We can classify test failure modes in power transformers according to transformer components

ABSTRACT

To prevent unexpected outages it is necessary to implement a field test programme. It has to be decided what tests should be performed and what information is expected to be obtained from these tests. This paper describes a common set of field tests on the basis of prescribed standards and years of field experience. Off-line and on-line tests are described as well as their use in diagnosis and trending. The paper also highlights the importance of training in this process to make conclusions and recommendations reliable.

KEYWORDS

field testing, life extension, predictive maintenance, off-line test, on-line test

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What's behind transformer field testing?

Power transformer predictive maintenance: field testing

Introduction

Power transformers are key assets in electric energy generation, transmission and distribution systems, and also an important element in the industry. In order to get maximum service reliability in this critical component, it is necessary to perform a scheduled set of suitable diagnosis techniques on each transformer.

We can classify test failure modes in power transformers according to their different components. From a practical and didactical point of view, it is helpful to divide the transformer into the following components and associated potential faults:

- *Electric Circuit.* Copper paths: contact problems at bushings, joints, windings, welded and soldered connections, tap changers
- *Magnetic Circuit.* Steel, yokes, loosening
- *Geometry of windings.* Symmetry, change of geometry between windings and windings to core, distances
- *Insulation system.* Oil, paper, contamination, water ingress, distances, ageing. This component usually defines the life of the power transformer

Figure 1. Breakdown of the dielectric system in a power transformer column

Field testing

The electric utility and electric power industries need to define their strategy and maintenance policy for their costly power transformer assets. Today, there are some on-line tests that will help to achieve this, but most of the checks rely on regular off-line measurements.

> **Today, there are many on-line tests that will help to assess transformer condition, but most of decisions are based on off-line measurements**

Off-line testing

Table 1 lists the standard off-line tests available for power transformers. Today there are instruments to conduct all the tests listed in the table. Sometimes a single instrument will include most of tests with the associated software to simplify its use for diagnosis and trending.

Figure 2. Baseline field testing of a power transformer before going into service (50 MVA)

Basic insulation testing (DC)

In traditional insulation resistance testing, the Insulation Resistance (**IR_1**) between windings and between each winding and the ground is measured. Test instruments use a DC voltage (typ.=5 kV dc). The insulation value is recorded over time, indicating the 1 minute and 10 minute (**IR_{10}**) values. From these, the Polarization Index (PI) is calculated as **PI**=IR_{10}/IR_1. Whilst the IR values have a strong dependency on temperature, the polarization index reduces this dependency. This measurement can detect serious problems, such as moisture, contamination or breakdowns. Testers usually plot the IR vs. time and also take a reading of the capacitance value **Cg**.

Advanced insulation testing (DC)

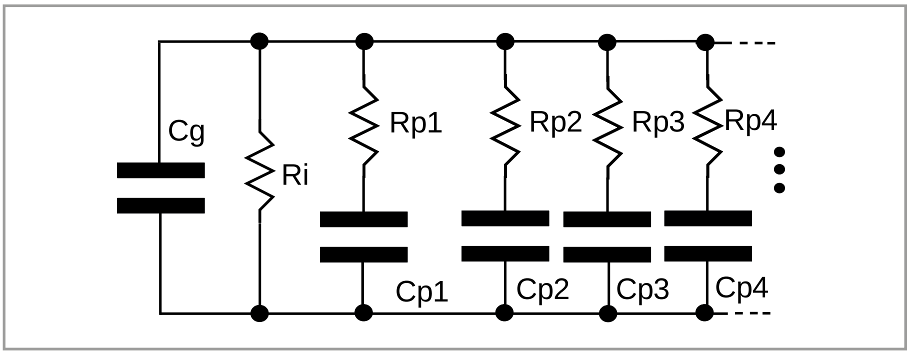
The two techniques below were developed to get an insight into oil-paper insulation. Even with good IR and PI results, power transformers can have a degraded insulation with moisture or contamination that will affect their lifetime. In the transformer, it is paper lifetime that usually limits transformer life, and these dc tests are tools that can help in assessing its condition.

