TRANSFORMER RISK ASSESSMENT CONSIDERATIONS

Victor Sokolov
ZTZ Service
Armando Bassetto
Jose Mak
Bassetto & Mak Group
Dave Hanson
TJ|H_2b Analytical Services

Abstract

This paper presents some practical guidelines to implement the transformer functional-based methodology by using the existing body of knowledge and technologies. The condition assessment of aged transformers is discussed. Some steps for detecting and identifying the risk of failures involving the mechanical, dielectric and electromagnetic systems, OLTCs, and bushings are proposed for power transformers even if they have an unknown history.

Introduction

There is huge transformer population, which has already been in service for 25-40 years. In the first quarter of this century, the electric power industry worldwide will face the challenge of how to manage the serviceability of this aged transformer population. The basic problem is to ensure appropriate actions are taken to promote the longest possible service life under any operating condition. Apparently, after long-term operation the condition of a transformer's insulation should be substantially changed.

A typical condition assessment approach is based on monitoring and identification of some traditional [1] and novel parameters, especially DGA, Furanic compounds; LR and FRA to identify changes of the winding geometry, PF and (or) Dielectric Response (DR) tests to establish the status of the solid insulation (level of moisture in cellulose, oil conductivity, and oil power factor). However, this approach sometimes gives no idea on how to qualify the functional state of a transformer, whether the used set of tests is sufficient to establish the real condition of the unit and particularly how to quantify the rate of transformer impairment.

CIGRE WG 12.18 has suggested a new functional-based methodology [2,3] which considers the assessment of the condition of a transformer on the relevant withstand strengths or spare margins and correlation between process of deterioration, defective condition, and relevant characteristics of the defective condition (image of defect).

This paper presents some practical guidelines to implement the transformer functional-based methodology by using the existing body of knowledge and technologies in order to manage and to extend the life of transformers, to reduce failures, and to produce a reliable and cost-effective power supply.

Conditions of a Transformer in the Course of its Life Cycle

The life of a transformer may be introduced as the change of its condition with time under impact of thermal, electric, electromagnetic, and electrodynamics stresses, as well as under the impact of various contamination and ageing processes. The withstand strength of the transformer will naturally decrease over its life due to various ageing processes (normal ageing), but may deteriorate faster than normal under the influence of contaminants or destructive processes.

CIGRE WG12.18 [3] suggested four basic conditions of a transformer:

- **Normal** condition such as new and service aged.

- **Defective**, that is, an abnormal condition mainly attributed to reversible processes like insulation/oil contamination, clamping relaxation, etc when the material has not yet been destroyed physically and could be restored even without transformer de-energizing.

- **Faulty** condition, which is mainly attributed to irreversible processes when something has really been destroyed, and remedial actions are needed by means of physical processing.

- **Failed** condition.

In some of these cases, economic aspects could be a decisive factor for classifying the condition. For example, fixing the problem caused by a hot spot due to loosened bolts could be a small job. However, it requires high costs due to necessity of draining the oil, subsequent drying out, etc.

Figure 1 shows a model of possible changes of a transformer condition in the course of its life cycle, and gives an idea about a risk assessment program:

A *defective condition* (e.g. high moisture in oil) jeopardizes a fault occurrence (e.g. track of discharge); however, a *critical defective condition* (e.g. presence of liquid water) forms a risk of immediate failure. Accordingly, a risk of occurrence of *critical defective condition* should be considered particularly.

A *faulty condition* is a risk of direct failure depending on the stage of the fault progressing and the functional component involved. A failure is typically preceded with an *"imminent failure"* condition.

Economic, technical and strategic factors determine the effective end of life of the equipment. The technical life may continue as long as the transformer retains its functional serviceability, which is determined by its four key properties:

- Electromagnetic ability and integrity, that is, the ability to transfer electromagnetic energy at specified conditions including permissible overexcitation and overloading.

- Integrity of the current carrying circuit.

- Dielectric withstand strength under the influence of specified operational stresses, considering a permissible level of deterioration.

- Mechanical withstand strength under the effect of specified through-fault currents.

A failure occurs when the withstand strength of the transformer with respect to one of its key properties is exceeded by operating stresses. Sometimes the transformer can maintain serviceability while being in a faulty condition (overheating, gassing), but it will fail immediately if a short-circuit or an open-circuit happens.

