FAILURE ANALYSIS OF TRANSFORMERS

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INTRODUCTION

The deregulation of wholesale electricity supply has led to a number of changes and new challenges for the electric utility industry and the market participants. Some of the energy companies are now drowning in debt and today's capital spending on new and replacement transformers is at its lowest level in decades. To make matters worse, power consumption is increasing at a rate of about 2 percent per year, and the load on each aging transformer continues to grow. Increased equipment utilization, deferred capital expenditures and reduced maintenance expenses are all part of a modern utility's strategies for T&D Assets.

TRANSFORMER FAILURE HISTORY

The Hartford Steam Boiler (HSB) has been insuring power equipment since its inception in 1866, when the burgeoning industrial revolution used steam to drive its machinery, its locomotives and riverboats. Today we insure a wide variety of industrial equipment, all over the world. HSB has investigated thousands of transformer failures, and using the data collected, we have conducted a number of studies on transformer claims. The most recent study was published at the 2000 Doble Client Conference. [1]

In that paper we showed our classification of transformer failures over a twenty-year period, for utility class transformers. The leading cause of transformer failures is what we call "line disturbance". This category includes switching surges, voltage spikes, line faults/flashovers, and other T&D abnormalities ... but *not* lightning.

TABLE 1 – Cause of Failures	
Electrical Disturbances	29.43%
Lightning	17.32%
Insulation issues	9.80%
Electrical Connection, Loose or High Resistance	7.38%
Maintenance issues	5.91%
Moisture	4.03%
Overload	2.01%
Sabotage	2.01%
Other	1.24%

However, this table only shows one dimension – the number of failures. The risk of a transformer failure is actually two-dimensional: the frequency of failure and the severity of failure. Figure 1 is a scatter plot, or sometimes referred to as an "F-N curve" (frequency –number curve). The frequency of failures for each cause is on the X-axis, and the dollars paid for each cause is on the Y-axis. According to this analysis, the Electrical Disturbance is the highest risk for all types of transformer failures. This figure also shows that lightning may have a higher frequency of failure than insulation issues, but the average claim cost for "insulation issues" is much higher than lightning. (Insulation issues include contamination, deterioration or inadequate insulation.)

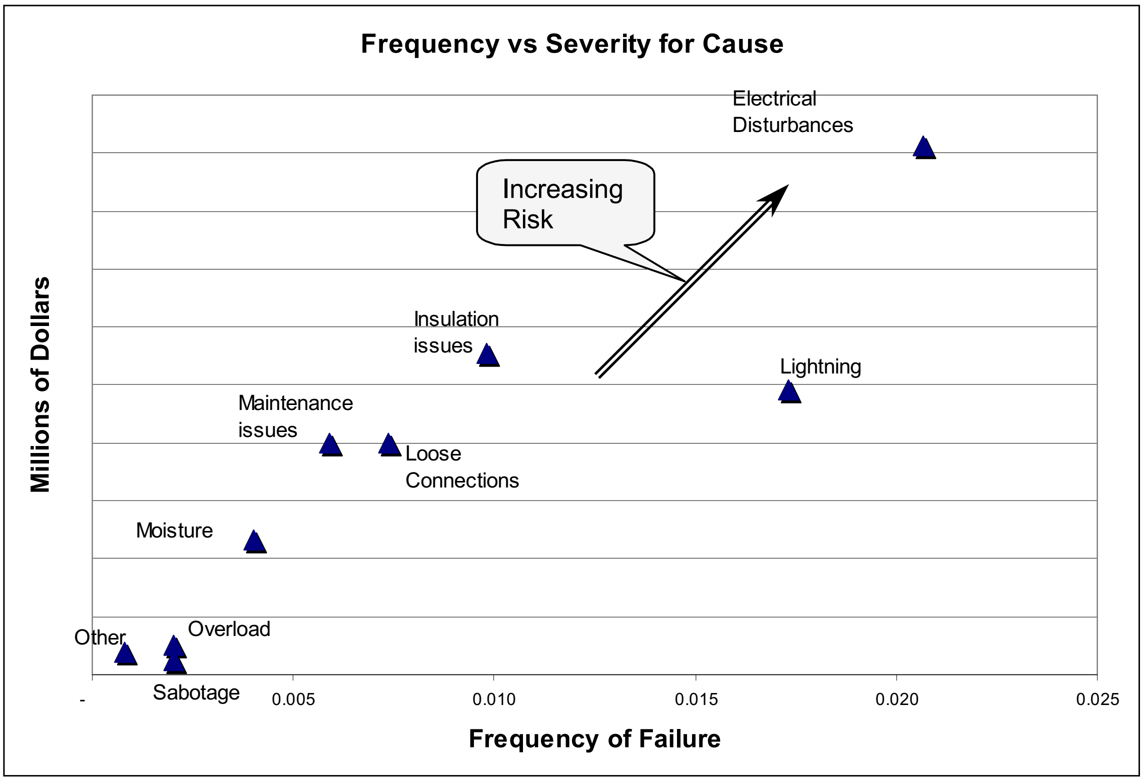

FIGURE 1 – Frequency - Severity of Transformer Failures

TRANSFORMER FAILURE MODES

The failure of a transformer can be a devastating and costly experience. However, it is an unfortunate fact that despite even the most rigorous preventative maintenance program, failures can and will occur. The foregoing classification of failures is admittedly general in nature, but usually sufficient for our claims process. However, in order to prepare an accurate failure scenario, and develop proper recommendations to prevent a recurrence, a more in-depth analysis of the failure is necessary. To accomplish this, it is necessary to first understand the different modes of failure for transformers.