PDC (Polarization and Depolarization Currents) is an accepted way to determine the parameters of the model from Fig. 3. Here charge/discharge currents are measured with the aid of a DC source and plotted in a current vs. time graph. Extensive work has been done in analytical models to relate the geometry and properties of oil to these currents taking also account of temperature. Whilst this allows an estimation of moisture in the insulation, the main benefit is that it provides a diagnosis of the dielectric components and the possible origin of problems if they exists in that part of the transformer.

RVM (Recovery Voltage Measurement) test plots the recovery voltage (vertically) against time (horizontally). The time

Table 1. Off-line tests for power transformer field testing

<table>
<tr><th>DC</th><th colspan="2">Insulation, OLTC, Bushings & Windings</th><th>AC</th></tr>
<tr><td colspan="2">Basic insulation:</td><td colspan="2">Advanced insulation:</td></tr>
<tr><td colspan="2">Insulation resistance, polarization index, C_g, core to ground</td><td colspan="2">FDS (Dielectric Spectroscopy). Tan δ to windings (C_H, C_L, C_{HL}), HV excitation current. Tan δ to bushings (C1/C2) & hot collar</td></tr>
<tr><td colspan="2">Advanced insulation:</td><td colspan="2">Open circuit test:</td></tr>
<tr><td colspan="2">PDC / recovery voltage</td><td colspan="2">Turns ratio / LV excitation current</td></tr>
<tr><td colspan="2">Winding resistance:</td><td colspan="2">FRA: Frequency Response Analysis</td></tr>
<tr><td colspan="2">Static/dynamic (OLTC)</td><td colspan="2">Short circuit impedance/voltage</td></tr>
</table>



Ri is the leakage resistance,
Cg is the geometric capacitance, and
the different Rp/Cp emulate the equivalent dielectric polarization circuit of paper-oil insulation

Figure 3. Equivalent diagram of the dielectric circuit of a transformer

> **In the transformer, it is paper lifetime that usually limits transformer life, and advanced insulation tests are tools that can help in assessing its condition**

” It was found that for more degraded insulation the crest of the time constant moved to the left in the RVM display

to the peak of the voltages relates to the time constant of the dielectric system (Rp•Cp = time constant in Fig. 3). This gives information of dissolved moisture, contamination and ageing. The RVM test records RVM as in Fig. 4, with maximum **TC** (Time Constant = predominant time constant), and also includes $\mathbf{IR_1}$, $\mathbf{IR_{10}}$ & **PI**. Initial attempts with RVM to assess moisture directly from the plots met with limited success, but more importantly, it was found that for more degraded insulation the crest of the time constant moved to the left in the RVM display.

These two techniques (PDC and RVM) for advanced insulation work in the time domain. A further method, FDS, works in the frequency domain and is described later in this paper. Last CIGRE work on dielectric response diagnoses [4] identifies PDC and FDS as the techniques which allow the clearest discrimination between the effects of oil condition and solid insulation moisture content.