It is important to distinguish between *complete* and *incomplete failure* when the transformer can partly retain serviceability despite some limitation (blocked OLTC, reduced load, etc.). The condition of a transformer should be analyzed also in terms of failure consequence: explosions, fires, tank rupture, tripping, long/short term unavailability. Anticipation and prevention of *catastrophic failure* should be a priority task.

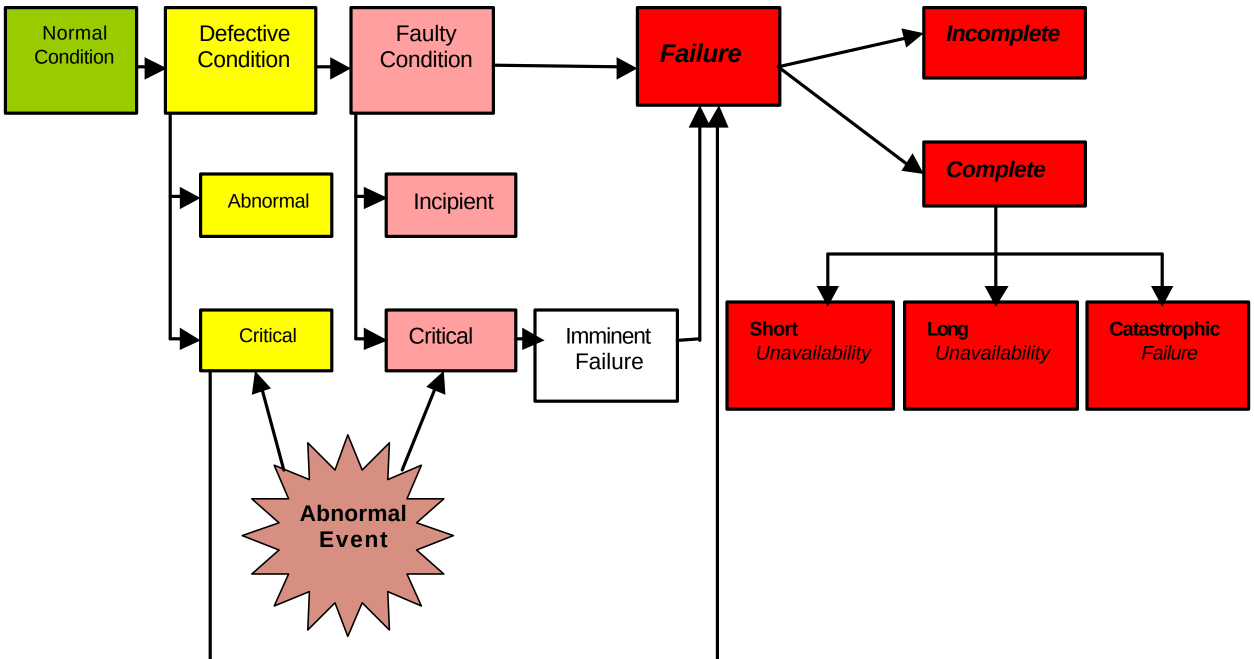


Figure 1
Conditions of a Transformer in the Course of Life Cycle

Failure as a Basic Motivating Factor for Risk Assessment

A failure is usually a touchstone of the equipment life expectancy, and failure analysis would be the most prominent way to anticipate possible reliability problems with an aged transformer population. The quantity of failure rate considering a representative sample, e.g., an observation for 5-10 years [4] and the determination of statistical correlation would be a valuable tool. Unfortunately, very limited information is available to establish any statistical trend in reliability of transformers after 25-30 years in operation.

Recently several valuable papers have been presented [4-7]. They were based on statistics available and advised a long-range forecast. They predict an exponential rise in failure rate after a certain period of operation. According to the least favourable CIGRE scenario [6], the failure rate would reach a 3% level after 50 years in operation for net transformers, and after 35 years for generating units.

The members of CIGRE WG12.18 collected and tabulated typical failure modes of large power transformers [8]. Most failures occur due to abnormal change of equipment condition over life, such as:

1. Shortened life due to accelerated deterioration of components particularly bushings and OLTCs.

2. Change in the condition due to ingress of water, particle contamination, ageing of oil, loosening of contacts and clamping forces, vibration, unusual stresses, etc.

