smaller transformers. This is particular true for large ODAF transformers, which in general operate at higher current densities and significantly higher loss densities than smaller ONAN, ONAF and ODAN cooled transformers.

Experience has shown that such transformers can have hidden hot-spots and that it is risky to load large transformer above nameplate rating without ensuring that all the serious elements such as bushings, tap changers and current transformers have been rated to carry the intended loading and that the transformer can do so without developing dangerous localised hot-spots in winding, core frame structures and tanks.

It has therefore become common practice for some utilities to specify and perform various forms of overload tests to ensure transformers have a verified overload capability, often for a specified duration only. This has lead to a proliferation of non standardised tests from some utilities, whilst other utilities mistakenly assume that all transformers can be loaded in accordance with the loading guide, without need to ensure that the transformer is free from dangerous hot-spots at the intended overload.

It is the view of WG 2.24 that overloading capability should not be taken for granted for large transformers rated more than 100 MVA or where the leakage flux value per limb exceeds 3 MVAr.

One of the tasks WG A2.24 set itself was to produce recommendations for suitable tests to verify transformers overload capabilities. It therefore looked at tests that would be suitable to verify test loading capability in accordance with the IEC loading guide 60076-7. (In the context of this document overload means loading above the nameplate rating).

Some Australian transmission utilities have specified and performed emergency overload tests as a routine test to prove the ability of its transformers to be overloaded in accordance with the requirements of IEC Loading Guide 60076 -7 and its predecessor 354, for more than 25 years.

The aim of the utilities was to ensure that all new transformers could be loaded in accordance with the IEC loading guide criteria of 1.3 p.u. for ODAF transformers rated $\geq$ 100 MVA ODAF, and 1.5 p.u. for all other transmission and bulk supply transformers within the constraints of a maximum winding hot-spot temperature of 140°C and/or a top oil temperature not exceeding 110°C, without causing any damage to the transformer beyond the accelerated ageing, which inherently will occur at such elevated temperatures.
This capability was verified by ensuring that the rates of increase of dissolved CO, $CO_{2,}$, hydrogen and other hydrocarbon gases per hour and their sum total, did not exceed specified maximum limits whilst the transformer is operating at a winding hot-spot temperature of 140 (-5,+0)^{c}C for a period of 12 hours.

The 12 hours period was somewhat arbitrary but the overload period must be long enough to ensure that gasses produced by any dangerous localised hot-spot are produced in sufficient quantity to be detected in the oil sample taken after the end of the overload test by DGA.

The benefit of adopting an overload verification test method as specified by some Australian transmission utilities is that their emergency overload tests verifies the loading capability conforms with the IEC 60076-7 loading guide, (except for Short Time emergency loading of 1.8 p.u. for medium power transformers and 1.5 p.u. for large power transformers).

An additional benefit of adopting the Australian test method is that it should not cause any design criteria changes for those manufacturers who already ensure their transformers comply with the requirements of IEC 60076-7.

WG A2.24 shares the concern about the risk of performing overload tests at the short time emergency loadings of 1.8 p.u. for medium power transformers and 1.5 p.u. for large power transformers. WG A2.24 considers testing at these loading levels is risky without very close and competent monitoring and control and consequently does not wish to recommend overload testing at these values.

It is important to remember that the initial load and stray losses during overloading and overload testing are much higher than at 1 p.u. load Viz.:

- @ 1.3 p.u. overload – 169% of losses at 1.0 p.u. load
- @ 1.5 p.u. overload – 225% of losses at 1.0 p.u. load
- @ 1.8 p.u. overload – 324% of losses at 1.0 p.u. load

These increases in losses are very significant, especially for ODAF transformers that may already be operating at relative high loss densities at 1.0 p.u. load. It is for this reason that WG A2.24 does not recommend testing at the short time overload limits and recommends to anyone who may wish to include short time testing at these limits to do so with extreme caution.

The loss increases listed above are approximate only, as the stray loss component will reduce slightly as the temperature and consequently the resistance increases, whereas the I^2R losses will increase further with temperature/resistance increases.

The recommended overload verification test and acceptance criterion recommended by WG A2.24 is set out below.

4.3. Special Test-Temperature Rise Test to Verify Long Time Emergency Loading Capability

The purpose of this test is to verify that the transformer can be overloaded in accordance with IEC 60076-7 Long Time Emergency Loading without causing any damage to the transformer beyond the accelerated ageing normally occurring at higher temperatures.

This emergency overload test is only intended to be performed on transformers where the asset owner intends to make use of the overload capability.

The recommended tests do not apply to generator step-up transformers where the turbo-generator normally is the limiting series element or other special purpose transformers (SVC, furnace, etc.). If an overload capability is required for such transformers the specific requirement should be verified by tests that replicate the intended overload requirements.

The test procedure recommended for verifying an overload capability in accordance with the IEC 60076-7 Long Time Emergency Loading is as follows:

- Temperature rise test at 1.3 p.u. rating for Transformers rated > 100 MVA
- Temperature rise test at 1.5 p.u. of highest rating for all transformer rated $\leq$ 100 MVA

These tests are in addition to the normal temperature rise test performed at 1 p.u. load.

The purchaser should nominate the tap position to be used for the Emergency Loading test, taking into consideration which tapping positions are most likely to be in use during overload conditions. This will typically be a tapping position that compensates for the voltage drop occurring within the transformer during a likely overload scenario. If the tapping position for the overload test is not nominated, then it is recommended that the tap position, 3 tapping steps from the maximum ratio tap shall be used.
The tap position used and the losses and current applied during test shall be recorded and stated on the test certificate.

The emergency overload temperature rise test shall be performed as a normal temperature rise test except:

1. The test shall be performed at 1.3 p.u. or 1.5 p.u. load current as applicable for the rating. It may commence at any oil and winding temperature which does not exceed the temperatures established at 1.0 p.u.
2. The test shall be carried out within the constraints of a maximum top oil temperature of 110°C and winding hot-spot temperature of 140°C (-5,+0) ^{0}C as determined by fibre optic probes.
3. If it becomes evident that these temperatures will be exceeded at the respective 1.3 p.u. or 1.5 p.u. loading, then the test shall be interrupted by a “temporary shutdown” when top oil temperature reaches 110°C or the winding hot-spot temperature reaches of 140°C (-5,+0)^{0}C as determined by fibre optic probes, whichever occurs first. This is to allow measurement of the average winding temperature rise by resistance method (IEC 60076-2) and to determine the winding gradients and the winding hot-spot

temperatures calculated by the conventional method for comparison with the winding hot-spot temperatures measured by the fibre optic probes. The resistance measurements shall be made on the primary and secondary phase windings which have the highest temperatures indicated by the fibre optic probes.

4. The overload test shall re-commence as soon as the resistance measurements have been completed and the results compared with the temperatures measured by fibre optic probes

   The p.u. load applied when the test re-commences shall be a p.u. load which will maintain a top oil temperature not in excess of 110^{0}C and /or a winding hot-spot temperature of 140°C (-5, +0^{0}C). The test shall continue for 12 hours after the top oil temperature has stabilised i.e. when change of top oil temperature is less than 3°C per hour.

The test sequence shall establish:

5. Time / temperature graph for top oil, tank and winding hot-spots at the respective 1.5 or 1.3 p.u. rated current.
6. Maximum local temperature rise in frames, tank and fittings at the respective 1.5 or 1.3 x rated current. It is recommended that this be done by infrared thermography scans. The temperatures exhibited by these components shall not exceed the winding hot-spot temperature or other agreed lower temperature limits, which may be applicable if there are materials with lower temperature limits in contact with these components (gaskets, seals etc.).
7. Winding temperatures and winding gradients of the primary and secondary windings, at the respective 1.5 or 1.3 x rated current and at the p.u current obtained at the end of the12 hours test, if not the same, both by optical fibre measurements and from temperature rise shut down measurements as per point 3 above, and at the end of the 12 hours temperature rise test.
8. The winding hot-spot temperature shall be determined:
   a. from measurement by fibre optics probes and
   b. also by calculation as follows:

$T_{WHS} = T_{Air} + \Theta_{TO} + H \times G_{WA}$ [°C]
T_{WHS} - Calculated Winding Hot-spot Temperature [°C]
T_{Air} - Ambient Temperature (Air) [°C]
Θ_{TO} - Top Oil Temperature Rise [°C]
G_{WA} - Average Winding Gradient by Resistance [°C]
H - Hot-spot factor calculated as per 60076-2 or if not available then 1.3

The highest value of (a) and (b) is deemed to be the "Winding Hot-spot" temperature "T_{WHS}".

The purpose of the extended period at high temperature, is to verify that the transformer can operate under such load conditions without causing any damage to the transformer, beyond the accelerated ageing normally occurring at higher temperatures.
It is therefore necessary that the transformer remains operating at the overload/high temperature condition, at sufficiently long time to generate enough gasses to be detectable and to be able to calculate the rate of gas evolution to assess the seriousness of any abnormal hot-spot, if present.

The hot-spot temperature in core clamps, tank and fittings at external surfaces shall be measured by infrared scans, thermocouples or thermometers.

The gas relay shall be operational during the temperature rise test and shall be checked for gas accumulation after this test.

It is recommended that duplicate oil samples be collected from the active oil flow such as from the bottom header from the cooler bank, or at another convenient sampling point immediately before the emergency overload test commences, at 6 hours after the oil/winding has stabilised at the limiting temperatures and within 30-60 minutes after the test has been completed.
It is also recommended that the location of the sampling point, the temperature of the oil sampled and the time of sampling be recorded at the time of each sampling event.

Dissolved gas analysis (DGA) should be performed on the oil samples taken before, during and after the test to determine: - The rates of increase in the level of the respective gases and total increase in content of gas in the final oil sample after the emergency temperature rise test has been completed.

The current IEC 60076-2 draft Standard includes guidance on gas level increases during normal temperature rise tests. WG A2.24 recommends that this document be consulted for guidance on the performance of various aspect of the temperature rise test.

One Australian transmission utility that has specified emergency overload tests for all its transmission and bulk supply transformers for more than 25 years, at 1.5 and 1.3 p.u. levels generally as at outlined above, include limits for gasses in oil in its specifications as set out in Table 4-1 below.

WG A2.24 supports the use of these limits as acceptance criteria, until additional results from other users can be reviewed and considered as a possible alternative.

Table 4-1: Limits for rates of increase of gas levels and final gas levels after long duration emergency temperature rise tests.

	H_2	CO	CO_2	$CH_4 + C_2H_6 + C_2H_4$	C_2H_2
	Values based on Total Gas Extraction Analysis Method				
* Rate of increase ppm/hr at 1 p.u. load	4	3	25	1	0
Final gas level ppm	150	115	950	38	0
	Values based on Head Space Gas Analysis Method				
* Rate of increase ppm/hr at 1 p.u. load	4	4	37	2	0
Final gas level ppm	169	167	1419	65	0

*The maximum permissible rate of increase in gas levels at a load in excess of 1 p.u. to be adjusted as follows:

$$\text{Rate of Rise at X p.u.} = \text{Rate of Rise 1 p.u.} \frac{(\text{Actual load @ X MVA})^2}{(\text{1 p.u. MVA})}$$

WG A2.24 recommends that the following acceptance criteria adopted:

- No free gas accumulation in Buchholz relay during the emergency overload test
- No evidence of abnormal hot-spots in tanks, fittings and windings determined by infrared thermographic scans
- Increased gasses in oil determined by DGA techniques shall not exceed the limits listed in Table 4-1.

- Gas levels in excess of these limits are not an automatic rejection criterion, but the cause of the increases shall be determined and remedied, as it most likely indicative of a severe localised overheating.

The Australian utilities have found very few transformers that have had gas level in oil in excess of the above limits. Those that have been found have all failed due to high CO and CO_2. Severe overheating and insulation degradation was found to have occurred in each case. Cases include overheating of mild-steel tie rods and overheating of electromagnetic flux shunts. The defects could all be remedied and the transformers passed subsequent tests after the remedies had been completed.

If the transformer under test is one of several transformers of same design and one or more transformers of same design have already passed the long duration emergency overload test, then consideration could be given for a shorter test than the twelve hours provided all winding hot-spot temperatures are within say ± 3 - 5°C of the temperatures measured on other transformers of identical design. Shortening the test duration would be a matter for agreement between the purchaser and the supplier.

It is considered that the Emergency Overload test is both a type test and also a manufacturing quality assurance test on the specific unit. It is for this reason it is classified as a routine test to be performed on all large transformers intended to be subjected to overload beyond its nameplate rating.

A number of design and manufacturing defects have been identified from the use of fibre optic probes and overload testing over the last 25 years. The types of defects identified include:

- Blocked oil ducts in windings
- Oil leakage past cylinders and oil flow washers
- Unbalanced oil flow between phases
- Oil flow not proportioned correctly between windings on same phase

These types of faults would probably not have been discovered during factory acceptance testing by a conventional temperature rise, where the winding temperature is typically measured in one set of phase windings only.

4.4. Comparison Data Levels for Long Duration Emergency Overload Temperature Rise Tests on new Transformers

The results set out in Table 4-2 covers dissolved gas analysis results from long duration emergency overload test on new transformers supplied to one Australian Transmission utility. The results has been accumulated over 25 years and would include results from approximately 100 transformers and several manufacturers, with the transformers ranging from 50 MVA to 400 MVA and a few autotransformer rated up to 1000MVA. More than 80 % of these transformers would have had ODAN or ODAF cooling at their highest rating.

The gas extraction methods would have included both total gas extraction method and headspace analysis. The information available does not allow segregation based on gas extraction methods.

Table 4-2: Analysis of total increase in gas level following long duration emergency overload test - total gas levels present after tests.

	H_2	CO	CO_2	$CH_4 + C_2H_6 + C_2H_4$
Average for transformers supplied by Australian manufacturers from 1993-2004	20	60	480	12
90 % percentile value for transformers supplied by Australian manufacturers from 1993-2004	45	111	1040	44
90 % percentile value for transformers supplied by Australian manufacturers 1983-1990	129	78	794	19
Average for transformers supplied by manufacturer "X"	40.4	46.5	229	3.2
90 % percentile value for transformers supplied by manufacturer "X"	76.3	94.2	447	8.1

4.5. Winding Resistance Tests Measurements for Temperature Rise Tests

4.5.1. Influence of cooling by fans and pumps during measurement of the cooling curve.

It considered best not to change the cooling method during the temperature rise shut down for measurement of the winding resistance. Any change in the cooling mode will introduce an additional transient effect that is likely to increase the uncertainty of the measurement and extrapolation back to time zero for the shut down. Further discussion and advice on correction for the falling oil temperature during the shutdown is planned to be given in annex C of IEC 60076 -2, currently being revised (2009).

4.5.2. Comments on timing for first measurement

The resistance measurement should commence as quickly as possible after the shut down and preferably in less than 2 minutes after the disconnection of the supply. The first few results will be false because of the inductive voltage drop. The measurement should continue for duration of at least 2 x the winding time constant, which is typically in the range of 3-8 minutes. IEC 60076-2 annex C referred to above provides comprehensive guidance on the procedure to be followed for measurement of winding resistance during temperature rise shut down measurements.

4.6. Caution on Emergency Overloading of transformers

Overloading of large transformer should always be treated with caution. It is the view of WG A2.24 that the overload capability should not be taken for granted for large transformers rated more than 100 MVA or where the leakage flux value per limb exceeds 3 MVAr.

WG A2.24 therefore recommends that emergency overload tests be performed with all following the methods and criteria set out in this Section, if the user intends to overload transformers to anywhere near the limits set out in the IEC 60076-7 loading guide and for all transformers rated > 100 MVA, if any MVA load beyond nameplate rating is contemplated. This is especially important for ODAF cooled transformers, which in general, operate at higher loss densities than transformer with less efficient cooling methods.

In addition to verifying the performance by emergency overload test, transformer users should also specify and ensure that bushings, tap changers and CT's used on the transformers are suitable for the intended overload. The following criteria can be used as a guide:

- Minimum continuous current rating of bushing $\geq$ 1.2 x maximum rated line current of transformer
- Minimum continuous current rating of tap changers $\geq$ (Maximum tapping current x the maximum p.u. overload) / 1.2
- Minimum continuous current rating of CT's fitted within transformers $\geq$ the maximum current passing through the CT's during overload / 1.2. Note, a suitable allowance must be made for the oil temperature during overload, if the CT is mounted in a location with high oil temperature
- Overload should be restricted and reduced significantly if moisture level in the solid insulation is $\geq$ 2%. Bubble formation occurs in paper at 140-150^{o}C
- Moisture level in oil can increase rapidly at high oil temperatures if moisture level in solid insulation is high (> 2%). High moisture level in oil can cause moisture saturation in oil and rapid loss of dielectric strength if oil with high level of moisture is cooled more rapidly than the moisture is reabsorbed back into the solid insulation.
- Oil samples should be taken and DGA performed at frequent intervals, whenever a transformer is subjected to significant overload until it has been established that the overload does not cause abnormal increases of gases dissolved in the oil.
- If additional cooling is required temporarily, use portable fans for forced-air cooling, water spray on radiators can be very effective but can causes corrosion if used repeatedly or for long periods.
- Consider the location of control cubicles. Tank mounted cubicles may be subjected to overheating and possible equipment failures during overloading of transformer if the temperature within the cubicle is too high. This is applies especially to cubicles mounted on transformer tanks that are located within a sound enclosure. For such installations control cubicles should be located outside the sound enclosure.

5. Thermal Design of Transformers

5.1. From Theoretical Life of Insulation Systems towards Thermal Design

5.1.1. Theoretical Life

The theoretical life expectancy of transformer has always been a controversial subject. The original IEC 354 Standard gave no indication and the new IEC 60076-7 indicates 150 000 hours for the thermally upgraded paper, determined from samples tested in sealed tube under laboratory conditions. This is in line with the IEEE Standard and applies to thermally upgraded paper at 110 °C.

For reference, the other IEEE and IEC values are as follow:

- 50% retained tensile strength : 65 000 hours
- 25% retained tensile strength : 135 000 hours
- 200 retained degree of polymerisation : 150 000 hours

IEC and IEEE also give the value from distribution transformer functional life test of 180 000 hours. It must be emphasised that these life expectancies are based on sealed tube tests which only consider the effect of temperature and aim to avoid the influence of moisture, oxygen, acids, contaminants and so on. Cigré Brochure 323 by task force D1.01.10 shows some of the effects of those other ageing accelerating agents.

It is however acknowledged that the thermally upgraded paper is less affected by the presence of reasonable amount of moisture than the normal Kraft paper

A low DP value or low tensile strength does not impair the dielectric withstand of the paper. The link between DP and insulation life expectancy is determined in a laboratory environment under singular and constant operating thermal conditions (e.g. 110°C for upgraded paper and it is implicitly referenced to 98°C for Kraft insulation material) and does not represent the actual operating conditions in a transformer. The value of DP = 200 has become almost if not universally accepted, as an end-of-life criteria.