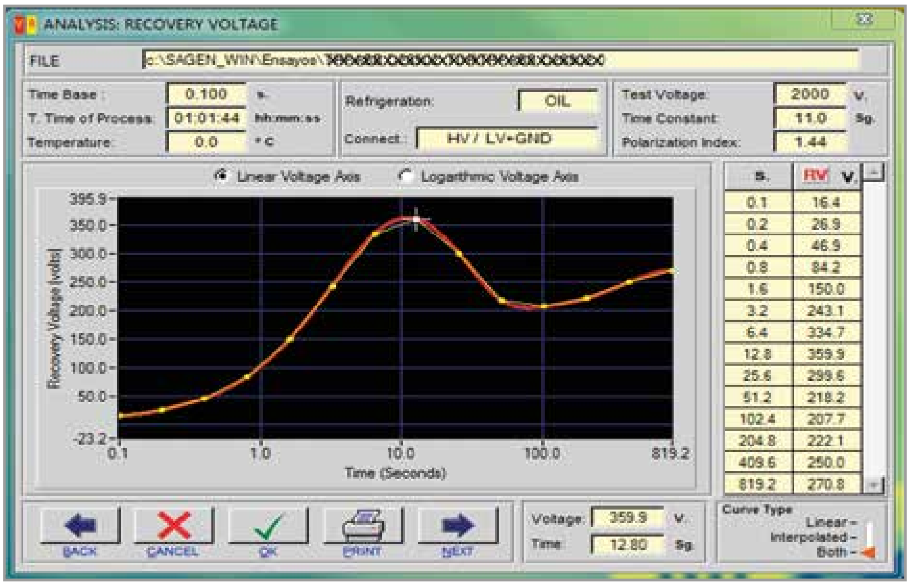


Figure 4. Test screen from a RVM test set with a time constant that is too low. Time Constant = TC = time of RVM plot crest

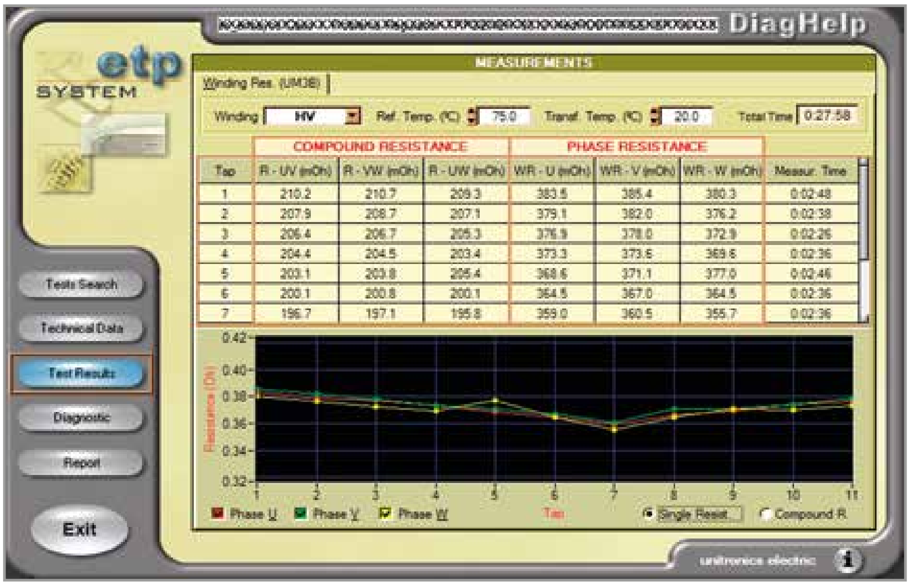


Figure 5. Plot results from a winding resistance test showing a problem in the high voltage windings (nominal position is 11, not 7). This was a problem at the tap changer

Winding resistance: static (DC)

This test determines the pure ohmic resistance ($\mathbf{R_B}$) from each phase both in high and low voltage sides, and, if a winding has a tap changer, it is best to perform the test at each tap position. Resistance measurement requires a four terminal or Kelvin connections with separated current insertion and voltage reading to avoid including the test cable resistance in the measurement.

Final results must be temperature normalized to allow comparison and trending to previous historical measurements and to the original factory test results. It is better to present single phase values rather than composite (phase to phase) values; these give a better understanding of the origin of possible faults. It is difficult to identify the cause of a winding resistance discrepancy from the measurements alone. Poor connections on windings or tap changer and shorts can be determined but they all require additional testing or physical investigation. Although this test is simple in concept, it can become complex in large transformers where the mix of very low resistive values with high inductances results in long delays whilst the readings stabilise.

Winding resistance: dynamic (DC)

There is also instrumentation available that can perform Dynamic Winding Resistance (**DWR**) measurements. This can be used to check the proper operation of the On-Load Tap Changer (OLTC); here the timing of the operation and changeover resistance are monitored to identify possible problems.

TTR, Transformer Turn Ratio (AC)

This test involves applying a low AC voltage to each high voltage winding phase, measuring the corresponding induced value at each low voltage winding, and determining the **TTR** for each tap changer position. This ratio value should be very close to nameplate values and can indicate electrical or tap changer problems.