A transformer can fail from any combination of electrical, mechanical or thermal factors. While it is difficult to define a "typical" failure mode for a transformer due to its complexity, most actual failures involve - and eventually result from - the breakdown of the transformer's insulation system. Therefore, although the actual cause of the failure of a transformer may be electrical, the insulation breakdown precipitating the failure may have resulted from electrical, mechanical or thermal factors. A transformer failure may have more than one causal factor.

Electrically Induced Factors

An electrically induced factor typically results in damage to a transformer's insulation system. Some of the more common electrically induced factors are:

- Operation of a transformer under transient or sustained over-voltage conditions - Depending on the magnitude and duration of the over-voltage, it can result in overstressing the insulation and overheating of the core.
- Exposure to lightning surges and switching surges - The electrical and mechanical design considerations for a transformer include lightning impulse and switching surge voltages. Both of these conditions can cause serious damage to the electrical and mechanical integrity of a transformer. Both lightning and switching surge impulses are large magnitude *traveling waves,* which travel at the speed of light. A transformer is designed and built with a user-specified BIL (Basic Impulse Level) rating. The BIL rating determines the level of lightning and

switching surge voltages that it can tolerate without damage. Surge arresters must be carefully selected in order to ensure that they will work *as* intended and *when and only when* intended. A transformer that has failed due to a lightning or switching surge generally displays damage that is localized near the line-end terminals.

- Partial discharge - Sometimes referred to as *corona,* partial discharge can be caused by poor insulation system design, by manufacturing defects, and/or by contamination of the insulation system (both the solid insulation and oil). Partial discharge can be likened to a low intensity arcing and will cause localized damage to the insulation and conductors. Evidence of corona can be seen in pitting of the cellulose insulation and conductor and, in more advanced cases, widespread black tracking which resembles "crow's-feet". This tracking is electrically conductive and can be visible on insulating barrier boards in the vicinity of the partial discharge activity. The black color of the tracks is formed by carbonization of the insulating oil by the partial discharge.
- Static electrification - This phenomenon is limited to very high voltage transformers (over 345 kV). When the temperature of a transformer's insulating oil is fairly low and the thickened oil is circulated rapidly, a static charge is developed between the oil and metal components of the transformer. When the magnitude of this charge exceeds the insulating oil's dielectric capability, it will flash over and the transformer can be destroyed or severely damaged in the process. Evidence of static electrification can be seen by partial discharge tracking on insulating barrier boards.

These failure modes may be discovered in combination with one another or in combination with other mechanical or thermal evidence. It is important for all evidence to be evaluated together in order to develop an accurate failure scenario.

Mechanically Induced Factors

A mechanically induced factor typically results in the deformation of a transformer's windings, resulting in the abrasion or rupturing of its cellulose insulation. If the damage is severe enough, the transformer can fail electrically. It is difficult to predict how long a transformer can survive with this kind of damage and is entirely dependent upon its severity. Winding deformation typically occurs in one of two ways: shipping damage or electromechanical forces.

Shipping or movement of the transformer: Although a transformer should be internally braced by the manufacturer to withstand the forces associated with this type of movement, the bracing may not be adequate enough; the shipper may not have followed the manufacturer's rigging instructions; or an accident may have occurred during the transportation.

Magnetically induced electromechanical forces: Advances in materials and winding design have resulted in much stronger windings, but many older transformers are still in service that have not benefited from these advances. When a transformer experiences an internal fault the windings can be subjected to magnetic forces that are significantly beyond their design capability.

In either of these cases, winding deformation can occur. The most common mechanically induced factors are summarized as follows:

- Hoop (inward radial) buckling of the innermost winding - In this case, the conductor will buckle inward toward the core between the axial spacers and will transmit the buckling to the core insulating cylinder at the axial spacer locations. A severe case of buckling will result in damage to the paper insulation. The degree of damage will determine whether or not a failure will occur immediately.
- Conductor tipping - This is a problem typically associated with *helical windings* which utilize paper insulated Continuously Transposed Cable (CTC). In this case, axial forces that exceed the CTC bundle's compressive capability will cause the bundle to tip. When the bundle tips, the paper insulation will tear open and expose the energized conductor. Because of the amount of insulation damage typically resulting from conductor tipping, an electrical failure will usually occur, almost immediately.
- Conductor telescoping - This involves *layer windings* made up of thin flat conductors which are supported end-to-end. When exposed to excessive axial forces, the individual conductors will telescope over one another. This causes the entire layer to become mechanically unstable, as well as damaging the paper insulation. The degree of damage to the insulation will determine whether or not a failure will occur immediately.
- Spiral tightening - This again involves layer windings and is caused by radial forces that tighten the winding. This can be evidenced by a spiral movement or shifting of the key spacers over the entire height of the winding.