From a practical viewpoint, a 50 % reduction in tensile strength corresponds to a DP below 300. The solid insulation mechanical withstand is becoming critical but the transformer can still offer a long life of service as the lowest DP area is not necessarily the most highly stressed.

5.1.2. From Theoretical Life to Real Thermal Life of Transformers

A transformer is not a sealed tube. Transformers (mainly transmission and distribution) do not see high loads therefore experience an average life of up to 30 – 40 years.

High load conditions (GSU and furnace transformers, hot climates, overloads) can cause accelerated thermal ageing when not taken into account.
Other factors such as oxygen and moisture also impact the life expectancy, that is why the main Standards request temperature rise limits that are lower than the thermal capability of the material. Further more, different insulation materials interact within the transformer. It would be a considerable mistake to use all materials up to their own limits. Some data on the influence of other ageing agents are referred to in the Cigré Brochure 323. It has to be noted that some recent research shows thermally upgraded paper has a higher sensitivity to oxidation. This greater influence of oxygen on TU paper at relatively low temperature may reinforce the wish to limit the guaranteed temperature of TU paper.

The predominant factor in transformer ageing is the yearly average hot-spot operating temperature and because the real hot-spot temperature is not, or more accurately was not, usually directly measured, the Standards had to define conventional temperature rises which allowed for a normal life expectancy.
Because it would have been impractical to define several temperature rises depending on the usage of the transformer, the option to cover the worst case, the constant power transformer e.g. a GSU) has been adopted in Standards.

For network and distribution transformers the hot-spot temperature will not only depend on the ambient conditions but also on the load. This is taken care of by the rated power definition. A transformer subject to variable load must be defined to achieve an average ageing of 1 per unit.
A convenient example discussed later in this document is the gas turbine generator step up transformer for which the load varies with the ambient temperature diminishing when the ambient temperature increases.
For other types of loads Standards such as IEC 60076-8 offers guidance on how to define the rated power.

It is more than likely that a GSU transformer will experience a full power throughput all year round and therefore rated power is an obvious value.

The basis of the design according to the Standards is always that the transformer shall be capable of continuously supplying (for IEEE) or being supplied (for IEC) its rated power independently of the ambient temperature. Under those conditions the transformer shall have

a normal ageing of one year per year which means that its yearly average ageing rate must be unity.
This is clearly reflected by the IEC definition that allows for a unity rate of ageing at 98 °C with a yearly average ambient of 20 °C.

For the IEEE definition the unity rate of ageing is defined at 110°C and based on the maximum daily mean temperature of 30 °C and a hot-spot temperature rise of 80 K. However, this is only a reference and as stated in the IEEE C57.92 (1981), Clauses 4.1.1 and 4.1.2.5, the continuous operation at 110 °C of TU paper leads to normal ageing which is 65 000 hours (7 years), The much longer life is explained "[…] because the annual average ambient air temperature in most locations in the US does not exceed 20 °C […] ". The idea of yearly average ambient is then clearly stated.
Transformers designed according to IEEE have a yearly average hot-spot temperature of 100 °C for a normal rate of ageing.

Table 5-1: Comparison of the different allowed temperature rises in standards.

Standard	**Paper type**	**Average winding rise**	**Yearly average ambient**	**Hot-spot rise**	**Hot-spot yearly average**	**Max monthly mean**
IEC	Kraft	**65K** ON 70K OD 760076-2 §4.2	20ºC 760076-2 §4.3.1	**78K**	98ºC 760076-2 §6.2	30ºC 760076-2 §4.3.1
						Max daily mean
IEEE 65 rise	TU Kraft	**65K** C57 12 00 §5.11.1.11	20ºC C57-92 1981 §4.1.2.5	**80K** C57 12 00 §5.11.1.11	100ºC	30ºC C57 12 00 §4.1.2.1
IEEE 55 rise	Kraft	55K	20ºC C57-92 1981 §5.1.2.5	65K C57-92 1981 §5.1.1 [40]	85K	30ºC C57-92 1981
Standard	**Paper type**	**Max monthly hot-spot**	**Maximum daily temperature**	**Maximum hot-spot temperature**	**Base for unity ageing rate**	**Life expectancy**
IEC	Kraft	108ºC	40ºC 760076-2 §4.3.1	118ºC	98ºC 760076-2 §6.2	Not defined
		Max daily hotspot				
IEEE 65 rise	TU Kraft	110ºC	40ºC C57 12 00 §4.1.2.1	120ºC	110ºC C57 93 §3.1	65kh C57 93
IEEE 55 rise	Kraft	95ºC C57-92 1981	40ºC C57 12 00 §4.1.2.1	135ºC	95ºC C57 93 §3.1	65kh C57-92 1981

Table 5-1 compares the different temperature criteria adopted by the IEC and IEEE Standards. It is noticeable that despite the discrepancies of the reference temperature between IEEE and IEC (respectively 110 °C and 95 °C) the thermally upgraded paper used by the IEEE is used at temperature levels which are nearly the same as the conventional Kraft paper used by the IEC (respectively 100°C and 98 °C) on a yearly average base.

For completeness, the data for 55 K rise transformers stated in versions of the IEEE Standard were restated here because they were supposed to apply to normal Kraft paper. It must be noted this particular data is based on very early theory and technologies.

Despite using a reference temperature of 110 °C for the unity rate of ageing of thermally upgraded paper it is worth noting that the IEEE Standard still requires an average winding temperature rise of 65 K for the conventional Kraft paper as does IEC Standard 60076.

5.1.3. From Real Thermal Life to Thermal Design of Transformers

The temperature limits indicated in the previous Section can directly be used as thermal design specifications. However, these limits are only indicated for average winding temperature. In this Section, these average winding temperatures will be used to define all other limiting temperatures needed for the thermal design of a power transformer.

Thermal Design Specifications of Insulation Systems

A significant advantage of thermally upgraded papers is their better resistance to loss of physical strength in operation. In the past, in the USA, the expression “55K-rise paper” is often used for standard (plain, non-upgraded) paper, whereas “65K-rise paper” is used for thermally upgraded paper. The numbers refer to the average oil rise temperature, indicating that the designed hot-spot temperature with upgraded paper is higher than with untreated paper. In IEEE today, the “65K-rise paper” is the standard way of working. This allows an increased continuous load rating of the transformer.)

For OD cooling, the 70 K rise can be used instead of 65 K. In fact, the only temperature rise that really counts inside a transformer is the hot-spot temperature rise. The problem is that the hot-spot rise can in general not be measured directly. The only winding temperature that can be easily measured is the average temperature. That is why Standards have indicated an acceptable average winding rises that should result in an acceptable hot-spot temperature rise as well.

In properly designed ON-cooled transformers, an average temperature rise of 65 K can result in a hot-spot rise of 78 K. With "properly designed", we mean that the necessary measures are taken to limit the hot-spot factor to a reasonable value.

In OD-cooled transformers, the temperature difference between the average oil temperature inside the windings and the top oil temperature is very small and as a consequence, the hot-spot rise will easily be much smaller than the acceptable 78 K if the average winding temperature rise would be limited to 65 K. The limit of 78 K can easily be met with a higher average winding rise.

This is linked to the oil flow inside the windings. For ON and OF cooled transformers the oil flow through the winding is only due to the natural convection caused by the winding losses. Therefore the oil velocity is usually low (around 4 cm/s typical) and the temperature of the oil increases greatly between the bottom and the top of the winding (20K typically). For OD cooled the oil is pumped through the winding at a much higher speed (usually between 8 and 25 cm/s), which induced a much smaller temperature rise of the oil when it passes through the winding (typically 5K) and also reduces the copper to oil gradient.

Figure 5-1 shows the typical temperature rise profile of ON/OF and OD cooled transformers. This diagram has been plotted with the typical examples of transformers, which were in the last revision of the IEC 354 before its withdrawal.

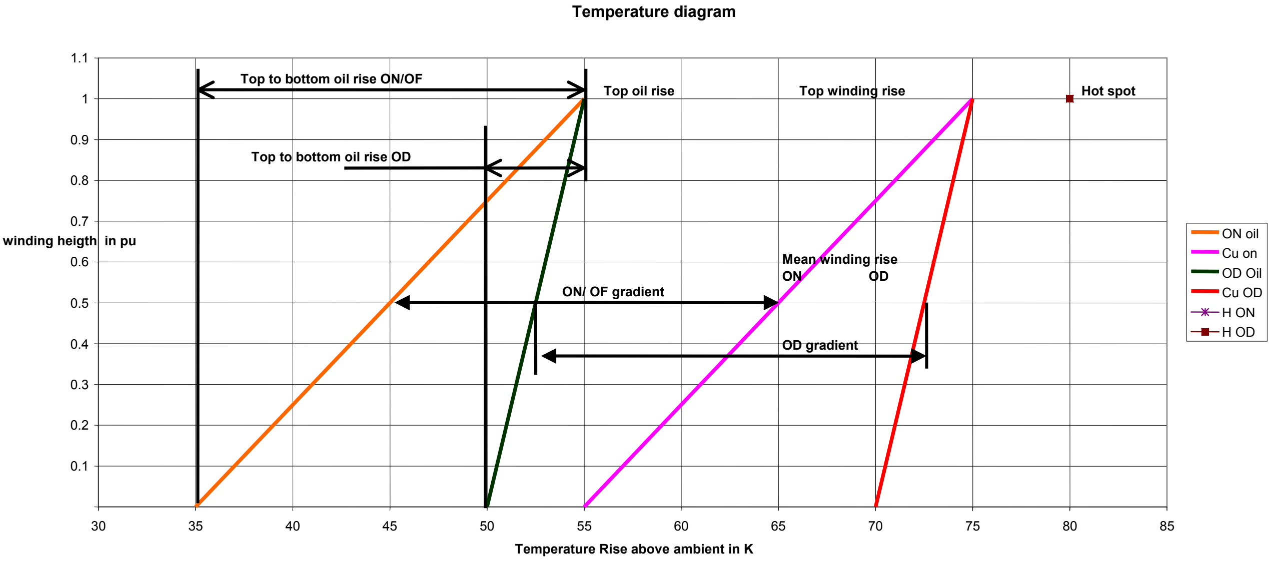


Figure 5-1: Typical temperature rise profile of ON/OF and OD cooled transformers.

Temperature rise limits must not only take account of the paper thermal withstand characteristics but also the properties and capabilities of the full complex insulation system. The parameters that are usually considered to lower the maximum allowable temperature rise include:

- Bubbling due to moisture in insulation, transformer must be design for a site operation with provision for moisture ingress.
- Copper sulfide due to potentially corrosive sulfur tendency of certain oils that have been demonstrated to become more aggressive when the temperature increases.
- Static electrification
- Etc.

Thermal design specifications of other components

Thermal criteria for metallic parts are limited by the gas production of the oil and usually 140°C is the maximum acceptable temporary temperature. For those parts in contact with cellulose insulation 120 °C is usually considered to be the maximum temperature independent of the cellulose type. Here again moisture and bubbling effects are among the limiting factors.

Gaskets and oil stability must be of course examined carefully.

The same type of criteria adopted for transformers may be used also for oil-filled bushings comprising cellulose insulations if the lowest effect of moisture and oxygen is taken into account.

For tank external surfaces other parameters such as personal safety and protection against contact with hot surface must be also part of the design. It is also likely that unacceptably hot surfaces will have an atmospheric corrosion resistance weakness.

Internal contacts such as those in leads and cleat bars as well as de-energised tap changer must be properly rated to avoid any coking risk. Here again the temperature rise limit is not linked solely to the thermal ability of the material itself but also to the complex insulation system that exists in a transformer.

5.2. Modelling of Cooling of Oil Immersed Power Transformers

Figure 5-2 shows a schematic two-dimensional section of an oil-immersed transformer consisting of an iron core, high and low voltage (HV and LV) winding, tank and radiator. Two types of windings are generally used, i.e. disc and layer windings. The former, shown in Figure 5-2 [59], consists of cylindrically wound insulated conductors, with spacers providing radial and axial oil channels. For the latter only axial oil channels are visible, as is shown in Figure 5-2 [40].

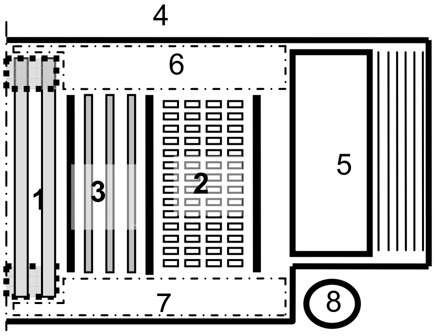


Figure 5-2: Cross-section of a transformer: (1) core; (2) disc type winding; (3) layer type winding; (4) tank; (5) radiator; (6) top oil volume; (7) bottom oil volume; (8) oil pump.

Power losses are generated due to the I^2R and eddy currents in the active part. The heat is transferred to the tank wall and to air-cooled radiators by means of an oil flow caused by buoyancy forces (ON: oil natural) or an oil pump (OF: oil forced). In turn the radiators are either cooled by natural convection (AN air natural) or by a fan forced airflow (AF: air forced).

The thermal-hydraulic model is developed with the following assumptions:

- The thermal behaviour of the transformer windings is assumed to be axi-symmetric. Thus a two-dimensional model can be used.
- Top and bottom oil volumes are isothermal and oil velocity in both volumes is neglected.
- Windings and core are thermally separate therefore, radial heat transfer between these components can be neglected.
- In absence of oil direction washers the oil flow in the radial oil channels of disc type windings is neglected. Both disc type and layer type windings are modelled as concentric cylinders, called winding layers.
- Heat transfer correlations from published sources are used.

In the following paragraphs the model equations are discussed.

5.2.1. Oil flow Model

A parallel axial channel network, as shown in Figure 5-3, models the incompressible oil flow. Each branch represents one axial winding or core oil channel. The oil flow through the radiator is modelled by one branch.

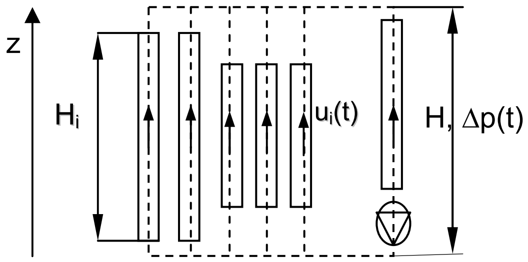


Figure 5-3: Oil flow network model (↑: convention for oil flow direction)

Starting from a developed laminar velocity profile the momentum equation is integrated over each channel length, resulting in the following one-dimensional ordinary differential equation

$$\Delta p(t) = \rho H_i \frac{du_i(t)}{dt} + \int_0^H \rho g dz + K \frac{32 H_i \mu}{D_{hi}^2} u_i(t) \qquad (9)$$

Here u_i is the oil velocity in channel i, Δp(t) is the time varying pressure difference over the oil channels and the factor K accounts for deviations from the assumed developed velocity profile.

Starting from these equations, more detailed or applied models can be derived. Manufacturers and researchers develop these models using FEM, discretisation, lumped models, network models or empirical models. The preferable calculation method depends on accuracy, transient behaviour, level of detail, and the transformers under consideration, for example.

Manufacturers have these models as propriety tools linked to their design practices.

5.2.2. Thermal Model

A thermal model is devised to represents the oil flow between windings, top and bottom oil volumes, tank, core and radiator oil mass.

Because natural convection plays an important role in all transformer-cooling regimes the buoyancy term in (9) has to be accurately determined. The axial oil temperature distribution T_{oil} is obtained by solving the one dimensional transient diffusion-convection energy equation for each oil channel in the windings and vertical core limb:

$$\rho c A \frac{\partial T_{oil}}{\partial t} = kA \frac{\partial^2 T_{oil}}{\partial z} - \rho u_i(t) c A \frac{\partial T_{oil}}{\partial z} + P_r q_r(t) + P_l q_l(t) \qquad (10)$$

with P_r and P_l the inner and outer channel perimeter, A the oil channel cross-section and q_r and q_l heat fluxes from the inner and outer contacting winding.
A similar approach is used to model the vertical core limb, the upper and lower horizontal core yokes as well as the upper and lower tank wall. The heat transfer between these different thermal masses and the surrounding oil or/and air is considered to be uniform.

The top and bottom oil volumes are both modelled by a transient energy balance.

As referred to above, more detailed or applied models can be further derived by using FEM and other analogue and digital modelling methods according to the complexity of the thermal study and desired accuracy. Again, manufacturers have these models as propriety tools linked to their design practices.

5.2.3. Radiator Model

A very important element in the thermal model is the radiator. The radiator is the most significant element for the heat transfer to the surrounding air and the mass of the radiators plus the oil they contain are important factors in transformer thermal transient modelling. Therefore these elements are also treated in detail.

When the air surrounding the radiator is at constant temperature and has negligible axial air velocity, an equation similar to (9) can be derived to determine the air velocity.

In air-forced cooling regimes, the air velocity is determined by the fan characteristics.

A transient convection energy equation models the axial oil temperature distribution in the radiator. Hereby, the axial temperature conduction in the oil channels is neglected.

$$(\rho Ac)_{oil}\frac{\partial T_{oilrad}}{\partial t}=m_{rad}c_{rad}\frac{\partial T_{oilrad}}{\partial z}-(hP)_{oil-rad}(T_{oilrad}-T_{rad}) \qquad (11)$$

with A the cross section of the radiator oil channel and m_{rad} the radiator mass flow. This equation can be solved using a first order explicit time integration with time-lagging of the non-linear terms.

A transient thermal model for the radiator mass itself, neglecting the axial heat conductance in the radiator body, results in the following differential equations:

$$(\rho Ac)_{rad}\frac{\partial T_{rad}}{\partial t}=(hP)_{oil-rad}(T_{oilrad}-T_{rad})-(hP)_{rad-air}(T_{rad}-T_{air}) \qquad (12)$$

with T_{rad}, T_{oilrad} and T_{air} the radiator mass, oil and air temperature distribution, A the radiator cross-section and P the radiator channel perimeter. This equation can easily be solved also using explicit first order time integration.

For the air side a similar equation as for the oil side is obtained.

$$(\rho Ac)_{radair}\frac{\partial T_{air}}{\partial t}=-m_{air}c\frac{\partial T_{air}}{\partial x}+h_{radair}P_{airrad}(T_{rmass}-T_{air}) \qquad (13)$$

5.3. Refinements on Thermal Calculation Models

Ageing of a transformer is determined by the electrical and mechanical conditions of insulation materials applied. Conventional insulation system consists of cellulose based materials and mineral oil. These organic substances have little resistance to heat. Their molecular decomposition can be already detectable at room temperature and is accelerated considerably at higher temperatures. Therefore, it is very important to obtain exact information about the temperature distribution in transformers, especially the winding hot-spot temperature.