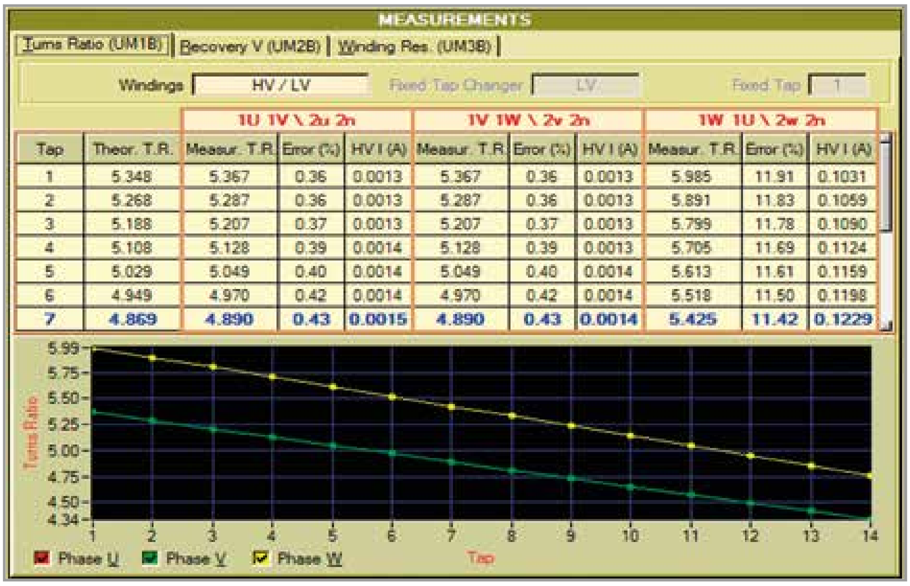


Figure 6. Results of a turn ratio test determining a short circuit between turns at low voltage side; green phase on top of red one, yellow phase separated. Phase W also shows a high I_0

Figure 7. Example of a field test set for power transformer evaluation ETP

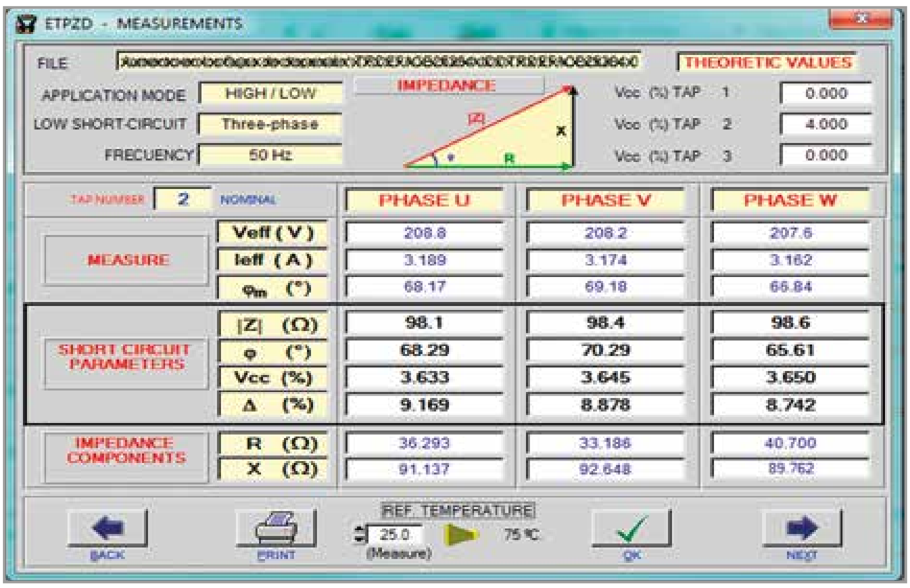


Figure 8. Results screen from a field short circuit test indicating changes in the geometric circuit

Instruments for measurement of winding resistance during operation of the on-load tap changer are available

Low voltage excitation current (I_0): During the TTR test, the magnetic circuit exciting current is also measured. This current flowing in the high voltage winding with the low voltage side open is proportional to the factory "no load current", but might not completely correlate. It is important to check differences between phases for these currents, and changes in trending of this value will help identify problems in magnetic circuit: degradation, loose core or hot spots in core. I0 can also be used to detect shorted turns and inter-strand faults to some degree. Because the current could be low, if there is any doubt about the results, they should be confirmed with a tan δ measurement, which can also perform this test, but uses a higher excitation voltage (10 kV) and thus gives a better current resolution. Again currents should be measured, compared between phases, and long term trending should be used to identify changes.