3. Winding buckling under effect of through-fault current.

The ZTZ-Service experience based on observation of a large transformer population (about 5,000 units) allows achieving the following conclusions:

1. *Failures are caused predominantly by ageing factors*. However, there is a poor correlation between transformer age and failure rate, primarily due to thermal degradation of insulation material. Transformer failures attributed to overheating or wearing out of winding conductor insulation often involve some inherent deficiency, especially unaccounted local heating by stray flux, bad or deteriorated cooling, and non-specified overloading.

2. *"Dielectric life" could be shorter than "thermal life"*. The basic traditional philosophy declaring, "the life of the transformer is the mechanical life of paper" is not valid so far. The most failures associated with the ageing process occur due to deterioration of the dielectric strength of oil-paper structure with by-products.

An operation condition is sometimes a significant factor to trigger a failure process. The following *risk areas* could be advised in terms of operation events:

- Electrical disturbance (lightning strikes, voltage spikes, switching surges) accompanied by particle-in-oil contamination or conductive residue on the insulation surface.

- Excessive resonance-mode over voltage caused by fast transients.

- Short-circuit event that results in current magnitude over 70% of the specified value.
- Returning to service after repair, oil refilling, relocation, or long term storage especially at low temperatures. Poor impregnation (presence of air bubbles) and high moisture cause typically occurrence of critical PD during temperature transient.

- Returning to service after Buchholz protection tripping.

Failure analysis has also advised the typical failure modes that may result in *catastrophic failures:*

- Puncture of insulating core of HV bushing. Flash over internal porcelain of HV bushing.

- Breakdown of insulation space HV winding-tank, HV bushing-turret.

- Breakdown the phase-to-phase insulation of the HV windings.

- Short-circuit in the LTC compartment (selector or diverter).

- Overheating the external terminal contacts resulting in burning-out gasket, oil leak, and failure of some porcelain insulators of the outside tertiary or LV bus.

Risk of Critical Defective Condition of Dielectric System

Presence of Bubbles in Oil May Cause Occurrence of Critical PD Even at Rated Voltage. The following sources of bubble occurrence could be suggested:

- Residual air trapped in insulation after oil refilling.
- Cavitation in oil process.
- Arcing in oil (acetylene evolution).
- Evolution of moisture vapour bubbles out of heated conductor insulation.
- Oil over-saturation with air accompanied with mechanical shock (through fault) or oil turbulence.

Sudden Ingress of Free Water May Cause Failure of the Transformer Immediately. The main source of water contamination is atmospheric moisture. The main mechanism of water penetration in transformers is through poor seals by the viscous flow of wet air created by a total pressure gradient. *Typical leaks are the top seal of draw-lead bushings, the seals in explosion vents, and leaks through poor sealing of nitrogen-blanketed transformers.* Large amounts of rainwater can be sucked into a transformer in a very short time (several hours), when there is a rapid drop of pressure (after a rapid drop of temperature that can be induced by rain) combined with insufficient sealing.

Increasing the Relative Oil Saturation in Presence of Particles (Fibres) Results in Sharp Reduction of Dielectric Strength of Oil. The dangerous effect of soluble water could be presented as a sharp increasing saturation percent due to the increasing conductivity of particles. Increase of the relative saturation, e.g., above 50%, results in the increase of water content in precedently non-conductive fibre particles up to 6-7%. Excessive moisture is inherent to transformers with open-breathing preservation system or to those that have insufficient sealing.

A substantial variation of the transformer temperature (heating and sharp cooling) and energizing the cooled transformer would promote dangerous condition.

High Oil Temperature Could Add Water. Oil is a water-transferring medium. Water is usually present in the oil in a soluble or dissolved form but may also be present as a form adsorbed by “polar” ageing products and called “bound water”. It has been found that as temperature increases, some bound water can be converted into soluble water.

Test results of the water content of aged oil sampled from three power transformers are shown in Table 1. After heating the oil at 100°C for 4-6 hours, the water content in oil increased significantly. A similar phenomenon has been observed in bushing and current transformer oils. Most likely, the dissolved polar compounds in the oil are the source of this additional water.