As previously described, the major heat sources are those generated in the active part i.e. the windings and core. This heat is absorbed by the oil and carried into some form of heat exchanger. The location and magnitude of the hot-spot temperature can be calculated by complex models that take into account the thermal and hydrodynamic phenomena together. This document refers to some aspects of these issues.

5.3.1. Load Losses

The losses caused by the current flowing through a conventional winding (not a superconductor winding) can be divided into two parts theoretically.

- I2R losses in windings and current carrying parts
- Stray flux induced losses (eddy current losses) in windings and other metallic parts. In iron parts the stray flux induced flux also generates losses.

Distribution of the loss generated in a winding varies both along the axial and the radial co-ordinates.

Effect of the Leakage Flux in Windings

Consider a typical cylindrical winding arrangement.

At the axial middle of the winding the leakage flux has only an axial component practically. Its radial distribution is linear approximately having the maximum flux density and as a consequence causing the maximum eddy current losses, in the layer adjacent to the leakage channel. For example, Table 5-2 below shows the percentage value of the calculated eddy current losses in a full transformer made of a LV of 8 radial turns, a regulation of 2 radial turns and an HV of 9 radial turns. Figure 5-4 gives a graphical representation of this example.

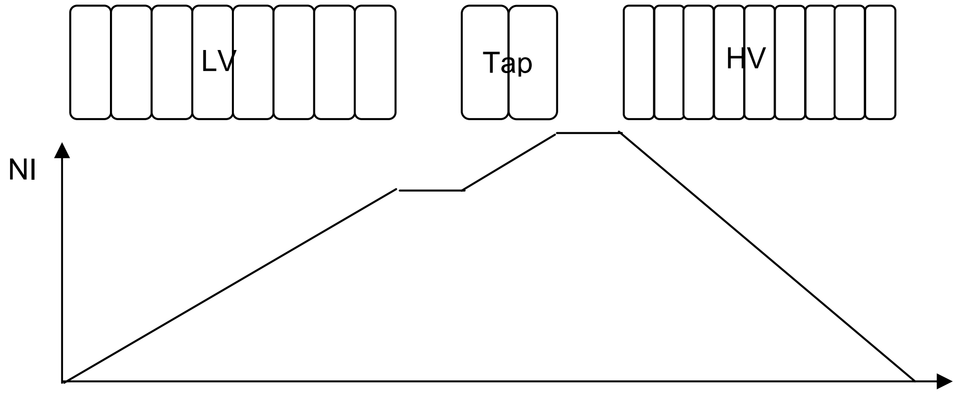


Figure 5-4: Section of transformer shown in a minus position with regulation in a subtractive mode.

Table 5-2: % value of the calculated eddy current losses in a disc winding with 8 turns radially.

Number of turn	1	2	3	4	5	6	7	8	1	2
Winding	LV								Taps	
Eddy current losses, %	0.2	1.2	3.3	6.7	11.5	17.8	25.7	33.6	11.5	19.8

Number of turn	1	2	3	4	5	6	7	8	9
Winding	HV								
Eddy current losses, %	19.5	15.7	12	8.8	6.0	3.8	2	0.8	0.1

At the top and bottom ends of the winding the leakage flux has a significant radial component so the distribution of eddy current losses can be significantly different.

Manufacturers or researchers develop different practical ways to take this into account, for example, selecting a value for ‘K’, the hot-spot factor.

Treatment of No-load Losses

No-load losses are located in the core and are generated by the magnetic flux. For practical reasons a temperature rise test with both rated current and rated voltage applied is not usually possible.

During a temperature rise test the transformer windings are partially short-circuited. The applied voltage is increased until rated current flows in the shorted windings. In this short circuit condition the core is not excited. The no-load losses are therefore added to the winding losses to measure the oil temperatures to achieve the effect of total transformer loss conditions. Finally, when temperatures in the transformer are stable the input current is reduced to rated value for a further one hour to establish the gradient between average winding and average oil (refer to IEC 60076-2 for further temperature rise test procedure information).

Effect of Temperature Differences

Temperature of the coolant increases from the bottom of the winding to the top. On the other hand, the temperature distribution is not the same along the winding radially because of the different losses and the different cooling conditions.
The winding intrinsic electrical resistance increase with increasing winding temperature, consequently increasing I2R losses but reducing the eddy current losses.

To determine the temperature distribution in a winding, cooling conditions need to be examined.

5.3.2. Natural Oil Flow in the Winding Cooling Ducts

In case of ON and practically OF cooled transformers cooling the oil is kept moving upwards in the vertical cooling ducts of a winding by the gravitational buoyancy.

Oil flow along the winding vertical surfaces shows boundary layer properties. Thickness of the hydrodynamic boundary layer (where oil flow is formed) and profile of the oil speed distribution is different in:

- unlimited oil ducts at the outer surface of the winding,
- limited oil ducts at the outer surface of the winding, and
- oil ducts between two layers of the winding (heated from both sides).

Laminar flow is characteristic only in a small region starting from the bottom of the winding. The thickness of the boundary layer increases with the height and is affected considerably by the temperature dependent oil characteristics like:

- kinematic viscosity,
- density,
- heat conductivity and
- specific heat.

In non-laminar and turbulent flow zones oil flows in a significantly wider layer, so the flow resistance of these zones can be negligible. The laminar zone mainly determines flow resistance of the vertical oil ducts.

In an unlimited half-space form heated one side by the winding losses, laminar flow is characteristic were $Pr \cdot Gr < 2 \cdot 109$. Thickness of the laminar boundary layer in the unconfined half space can be calculated by Eckert formula
The velocity profile in this region is shown on Figure 5-5.

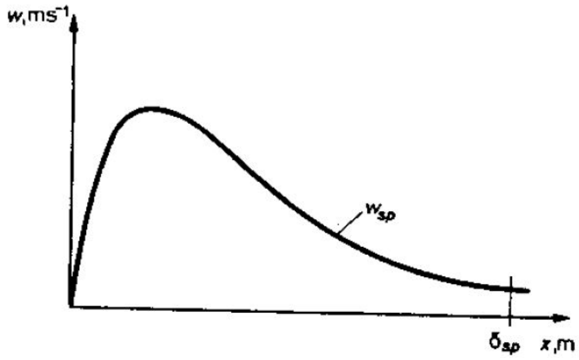


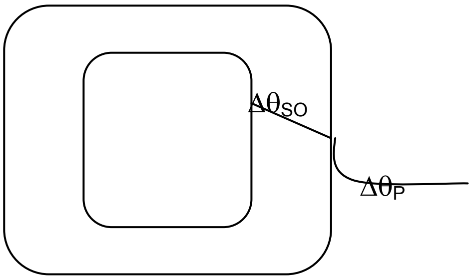
Figure 5-5: Velocity (w) distribution versus distance from the heated wall (x) in unconfined half space

The thermal boundary layer (where the heat transport from the winding to the oil is performed) is always thinner than the hydrodynamic one.

Oil flow and heat transfer in the radial (horizontal) oil ducts:
The nature of the oil flow in the radial ducts depends on the width/length ratio of the duct. In relatively narrow oil ducts definite oil flow may not occur naturally, and the loss-generated heat can come out to the axial oil ducts only by turbulent heat transfer. In this case the oil is mixed in the radial ducts, the heat transfer between the copper and the oil is better than in case of boundary layer flow, but the heat can come out to the axial oil channels with a much higher temperature gradient.

5.3.3. Difference between Mean Winding and Oil Temperature (The Winding Gradient)

Difference between mean winding and oil temperatures also called the gradient 'g' can be calculated as the sum of surface temperature drop in the oil ($\Delta\Theta_{SO}$) and the temperature drop across paper insulation of the conductor ($\Delta\Theta_P$).



$$g = \Delta\theta_{SO} + \Delta\theta_P$$

with:

$$\Delta\theta_P = q.\frac{\delta}{\lambda_P}$$

q is the heat flux density [W/m²]
δ is the thickness of the conductor insulation,
λp is the thermal conductivity of the insulation paper.
The value of $\Delta\Theta_{SO}$ depends on the cooling mode

ON and OF Cooling

In case of ON and OF cooling, the higher heat flux density (q) through the conductor surface causes higher heating and higher buoyancy forces, which causes higher oil speed and improved heat transfer coefficient (α) in the oil ducts.

$$\alpha = \frac{q^m}{C_0} \text{ or } \alpha = \frac{\theta^\varepsilon}{C'_0}$$

In general, convection cooling is determined by m=0.2 (ε=0.25) "classically". In case of windings with cooling ducts also m values exceeding 0.2 were observed - maximum about 0.4 (ε=0.667)

$$\Delta\theta_{SO} = \frac{q}{\alpha}$$

Therefore, the surface temperature drop can be obtained as

$$\Delta\theta_{SO} = C_0 . q^{1-m} = C_0 . q^n$$

where C_0 and n depends on the arrangement, but n < 1 in all cases.

In the standard (IEC and IEEE) I^2 instead of q is used (I is the load current) and applied on the total winding gradient g

$$g \sim kI^{2n} \sim kI^y \qquad \text{(as n is typically 0.9 y=1,6)}$$

OD Cooling

In the case of OD cooling, conditions of the heat transfer change substantially. Because a high-speed oil flow is forced through the cooling ducts by an external pump, the oil speed is independent of the heat flux density. Assuming the same heat flux density and different oil speeds, the temperature drop across the solid conductor insulation is the same, while the surface temperature drop will be less at higher oil speeds. At oil speed values of a few dm/s the surface temperature drop decreases to such an extent that further increase of the oil speed is not reasonable. The surface temperature drop is proportional to the heat flux density through the conductor surface (m=0, n=1, y=2):

$$g \sim kI^2$$

which is what is found in the present Standards.

5.3.4. Consequences for winding gradient decay time

A constant heat transfer coefficient α stands for heat dissipation proportional to the heating of the winding. This is also valid during the decay (time t) of the average winding gradient to average oil after shut down of the winding current.

Winding decay to oil (OD): $g(t) = g.e^{-t/\tau}$

With: $\tau = m \cdot c / (\alpha \cdot A)$

m: mass of winding

c: specific heat of winding

A: surface area of winding

In case of ON cooling, α decreases with decreasing $\Delta\vartheta_{w\text{-}o}$ (t). Therefore the decay no longer follows the exponential equation *:

ON: $$g(t) = \frac{g}{\left(\varepsilon . \frac{t}{\tau} + 1\right)^{1/\varepsilon}}$$

OD corresponds to ε = 0.

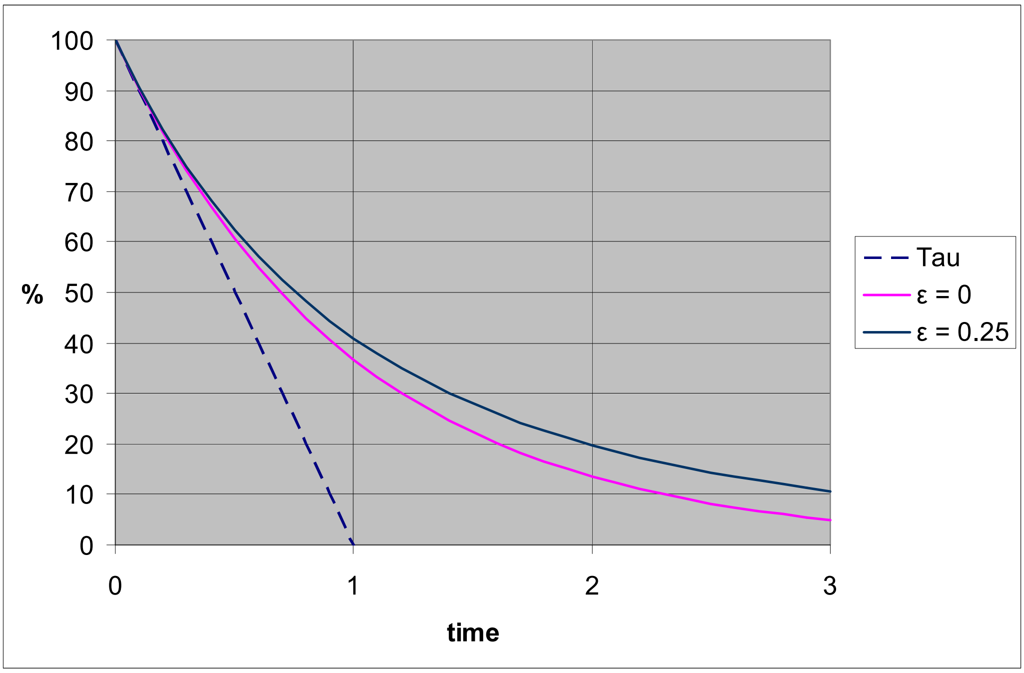


Figure 5-6: Exponential decay time.

Table 5-3: Numerical values from [46]

E	**m = ε / (1 + ε)** **m**	**y = 2 / (1 + ε)** **y**	**Δϑw-o (%) at t = τ** **%**	**τ`= τ / x for 36.79 % value** **x**
0	0	2	36.79	1
0.25	0.2	1.6	40.96	1.136
0.5	0.333	1.333	44.44	1.279

5.3.5. Temperature difference between oil entering and leaving the winding ($\Delta\Theta_o$-$\Delta\Theta_{ob}$)

Having q heat flux density transferred in the oil through A_c convection surface of the winding, the oil will be heated with a temperature rise of

$$\Delta\theta = \frac{q.A_c}{c_{oil}.\dot{m}_{oil}} = C_1 \cdot \frac{q}{\dot{m}_{oil}}$$

c_{oil} is the specific heat of the oil

$\dot{m}_{oil}$ is the mass flow of the oil

In the cases of ON and OF cooling, the pressure provided by buoyancy is proportional to this temperature rise

$$\Delta p_b = C_2.\Delta\theta = C_1.C_2 \cdot \frac{q}{\dot{m}_{oil}} = C_3 \cdot \frac{q}{\dot{m}_{oil}}$$

Comparing the last two equations, it can be seen that the Δp_b is proportional to $\Delta\theta$.
On the other hand, as it was stated above, the flow resistance of the oil ducts in a winding is determined by the laminar zones. In case of laminar flow Δp_w pressure drop in the winding can be calculated as

$$\Delta p_w = C_4.\dot{m}_{oil}$$

Under OF cooling, the hydraulic resistance of the connected cooling circuit can be neglected, because it is usually compensated by the pressure of an external pump. The mass oil flow $\dot{m}_{oil}$ can be ensured in the winding continuously, only if

$$\Delta p_b = \Delta p_w$$

Consequently, the temperature difference between oil entering and leaving the winding depends on the transferred heat as

$$g = C.\sqrt{q}$$

Under ON cooling the temperature difference can be modified by the cooling circuit. It can be smaller if the buoyancy is increased by raising the centre of the cooling, and it can be bigger if such an increase is insufficient to overcome the pressure increase caused by the hydraulic resistances extraneous to the windings.

In case of OD cooling, the constant pressure provided in the winding oil ducts by external pump ensures a constant oil mass flow. So the temperature difference between the oil entering and leaving the winding is proportional to the heat flux density transferred.

$$\Delta\theta = C.q$$

which is typically known as $\Delta\theta = \frac{2kW}{Q}$

where 2 is 1/C of the oil
kW is the losses to evacuate in OD
Q is the oil flow due to the pumps

In theory the value C of the transformer should vary depending on the temperature. In practice this variation can be neglected within the temperature range used in a transformer. Typically C_p is 2.29kJ/kg between 60° and 100ºC with a density of 0.86 at 60ºC and .84 at 100ºC. 1/C then varies between 1.97 and 1.92. The value of 2 has been considered as a good enough approximation for years.

5.3.6. Temperature Distribution in the Winding

These detailed calculations differ between single conductors. Especially in case of large power transformers the values will exceed the conservative calculation with averaging the hot-spot temperatures. Before application of increased values the thresholds of the Standards should be adopted. In addition, the oil temperature level inside windings gains the level of the surface temperature of the winding insulation. Therefore the oil temperature level in windings exceeds the top oil temperature measured at the tank cover or the cooler inlet.

Moreover there are deviations of local temperatures in transformers.