Short circuit impedance test / leakage reactance (AC)

This test is similar to the factory short circuit test. It is based on the phase by phase injection of an AC current in each high voltage side with a good *(very low resistance)* short circuit connected on the low voltage side. The measured voltage, current and phase are used to calculate the impedance at a particular base MVA.

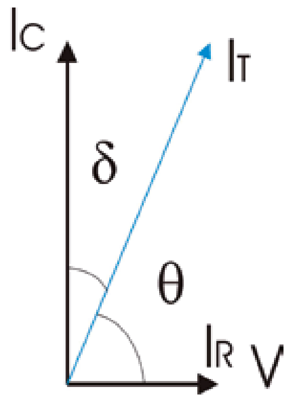
This deduced short circuit voltage test Vsc (%) is a field test that simulates the factory test and will report similar values giving an indication of geometrical failure modes: winding displacement, mechanical deformations, asymmetry, etc. Here, it is usual to record data at the nominal tap changer position. If a geometric problem is suspected from the field short circuit test, FRA tests and the historical variation of capacitances resultant from tan δ test could also help in the diagnosis.

"If a geometric problem is suspected form the field short circuit test, FRA tests and the historical variation of capacitances resultant from tan δ test could also help in the diagnosis

Figure 10. Collapsed winding degradation detectable with FRA

Tan δ capacitance for winding & bushings (AC, 50 Hz / 60 Hz)

Here we use an AC Schering bridge to measure the angle by which the measured value fails to give the expected 90º corresponding to a perfect capacitive insulation. The bigger this angle, the greater the losses, and hence the degradation. Simultaneously to the **tgδ (%) measurement**, the capacitance between windings or windings to ground is measured, but this time with high voltage. This test is usually performed at 2 kV and 10 kV.



Resistive current I_R is in phase with the voltage
Capacitive current I_C is out of phase by 90º
Total current I_T defines δ angle and its tangent

Figure 9. Diagram of currents flowing through dielectric

With the different instrument test modes GST/UST (Grounded/Ungrounded Specimen Test), different areas of the transformer insulation can be tested: HV winding to core and tank $\mathbf{C_{HG}}$, LV winding to core and tank $\mathbf{C_{LG}}$, HV to LV $\mathbf{C_{HG}}$, or even bushings. In bushings the internal insulation is tested with the measurement of its capacitances **C1/C2**. This can be tested independently from winding insulation using bushing capacitive or test tap. If there is no test tap or a problem is suspected, a tan δ instrument can also perform an external insulation bushing testing called "hot-collar", which could check for local defects like cracks in the porcelain or lack of oil.

Tan δ will detect oil degradation/contamination. Capacitance can even identify geometrical changes in windings and short circuits between layers in bushings.

Most modern instrumentation allows testing not just at 50 Hz / 60 Hz, but in a frequency range (15 Hz - 400 Hz) that can provide further help in diagnosis.

FDS/DFR (AC: 1 mHz to 10 KHz)

Frequency Domain Spectroscopy (**FDS**) or Dielectric Frequency Response (**DFR**) is the traditional tan δ test, but this time measured at a range of frequencies and usually with a low AC voltage. Utilities, CIGRE & IEEE are working hard on this test because it is expected that with more experience of maintenance problems and plot alterations we will learn more about the dielectric system. Instrument manufacturers provide complementary software that uses a simplified model of the transformer insulation to get an indication of *moisture in paper* and oil conductivity.