The tightening of the winding can damage the paper insulation and cause it to become mechanically unstable. The degree of damage to the insulation will determine whether or not a failure will occur immediately.

- End-ring crushing - This condition occurs when the mechanical strength of the radial end ring at the bottom of the winding is exceeded by the winding's axial forces, resulting in mechanical instability of the entire winding.
- Failure of the coil clamping system - This system is intended to maintain a constant clamping force on the coils at all times. When a transformer is subjected to large sudden increases in current flow (e. g., when a large block of load is suddenly added, or when a fault occurs in the system), the resulting magnetically induced electromechanical forces try to spread the winding coils apart axially. The coil clamping system restrains the coils from this movement. If a failure of the clamping system occurs and the restraining force is absent, the transformer may operate normally for a period of time. However, when the transformer is subjected to a sudden large increase in current flow, its coils will spread apart. This movement is very sudden and violent, resulting in severe deformation of the coils and damage to the cellulose insulation. The damage can cause an immediate electrical failure.
- Displacement of a transformer's incoming and outgoing leads - Sometimes the connection of the transformer leads can break in the area where they leave the windings, or the lead supports can break. The degree of damage to the insulation will determine whether or not a failure will occur immediately.

A thorough failure investigation must consider that evidence indicating the presence of any of these mechanical problems does not necessarily mean that the cause of the failure has been found. In some cases, damage such as outlined above may simply have been the result of collateral damage due to a fault.

Thermally Induced Factors

The degradation of a cellulose insulation system is to be expected over time. Normal heating generated by the loading of a transformer will thermally degrade the insulation. Thermal degradation results in the loss of physical strength of the insulation that, over time, will weaken the paper to the point where it can no longer withstand the mechanical duty imposed on it by the vibration and mechanical movement inside of a transformer. However, a transformer designer is cognizant of these implications and allows for them in the design. A well-designed (and properly operated and maintained) transformer's insulation system should be able to provide reliable service for 20 to 30 years or more. The reasons for the premature failure of a transformer are generally either poor operating and maintenance practices, or defective workmanship and/or materials. The most common thermally induced factors are summarized as follows:

- Overloading of the transformer beyond its design capability for extended periods of time.
- Failure of a transformer's cooling system. This can include blocking or fouling of the radiators or coolers, the failure of the oil pumps, and the failure of a directed flow oil distribution system.
- Blockage of axial oil duct spaces, limiting the amount of cooling oil to the windings in the immediate area.
- Operating a transformer in an overexcited condition (over-voltage or under-frequency). This can cause excessive stray magnetic flux to severely overheat insulation in close proximity to the core or other structural members.
- Operation of the transformer under excessive ambient temperature conditions.

If evidence of thermally induced problems is found, it must be considered and combined with any other evidence discovered of mechanical or electrical problems to develop a complete failure scenario.

CONDUCTING THE FAILURE INVESTIGATION

As an aid to the investigation, we recommend the IEEE Standard C57.125 “Guide for Failure Investigation, Documentation, and Analysis for Power Transformers and Shunt Reactors” [2]. This guide can be used to ensure that all important factors are considered and examined in a failure investigation. The IEEE document is an excellent source of information for an Investigator to help develop a general “battle plan” prior to arriving at the site, and the various checklists are very useful. The guide also contains comprehensive appendices on transformer construction, diagnostic testing, and sample failure investigation case histories.

A failure investigation typically begins after a transformer has been tripped off-line by a protective device, or when someone suspects that the transformer is no longer suitable for service. The decision of what to do next (after a transformer has been tripped by a protective device) will vary depending on the circumstances and the operating procedures of the owner-user. But, when a transformer fails, time is of the essence and a prompt investigation is paramount. Work crews are almost always on site before the Investigator arrives. Valuable information can be innocently destroyed by work crews attempting to restore service. Therefore, upon notification of a failure, instruction should be given to the work crew to minimize any disruptive impact on the investigation. Cooperation at all levels of the owner-user can speed up the investigation at the site and improve the accuracy of the diagnosis.

The investigation is comprised of four major components: Preparation, Testing, Inspection, and Conclusions. The preparation begins as soon as the Investigator is notified. The Testing and the On-Site Inspection may occur simultaneously. In some situations, the Investigator may be able to prescribe a series of tests, before arriving on site. The Inspection may involve three steps – an external examination, an internal examination, and a teardown inspection. Once sufficient data has been gathered from the inspection and test, the engineering analysis can hopefully lead to contributing causal factors.