5.4. Typical temperature Profiles

5.4.1. Typical Temperature Profiles in Transformers

Temperatures in cooler (oil), windings (oil) and windings for a transformer with radiators.
The numbers indicate the progress by forced cooling.
Note the high winding temperatures in case of OFAF despite the low radiator oil temperatures

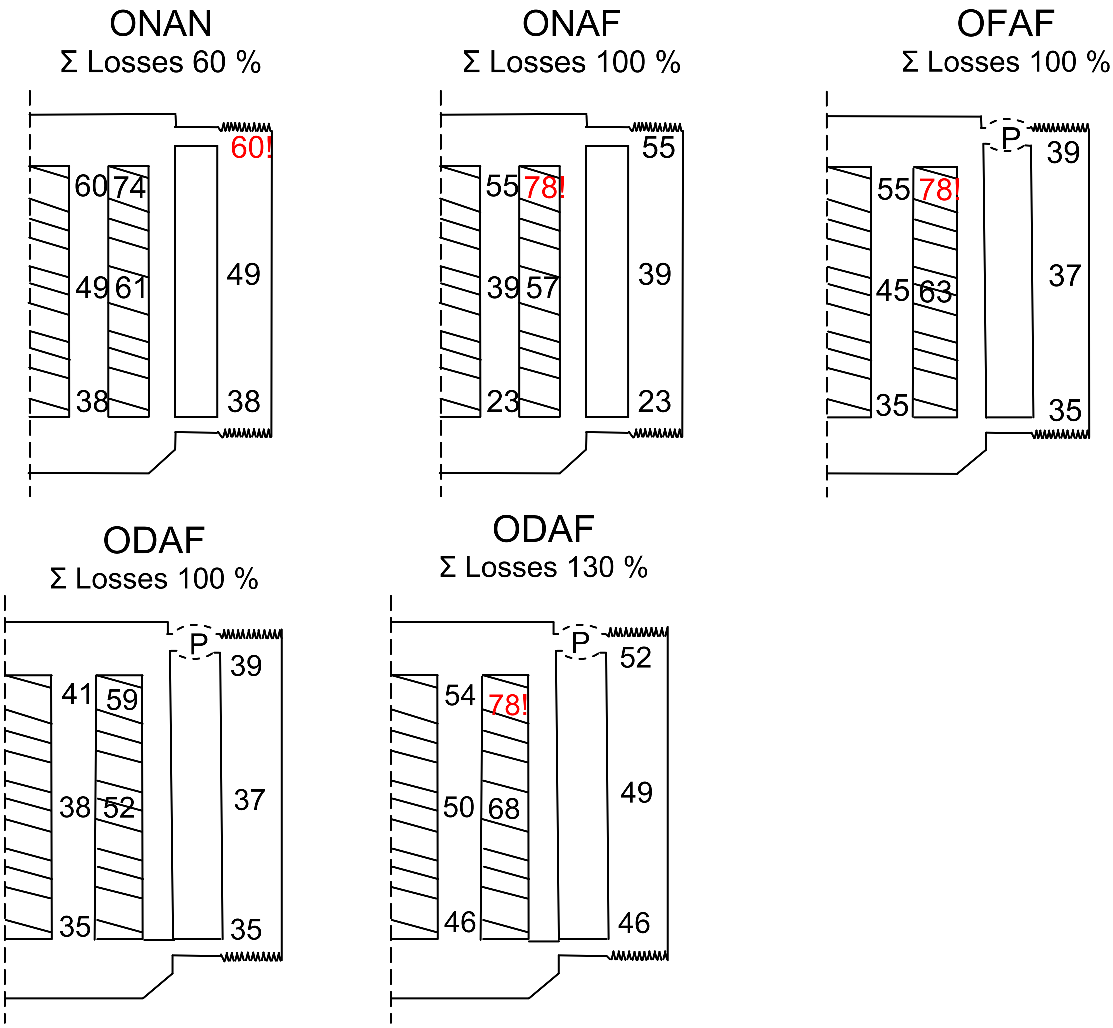


Figure 5-7: Typical temperature profiles in transformers

Elevated temperature of top coils of some winding can results in premature critical localized deterioration

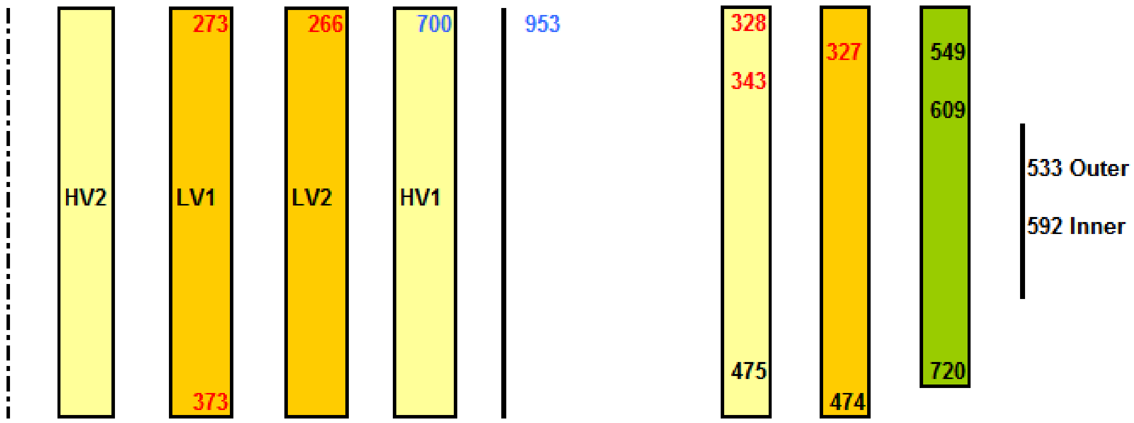


Figure 5-8: Ageing profile of 700MVA 400 kV GSU, OFAF after 14 years (left) and of 730 MVA, 400 kV transformer, OFAF after 13 years (right).

Temperature profile can determine ageing profile of the transformer

Table 5-4 and Figure 5-9 refers to a 700 MVA transformer, in which thermal life is practically determined by the condition of the LV1 winding top coils that involving less that 2% of total amount of insulation.

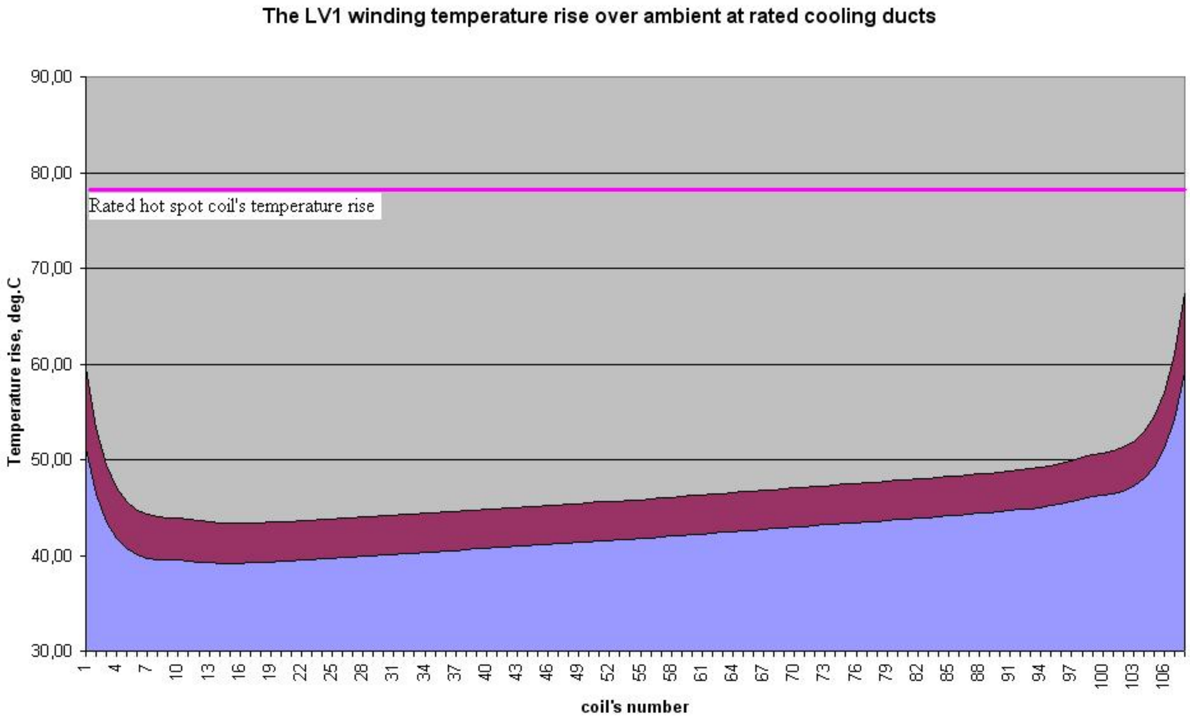


Figure 5-9: Temperature profile of LV1 winding in a 700 MVA GSU transformer

Table 5-4: DP test data in a 700 MVA GSU transformer

		DP Winding	**DP Pressboard**
HV1	**Top**	486	1004
	Bottom	640	990
HV2	**Top**		
	Bottom		713
LV1	**Top**	300	990
	Bottom		
LV2	**Top**		
	Bottom	526	515

5.4.2. Typical Thermal test and use of IEC and IEEE

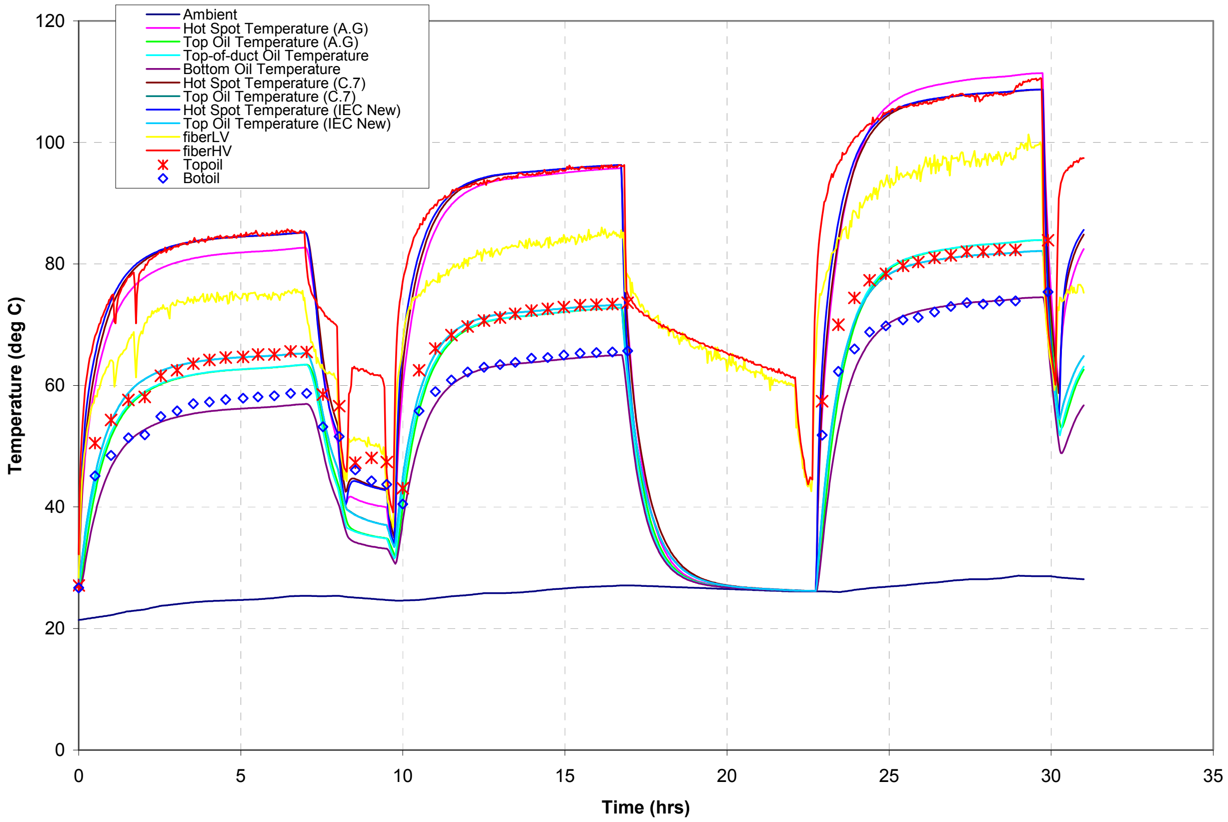


Figure 5-10: Comparison of dynamic temperature prediction by different methods and standards.

5.4.3. Maintaining inadequate oil temperature during transformer operation results in additional ageing

A normal top oil temperature is considered to lie within the range of 75-85°C For example, IEEE recommends a maximum permissible top oil temperature of 95°C irrespective of transformer thermal performance peculiarities. In fact there is a balance between rise of winding temperature above oil and rise of oil temperature above ambient and any imbalance can result in unnecessary oil and insulation overheating [55].

5.5. Specified Characteristics of Thermal State of a Transformer

5.5.1. Cooling Method

Cooling a transformer can be achieved by several means, from the simplest to the most advanced. The choice of the cooling method is usually made by the purchaser, nevertheless some well-known properties and general application cases are worth noting here.

ONAN

This is the simplest version of the cooling of transformer, where all circulation forces are coming solely from the natural thermal head.

In this cooling mode the oil flow depends on the actual load of the transformer. The top to bottom temperature difference is usually high.

This cooling method does not require any auxiliary power and is therefore well adapted to remote substations where maintenance could be a problem. Its main draw back is the large footprint introduced by the use of radiators.

ONAF

Adding fans to the radiators of an ONAN cooled transformer creates an OAF type transformer cooled classification. Nothing is changed on the oil side, and the oil flow still follows the load.

On the air side, usually above a certain temperature, the heat exchange is enhanced by means of fan forced airflow.

Those transformers with two stage cooling are well adapted to transformer with a relatively low load most of the time and some peak load periods where the fans will operate.

The footprint of the erected transformer is reduced compared to a full ONAN unit but some maintenance and an auxiliary power supply is needed.

OFAF

Two ways of creating an OFAF transformer exists. Either by just adding pumps to a radiators and fans (ONAF) cooled transformer and thus creating a possible three-stage transformer cooling system or by using forced oil air-blast coolers from the outset. Forcing the oil through the cooling system will result in a very small top to bottom oil temperature difference but this has a very limited impact on the actual oil temperature inside the winding, as the oil circulation inside of the winding is still natural.

Using forced-oil cooled transformers requires some caution especially as far as hot-spot temperature determination is concerned. Top oil is not reflecting the actual oil which surrounds the hot-spot. Further more, forcing cold oil outside of the winding may impair the natural oil flow if badly designed.

The advantage of an OFAF cooled transformer is its increased power capacity within the same footprint.

ODAF

With ODAF cooling, the oil is directed to inside the windings and the oil flow does not depend on the load. The higher oil speed inside the windings reduces the gradient between the windings and their surrounding oil and also reduces the winding top to bottom oil temperatures.

The top oil temperature can now be regarded as more accurately reflecting the oil temperature that surrounds the hot-spot.

ODAF can be achieved either by adding pumps to radiators and fan cooled transformers, and if the pumps are designed properly, a natural stage of oil cooling can still be achieved directly through the pumps. ODAF can also be obtained with air-blast coolers.

Air-blast coolers are the most compact and efficient coolers available, but they need constant power supply and frequent maintenance.

ODWF or OFWF

With water instead of air as the cooling medium, both forced and directed oil can be achieved with the same pros and cons as discussed above. Water-cooling allows very high capacity, very small volume coolers to be used but a with a higher level of required maintenance.

5.5.2. Top oil temperature

The top oil temperature is a mixture of the oil temperatures leaving windings and core and the tank bulk oil temperatures. The indicated tank cover top oil measurement depends on location of the temperature sensor and is a function of climate conditions (sunshine, rain, etc.) at the time. Variation of core temperature influences the sensor readings. Overloading of transformer is in most cases accompanied by over excitation and a relevant increase of core temperature due to the effect increased stray fluxes. This all adds an uncertainty to the determination of a realistic top oil temperature.

The maximum oil temperature is the temperature of oil leaving the most thermally stressed winding. Oil temperatures leaving windings are always hotter (typically by 5-10K and in some design 15-20K)) than top oil temperatures. Differences do exist between HV and LV, in ON and OD systems and particularly in OFAF cooling systems.

5.5.3. Forcing of oil in OFAF –mode

Forcing of oil in OFAF–mode can increase oil temperature if the cooling equipment is not coordinated properly with the hydraulic resistance and oil flow rates through the windings.

Under OFAF cooling, in order for oil to flow through the core and windings the total oil pressure has to exceed the required oil lift in the cooling ducts and the loss of pressure due to hydraulic resistance. However, increasing pump pressure makes sense only if it achieves sufficient pressure to equal to that needed to lift oil in the space outside the windings (level oil in conservator). Forcing oil circulation can result in deterioration of oil flow through windings and increase oil and winding temperatures.

The mean rise of winding temperature does not reflect real thermal state of winding. Some coils may have a temperature substantially higher than the mean winding temperature and it is very important to understand temperature profile of the winding (Figure 5-11).

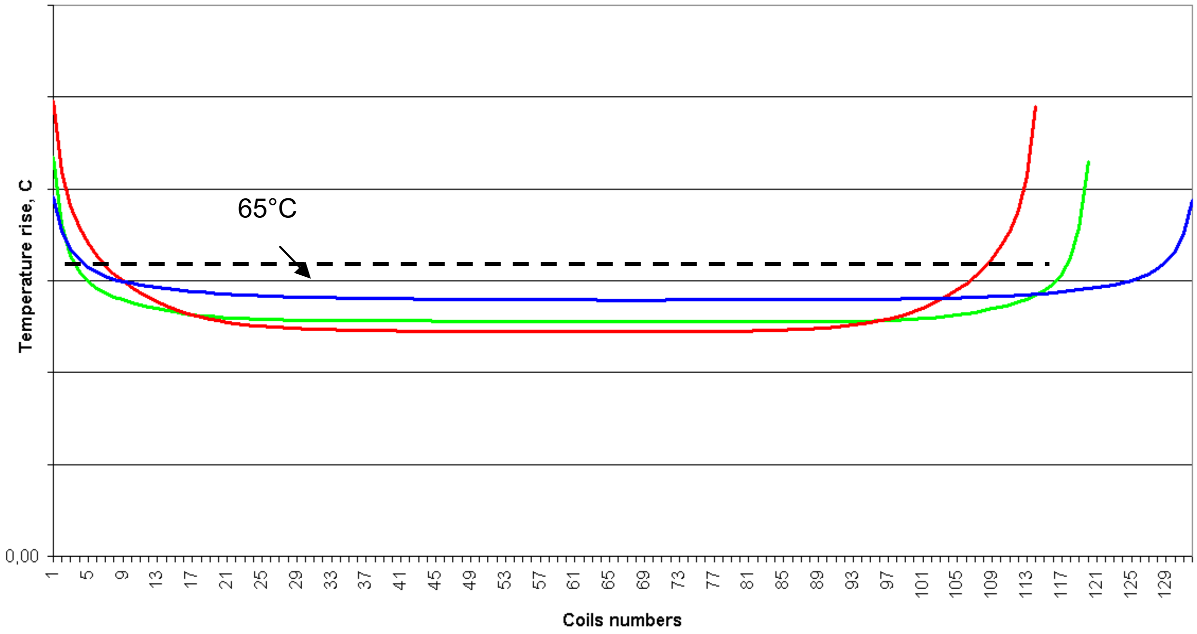


Figure 5-11: Temperature profile of LV windings of three types of 700MVA GSU transformers

5.5.4. Interpretation of winding temperature through one exponent may result in underestimation of top coil temperature

The transformer cooling process involves at least two components:

1. A fast exponent exhibiting cooling of a winding to the bulk oil temperature and,
2. A slow exponent to represent the bulk oil cooling, or the transformer, down to ambient temperature e.g.

$$\theta(t) = g.e^{\left(t/\tau_W\right)} + \Delta\theta_{OAir}.e^{\left(t/\tau_{tr}\right)}$$

Re- processing the temperature rise tests using the sum of these two exponents has shown more realistic picture of winding heating.