FRA, Frequency Response Analysis (AC: 20 Hz to 2 MHz)

The power transformer is characterised by the complex R-L-C equivalent circuit inside it. With frequency Response Analysis (**FRA**), we can see for each phase and winding the plot of poles & zeros that represent the resonances of the inductive and capacitive elements of the winding. Changes in each phase plot (also called "signatures") are the representation of the alterations (mostly geometrical) of the different winding characteristics inside it (number of turns, resistance, distances, etc.). Changes will be checked between phases, similar transformers or over time (trending). There are also standards [5,7,8] and other references [6] that can help to give an idea of the differences between patterns of each phase in order to asses if there are any "distortions" in windings, and if so, their possible origin.

Table 2 reviews state-of-the-art on-line tests for predictive maintenance in power transformers.

Table 2. On-line tests for power transformer field testing

TRANSFORMER/DIELECTRIC/BUSHINGS/OLTC	
Tan δ	Thermography (IR)
Partial discharge (UHF/Ultrasonic)	OLTC monitoring
Insulating oil	
Physic-chemical oil test	DGA (Dissolved Gas analysis) either manual or continuous
Furan testing	

Equipment with improved features and resolution enables a detection of most failure modes that generate a thermal fingerprint (bushing, coolers, pumps, fans, OLTC, etc.)

On-line predictive tests for transformer/dielectric

Today there are some procedures that can be performed on-line in power transformers and give us valuable information about its operation.

Partial Discharge (PD). The working groups [9, 10] identified two tests as the most successful in field tests to assess and even locate the origin of the PD: **UHF** and **Ultrasonic**. Both of them install sensors working in frequency spectrum areas with very low noise (this allows the instruments to reject any PD-like interference from outside elements).

Tan δ. A sensor is attached to each test tap of the bushings and sometimes to potential transformers, so that tan delta is monitored for each bushing. The idea is to pick up failure modes that may result in a fast thermal runaway that could destroy any of the bushings. This problem could develop too rapidly to be identified by regular off-line C1/C2 tests.

OLTC monitoring: vibration, acoustic, motor torque, etc.

Thermography. Thanks to the availability of equipment with improved features and resolution we can detect most failure modes that generate a thermal fingerprint (bushing, coolers, pumps, fans, OLTC, etc.).

On-line predictive tests for transformer oil

Today we have two common ways available for oil testing measurements in the field:

Manual oil sampling. Oil is sampled (working with strict standard procedures [11, 12]) followed by laboratory analysis. It is very important to record the oil temperature when sampling. It is usual to perform physicochemical testing in oil with some tests done on-site. *Breakdown voltage* monitors the ability of oil to withstand an electric field and is a good indicator of oil quality. *Moisture in oil* gives an indication of water ppm in oil itself. Whilst moisture in oil is being measured, the result is used to indirectly determine the moisture in the paper insulation system at a particular temperature. This equivalence is not too good, so FDS can complement this information. It is really important to know this parameter as water is the worst enemy of the power transformer.

Laboratory DGA (Dissolved Gas Analysis) is a test usually performed by sending samples to laboratory to analyse each gas inside the oil in ppm. IEEE & IEC have standards [13,14] that can guide us in the decision making process to diagnose gas in oil both for levels and trend. There are several diagnosis procedures in these standards like Gas Ratios, Roger Ratios, Key gases, JAPAN ETRA (Electric Technology Research Association), etc. One of the most successful tools to assess these results are the different **Duval Triangles** that compare gas concentrations of each type. At the end of 2014, the **Duval Pentagon** promised a new insight to classify transformer problems and their progress. Results will be able to indicate the presence of PD, thermal or electric problems under way and also if the paper is involved in the problem.

Sometimes **Furan** content is also requested from the laboratory because it provides an indication of degradation status of paper (furans are present in the oil only as a by-product of paper degradation and correlate well with paper Degree of Polymerization (**DP**) [17]).

Continuous oil DGA. Today, there are systems available to take samples from oil in a continuous mode. Instrument manufacturers usually provide two levels of complexity to their gas analysers: one level of instrument monitors 1, 2 or 3 gases (H_2, or some basic gases like those for Duval triangle) and another of systems that monitor most key gases analysed in DGA (7-9 gases). These are combined with moisture and operational parameters of the transformer to give an overall view of the oil´s condition. DGA is a well-established tool to diagnose failure modes in power transformers. Both gas amounts and gas ratios are indications of different failure modes in progress and point to their possible origins, as well as if paper is involved in the problem.