PREPARATION /INFORMATION GATHERING

Some preparation, prior to arrival at the site may prove to be valuable, and save considerable time and effort. Information that should be requested or gathered prior to the Investigator's arrival would include:

- All historical DGA test results
- All historical oil screen test results (e.g., dielectric breakdown, acidity, interfacial tension)
- All historical diagnostic field test reports (e.g., Doble power factor, frequency response analysis)
- A copy of the transformer nameplate
- All maintenance and other work records
- A copy of the factory test data sheets
- A record of local weather conditions at the time of failure
- A record of the approximate loading at the time of failure
- A system one-line diagram showing the locations and types of protective devices
- A record of all relay operations ("flags" or "targets") at the time of the failure
- Any system dispatcher's logbook pages which pertain to the failure
- A list of any faults or switching events in the system just prior to the failure
- If the transformer is equipped with surge arrestors that have operation counters, did any of the arrestors operate just prior to the failure?
- A list of any recent ancillary equipment problems, such as CT or PT failures, or blown fuses on capacitor banks.

This information will provide a history of the condition of the transformer and may give some indications of system conditions that may have contributed to or caused the failure.

ON-SITE INSPECTION

The on-site inspection is the logical next step in the process. Upon arrival at the site the Investigator should interview any employees who may have been in the vicinity at the time of the failure. Try to get as much information about what they saw *and heard*. When all interviews are concluded, a visual inspection should be performed.

External Inspection - Photographs are an essential part of an external inspection and help to record or document valuable information for later analysis. The experienced investigator will look for the following visible abnormalities in the transformer:

- Bulging or rupture of the external tank
- Evidence of an oil spill or a fire
- Evidence of the operation of a pressure relief device
- Damage to the bushings or surge arrestors
- Damage to the radiators, fans, or pumps
- Damage to the conservator
- Low oil level in main tank
- Evidence of overheating (blistered paint, etc.)
- Evidence of a foreign object or animal contact (burn marks or debris on top of the tank or nearby bus)

- Evidence of vandalism or sabotage
- Position of the LTC – as found
- Position of the DETC - as found
- Oil Level in the LTC compartment
- Damage to the Control Cabinet

Careful notes should be taken to supplement photographs. Any items in the Preparatory list (such as historical test data, or relay "flags") that were not available in advance should be gathered at this time. If no visible damage is found externally, the next step in the investigation is usually a prescribed set of diagnostic tests, which are outlined in the next section.

Internal Inspection - Depending on the nature of the failure, there may be very little to see externally. In some situations, an internal inspection may be performed on-site to assess the extent of damage. Sometimes the tank is completely drained of oil, while in some cases the oil is just lowered enough to expose the top of the core and coil assembly.

Before entering the tank, all SAFETY rules must be observed. In many cases, safety officials may consider the transformer tank a "Confined Space", and a Confined Space Entry program must be followed. Do not attempt this alone. The tank must be vented to the atmosphere for a reasonable amount of time to expel the combustible gases. Combustible gases in the tank are heavier than air, and present an asphyxiation hazard. After the tank's atmosphere has been tested and determined to be safe, we recommend personnel wear a calibrated Confined Space Monitor for the duration of the internal inspection. If the gas monitors indicate a low oxygen level at any time during the inspection, all personnel inside the tank should be evacuated.

Prior to entering the tank, all personnel should remove loose personal items, such as jewelry, wallets, combs, paper clips, pocket change, and the like. The only items that should be carried inside the tank are a camera, pen and paper, and a flashlight. These items should be recorded before entry, and then verified after leaving the tank. Leaving a flashlight inside a high voltage transformer could later be catastrophic. (It's possible to find almost anything inside of a failed transformer, including screwdrivers, pliers, welding rods, and safety glasses from a previous work crew's carelessness. In one true story, a wooden ladder was found inside a large power transformer that had been in service for over twenty years before it suffered a failure.)

Internal abnormalities to look for inside the transformer include:

- The odor of burnt insulation
- The appearance of burnt oil or insulating fluid ("good" oil has a clear amber color; burnt oil is dark and opaque, similar to burnt coffee, with an unmistakable acrimonious odor.)
- Evidence of metal deposits (splatter or "BB's") *
- Evidence of broken insulating material (paper, wood, barrier board)
- Obvious physical damage (broken porcelain, burnt or charred leads)
- Displacement of the coils
- Damage to the coil clamping system
- Evidence of arcing between turns, or between windings
- Evidence of partial discharge activity (carbonized tracking marks)
- Evidence of any free water in the bottom of the tank (Since water is heavier than oil, the presence of water in the tank, will cause rust at the bottom.)

* Molten droplets of metal form tiny spheres, similar to "BB's". These deposits can be found almost anywhere in the transformer, including the top of the yoke, the tops of the coils, on internal ledges of the tank, and on the bottom of the tank.

If the internal inspection does not provide sufficient information as to the cause of the failure, it may be necessary to de-tank the transformer and perform a diagnostic teardown to search for the damage and clues. A diagnostic teardown is a painstaking, meticulous process that is usually accomplished in the shop of a repair firm or manufacturer. If the transformer is large enough, it is quite common for a teardown to involve personnel from the owner, the insurer, the manufacturer, and one or more consultants to represent their various interests.