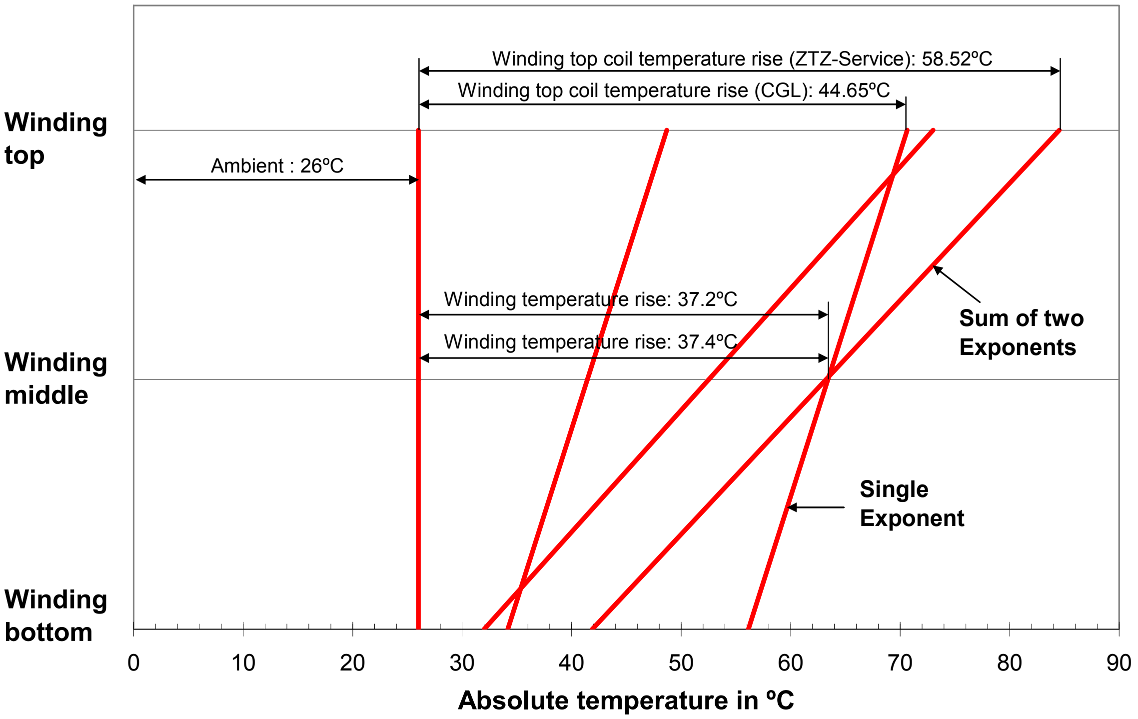


Figure 5-12: Interpretation of temperature rise test of series winding of 315MVA autotransformer: Winding top coil temperature rise using a single exponent is 44.6°C, and using the sum of two exponents is 58.5°C.

Re-processing of the temperature rise test data of the 315MVA autotransformer (Figure 5-12) showed that in spite of the fact the winding mean temperature rises above ambient appeared to be practically equal using either the single or two exponents, the temperature of the top coils actually can be much higher than that determined using only one exponent. Figure 5-12 shows temperature profile of the series winding as a linear one assuming one point is the bottom oil temperature and second point is the mean oil temperature. The estimated top coil temperature rise appeared to be 58.5ºC against 44.60ºC that follows from the single exponent interpretation.

5.6. Different Hot-Spot Models

As it is clear form the above, calculation of the oil flow and the temperature distribution in a transformer can be performed by a 3D model which can consider:

- arrangement and dimensions of the winding elements and oil ducts,
- loss distribution in the winding
- temperature dependence of the oil characteristics
- nature of the oil flow in axial and radial oil ducts
- change in the cooling conditions along the winding.

The model can be simplified into 2D or 1D models, but in this case the hot-spot temperature can be calculated only by significant approaches and estimations. These estimations can be made on the base of manufacturer’s experiences.

5.6.1. Comparison of hot-spot models in IEEE and IEC guides

A comparison has been made of the several hot-spot models described in IEEE and IEC guides. The comparison only focuses on the hot-spot temperature calculation and the factors involved. The detailed formulas are repeated here as they are available in the in the guides.

The following guides have been compared:

- IEEE Std C57.91-1995, IEEE Guide for loading mineral-oil-immersed transformers
- IEEE Std 1538-2000, IEEE Guide for determination of maximum winding temperature rise in liquid-filled transformers (only steady state, not transient)
- IEEE Std C57.119-2001, IEEE recommended practice for performing temperature rise tests on oil-immersed power transformers at loads beyond name plate ratings
- IEC 354 1991, Loading guide for oil-immersed power transformers
- IEC 60067-7 (draft for voting) Power Transformers – Part 7: Loading guide for oil-immersed power transformers. The formulas given in the former IEC 354 are the same as the one of IEC 60067-7 in steady state mode (at t=∞)

Steady State

All models use the following steady state equation for the hotspot temperature:

$$\theta_{Hg} = T_{Air} + \Delta\theta_O + Hg$$

Θ_{HSTO} is the hot-spot over top oil temperature rise

In the IEEE C57.119 and IEC 354 the above formula is used for non-forced oil cooled transformers. In case of forced oil cooled transformers the following equation is used:

$$\theta_{Hg} = T_{Air} + \Delta\theta_{Ob} + 2.(\Delta\theta_{Om} - \Delta\theta_{Ob}) + Hg$$

Main differences are the use of bottom oil temperature and average oil temperature in the winding instead of top oil temperature. The IEC 354 uses the above formula only for OF transformers; for OD transformers the above equation is corrected with a variation of ohmic resistance (formula (3) in IEC 354).
Note: these different formulas for ON, OF and OD do not appear in the new draft IEC loading guide 60076-7. Here only one formula is used.

Another difference appears when one considers absolute hot-spot temperatures. IEC and IEEE both refer to different climatic conditions: IEEE refers to an average ambient temperature of 30ºC, IEC to an ambient average of 20ºC. This has as a consequence that for the same ambient temperature the allowed hot-spot temperature for IEEE equals 100ºC opposed to an allowed 110ºC for IEC. This difference in design limits can have an influence on the comparison of the different Standards and should be considered when comparing average life and calculated hot-spot temperature rises of transformers built according to the different Standards.

Loads different than rated

This equation is based on rated power and temperature rise test at rated power. When the load differs from rated value then the following corrections are used (K is the ratio of the load to rated load):

$$\Delta\theta_O = \Delta\theta_{Or} . \left[\frac{1 + K^2 R}{1 + R} \right]^x$$

and

$$Hg = Hg_r . K^y$$

The exponents x and y (IEC 600776-7 table 5) are n and 2m respectively, in IEEE C57.91 (Table 5). Both exponents differ between both guides. In IEC the oil exponent is mainly higher than in IEEE C57.91 and the winding exponent is mainly.

Table 5-5: Comparison of x- and y-exponents defined in different standards.

	Exponent	**X**	**Y**
ON	IEC 60076-2	0.9	1.6
	IEC60076-7	0.8	1.3
	IEC354	0.9	1.6
	IEEE C57-90	0.9[1]	1.6
	IEEE C57-91	0.9[2]	1.6
	IEEEC57-92 1981	0.9[3]	1.6
OF	IEC 60076-2	1	1.6
	IEC60076-7	1	1.3
	IEC354	1	1.6
	IEEE C57-90	0.9	1.6
	IEEE C57-91	0.9	1.6
	IEEEC57-92 1981	0.9	1.6
OD	IEC 60076-2	1	2
	IEC60076-7	1	2
	IEC354	1	2
	IEEE C57-90	1	2
	IEEE C57-91	1	2
	IEEEC57-92 1981	0.9	2

Note 1: IEEE C57 90 test guide gives x= 0.8 for ONAN transformer and 0.9 for ONAF knowing that ONAN transformers are more likely to be distribution transformers.
Note 2: IEEE C57 91 gives x = 0.8 for ONAN and 0.9 for ONAF
Note 3: IEEE C57 92 1981 edition gives x = 0.8 for OA cooled transformers (equivalent to ONAN) and 0.9 for OA/FA cooled transformers (equivalent to either ONAF or two stages ONAN /ONAF)

It must be noted the aim of IEC 60076-2 is the temperature rise test and therefore the exponents used in this Standard must be chosen in such a way that they penalize the manufacturer that supplies insufficient losses or current during the test. The exponents used in the test must be such that they maximize the user protection and encourage the manufacturer to perform the tests at the rated current as far as possible.
IEC 60076-7 is a loading guide and therefore can use different sets of exponent which could be either more realistic or more permissive, the choice to use either being the responsibility of the user.

'Transient State' or 'Dynamic' Mode

In case of a sudden change of load (i.e. in a daily load profile) the transformer is heated in a transient way. Due to the heat generated in the windings, the winding temperature will change more quickly than the surrounding oil. It takes a longer period before the oil temperature to responds to the load change. Typically the time constant for the winding will be several minutes, for the core about 1-2 hours and for the tank bulk oil several hours (see IEC 354 table 2 and IEC 60076-7 table 5). The IEEE C57.19 does not mention general values but gives equations to calculate the time constant for the oil (eq. 12 and 13) based on temperature rise test data and transformer data.

IEC 354 and IEEE C57.19 use the general simple formula of:

$$1 - e^{\left(t/\tau\right)}$$

where τ = the time constant of oil or windings to calculate the transient behaviour. Both methods take account for the change in ambient temperature during the change of the load.

The new draft IEC 60076-7, Loading Guide uses a more extended formula which takes into account the 'overshoot' of temperature in case of a sudden rise of transformer load. In this condition the oil temperature of the mass of the oil has a lower level than at equilibrium condition. Therefore, the higher viscosity causes bad cooling conditions. Different factors that influence the time constants are used for oil, hot-spot in the winding and for a drop in the load (f1, f2 and f3 resp.). These factors are partly based on the observations made by H. Nordman, Finland [39]. The factors f1, f2 and f3 can only be determined using several hot-spot sensors inside a transformer and measuring these during a heat run test with all losses (no-load and load). Indicative values are given in IEC 76006-7,Table 5.

One remark has to be made: it is not clear on what type of transformers these values are based, so it remains uncertain if these values are accurate enough for different types of transformers and for different manufacturers. These factors stand for a simplified method to describe the heating of a transformer during a temperature rise test. It is assumed that it cannot be applied to transient conditions.

In IEEE C57.91 the time constant of the top oil is recalculated based on the difference between start and ultimate top oil temperature (eq. 14 and 15, both at rated load) and on the ratio of the load to the rated load of the transformer (eq. 22). In the IEC loading guide the time constant is kept at the same value for all different loads (each cooling stage may have its own time constant). The correction of the time constant according IEEE goes into the correct direction. Physically there is no e-function with a constant time constant.

IEEE C57.91 contains an Annex G which describes an extended method for calculating the transient temperature rise in transformers (this Annex is based on the theory published by L. Pierce [43]). In this method the change of the viscosity of the oil is included. Also the influence of the winding temperature on the losses is included explicitly; losses are split into I2R losses (PW) and eddy losses (PE). The calculation is based on the heat transfer equations, heat loss of windings and heat loss of the cooling. Also, some simple formulas are included for the stray loss and the core loss in case of over-excitation. In this case more data of the transformer has to be used in the calculations.

In the article by H. Nordman [39] a comparison is made between the use of the overshoot factors as included in the new draft IEC loading guide and the IEEE C57.91 model in Annex G. The results show that the IEC calculations are conservative compared to the measured values (calculated temperatures are slightly higher than measured). The IEEE model gives temperature values slightly lower than the measured temperatures.

5.6.2. Oil and winding factors, x and y, according to IEC (Summary)

WG A2.24 made an analysis of several overload temperature rise tests on number of transformers.

Transformers are subdivided into the different cooling modes: ONAN, ONAF and ODAF. Only overloads with the same cooling mode are considered. The temperature rise test data with nominal losses is compared to data from comparable tests with losses equivalent to an overload with the same cooling mode. The overloads varied from 110% to 167% rated load for the different transformers.

The top oil exponent, y, and the winding exponent, x, are calculated based on the values mentioned in the test reports. The winding exponents are calculated for the individual LV and HV windings. Other windings are not considered. The mean values for these exponents are indicated in Table 5-6 (upper value). Also the corresponding deviation is calculated (lower value). For each cooling mode the number of transformers is given. Also the mean value and deviation are calculated for all winding exponents (y_all).

Table 5-6: Calculated values

	# transf.	y_all	y_HV	y_LV	x
Total	26	1,82 0,40	1,80 0,42	1,85 0,37	0,72 0,08
ONAN	4	1,90 0,20	1,80 0,20	2,04 0,07	0,77 0,06
ONAF	17	1,81 0,42	1,85 0,43	1,77 0,40	0,72 0,07
ODAF	5	1,80 0,42	1,58 0,42	2,03 0,28	0,68 0,13

Table 5-7: The exponents according to IEC

	Current IEC		New IEC	
	y	x	y	x
ONAN	1,6	0,9	1,3	0,8
ONAF	1,6	0,9	1,3	0,8
ODAF	2,0	1,0	2,0	1,0

The hot-spot factors are not mentioned in this analysis where there were no hot-spot measurements in these cases.

The nominal power ranges from 85 to 112 MVA for the ONAN transformers, from 21, 2 to 300 MVA for the ONAF transformers and from 300 to 675 MVA for ODAF transformers. No difference is made between double-wound and auto transformers.

5.6.3. Transformer Temperature Rise Data Analysis – Australian Data

Introduction

The Australian utility Powerlink has since early 1980's performed emergency overload tests as a standard type test on its transformers in addition to the normal temperature rise test performed at the 1.0 p.u. rating.

From 1980 up to 1998 transformers were mostly bought as ODAN cooled units. From 1998 to the present, transformer were mostly bought as ODAF cooled transformers.

Fibre optic probes have been routinely fitted to most of Powerlink's large transformers since 1985.

The overload testing has resulted in a fairly large collection of temperature rise test data at two loadings for same cooling method. The temperature rise data from these transformers has been analysed to investigate and determine the values of:

- winding temperature rise exponent (y),
- oil temperature rise exponent (x), and
- hot-spot factor (k)

In earlier years winding temperature rises were only measured in one phase, in latter years they have been measured in all three phases

Only temperature rise test data using the same cooling method were utilized for each transformer.
Actual test current and test losses were used, where available, rather than their 1.0 p.u. “corrected” values, in order to conserve the accuracy of the results.

The transformer data analysed is comprised of temperature rise data from:

- Nine 275/110kV auto-transformers with neutral-end tappings
- Two 330/275kV auto-transformers without tappings
- Fourteen 288/138kV auto-transformers with 138kV line-end tappings and one 330/132kV auto-transformer with 132kV line-end tappings
- Twelve 132/69kV auto-transformers with series winding mid-point tappings
- Twelve 110/33kV, 132/33kV and 132/22kV double-wound transformers with neutral-end tappings

These different transformer designs were analysed, first sorted only by cooling method, and subsequently sorted by both their separate winding configurations and cooling condition.

Formulas for deriving Values

In order to calculate the winding temperature rise exponent:

From IEC 60076-2, it can be stated that once the gradient has stabilised:

$$G_{EMER} = G_{TEST} \cdot \left(\frac{I_{EMER}}{I_{TEST}} \right)^{y} \qquad y = \ln\left(\frac{G_{EMER}}{G_{TEST}} \right) \Big/ \ln\left(\frac{I_{EMER}}{I_{TEST}} \right)$$

It should be noted that in order to calculate y, both tests must be full length temperature rise tests rather than “Gradient Runs” in order for the top oil temperature to stabilise, as is discussed below.

In order to calculate the oil temperature exponent - x:

From IEC 60076-2, it can be stated that:

$$\Theta_{TO\_EMER} = \Theta_{TO\_TEST} \cdot \left(\frac{P_{L\_EMER}}{P_{L\_TEST}} \right)^{x} \qquad x = \ln\left(\frac{\Theta_{TO\_EMER}}{\Theta_{TO\_TEST}} \right) \Big/ \ln\left(\frac{P_{L\_EMER}}{P_{L\_TEST}} \right)$$

In order to calculate the hot-spot factor - k:

$$T_{HS} = T_{TO} + k.G$$
$$T_{TO} = T_{Air} + \Theta_{TO}$$
$$G = T_{WA} - \left[T_{TO} - \frac{(T_{TO} - T_{BO})}{2} \right]$$

Assuming that the T_{FO} is equal to the T_{HS}, it is apparent that:

$$k = \frac{\left(T_{FO} - T_{AIR} - \Theta_{TO}\right)}{G}$$

$$k_{AVE} = \frac{\left(T_{FOA} - T_{AIR} - \Theta_{TO}\right)}{G_{WA}}$$

$$k_{MAX} = \frac{\left(T_{FOMAX} - T_{AIR} - \Theta_{TO}\right)}{G_{WA}}$$

Note: These equations assume that the oil temperatures occurring in the common and series windings for an autotransformers (or LV and HV windings, for the double-wound transformers) are the same temperature and that the oil flow from the core, tertiary and tapping winding has negligible effect on the top oil temperature.

This investigation has revealed that this assumption is not correct, and it was therefore not possible to determine x, y or k with a high degree of accuracy.

Methodology

A normal temperature rise test was performed at the 1.0 p.u. rating. This test was then followed by an Emergency Overload Capability Test.

The overload testing commenced at approx:

- 1.5 p.u. current for all ODAN transformers and for ODAF and ONAF transformers rated < 100MVA and at,
- 1.3 p.u. current for ODAF transformers rated > 100MVA.

This loading is maintained until the winding hot-spot temperature reaches 130–140°C. At this point a temperature rise “shut down” is performed and the winding temperature by resistance measured to determine the winding gradient and the hot-spot gradient (the “Gradient Run”).

The gradient run typically takes 1-3 hours if performed immediately after the 1.0 p.u. test. In this short timeframe oil temperatures will not have stabilized for the 1.5 or 1.3 p.u. losses, so this data cannot be used to calculate x-values. It can, however, be used to calculate y-values for the transformer, as the winding gradients have stabilised. The time constant for the windings is typically in the range of 3 to 10 minutes.

After the gradients have been determined the overload temperature rise test re-commences for the “long duration overload test” at a per unit load which will maintain the winding hot-spot temperature within 130-140°C - typically at 1.2 to 1.4pu. The tests continue until the winding hot-spot temperature has remained at 130-140°C for 12 hours, by which time the oil temperatures within the transformer will have stabilised. The main purpose of this test is to check the rate dissolved decomposition gasses generated at the elevated temperatures 130-140°C. The oil rise data from the latter part of the Emergency Temperature Rise Test has been used to calculate the x values. Values for y were also calculated where the winding temperatures were measured at the final shutdown.

For calculating y, the mean gradient of the three phases was used wherever three phase data were available, so as to minimise errors caused by uneven temperatures rises between phases. The average gradient of the measured phases was used in calculating k only for the average and maximum k values for that voltage. In all other calculations, the gradient for that specific winding was used.

It should be noted that both formulae used to calculate x and y would work for any two sets of data from the same transformer, provided the same cooling condition was in use. Because of this, actual test values, rather than values corrected to the transformer's rating, has been used. For the purpose of this investigation, data from temperature rise tests near rated current, and from emergency overload temperature rise tests with the same cooling measures, were used without any correction, where available.