Diagnosis & trending

Each of previous test measurements result in a set of different parameters or graphs. Some of them can be directly compared to nameplate or factory results. These numbers or diagrams must pass different criteria evaluation, even correlate together and with trend to finish with a recommendation for the transformer status, remnant life, or possible repair work.

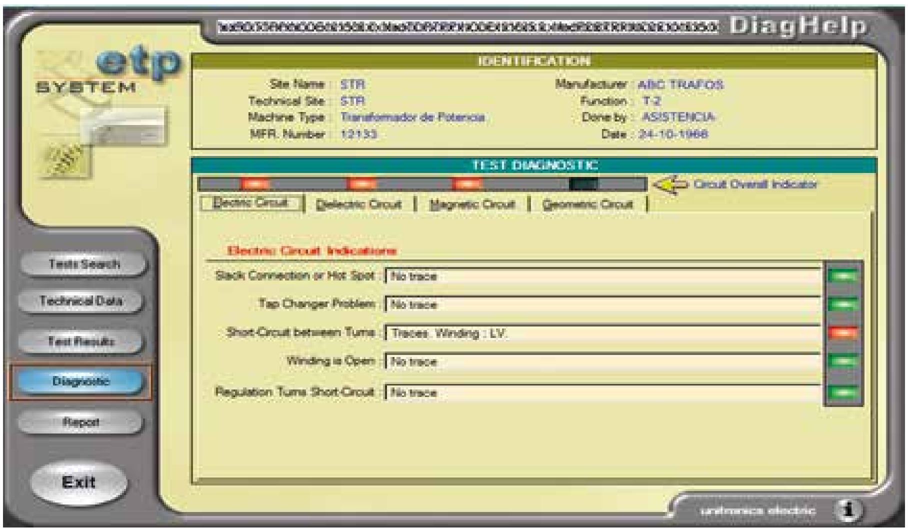


Figure 11. Lookup of an Expert Diagnosis Software for power transformer evaluation. ETP DiagHelp

Sometimes trending can be more important than an individual diagnosis based only on immediate results, because trending reveals the speed of degradation

Diagnostic criteria can change depending on the transformer, testing companies or end users, but they exist as a minimum set of reference values; some are normalized [1] and others [2, 3] come from an empirical approach. Today, we have available Expert Diagnose Software that can perform a failure interpretation based on the above criteria. These software applications give an indication of the machine status, but it must be the maintenance expert who, with all the machine data, performs the final diagnosis and makes recommendations in reference to repair, continuance of operation, programming new tests, even service limitations, etc.

Another key point in diagnosis is the review of *history/trending* of transformer test results. Sometimes trending can be more important than an individual diagnosis based only on immediate results. Trending reveals the speed of degradation.

It is also necessary to perform a *baseline test*, either for unknown transformers or at commissioning, for two reasons: firstly, to be certain the transformer is in good condition and fulfils contractual requirements, and secondly, to have data available to refer to in future tests and assessments.

Training

When a transformer is going to be tested, it is important that people who perform the testing (either the company staff or outside contractors) are duly trained and skilled in testing. It is important to have confidence in the test results in order to make a good transformer diagnosis and not overlook failure modes in progress. Whilst some 2-3 days are required to receive enough training to perform satisfactorily both testing and preliminary diagnosis, it takes longer to become an expert and special problems may need the expertise of an external consultant.

Conclusion

Predictive maintenance programmes increase our knowledge on the status of the power transformer and this increases reliability of our asset portfolio. The results make us more competent, reduce insurance costs and will work to the aim of **transformer life extension.**

Today there are available test systems that simplify measurements, reduce test errors and testing time, and make data easier to work with. As some diagnosis expertise is lost due to staff retirement and renewal, the last step is to have well-trained staff, so that all processes from measurement through diagnosis to recommendations are reliable.

Acknowledgments

I wish to thank the editorial board for their suggestions, to my friend Kevin Handford for his help with the English adaptation of the paper, and to my family for giving me the extra time needed to write this paper.

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