DIAGNOSTIC TESTING

In many of our investigations, when a transformer failure has been reported, there is no obvious external damage to be seen. We must then depend upon diagnostic testing to help identify existing weaknesses or faults and to give some indication of the possibilities for repair. No one electrical test can assure continued operation or expected service reliability, and no combination of electrical tests can substitute for a careful visual internal inspection. Only the careful recording and plotting of the test results makes it possible to get the needed information out of a test and to compare the values with those of previously conducted tests. It should be noted that several tests may be interpreted together to diagnose a problem. The manufacturer's acceptance criteria should also be consulted, because it may take precedence over the criteria in this document.

Before performing any tests, precautions should be taken to ensure that the transformer is disconnected from all power and auxilliary sources and has been properly grounded. Electrical tests should not be conducted until the unit has been tested for combustible gas and has been found to be safe. Special Note: In order to perform a power factor test, or any other test that requires high voltage, the transformer must be filled with insulating oil. Samples of insulating fluid should be taken for screen tests and dissolved gas analysis. (The samples must be taken prior to opening the transformer for inspection.) Table 2 is a suggested checklist of electrical tests. A brief discussion of these tests and some interpretive discussions are included in Appendix 1 to provide guidance on acceptance criteria.

TABLE 2 - Diagnostic Tests						
Suspected Problem	Prescribed Tests					
Turn to Turn Shorts	Oil Test	Turns Ratio	Winding Resistance	Exciting Current	Induced Voltage /RIV	FRA (1)
Open Winding	Oil Test	Turns Ratio	Winding Resistance			
Major Insulation Damage (Phase to Ground, etc)	Oil Test	Power Factor	Insulation Resistance	Exciting Current	Induced Voltage /RIV	FRA
High Moisture Levels	Oil Test	Power Factor	Insulation Resistance			
Mechanical Damage	Oil Test	Exciting Current	Induced Voltage/RIV (2)	FRA		
Core Overheating	Oil Test	Insulation Resistance (Core Ground)	Exciting Current			

1. Frequency Response Analysis
2. Radio Influence Voltage

CONCLUSIONS

Final conclusions on the transformer failure cannot be formulated until all the Preparatory Data is collected, the inspections are completed, the diagnostic tests are performed, and the test results interpreted. Often a hasty conclusion to meet an arbitrary deadline can lead to the wrong diagnosis. After all the information is gathered, an in-depth analysis of the failure will allow you to prepare an accurate failure scenario and, most-important, develop proper recommendations to prevent a recurrence.

REFERENCES

[1] Bartley, William "Analysis of Transformer Failures", Proceedings of the Sixty-Ninth Annual International Conference of Doble Clients, April 2000

[2] IEEE Std C57.125-1991, IEEE Guide for Failure Investigation, Documentation, and Analysis for Power Transformers and Shunt Reactors

[3] IEEE Std C57.104-1991, Guide for Interpretation of Gases Generated in Oil-Filled Transformers.

[4] IEEE Std C57.106-2002, Guide for Acceptance and Maintenance of Insulating Oil in Equipment

[5] IEEE Std 62-1995, IEEE Guide for Diagnostic Field Testing of Power Apparatus – Part I: Oil Filled Power Transformers, Regulators, and Reactors

[6] IEEE Std C57.140 Draft 8 (10/1/02) Guided for the Evaluation and Reconditioning of Liquid Immersed Power Transformers

[7] Lewand, Lance, Doble Engineering, "Using Analytical Techniques to Determine Cellulosic Degradation in Transformers", *NETA World*, December 2001

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APPENDIX 1 - ELECTRICAL DIAGNOSTIC TESTING

DISSOLVED GAS-IN-OIL TESTING

When a transformer's insulating oil is exposed to excessive heating under either normal or abnormal operating conditions, the heat is transferred to the oil and, if a sufficient amount of heat is present, combustible gases are created. Over the past few decades, a great deal has been learned about the conditions that cause the creation of these gases, and a methodology has been developed to evaluate the condition of a transformer based upon an examination of the gases dissolved in the insulating oil. This type of test is called Dissolved Gas-In-Oil Analysis (DGA) and is in common use throughout the world. In performing this test, a transformer does not have to be de-energized in order to draw the required oil sample.

The engineering evaluation process of DGA testing looks for the formation of certain key gases, which may signal developing problems in a transformer. These key gases are:

Hydrogen (H_2) - Hydrogen can be created when insulating oil is exposed to a partial discharge (corona) in the transformer. Hydrogen can also be created with excessive moisture levels.

Carbon Monoxide (CO) - Carbon Monoxide can be formed when cellulose (paper) insulation is exposed to excessive heat, such as during periods of overloading of a transformer.

Methane (CH_4) - Methane can be formed when insulating oil is exposed to excessive heat from intimate contact with a hot metal.