The hot-spot factor could be calculated from any individual test run, but proved to be quite prone to errors, with over a third of the calculated k-values being equal to less than unity, a physical impossibility as it denotes a temperature for a point that is cooler than the average temperature of the winding i.e. not a hot-spot.

A value for k was also calculated as the average value of the k HV and k LV "maximum values", and another k value using the "average values" instead. The theory behind this is, if the oil temperature produced by the two windings is not even, then the calculated hot-spot factors will be higher than the true factor in one winding, and proportionately lower for the other winding. For small temperature differences, this should give a more accurate value for k. It should be noted that this value was calculated regardless of whether either the LV or HV value used were less than unity or not. This, together with all other k-values, assumes that the tapping winding will not have any major effect on the oil temperature (an assumption that is not entirely correct for all transformers).

The data was sorted by winding type, and then subcategorised by the cooling configuration in use. The data was also totalled and sorted by the cooling method only for a general comparison. The summarised results are presented in Table 5-8 till Table 5-19.

Results

Table 5-8: Results for y-exponent of nine 275/110kV Autotransformers with Neutral-End Tapping only.

Winding Temperature Rise Exponent (y)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings HV LV	Standard Deviation	No. Data Values
ONAF	1.6	1.6	1.3	No data	N/A	0
ODAN	2.0	1.8	2.0	2.06 2.32	0.26 0.35	4
ODAF	2.0	1.8	2.0	2.13 2.35	0.32 0.41	5

Table 5-9: Results for x-exponent of nine 275/110kV Autotransformers with Neutral-End Tapping only.

Oil Temperature Rise Exponent (x)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings	Standard Deviation	No. Data Values
ONAF	0.9	1.0	0.8	No data	N/A	0
ODAN	1.0	0.8	1.0	0.90	0.00#	1
ODAF	1.0	1.0	1.0	0.84	0.05	3

Only one value of data was available.

Table 5-10: Results for y-exponent of two 330/275kV Autotransformers with no Tapping Winding only.

Winding Temperature Rise Exponent (y)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings HV LV	Standard Deviation	No. Data Values
ONAF	1.6	1.6	1.3	No data	N/A	0
ODAN	2.0	1.8	2.0	No data	N/A	0
ODAF	2.0	1.8	2.0	2.17 2.55	0.49 0.71	2

Note: There was no oil temperature rise data for this set of Transformers.

Table 5-11: Results for the y-exponent of fourteen 288/138kV Auto-Transformers with 138kV Line-End Tapping and one 330/132kV Auto-Transformer with 132kV Line-End Tapping.

Winding Temperature Rise Exponent (y)	Current IEC Standards	1981 Australian Standards	Proposed Standards	Findings HV LV	Standard Deviation	No. Data Values
ONAF	1.6	1.6	1.3	No data	N/A	0
ODAN	2.0	1.8	2.0	1.93 1.82	0.24 0.23	14
ODAF	2.0	1.8	2.0	1.55 1.17	0.21 0.00#	2 1

Only one value of data was available.

Table 5-12: Results for the x-exponent of fourteen 288/138kV Auto-Transformers with 138kV Line-End Tapping and one 330/132kV Auto-Transformer with 132kV Line-End Tapping.

Oil Temperature Rise Exponent (x)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings	Standard Deviation	No. Data Values
ONAF	0.9	1.0	0.8	No data	N/A	0
ODAN	1.0	0.8	1.0	0.73	0.10	7
ODAF	1.0	1.0	1.0	0.85	0.08	4

Table 5-13: Results for the y-exponent of twelve 132/69kV Autotransformers with Series Winding Mid-Point Tapping only.

Winding Temperature Rise Exponent (y)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings HV LV	Standard Deviation	No. Data Values
ONAF	1.6	1.6	1.3	1.76 1.65	0.14 0.03	2
ODAN	2.0	1.8	2.0	1.80 1.71	0.22 0.21	4
ODAF	2.0	1.8	2.0	1.78 1.54	0.55 0.15	5 4

Table 5-14: Results for the x-exponent of twelve 132/69kV Autotransformers with Series Winding Mid-Point Tapping only.

Oil Temperature Rise Exponent (x)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings	Standard Deviation	No. Data Values
ONAF	0.9	1.0	0.8	0.82	0.10	2
ODAN	1.0	0.8	1.0	0.72	0.01	2
ODAF	1.0	1.0	1.0	0.90	0.03	3

Table 5-15: Results for the y-exponent of twelve 110/33kV, 132/33kV and 132/22kV Two-Winding Transformers with Neutral-End Tapping only.

Winding Temperature Rise Exponent (y)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings HV LV	Standard Deviation	No. Data Values
ONAF	1.6	1.6	1.3	1.61 1.05	0.00#	1
ODAN	2.0	1.8	2.0	1.75 1.82	0.39 0.34	9
ODAF	2.0	1.8	2.0	2.34 2.04	0.41 0.20	7

Only one value of data was available.

Table 5-16: Results for the x-exponent of twelve 110/33kV, 132/33kV and 132/22kV Two-Winding Transformers with Neutral-End Tapping only.

Oil Temperature Rise Exponent (x)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings	Standard Deviation	No. Data Values
ONAF	0.9	1.0	0.8	No data	N/A	0
ODAN	1.0	0.8	1.0	0.84	0.08	4
ODAF	1.0	1.0	1.0	0.91	0.01	2

Table 5-17: Results for the y-exponent of the full set of data.

Winding Temperature Rise Exponent (y)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings HV LV	Standard Deviation	No. Data Values
ONAF	1.6	1.6	1.3	1.71 1.45	0.11 0.35	3
ODAN	2.0	1.8	2.0	1.88 1.87	0.38 0.40	32
ODAF	2.0	1.8	2.0	2.06 2.02	0.47 0.55	21 19

Table 5-18: for the x-exponent of the full set of data.

Oil Temperature Rise Exponent (x)	Current IEC Standards	1981 Australian Standards	Proposed Draft Standards	Findings	Standard Deviation	No. Data Values
ONAF	0.9	1.0	0.8	0.82	0.14	2
ODAN	1.0	0.8	1.0	0.77	0.12	14
ODAF	1.0	1.0	1.0	0.87	0.07	12

Table 5-19: Hot-spot Factor Averages: As the data for all categories is similar where adequate data is present, the overall data may be used to adequately model all cases.

Calculation Name	Value
k_{HV} of All Phases	1.265
k_{LV} of All Phases	1.291
k_{HV} of Hottest Phase	1.348
k_{LV} of Hottest Phase	1.340
Average of k_{HV} and k_{LV} Means	1.208
Average of k_{HV} and k_{LV} Maxima	1.306

Discussion

For autotransformers with constant MVA rating, common winding currents can change significantly across the tapping range, whereas with double-wound transformers, the winding current changes are significantly less across the tapping range.
This means that the load losses, which are largely proportional to the square of the current, are altered even more so. Therefore, in an autotransformer, the losses in the common winding will often be very high compared to those in the series winding at one end of the tapping range, causing the common windings to be much hotter than their series counterparts, with the opposite effect occurring at the other end of the tapping range. The same effect is present in double-wound transformers, but to a much lesser extent.

For this reason, the hot-spot data in this analysis was often found to have a very low Hot-spot Factor (HSF) calculated from the LV gradient, and a very high HSF when calculated from the HV gradient, or vice versa (if the test was completed on a low current tapping). For this reason, an average of the common and series winding's calculated hot-spot factors was also calculated. Although this is not mathematically correct, it does give a good approximation provided the temperature difference between the series and common windings is fairly small.

Calculation of Winding Gradient Exponent 'y'

The method used to determine the winding gradient is:

- (Average winding temperature from resistance measurement) – (Mean Oil Temperature cooler bank (MOTcooler bank).
- (MOTcooler bank) = Top oil temperature – (½ x the cooler bank temperature drop)
- Cooler drop = Temp. of oil in cooler bank top header less the temp. of oil in cooler bank bottom header.

Significant inaccuracies can occur in calculation of the gradient where the mean oil temperature of a specific winding (MOT winding) differs significantly from MOTcooler bank.

- Gradients calculated for windings with (MOT winding) > (MOTcooler bank) will be higher than its true gradient.

- Gradients calculated for windings with (MOT winding) < (MOTcooler bank) will be lower than its true gradient.

The result is that these methodology "errors" makes it impossible to calculate the y value accurately where (MOT winding) is not = (MOTcooler bank).

To minimise errors in calculations of y, all obtained values for the winding temperature rise exponent where the two tests were completed on different taps were disregarded, as the error introduced by change in current ratio losses and mean oil temperature would magnify the already inherent inaccuracies.

It has been reported that the gradients taken after 1-3 hours after load increase can give a too high a value for both ON and OF transformers. This would be due to the fact that the oil circulation speed adapts more slowly to the new load conditions than the windings. Even after 5 hours, the reported measurements showed an increase in gradient 10 – 20% higher than if the measurements had been taken in the real steady-state condition.

The measurements taken after 1-3hours for ON and OF are thus still values taken during the overshoot period and not during the steady state period after a load change. In OD transformers this overshoot phenomenon will not occur, and therefore the measurements for an OF transformer can be made after 1-3hours already.

Recently it has also been observed that the values for the y-exponent are highly dependent of the presence of radial spacers in the winding or not. Without the presence of radial spacers values for y can be much higher (values slightly less than 2 are reported).

The presence of radial spacers is however not recorded for the transformers used in the above study. Therefore, the effect of radial spacers requires further study and research.

Calculation of the oil exponent 'x'

All x-value data obtained from "gradient runs" was disregarded, because the recorded top oil rise is not a measure of the stabilised temperature, and as such, cannot be accurately compared with the test losses when calculating the x exponent. However, x values calculated from temperature rise tests with stabilised top oil temperatures with different loading (losses) should be a reasonable representation of the true x values.

Calculation of winding hot-spot factor 'k'

It should be noted that each phase will not heat evenly, and that the fibre optic probes used to locate the hot-spot temperature can never be positioned exactly at the hot-spot, and as such, will always read low. For these reasons, the hot-spot factor should be rounded up and considered to be higher than what is found by any form of analysis based on this data.

Conclusion:

From the findings of this analysis, the following values were found to give the best representation of x, y and k:

x = 0.8 for transformers with ODAN
x = 0.8 for transformers with ON cooling
x = 0.9 for larger transformers with ODAF cooling

y = 1.7 for transformers with ON cooling
y = 1.9 for transformers with ODAN cooling
y = 2.0 for larger transformers with ODAF cooling

k - The analysis supported the presently adopted hot-spot factor value of k = 1.3 for these types of transformer.
It should be noted these findings are mostly based on test results for large transmission and bulk supply autotransformers with forced-oil and in many cases also forced-air cooling.

6. In Service Units

6.1. Assessing Thermal Life of Transformer of In Service Units

A survey of existing transformer condition monitoring systems including those systems developed by manufacturers of transformers, shows that the assessment of the thermal life of a transformer follows the two-step approach as described, for example, in IEC Standards and IEEE Guides.

In the first, the winding hot-spot temperature is determined according to the hot-spot calculation method prescribed using the measurements of the top-oil temperature and the load current. The hot-spot models of some previous editions of the Standards and Guides are still in use because these were more readily applicable to transformers in service. In case of transformers with forced oil cooling, some transformer condition monitoring systems use the bottom-oil temperature as a reference temperature instead of the top-oil temperature. In case of transformers employing multiple –stage cooling regimes e.g. a transformer with ONAN / ONAF / ODAF cooling, the transformer specific parameters used in the hot-spot model differ 'significantly' between the different cooling stages and are taken into account by some transformer condition monitoring systems.

The second step is to determine the degree of insulation ageing based on this hot-spot temperature. Different temperature systems can be distinguished according to the Standards and the type of insulation material used. Table 6-1.

In some cases, insulation samples can be obtained and DP values measured in order to check the calculated ageing of the insulation material, or to find problem areas in the transformer. The following Section 6.3 gives some illustrations of the distribution of DP values in a standard transformer and of the use of DP measurements in real life transformers.

Table 6-1: Rated hot-spot temperatures for normal ageing

Ageing calculation method	Type of paper	Rated hot-spot temperature for normal ageing
IEEE 55 °C rise	Kraft paper	95 °C
IEEE 65 °C rise	Thermally upgraded paper	110°C
IEC	Kraft paper	98 °C
Aramid paper ageing	Aramid paper	188 °C

Note: in some 'more advanced' transformer condition monitoring systems, the -moisture content in the paper insulation and the oxygen content in the transformer oil are also taken into account in the calculation of the 'combined' ageing of the transformer insulation.

6.2. Service experience of ageing transformers

Technical Life of a transformer may be determined by several components:

- “Dielectric Life”-life-span up to critical reduction of dielectric margin of major and minor insulation
- “Mechanical life” of windings under the impact of through fault currents, vibrations, etc.
- “Life of accessories”, especially bushings and LTC’s, which sometimes can be shorter than the complex life expectancy of the transformer active part.
- “Thermal Life”-time up to the winding (conductor) insulation critical decomposition stage that, in turn, is considered as mechanical end-of-life of paper, e.g. DP≤200

Analysis of failure statistics including 108 failure cases that occurred in 2000-2005 [56] showed the following:

- Average age of failed transformer is between 20-22 years. However contribution from generation “after 25” becomes weightier with years. Average failure rate remains at around 1-2%.
- Failure profile cannot be approximated with one single function due to presence of several degradation mechanisms. Each typical failure-mode can be approximated with a particular function.

6.2.1. Insulation dielectric - mode failures

Dielectric failures are the predominant failure mode of transformers by accounting for 35-50% of the total number of failures. There also has been a clear trend of increasing dielectric failures with time. The failures were associated with oil gap breakdown (particularly large gap “shield of bushing-turret”), surface contamination and degraded impulse strength, short-circuits between turns and coils on the most electrically stressed HV and tapping windings.

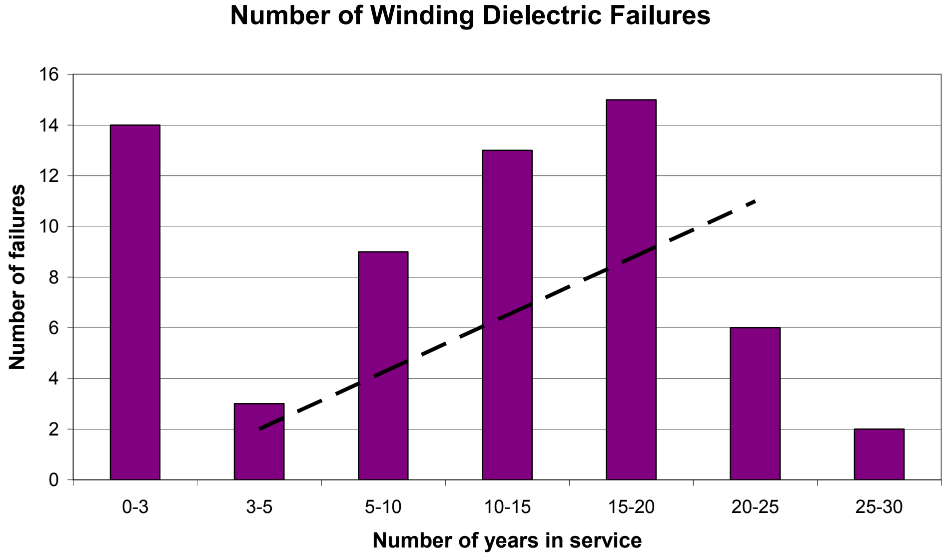


Figure 6-1: Dielectric–mode winding insulation failures.

6.2.2. Mechanical – mode failures

About 10% of transformers failed due to movement of winding caused by short-circuit mechanical stress. In these cases 80% of the failures were caused by radial buckling of the common and tertiary windings of autotransformers and the LV windings of step-down transformers.

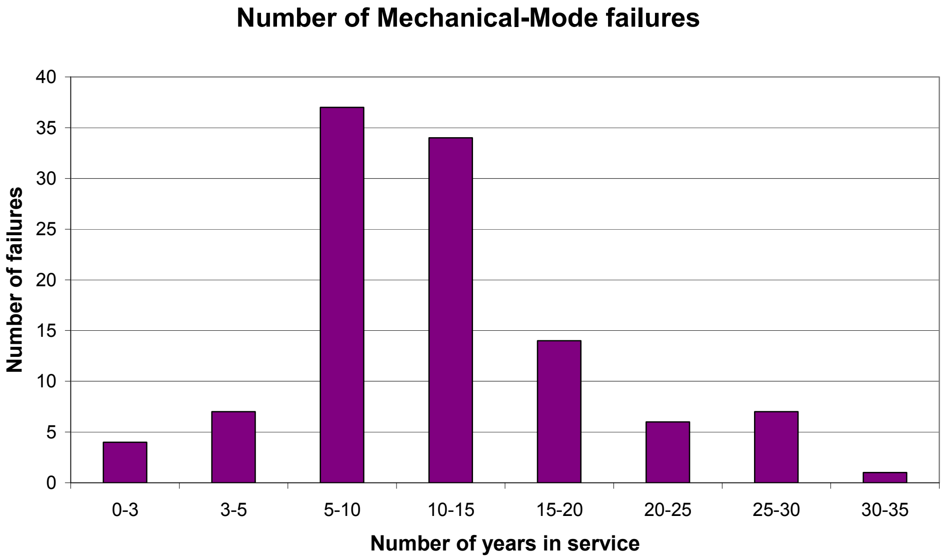


Figure 6-2: Mechanical –mode failures.

6.2.3. Failure of Accessories

HV bushings are still one of the weakest transformer components responsible sometimes for more than 30% of transformer failures. Most failures occurred in the timescale 7-15 years, however there are symptoms of ageing-mode failures after 20 years. Wear can be observed in form of OLTC failures though failure rate due to contact deterioration can be approximated with lognormal distribution.

Table 6-2: Failure rate of transformer accessories (% of total number of failure).

Component	GSU	Auxiliary (coupling)	Transmission
Bushing	13.3		38
OLTC**	4.4	42.8	7.9
DETC	2.1		-

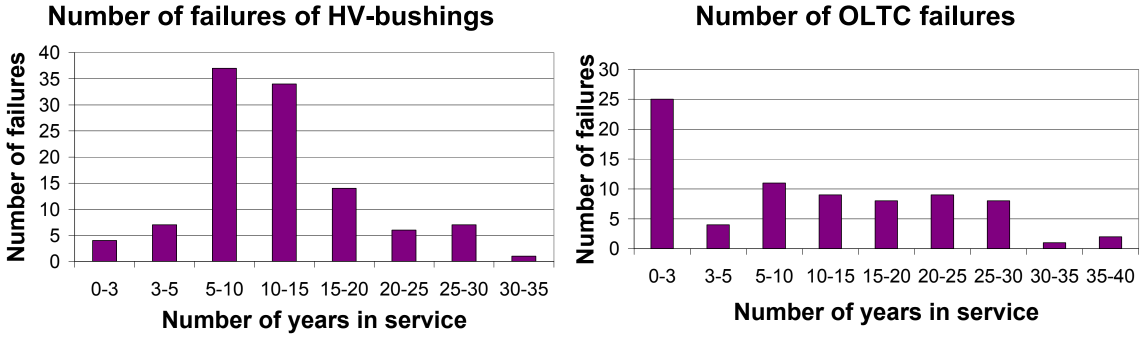


Figure 6-3: HV bushings (left) and OLTC (right) failure.