Table 1

Transformation of Bound Water to Soluble Water from Aged Oil (blanked samples)

Sampled Transformer	**Oil Properties**	**Water Content ppm**	
		Before heating	After heating at 100°C for 4-6 hours
25MVA, 110 kV 11 years	Acidity = 0.038 mg KOH/g IFT = 32.0dynes/cm Saponification number = 0.097 mg KOH/g	29	40
40.5 MVA 110 kV 18 years	Acidity = 0.133 mg KOH/g IFT = 23.18dynes/cm Saponification number = 0.44 g KOH/g PF = 10.8 % at 90 C	25.8	50
150 MVA 220 kV 25 years	Acidity = 0.055 mg KOH/g IFT = 28.8 dynes/cm Saponification number = 0.138 g KOH/g	17.7	32

Tests performed in ZTZ – Service Material Lab

Another source of additional water can be attributed to particles in oil. Figure 2 shows a case with migration of moisture into an oil contaminated with particles (the number of particles in the range 3-150 µm per 10 ml is 22,950). Heating the blank oil sample up to 70°C resulted in fast evolving water in oil. Initial moisture content was restored only after 20 hours of cooling. Ageing degree of the oil was low: acidity = 0.037 mgKOH/g, IFT = 42 mN/m, saponification number = 0.064 mg KOH/g.

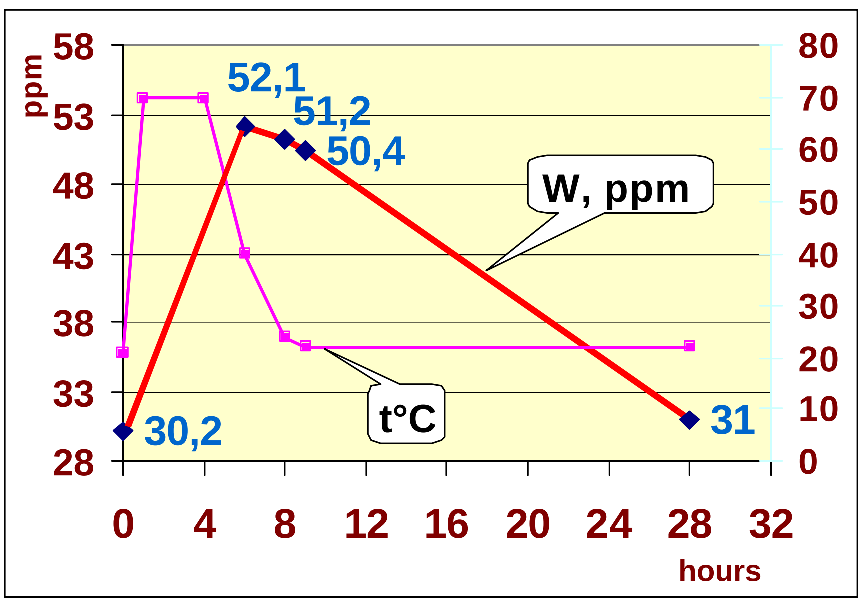


Figure 2

Temperature Migration of Moisture in Oil Contaminated with Particles

(Sample from A 400 MVA, 110 KV GSU Transformer after 13 Years In Service.

Test Performed In ZTZ-Service Material Lab)

Particle Contamination is The Main Factor of Degradation of the Dielectric Strength of the Transformer Insulation. The most dangerous particles are conductive particles (metals, carbon, wet fibres, etc.). CIGRE WG 12.17 “Particles in oil” collected approximately 50 major failures predominantly of 400-800 kV transformers, which were attributed to particles contamination. During utilization at normal and overload temperatures, oil slowly forms sludge particles "polymeric" in nature. Based on Velcon Filters research, these could be from one to five microns in size, and this contamination is difficult to remove by common filtration medias. Ageing destruction of cellulose insulation would result in fibres partition.

Localized oil overheating over 500°C would be a symptom of carbon formation. Any transformer (shunt reactor) that has a source of localized oil heating may be at a time a source of carbon generation. Clay and carbon particles are difficult to remove using conventional filter medias.

A typical source of conductive particles is attributed to the wear of bearings of oil pumps.

Trapping Effect of Transformer Components Forms a Dormant Incipient Fault. Particles existing in oil do not remain in oil due to the effect of gravity, oil flow, and particularly the effect of electrical and electromagnetic fields that attract the conductive particles and simultaneously deposits them on the winding surfaces, pressboard barriers, and bushing porcelain.

This phenomenon could be especially critical:

- For converter transformers where DC voltage reinforces particle attraction;
- For shunt reactors where high electromagnetic field strongly attracts particles depositing them on the barrier closest to the winding;
- For EHV power transformers;
- For HV bushings that operate in contaminated oil.

Experience has shown that dielectric withstand strength of the oil part of HV bushing could be very sensitive to contamination of transformer oil with conductive particles. There have been several documented cases associated with a deposit of carbon on the lower porcelain, which originated from the localized overheating of the core, and with deposits of iron particles on the porcelain surface, which originated from pump bearing wear. Some typical cases with severe contamination of insulation are shown in the Table 2.