Ethane (C_2H_6) -Ethane can be formed when insulating oil is exposed to excessive heat from a hot metal. (The temperatures required for the formation of Ethane are higher than those required for the formation of Methane.)

Ethylene (C_2H_4) - Ethylene can be formed when insulating oil is exposed to excessive heat from a hot metal. (The temperatures required for the formation of Ethylene are higher than those required for the formation of Methane or Ethane.)

Acetylene (C_2H_2) - Acetylene is typically associated with electrical arcing. (The temperatures required for the formation of Acetylene are higher than those required for the formation of Ethylene, Methane or Ethane.)

IEEE Standard C57.104 [3] provides guideline threshold levels for key dissolved gases found in insulating oil samples. These levels are referred to in C57.104 as "Norms" and are not intended to be absolute alarm points, but simply "red flags" to alert a user to the possibility of a problem.

OIL SCREEN TESTING

Since the insulating oil immerses all of the electrical conducting parts of a transformer, an analysis of the oil's physical properties can help to diagnose both potentially developing internal electrical problems and physical deterioration of the oil. The physical screen tests of the oil will ensure that it is capable of continued service as a high quality dielectric fluid that is free from harmful impurities. The laboratory testing should be performed in accordance with the applicable ASTM Standard, or its international equivalent. The key screen tests are as follows:

Dielectric Breakdown - Dielectric strength of an insulating liquid is the minimum voltage at which electrical flashover occurs between two electrodes. A low dielectric strength indicates the presence of moisture and other contaminants, which could reduce the dielectric performance of the oil. Two ASTM test methods are in common use in the power industry: ASTM D877 and D1816. Although D877 is the minimum required test, ASTM D1816 is more sensitive to moisture and is recommended as the preferred test.

Specific Gravity - This test evaluates the physical composition of the oil by comparing its specific gravity to that of water (the presence of contaminants will alter the oil's specific gravity). ASTM Std. D1298.

Interfacial Tension - The Interfacial Tension of an oil is the force in dynes/cm^2, required to rupture the oil film existing at an oil-water interface. When contaminants, such as oxidation products are present in the oil, the film strength of the oil is weakened. ASTM Std. D971.

Color - The Color test compares the oil with standards of colored glass. New oil in pristine condition should be bright and clear. Service-aged oil will have a slight amber color. Dark and opaque oil may be a sign of undesired electrical or chemical activity. ASTM Std. D1500.

Moisture Content - The presence of excessive moisture will accelerate metal corrosion and shortens the life expectancy of cellulose insulation. Recommended limits for water content are dependent upon the voltage rating of the electrical equipment (the higher the voltage rating, the less water that can be tolerated). These limits are listed in IEEE C57.106 –2002 [4]. This is also known as the Karl Fischer test. ASTM Std. D1533.

INSULATION POWER FACTOR TEST [5]

The Insulation Power Factor test and the Dissipation Factor test are two very similar methods of measuring the insulation condition using alternating current techniques. Both tests are considered non-destructive, as the applied test voltage is not greater than the insulation rating of the material being tested.

The Power Factor test is commonly used in the USA and uses a self-contained field test set produced by Doble Engineering and others. The test set uses 110V power and includes the necessary transformer for stepping up the voltage to the appropriate test level. The Dissipation Factor Test (also known as tan delta test) has been used in Europe and in some instances in the USA. This test uses a Schering Bridge and a separate transformer to apply the test voltage.

Power Factor is obtained by measuring volt-amperes and watts, which result from applying a given voltage to an insulation system. The power factor is a dimensionless number obtained by dividing the watts by the volt-amperes and can be represented by the cosine of the phase angle between them. By convention, power factor is usually spoken of as percent-power-factor, which is one hundred times the raw value obtained from the basic calculation.

Measurements are made on each winding to ground and each winding to all other windings in the transformer. Current leakage through the insulation is measured and the power factor calculated as the ratio of the watts-loss to the apparent power input. Temperature and relative humidity are considered in the testing and the power factor is corrected to 20°C using tables for accurate comparison with previous and future readings. The power factor on a service-aged transformer in good condition should be in the range of 0.5 to 1 %. Many utilities use a power factor value of 0.5% as acceptance criteria for new transformers. If a new transformer has a power factor above 0.5%, the transformer has not been dried properly. The OEM must then re-filter the oil to lower the moisture content. It is not unusual to find a power factor as low as 0.05% for a new transformer in good condition.

TURNS RATIO TEST [5]

When coil insulation between turns of a transformer fails, a portion of the coil shorts out causing a change in the design turns ratio and an alteration of the secondary voltage. The turns ratio can be tested with an instrument called a TTR meter, made by Biddle/AVO and others. With this device, 8 VAC is applied to one winding and the voltage induced in the other windings is measured. The Doble test set can also be used to measure turns ratio. In either method, the ratio of the high to low voltages is calculated to three decimal places. This number is then checked with the original transformer values. If the calculated ratio has a variation greater than 0.5%, a turn-to-turn fault probably exists in the winding and should be investigated.