6.2.4. Thermal-mode failures

Thermal mode failure rate still does not exceed 5-7 % of total umber. However, there has been a trend of increasing failures in population of generator step-up transformers having predominantly OFAF cooling systems and operating continuously at over 90% of rated load.

Analysis has identified the following failure causes:

- Overheating of the coils of winding blocked by angle collars preventing oil flow and proper cooling.
- Underestimation of winding temperature, especially of LV windings in large generator transformers with OFAF cooling system.
- Deterioration of cooling due to bulging wire insulation.

Hence the main causes of thermal failures were not normal ageing but design deficiencies.

In recent years there has been a remarkable number of transformer failures associated with electrical short-circuits between CTC (continuously transposed conductor) wire strands caused by overheating and critical decomposition of insulation. CTC wire could be subjected to very high compressive stresses particularly in location between radial spacers and is likely to be most sensitive to ageing deterioration.

Over 13% of failures of generator transformers are associated with overheated insulation of leads and connections formed from the same CTC wire as the winding, particularly the insulation of winding exit leads.

It has been commented that a lot of transformers are considered critical and taken out of service based on thermal ageing assessments. This partially explains the lower thermal failure rate because it can be predicted. Therefore it is worthwhile doing a post-mortem investigation of electric insulation systems in those transformers. The data obtained is needed for utility asset management decisions as well as for future Cigré research.

6.3. Practical Examples of the use of DP-Measurement

6.3.1. DP Distribution in real life transformer

The exact DP values in a transformer can vary greatly. However, the higher the temperature of the insulation material, the quicker the DP value at that particular location will decrease. Figure 6-4 illustrates this with the ageing profiles of a 42-year-old autotransformer and a 48-year-old network-transformer.

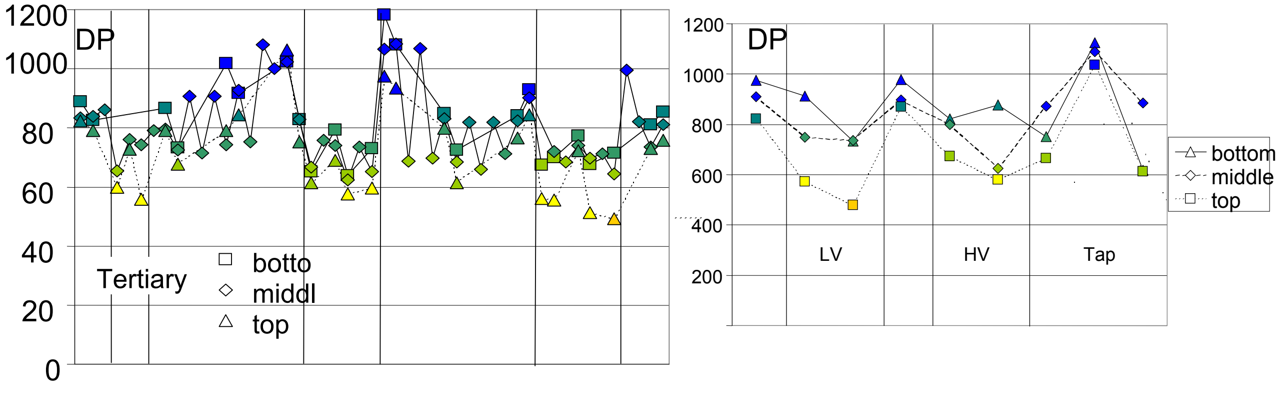


Figure 6-4: Ageing profile of 600 MVA 380/220 kV autotransformer, OFAF after 42 years (left) and of 31.5 MVA, 110/63 kV transformer, ONAN after 48 years (right).

The DP values of 1200 and 200 are based on laboratory tests. In practice, the initial DP value of new transformers is around 1000 after processing and temperature rise test, especially after overload tests. A 50 % reduction in insulation mechanical strength occurs when the DP value reaches 350. The DP value equivalent to insulation end of life is 200 but is not an exact value. The DP for end of life depends on the risk criteria of the user.

6.3.2. Investigation into the Cause of Failure of a 20MVA Transformer using DP-Measurements

The transformer in this example experienced a breakdown. Upon inspection, a carbonised layer was found on the insulation in the neighbourhood of the breakdown. However, the carbonised layer seemed to be a deposit and did not originate from carbonised insulation material. Measurements of the DP-value strongly supported statement. The measured values are shown in Figure 6-5.

These values illustrate that no general overheating took place. They also illustrate that the breakdown was initiated primarily by an electrical phenomenon instead of a thermal phenomenon.

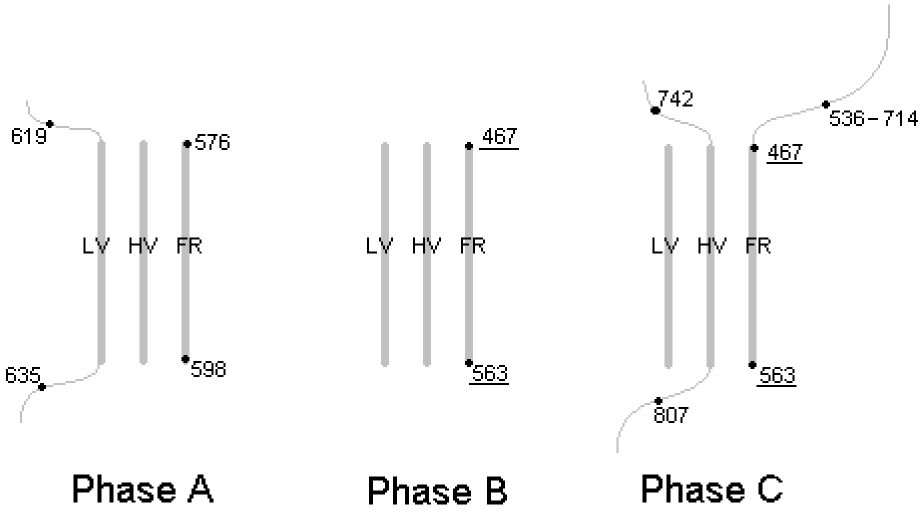


Figure 6-5: Visual representation of DP values Measured at 20MVA transformer after breakdown.

6.3.3. Use of DP-measurements to find Thermal Design Deficiencies

After 6 months in service, a 38MVA ONAF transformer exhibited rather high values in the results of a DGA measurement. Interpretation of these values indicated the possibility of stray gassing or a thermal design deficiency in the lower temperature range. Because of the high concentration of i-butane, the thermal design deficiency was the most probable cause.

Therefore, DP-measurements were performed for samples from different places of the active part. The results of these measurements are shown in Figure 6-6 till Figure 6-8. These measurements showed most values were around the expected average DP of 960-980. Only at the transformer leads were lower values were found. The lowest value was positioned exactly above the end of an oil cooling-duct. The hot oil exiting this duct heated the parts of the lead above this duct to an above average temperature, causing the high gas content illustrated by the DGA measurement.

The insulation around these parts of the leads was replaced. DGA levels returned to normal when the transformer was put back into service.

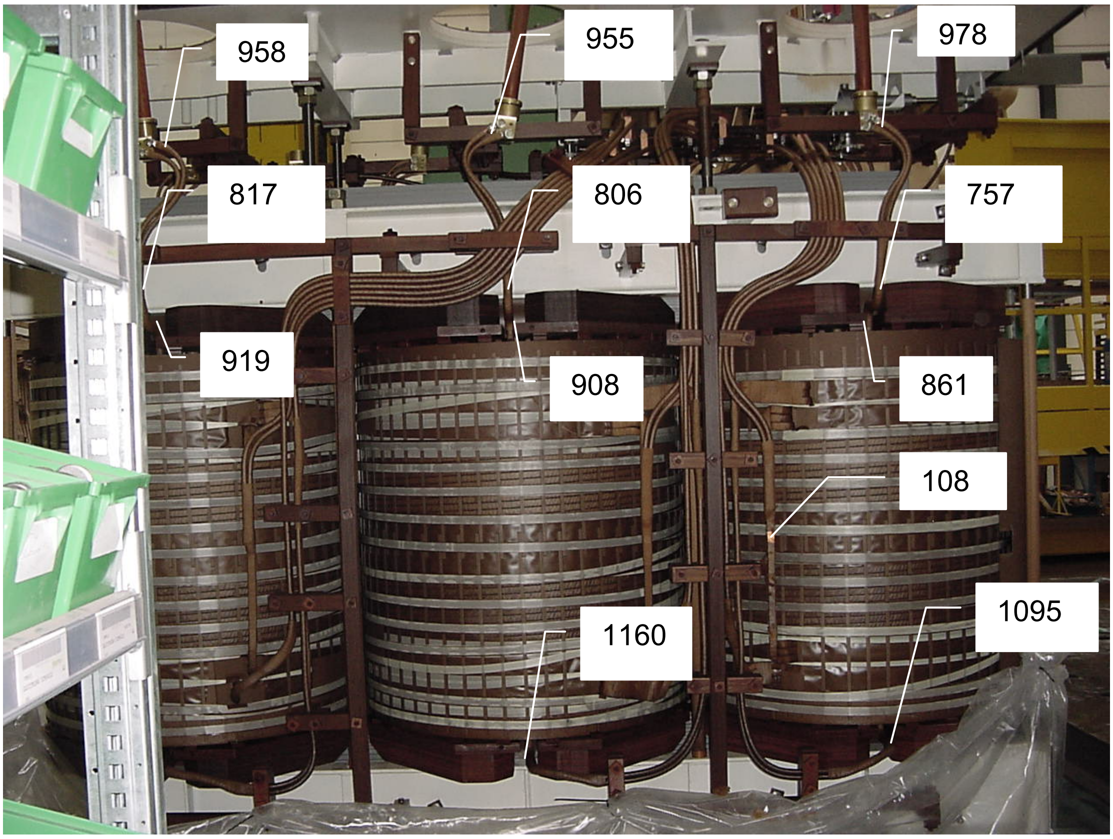


Figure 6-6: Visual representation of measured DP-values for HV side of 38MVA transformer.

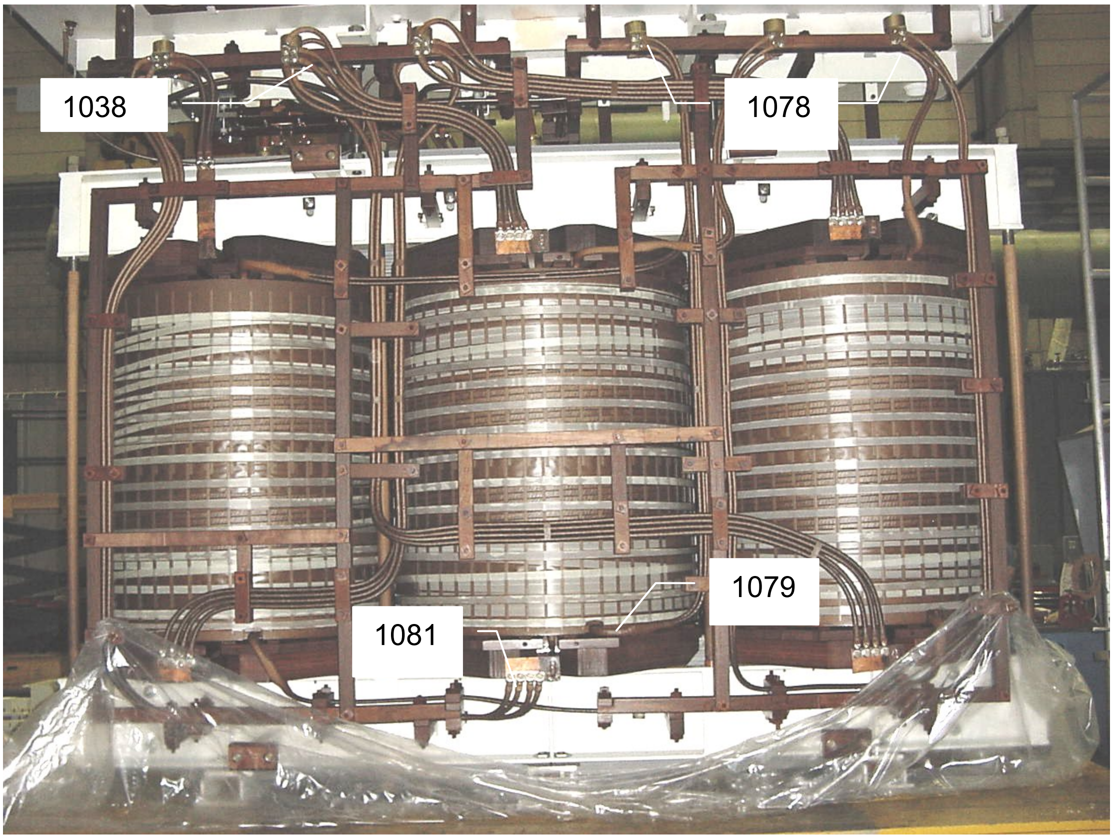


Figure 6-7: Visual representation of measured DP-values for LV side of 38MVA transformer.

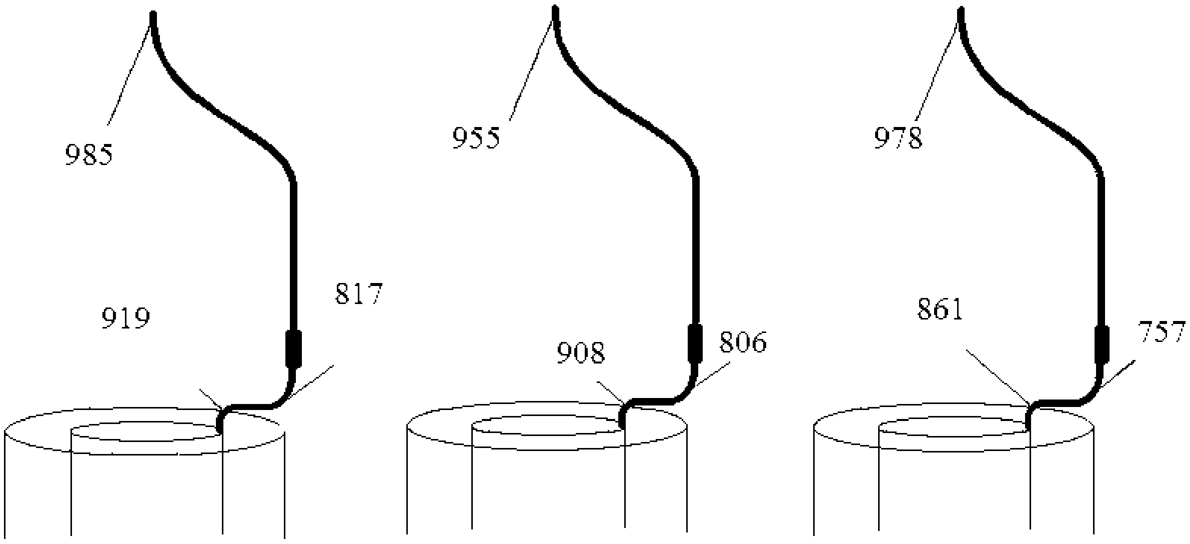


Figure 6-8: Graphical representation of measured DP-values for the leads of a 38MVA transformer.

6.4. Practical Examples for Design for Thermal Performance

The load on some transformers depends on the ambient temperature. For those transformers an optimum design will be such that it's ageing is equivalent to any conventional network transformer.

In order to make a correct thermal design, it is important to fully understand the characteristics of the loads and working conditions of the transformer. A full understanding will only be possible after sufficient contacts and discussions with the user of the transformer.

Examples of applications which could benefit from special care and attention to thermal design are temperature dependent loads such as gas turbines or industrial loads which produce above normal levels of harmonics such as rectifiers, wind turbines, traction loads etc.

An example of transformers used for gas turbine fed generators is presented in the following Section 6.4.1.

6.4.1. Thermal Impact of Gas turbine Applications

A GSU used for gas turbine (GT) fed generator is the most common example of a transformer load that is dependent on ambient temperature. Gas turbine output energy depends on the air-inlet ambient temperature and decreases when the temperature increases. To understand the impact of such behaviour some facts on conventional GSU need to be considered.

A conventional GSU is used at rated power all year around which means that on a yearly average basis its hot-spot temperature is 98 °C and its yearly average ageing rate is 1 p.u.

A conventional transformer generally undergoes ambient temperature variations so that its relative ageing rate is not constantly equal to unity. During hot periods, the relative ageing rate increases up to 10 at an ambient temperature of 40°C and on the contrary, during cold periods, the relative ageing rate decreases to 0.01 for an ambient temperature of - 20°C, so that on average over a year, the relative ageing rate is equal to unity.

Figure 6-9 shows the change in the hot-spot temperature of an apparatus operating at constant power over the entire range of standard ambient temperatures. This variation is plotted using the same assumptions as those used by IEC (i.e., the gradient does not vary with the copper temperature, which leads to neglecting the copper resistivity variation as a function of temperature).

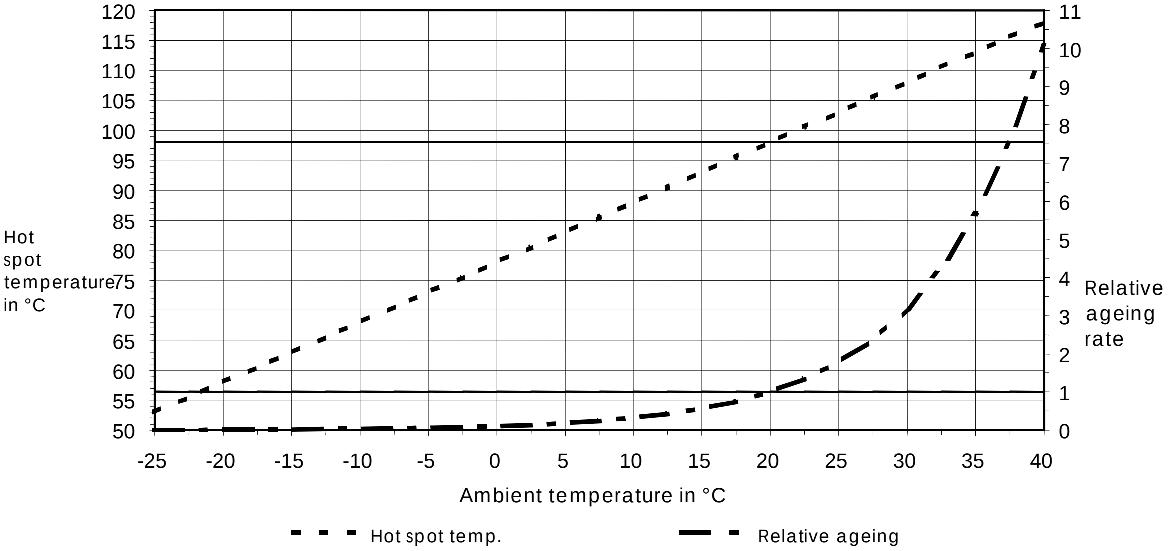


Figure 6-9: Change in relative ageing rate with changing hot-spot temperature for apparatus working at constant power.