Table 2
Cases with Local Contamination of Transformer Components

Case	Origin of Contamination	Condition of Insulation
Large UHV transformer	Carbon from the LTC diverter switch escaping into the main tank	Trapping effect of electrical field Particle collected in area with high stress concentrating on the outer circumference of part duct barriers and inside the winding
Converter transformer, 750 kV	Oil tar infiltration	Electrofilter effect of DC field Oily conductive mode residue on the barriers and valve winding
Shunt reactors, 400 kV	Aluminium particles due to mechanical attrition of aluminium shields	Trapping effect of electromagnetic field of winding Severe contamination of winding and pressboard sheets facing to winding Traces of PD
115 kV bushings	Leaching substance of rubber gasket and high content of dissolved metals in transformer oil	Trapping effect of bushing Formation of conductive stain on the bottom porcelain of the bushings Concentration of conductive substances in the form of strips
Transformer 200MVA, 220 kV bushing	Carbon formation in the place of localized core heating	Trapping effect of bushing Carbon deposit on the bottom porcelain surface
Transformer, 1000 MVA, 500 kV bushing	Carbon formation in the place of localized core heating	Trapping effect of bushing shield Carbon deposit on the bottom shield

Deposits of oil sludge or conductive particles on the surface of barriers reduce breakdown voltage particularly under effect of switching surge impulse. Study of dielectric characteristics of the contaminated pressboard patterns taken from a converter transformer has shown (Table 2) that electrical field attracts predominantly conductive particles that reduce surface resistivity as low as ten times, and cause a critical reduction of dielectric strength across the surface.

Table 3 summarizes several sources of typical contamination.

Table 3
Sources of Typical Contamination

Water Entering As Vapour	Direct exposure of the insulation to air during installation and inspection Ingress by viscous movement of wet air through unsealed oil expansion systems (conservator tanks) and through loose or cracked gaskets (at flange connections)	Most of the water is stored in the thin structure that operates at oil bulk temperature (20-30% of the total insulation mass) Presence of "wet zones" (typically bottom part of insulation of outer winding)
Liquid Water	As a by product of the ageing of the insulation system Damaged water heat exchangers When the transformer is under less than atmospheric pressure because of bad gaskets and loose connections (the top seal of draw-lead bushings, the seals in explosion vents, leaks through poor sealing of nitrogen blanketed transformer) Condensation in the coolest regions	Concentration in the vicinity of hot spots Bound water in oil Typically on the bottom parts of the tank and coolers Diffusion into the oil Temperature migration Movement of ice by oil flow
Particles	From manufacturing process Dress and test dirt Oil ageing Wear of aged cellulose Overheating of metals (carbon) Carbon from OLTC Wear of the pump bearings	Migration in oil Sediment under effect of gravity, oil flow and particularly effect of electrical and electromagnetic fields that attract the conductive particles and stimulate their deposit on the winding surfaces, pressboard barriers, bushing porcelain

Condition Quantification, Warning and Risky Areas

Occurrence of a defective condition should signify that the transformer entered some warning area. Accordingly, the faulty condition could be related to some risky area where the transformer can fail. In the range of risky area, an area of imminent failure and an area of imminent catastrophic failure can be recognized.

Usually *"caution level"* and "*alarm (risky) level*" are defined in terms of test data quantities, e.g., gas concentration, water content, insulation PF, etc. However, change of diagnostic parameters may be caused by either dangerous or harmless phenomena. Hence an approach to quantification of defective/faulty condition in terms of degradation of the transformer withstand strength could be more appropriate.

Dielectric System. Condition-based monitoring of power transformer insulation should centre on the prediction of a substantial drop in the dielectric safety margin under the impact of moisture, oil degradation by-products, contaminating particles, paper decomposition, and partial discharge activity. It is possible to define two critical stages of dielectric strength degradation:

- **Caution level** *(Defective condition)*: reduction of the initial withstands strength under the impact of degradation agents. It results in appearance of usually non-destructive partial discharges (PD) at operating voltage and reduction of the impulse withstand strength. Winding distortion could be another reason of the dielectric withstand strength degradation.