INSULATION RESISTANCE and POLARIZATION INDEX [5]

The insulation resistance test is one of the least costly to perform in terms of test equipment and has become one of the most popular diagnostic tests. The insulation resistance and polarization index (PI) tests are useful indicators of contamination and moisture on the exposed insulation surfaces of a winding, especially when there are cracks, pinholes or fissures in the insulation.

The insulation resistance is the ratio of the DC voltage applied and the resultant current. When a DC voltage is applied between the winding and ground, four components of current will flow. The first two current components decay quickly with time. The second two are determined primarily by the presence of moisture or a ground fault and are relatively constant with time. Moisture may be absorbed within the insulation and/or condensed on the surfaces that are often dirty. If this leakage or conduction current is larger than the first two components, the total charging current (that is, the insulation resistance) will not change significantly with time. Thus, to help determine how dry and clean the winding is, the insulation resistance is often measured after 1 minute and after 10 minutes, and the ratio of the 10-minute reading over the 1-minute reading is called the polarization index (PI).

When an actual fault or insulation puncture has occurred, the insulation resistance will be close to zero, and this is easily recognized as being unacceptable. However, it is difficult to set a practical pass/fail criterion for the insulation resistance test when the insulation is not punctured. Industry practice for an acceptable minimum is 1 Megohm for each KV + 1 Megohm. Good dry insulation will have an insulation resistance of several hundred Megohms or more.

WINDING RESISTANCE TEST [5]

It is always desirable to determine the presence of any high resistance joints, corrosion, fractures or dimensional reductions in the cross sectional area of conductors. With time in service, the mechanical vibration of operation can lead to failure or partial failure of conductors. Insulating blocks can also vibrate and wear away part of the cross section of copper conductors. Only the precision of resistance measurement offered by a Kelvin bridge or micro-ohmmeter will allow the detection of the subtle changes in conductor resistance caused by these types of damage. These instruments incorporate a measurement range that spans the resistance values offered by most copper windings and conductors used in electric power apparatus. Kelvin bridges and micro-ohmmeters measure to five significant digits with at least 0.25 percent accuracy.

The test results for each phase are compared with the other two phases, and compared with the original resistance test. A lower-than-normal resistance might indicate a turn-to-turn short-circuit whereas a higher-than-normal resistance can be the result of a bad connection or damaged windings. A two-percent (2%) variance from expected is usually an indication of an abnormality in the winding circuit. It should be noted that with only a two-percent deviation from expected being a significant indication, the proper calibration of the instrument and proper measurement techniques are critical.

OVERPOTENTIAL AND DC LEAKAGE TESTS

The trade name "Hi-Pot" is used universally, throughout the industry, but the correct generic name is overpotential test. The hi-pot test is a widely used test, recommended by many OEM's, and potentially a destructive test. It is used to test the insulation integrity of all types of electrical apparatus, including transformers, generators, motors, bus, and cables. A high voltage is applied between the windings and ground. A flaw in the insulation system is detected by a breakdown of the insulation. The failure then needs to be repaired before the equipment is returned to service.

HSB's Opposition: For decades, engineers at HSB have disagreed with OEM engineers over the merits of these tests as an annual maintenance practice. If the test is conducted, and a failure does not occur, some engineers believe there is a certain assurance of safe operation at normal voltage for the next operating period. But, these tests may result in the breakdown of a winding which otherwise might have lasted for a considerably longer time. The owner-user may weigh this risk against the possibility of a failure occurring during a less convenient time and decide to run the test anyway.

FREQUENCY RESPONSE ANALYSIS [6]

Frequency Response Analysis (FRA) is a diagnostic test that is used to help identify possible deformations and movements in the transformer's core and coil assembly and other internal faults. FRA consists of measuring the impedance of transformer windings over a wide range of frequencies and comparing the results of these measurements with previous results or results from an identical transformer. The basis of the FRA technique is that the impedance of the transformer (resistance, inductance and capacitance) is related to the construction and geometry of the windings. Deformations and movements have an effect on both inductance and capacitance that may be reflected in the resulting frequency response.

Measuring the frequency response of a winding within a transformer gives a fingerprint for that winding or transformer. The analysis requires measurement of both input and output signals, which are then ratioed to give the response. There are basically two methods: impulse method and sweep frequency method. Both methods are currently used within the industry.

PARTIAL DISCHARGE DETECTION [6]

Partial Discharge occurs in an insulation system when a local breakdown of the insulation medium causes a redistribution of charge within the system. Partial Discharge generates low-amplitude current pulses that are of short duration. Two different techniques are in common use to detect and measure these signals in transformers. One technique consists of measurements with a radio noise meter; levels are measured in microvolts and are referred to as RIV signals. (See Induced Voltage Test) The other method consists of acoustical measurements with an ultrasonic transducer.