The possibility of supplying energy from a gas turbine varies with the ambient temperature and is shown by a curve as a function of the ambient temperature, the colder it is, the greater the amount of energy produced is. Therefore a transformer coupled to a gas turbine will also undergo load variations as a function of the ambient temperature.

In order to ensure a unitary mean relative ageing rate, it is therefore necessary to define the transformer so that whatever the ambient temperature, it operates under the annual mean temperature conditions of a "conventional" transformer i.e. a yearly average temperature of the hot-spot of 98°C

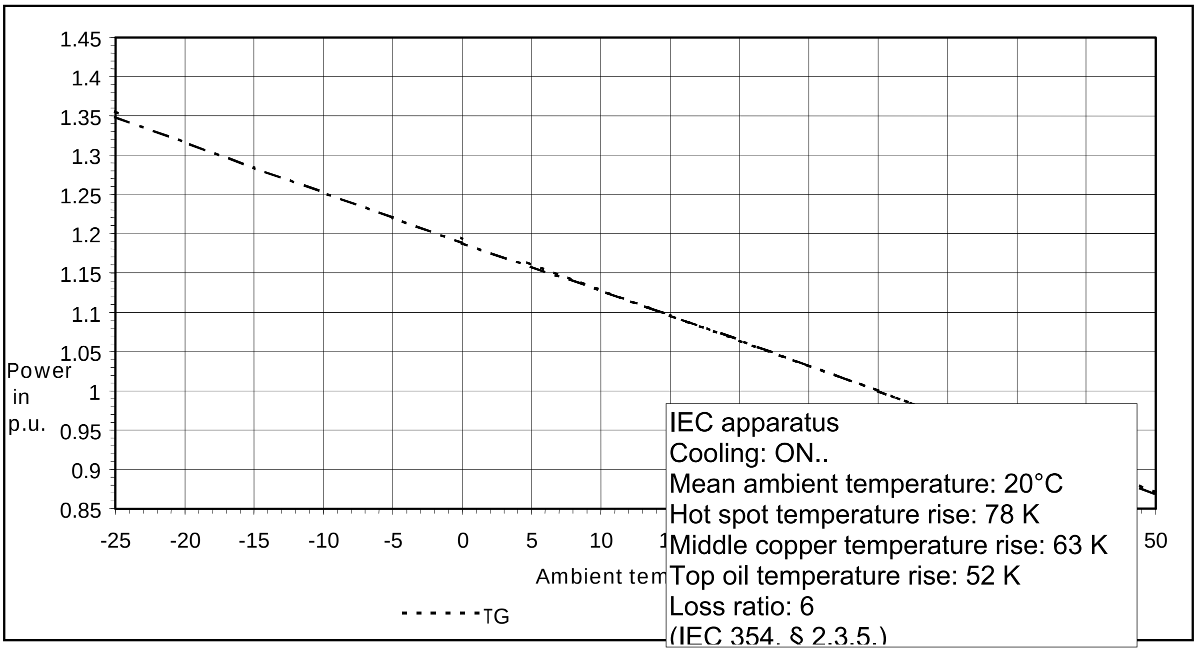


Figure 6-10: Typical output capability of gas turbine

A GT transformer defined in such a way will then have an ageing rate as shown on the example below. The curves illustrate the GT transformer can have an ageing rate which varies significantly less than the conventional transformer as the load variation compensates partially for the ambient variation when the conventional transformer at constant load sees its hot-spot temperature fully follow the ambient variation. But both have an average rate of ageing of unity. Similar curves can be drawn for different cooling mode temperature rises and load ratios by using the IEC 60076-7 formulas.

It should be noted that in the example below the formulas for Kraft paper have been used neglecting the copper time constant and considering steady state temperature as this type of loading is never a dynamic loading i.e.

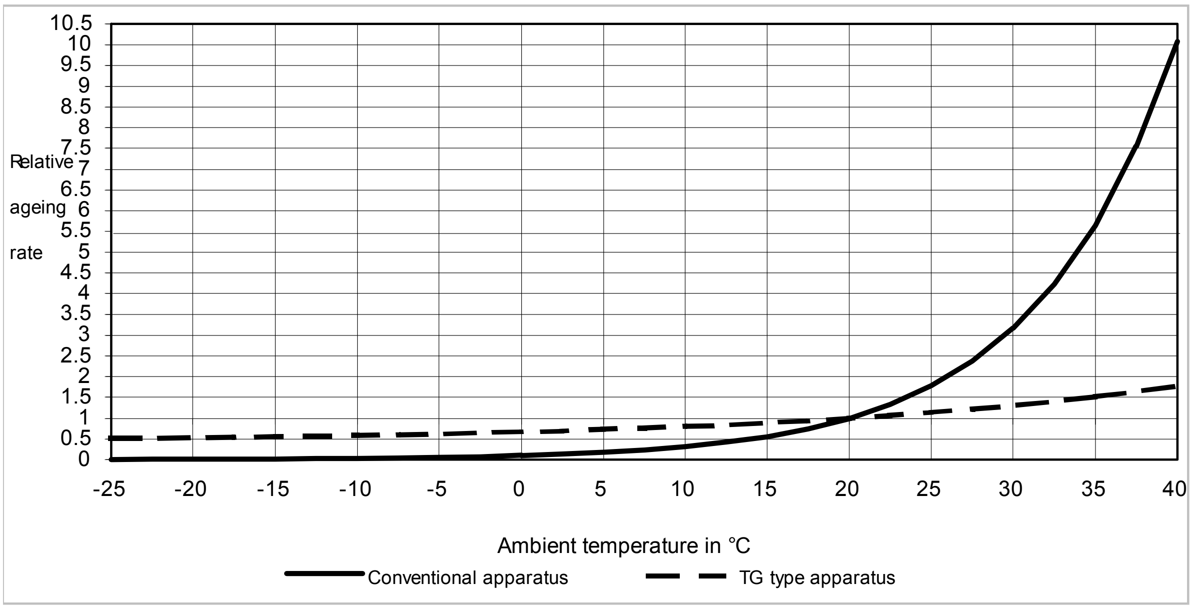


Figure 6-11: The typical ageing rate of a gas turbine transformer rate of a gas turbine transformer

For gas turbine transformers, the rated power, Sr, is a conventional value which is only used to establish guarantees and to carry out temperature rise tests. The transformer is able to transform more power at low ambient temperature than at high ambient temperatures. Optimal sizing should therefore be based on the oil temperature, the middle copper and above all the hot-spot so as to ensure unitary ageing over the entire operating range.

To visualize this ability a load capability curve is usually drawn. The load capability of a gas turbine transformer is a curve showing the apparent power as a function of the ambient temperature and for a given hot-spot temperature. This curve is determined by calculating the power which gives the required hot-spot temperature (in general 98°C and 118°C) for each ambient temperature. Power curves for typical turbines have a slightly weaker slope than that of the transformer load capability. The transformer rating can therefore be defined to match the turbine power.

As for the respective shapes of the power curves, and in line with the above, it is suitable to design the transformer for the annual mean ambient temperature gas turbine output. The result of such a design is plotted in Figure 6-12.

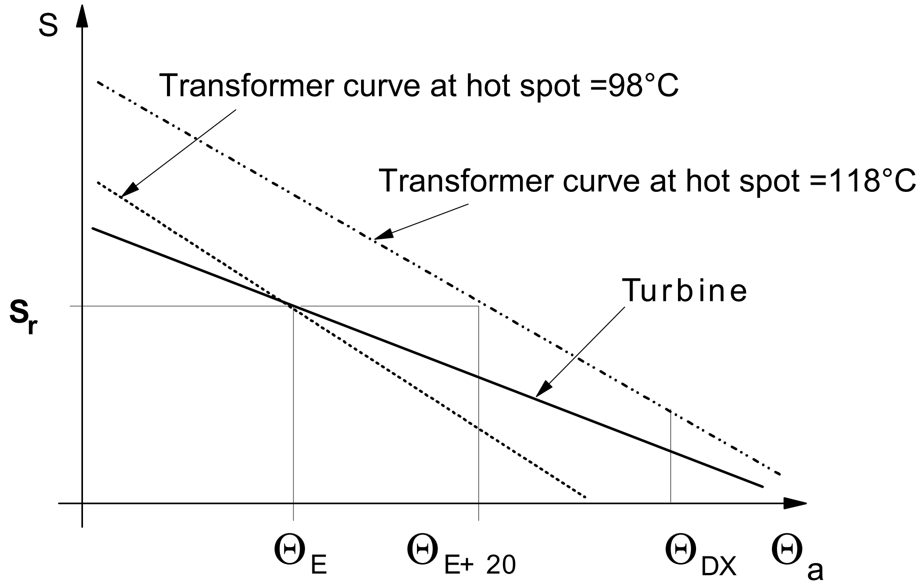


Figure 6-12: Typical power curves of a gas turbine transformer

Appendix A: Sample Data of DP-Measurements

Item	MVA, kV, Cooling;	Years	Paper, Preser-vation	Min DP location	Comments
1	31.5 MVA 110 / 63 kV, ONAF	48	Kraft Free-breathing	Top of LV (450)	Good state after 48 years Top of HV & RV- (600)
2	140 MVA 220 / 110 kV OFAF	30	Kraft Free-breathing	Top HV (App. 200)	Close to end of life after 30. Top and bottom of HV had similar ageing state; Likely poor oil circulation though layer type HV
3	600MVA, 380/220, OFAF, single phase Autotransformer	42	Kraft Free-breathing	Top of HV (450)	A good state after 42 Deterioration of likely unloaded tertiary winding (570) due to impact of oil by-products; Loaded Top LV (DP=600)
4	730 MVA, 22/420 kV , OFAF Failed due to short-circuit between LV	14	Kraft Free-breathing	Top of LV1-LV2 (215-250) helical type from CTC wire	Close to end of life after 14 years Localized ageing of several top coils; High local temperature; Impact of oil by-products Bulging CTC wire; Obstacles to oil flow on input to windings
5	500 MVA, 400/132/22kV, 3-phase autotransformer ONAN/OFAF Failed due to short-circuit between tap leads	16	Kraft Free-breathing	Bottom of LV (770)	Practically un-aged insulation after 16 Most loaded Common Top=860; Poor oil flow to LV and TW
6	700 MVA, 22/420kV, GSU, OFAF Failed due to leads overheating	20	Kraft Free-breathing	300 - top LV1 helical type from CTC wire	Significant localized deterioration after 20 Discoloration of HV2-top part due to sludge deposits Overheating of LV leads termination

Item	**MVA, kV, Cooling;**	**Years**	**Paper, Preser-vation**	**Min DP location**	**Comments**
7	500 MVA, 275/132/22kV autotransformer ONAN/ODAF 22 years Failed due to short-circuit between step at LTC selector	22	Kraft Free-breathing	Top of Un-loaded Tertiary (552)	DP samples from most loaded Series and Common-windings 590 and 613 Elevated oil temperature on ONAN-cooling mode; Impact of oil by-products
8	800 MVA, 400/275/22kV, ONAN/ODAF short-circuit between tap leads []	23	Kraft Membrane	Top of Series (273) and Common (275) Overheating of tap leads	High deterioration of un-loaded TW (296). Predominant deterioration of outer layers High oil temperature and high temperature rise above oil; impact of oil by-products
9	700 MVA, 20/420, OFAF, GSU Failed due to overheating LV leads	14	Kraft Membrane	Top of LV1 and LV2-(266-273)	Significant deterioration after 14 Localized ageing Sediment of sludge on top third of LV1 Overheating of HV and LV leads High temperature due to CTC bulging and high oil temperature leaving winding
10	700 MVA,20/300kV, OFAF Failed due to overheating LV leads	17	Kraft Free-breathing	Top of LV2 (486) and HV (448)	2FAL>3 from leads overheating overheating leads: Poor cooling due to improper collar washer disposition
11	700 MVA, 20/300kV, OFAF Failed due to overheating LV leads	18	Kraft Free-breathing	Top of HV1 (237) and Top of LV2 (237)	2FAL>3 from overheating leads sludge deposit on HV1

Item	MVA, kV, Cooling;	Years	Paper, Preser-vation	Min DP location	Comments
12	350 MVA 20/420kV, single-phase GSU ODAF Failed due to shirt-circuit in diverter switch	20	Kraft Membrane	Top of some layers of HV winding (206-218) and HV lead (218)	Close to end of life after 20 Insufficient oil flow through layer type winding, Low temperature drop in coolers (3C)
13	80 MVA, 88/33kV ONAN/ONAF Failed due to LV winding distortion	31	Kraft Free-breathing	Top of HV (265) and LV (290)	High rise of oil temperature leaving winding (90C at 30C ambient), rise of top oil above ambient (44C) and rise of top winding above oil (31,27) Elevated current density and limited cooling
14	80 MVA, 88/33 ONAN/ONAF	31	Kraft Free-breathing	Top of LV (349) and HV (380)	Good state after 30
15	15 MVA, 132 kV, Generating Station unit	37	Kraft Free-breathing	Top of HV-200	Close to end of life; Only 20% of total time loaded>75% Impact of Oxidized oil
16	50 MVA, 230 kV single – phase autotransformer failed due to lighting	36	Kraft Gas-blanked	Top of HV (outer layer) (525)	A good state after 36; Loaded to nameplate for 30years
17	860 MVA, 230 kV three phase GUS transformer, TU paper Failed due to overheating top tap lead joints	20	TU paper	Top of HV-(450)	
18	11 MVA, 138 kV; water-cooled	9	TU paper Free-breathing,	Top of 4th coil-(785)	
19	Shunt reactor 60 MVAR ,345 kV;1972,	19	TU paper	Top (757-764)	Loaded 8-12 hours a day

Item	MVA, kV, Cooling;	Years	Paper, Preser-vation	Min DP location	Comments
20	Single phase shel-form autotransformer 333 MVA, 765 kV	5	TU paper	Top of tertiary (660) Top of HV- (629)	Loading 20-50% Tertiary was practically unloaded
21	50 MVA, 345kV,1969, 21 years. Failed due to short-circuit between tertiary terminals	21	TU paper	Top of HV (362)	50% of tome loaded>75%

Appendix B: Symbols and Abbreviations

I	Rated current	[A]
I_{EMER}	Current used for Emergency Overload Test	[A]
I_{TEST}	Test Current	[A]
K	Load of the transformer	[kVA] or [MVA]
$P_{L\ EMER}$	Summated Losses for Emergency Overload Test	[kW]
$P_{L\ TEST}$	Summated Losses at “Rated” Test Loading	[kW]
R	Ratio of load losses to no-load losses at rated current	[-]
E	Activation energy	[kJ/mol]
DP_0	Degree of polymerisation at time 0	
DP_t	Degree of polymerisation at time t	
α	Amount of acids	
q	Water content	
c_{oil}	Specific heat of the oil	[°C.m^3/s]
$\dot{m}_{oil}$	Mass flow of the oil	[Kg/s]
Δp	Pressure drop	[Pa]
Δp_b	Pressure provided by buoyancy in a ON.. winding	[Pa]
Δp_w	Pressure drop in the winding	[Pa]
t	Time	[s]
τ	Time constant	[1/s]
τ_W	Time constant of temperature the winding	[1/s]
τ_{tr}	Time constant of temperature of the oil	[1/s]
η	Ageing factor	
$A(\alpha,q)$	Environmental factor in ageing factor	[-]
x	Oil Temperature Rise Exponent	[-]
y	Winding Temperature Rise Exponent	[-]
k	Hot-spot Factor for Winding Gradient	[-]
k_{AVE}	Average Hot-spot Factor for Winding (HV or LV)	[-]
k_{MAX}	Maximum Hot-spot Factor for Winding (HV or LV)	[-]
T	Absolute temperature	[°C]
T_{FO}	Temperature measured by fibre optics	[°C]
T_{WHS}	Calculated Winding Hot-spot Temperature	[°C]
T_{Air}	Ambient Temperature (Air)	[°C]
T_{TO}	Top Oil Temperature	[°C]
T_{BO}	Bottom Oil Temperature	[°C]
T_{HS}	Hot-spot Temperature	[°C]
T_{FOA}	Average Fibre Optic Temperature for that Voltage	[°C]
T_{FOMAX}	Maximum Fibre Optic Temperature for that Voltage	[°C]
T_{WA}	Average Temperature of Winding (from Resistance)	[°C]
ΔT	Temperature difference	[°C or K]
Θ	Temperature rise	[°C or K]
Θ_{TO}	Top Oil Temperature Rise	[°C or K]
Θ_{WO}	Temperature rise between winding and oil	[°C or K]
Θ_{OAir}	Temperature rise between oil and ambient air	[°C or K]
Θ_{HSTO}	Temperature rise between hotspot and top oil temperature	[°C or K]
Θ_{BO}	Bottom oil temperature rise	[°C or K]
Θ_{OA}	Average oil temperature rise	[°C or K]
$\Theta_{TO\ EMER}$	Top Oil Rise for Emergency Overload Test	[°C or K]
$\Theta_{TO\ TEST}$	Top Oil Rise at “Rated” Test Losses	[°C or K]
Θ_{WAHS}	Temperature rise between hotspot and average winding temperature	[°C or K]
Θ_{CO}	Temperature rise between conductor and oil temperature	[°C or K]

G	Calculated Gradient	[°C or K]
G_{EMER}	Average Winding Gradient from Emergency Overload Test	[°C or K]
G_{TEST}	Average Winding Gradient at “Rated” Test Current	[°C or K]
G_{WA}	Average Winding Gradient by Resistance	[°C or K]
DETC	De-Energized Tap Changer	
LTC	Load Tap Changer	
OLTC	On-load Tap Changer	
HV	High Voltage	
LV	Low Voltage	

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