- **Alarm (Risky) level** *(Faulty condition)*: appearance of destructive PD, progressing surface discharges, and creeping discharge occurrence. Two levels of defective conditions could be suggested:

  1. Possible reduction of the dielectric margin with respect to specified stresses by 10% or more.

  2. Possible occurrence of critical PD at the rated voltage.

Some recommendations about quantification of defective and faulty condition of transformer dielectric system are shown in the Table 4. This issue needs further study.

Table 4
Characteristics of Dielectric System Defective and Faulty Conditions

Caution Levels	**Alarm Levels**
An increase of the oil relative saturation over 20% at operating temperature in presence of particles (water content in fibres >2.5%).	An increase of the relative saturation over 40-50 % at operating temperature at presence of particles (water content in fibres >6-7%) Presence of free water in oil
Water in major insulation that can result in evolution water in oil at high temperature and increase of the relative saturation of oil over 40% at minimum operative temperature. Water content in barriers >1.5-2% should be considered.	Water in major insulation that can result in evolution water in oil at high temperature and increase of the relative saturation of oil over 40-50% at normal operative temperature. Water content in barriers 3-4% should be considered.
Particles contamination. Presence of particles 5-150 microns more than 1000 in 10 ml. Possible carbon generation at a place of localized oil heating above 500°C.	Particles contamination (Classes by NAS 1638): 10-12; The presence of visible and conducting (metal, carbon) particles.
Possible bubble evolution at a place of localized oil heating above 800°C (Generation of C_2H_2)	Water in winding conductor insulation that may result in bubble evolution during overloading. Water content of 1.0-1.5% and gas saturation should be considered Large (3-5 mm) air/gas bubbles in oil
Oil ageing level that results in deposit of [illegible]	Oil ageing level that results in occurrence of [illegible]

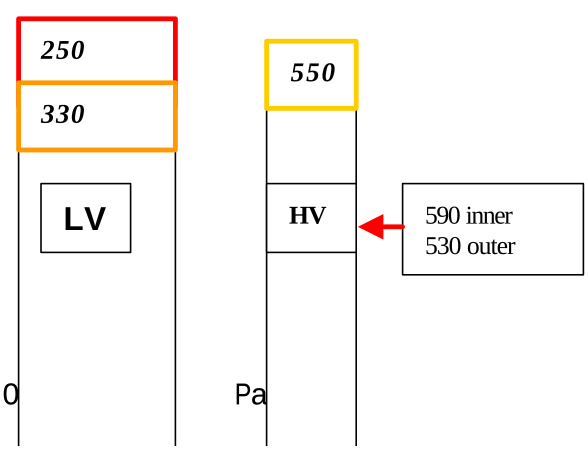
sludge across the pressboard under effect of electrical field	sludge that can reduce dielectric strength of oil
PD occurrence The 1st warning signal, q> 500-1000 pC The signal of defective condition q>1000-2500 pC	PD occurrence The 1st fault signal q>>2500 pC Critical condition q>>100,000-1000,000 pC The rate of discharge-mode gas generation more than 1 ppm per Joule

Critical Decomposition of Cellulose (Conductor) Insulation

The ageing factor may be expressed as a number of scissions of cellulosic molecule, in terms of reduction of degree of polymerization (DP). There has been no unanimity in the interpretation of insulation condition and particularly the end of life in terms of DP reduction. There has been a common opinion that values of DP < 400 mean that the transformer has entered the last third of its life. Some experts [9] consider that a more reasonable critical condition could be suggested from a short circuit standpoint when the paper has reached 50% of its life (DP is in the order of 450).

The end-of-life criterion is based on a DP of 200 of the conductor insulation near the hot-spot temperature. However, a hot spot area is typically beyond the range of sampling to perform direct DP testing. A complex temperature profile of windings results in significant variation of DP values in different parts of winding. A typical case investigated by ZTZ-service is shown in Figure 3.

Estimation of temperature distribution and insulation life assessment has shown that only a few sections of the LV winding have been subjected to excessive temperature due to deterioration of cooling ducts. Combined effect of temperature and oil ageing products caused a drastic deterioration of portion of insulation, which was estimated to weigh about 40 kg. Accordingly, relative amount of furanic compounds that accompany insulation would be very limited.