The acoustic method of detecting partial discharge offers good sensitivity to many types of partial discharge sources, and in some situations, permits the site of the source to be located. The acoustic technique has the advantage that it can be used on energized equipment, and it is not susceptible to interference from outside sources, when properly applied. Acoustic signals are measured using ultrasonic transducers that are coupled to the outside wall of the transformer tank. In addition to the transducers, the other test equipment components are an amplifier and a display device. Self-contained, portable acoustic detectors are available for quick go-no-go field test programs. However, locating the partial discharge source requires specialized measurements and custom-designed software and equipment.

DEGREE OF POLYMERIZATION (DP) [7]

The degree of polymerization test is used to assess insulation aging and is performed on paper samples taken directly from the transformer so it is an intrusive test. The DP provides an estimate of the average polymer size of the cellulose molecules in materials such as paper and pressboard. The DP correlates well with mechanical properties such as tensile strength but has the advantage that it can be performed on used materials that have taken a set during service life. Generally, paper in new transformers has a DP of about 1000. Aged paper with a DP of 150-200 has little remaining mechanical strength, therefore making the windings more susceptible to mechanical damage during physical movement, which can cause the paper to tear or crumble. This may occur when transformers are moved or during events such as through faults. Since paper insulation does not age uniformly due to thermal, water, oxygen and byproduct concentration gradients, samples from several distinct locations provide the best diagnosis. The DP test provides the most reliable indication of the overall aging of the paper insulation, as it is a direct measurement.

INDUCED VOLTAGE TEST [5]

The AC Induced Voltage test is performed at the factory and in the field, to verify the turn-to-turn, layer-to-layer and section-to-section insulation of the windings of a transformer. The transformer must be de-energized and disconnected. The use of an induced voltage test in the field, however, is very limited due to the size and cost of the test equipment required. For large power transformers, this equipment might include a large engine-generator set, a step-up transformer, power factor correction reactors, and a tuning transformer to get a higher frequency. (A frequency range of 180 to 400hz is used to avoid saturation of the core when applying a voltage beyond the normal rating of the transformer.) This equipment is typically mounted on a special, large eighteen-wheel tractor-trailer.

Because the test voltage can be beyond the normal voltage rating, this can be a destructive test and can cause further damage. In reaching the basic decisions relative to performance of a potential destructive test, the owner is faced with divergent and conflicting alternatives. In the final analysis, this is a risk assessment decision for the owner. Their judgment will depend on the importance of a particular transformer to their system and other business and economic factors. The owner and the manufacturer/repair firm should agree upon the test voltage before commencing the test. In the factory, this test level is typically 170% of rated voltage; but, the maximum level in the field is usually 125% of rated voltage.

The test set supplies an AC voltage to the low voltage winding, which induces a voltage in the high voltage winding. The test voltage is typically applied for a duration of about one hour. Current is measured on each phase of the low voltage winding. Partial Discharge activity is monitored using the HV bushing capacitance taps or potential taps of the unit under test. The signal available from the capacitance tap is a low voltage representation of the voltage existing on the bushing top. The low voltage signal is fed into a sensitive metering circuit (called an RIV meter) designed to measure partial discharge. Radio Influence Voltage (RIV) is measured in microvolts.

A transformer is considered to have successfully completed the test if the current flowing during the test does not exceed the expected excitation current, and there is no evidence of unacceptable Partial Discharge (corona) activity. New transformers under factory test should have RIV less than 100 microvolts. For field tests, RIV measurements are usually taken on each phase every 5 minutes, and the results of the three phases are compared to one another. A problem phase will typically have much higher RIV measurements than the other two.

EXCITATION CURRENT TEST

The excitation current test can detect incipient damage to a transformer's windings and core. Short circuit forces can displace the windings during a nearby external fault, or the windings may be damaged during transportation of the transformer. The excitation current measurement is the simplest method for detecting this type of damage before actual failure occurs. This current, at no load, excites the magnetic flux in the iron core. Its magnitude depends on the applied voltage, the number of turns in the winding, the dimensions, the reluctance and other conditions of the core. An excessive current may be due to a partial short-circuit between one or more turns in the winding, or it may be due to some defect in the magnetic circuit which changes the reluctance of that magnetic circuit.

The test is commonly performed in conjunction with a Power Factor Test (while the transformer is de-energized and disconnected). The test voltage can be supplied by the PF test set, and is normally applied to the high voltage winding to avoid inducing a hazardous voltage level. The applied test voltage is usually no more than 10% of the winding's rated voltage. The current on each phase of the HV winding is measured by a sensitive ammeter (such as the one on the Doble test set). For three-phase core form transformers, a pattern of two similar currents and one lower current can be expected. The winding on the center leg of a three-legged core has a lower magnetic reluctance than the other two phases, which results in lower excitation currents.

The test values on the outside legs should be within 15% of each other, and the center leg should not be greater than either outside leg. Results compared to prior tests should not vary more than 5%. However, Exciting Current readings can be affected by residual magnetism of the core. If the expected current pattern is not achieved, a turn-to-turn ratio or a winding resistance test can be run to confirm the exciting current test results.