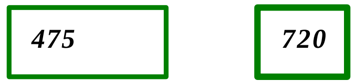


Figure 3
DP Profile of Conductor Insulation in a Large Power Transformer.
(Test Performed in ZTZ-Service Material Lab)

Accelerated insulation degradation in that particular transformer has been attributed to deterioration of LV winding cooling due to diminishing radial ducts and to the effect of oil degradation by-products. Greater deterioration of insulation surface layers has been attributed to the effect of acidic and non-acidic polar compounds adsorbed by cellulose from oil. Hence, a risky level of insulation deterioration can be advised only based on a comprehensive transformer design review, the determination of winding temperature profile, and considering the moisture content and the oil ageing status.

Typical Defects and Faults in OLTC. In the case of contact overheating, the following failure scenario could be suggested:

- Formation of film coating that reduces the contact surface and increases the contact resistance and its temperature.
- Rise in contact temperature results in a progressive rise of contact resistance and corresponding progressive rise of temperature, erosion of the contacts, coking, and gas generation.
- The failure process typically results in open-circuit or breakdown between phases due to severe oil contamination and often accompanies failure.
- Film coating increases the breakdown voltage between the contacts making contact resistance appropriate to the current value.

Oil temperature, contact design and material, and oil quality affect the process of contact degradation. Failure occurrence depends on current value and frequency of OLTC operation.

Caution condition:

- Increase of the initial contact resistance three times as much corresponds to the rise of contact temperature above oil from 20°C up to 40°C.
- Dependency of the contact resistance on applied current.
- Rise in oil temperature near contact over 100-105°C.

Alarm condition:

- Increase of the initial contact resistance 5-10 times as much (erosion of the surface).
- Rise of the contact temperature over 300°C.
- Faulty gas generation, e.g., over 0.1 ml/cm^2 per hour with trend of increasing the rate of gassing.

HV Bushings. CIGRE WG 12-18 [8] suggested distinguishing between two different failure modes in paper-oil impregnated HV bushings:

- Local defects in a bushing core that progress if short-circuit between layers, insulation puncture, and practically inevitable explosion. Here two types of physical developing faults can be expected:

    - Electric-destructive ionization in the place of overstressing due to poor impregnation, overstressing, bubble evolution (vacuum occurrence), X-wax deposits, etc.

    - Thermal-dielectric overheating and thermal instability due to oil-paper ageing, oil instability, and graphite ink migration, etc.

- Degradation of the dielectric withstand strength of oil and across the core or porcelain surface that progresses in flashover along the surface and practically inevitable explosion. These phenomena are typically originated from:

    - Critical ageing the oil, formation of semi-conductive residue on the lower porcelain;

    - Moisture penetration.

Caution (defective) condition:

This condition depends on the bushing design. However, in general the following are suggested limits:

- Increase of the PF C_1 above 0.5 % in the range of temperature 20-60%.

- Rising PF C_1 with temperature, the symptom is high moisture of the ageing oilpaper bulk.

- Rising PFC_2 (Test Tap) with temperature, the symptom is oil deterioration.

- Increasing PF C_2 (Potential Tap) above the PF C_1 and with temperature, the symptom is contamination of surface layers with oil ageing products.

- Reduction of PF C_1 below some minimum value (typically less than 0.15-0.1 %), the symptom is the deposit of conductive residue on the porcelain.

- Increase of the oil PF, appearance of metal containing colloids.

- Discoloration of the porcelain.

- Deposits of conductive sediment on the porcelain.

Alarm condition:

The monitoring technique that will give the warning of a faulty condition and the earliest warning of imminent failure will vary depending on the nature of the failure and bushing design. In the case of progressive faults within the core, alarm settings could be determined considering short-circuits between two capacitive layers.

One detection method will not catch all failures. Therefore, a group of relevant tests would be recommended. An on-line method is required because of the erratic and sometimes rapid nature of bushing failures:

- Relative PF C_1 (tan delta) and imbalance (sum) current ratio typically give the early warning of localized fault within the core and presence of conductive residue on the porcelain.

- Relative capacitance C_1 and leakage current ratio follow rise in PF if short-circuit between layers occurs.

- PD activity over 500 pC (core fault involved) and over 1000 pC (PD in oil).

- Faulty PD-pattern gas generation that follows PD activity.

- Appearance of furan compounds, carbon monoxide, and dioxide (dielectric overheating involved).

How to Assess Condition of a Transformer with Unknown History

Based on the above-stated issues it is possible to suggest an approach to transformer condition assessment using the conditional checklist as a test questionnaire (Table 5). Different transformer designs require different and likely more questions.

Table 5
Conditional Checklist for a Transformer Condition Assessment

Design Review	Operation Condition Review
General Status. Condition of the Electromagnetic System	

What is the general thermal health of the transformer? Shall we expect any unusual processes causing destruction of insulating materials? Are there symptoms of internal overheating, sparking, and arcing? Are there signs of unusual noise, vibration? Is there any external overheating? Does localized overheating of oil produce dangerous by-products (carbon, metallic particles)? Is the gassing attributable to the main flux, or to the stray flux, or does it involve contact (joint) overheating?
Dielectric Status
Is there a source of liquid water penetration? Is there a source of unusual contamination (pump failure, OLTC)? What is the level of contamination with water and particles? Shall we expect a substantial reduction in the dielectric margin at operating temperatures? Does oil contamination result in PD occurrence at rated voltage? What is the level of water content in conductor insulation? Shall we expect bubble evolution at overloading? Is there abnormal heating of cellulose? Shall we expect an abnormal (accelerated) rate of ageing of insulation? What is the oil ageing level? Can the oil ageing level result in the occurrence of sludge?
Mechanical Status
Is there loosening of the winding clamping? Shall we expect distortion of winding geometry: hoop-buckling, axial twisting?
OLTC Status
Is there excessive mechanical wear of the OLTC components? Shall we expect contact deterioration of the OLTC including diverter switch compartment? What is the level of the OLTC contamination with water and particles?
Bushing Status
Is there contact or local overheating? Is there a local defect in the core of the bushing? Shall we expect noticeable ageing of the oilpaper bulk? Shall we expect moisture penetration into the bushing? What is the ageing status of the oil in the bushing? Is there conductive staining of the internal porcelain?

Due to the limitation of existing diagnostic techniques, not all the questions can be answered. However, the techniques available allow determination of the level of functional serviceability of the equipment and advise the ranking in terms of condition classification. It is remarkable that a significant amount of information can be received on-line predominantly by means of a comprehensive oil analysis.

The following questions can be answered by conducting on-line and off-line tests.

1. *Shall we expect the presence of unusual processes within a transformer causing destruction of insulating materials?*

Tests On-Line. Analysis of gaseous, liquid and solid by-products including:

- DGA (main tank, OLTC compartments)
- Furans, phenols, and cresols
- Particle identification
- Oil ageing by-products

Complementary Tests Off-Line. A set of tests depending upon the presumed origin of destruction.

2. *Shall we expect a substantial reduction in the dielectric margin at operating temperatures? What is the level of water content in the solid insulation? Shall we expect bubbling evolution at overloading?*

Tests On-Line

- Design review (safety margin)
- Condition operation review
- Water heat run test (WHRT) considering load increase
- Particle counting and identification
- Metals in oil, DGA, oil ageing degree
- Vibro-acoustic test
- PD test
- Air (oxygen/nitrogen content)

Complementary Tests Off-Line

- Sealing test
- Estimation of water content of the insulation surface contamination using temperature response of PF and insulation resistance
- Dielectric frequency response of the insulation space

3. *Is there loosening of the winding clamping? Shall we expect distortion of winding geometry (radial buckling, axial, and twisting)?*

Tests On-Line

- Design review (safety margin)6
- Condition operation review
- Vibration spectra including temperature response

Complementary Tests Off-Line

- Winding capacitance
- Leakage reactance (LR)/leakage impedance
- Low voltage impulses (LVI)
- Frequency response analysis (FRA)
- Frequency response of stray losses

Conclusions

In order to make the best decision about managing the serviceability of a huge aged transformer population, it is imperative to understand the condition of the equipment. CIGRE WG 12.18 has suggested a new functional-based methodology [2, 3]. Some practical guidelines to implement the transformer functional-based methodology by using the existing body of knowledge and technologies were presented in the paper.

The diagnostics have to be centered on the prediction of the substantial drop in the dielectric safety margin under impact of moisture, oil by-products, contaminating particles, partial discharge activity, tracking and creeping discharges, and paper ageing. The functional failure model chosen highlights the most dangerous processes where attention has to be concentrated.

The scope of tests and their interpretation depend on sensitive points of components, their expected failure modes and on variability of the design (diagnostic accessibility). Design review should be a critical step of condition assessment. Implementation of the test program presented, which is focused on a detection of possible defects utilizing a group of the relevant methods, has allowed to identify a number of defects in aged transformers. Most of the problems could be detected on-line, especially utilizing the oil as a diagnostic medium, as well as by utilizing several other monitoring methods whose effectiveness has been proven in practice.

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