



Transformer Fluid: A Powerful Tool for the Life Management of an Ageing Transformer Population

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rtant to characterize those aspects of the basic chemical composition that define these fundamental fluid properties. Fortunately, once they are known, the basic composition and the associated properties will generally not change unless substantial mixing with another fluid occurs.

In addition to the major and minor fluid components, there are a number of important components found at low levels. The reasons for their importance are diverse. For example, consider components such as sulfur, silicon, 2,6-ditertiary-butyl para-cresol or poly-aromatic hydrocarbons.

Sulfur in transformer oil is usually kept below 1%. Cigre WG 15.01 has suggested that heat and electrical stress may change the sulfur in the oil to a form of corrosive sulfur, which has a detrimental effect on copper. Sulfur may also be introduced from other transformer components and similarly changed to form a corrosive sulfur. Recently, one utility reported failures of several shunt reactors where the suggested failure mechanism was a short-circuit between adjacent turns due to corrosion caused by copper sulfide. Utilities typically specify oil with a low corrosive sulfur content but do not have any specification for the total sulfur content.

Silicon in transformer fluid, with the obvious exclusion of silicone fluid, is usually found as an additive at less than 5-10 parts per million. At these low concentrations silicon contributes antifoaming properties which aid processing under vacuum. At higher concentrations silicon enhances foaming and can severely interfere with vacuum processing operations.

2,6-Ditertiary-butyl para-cresol (DBPC) or 2,6-ditertiary-butyl phenol (DBP) is sometimes added to transformer oil at concentrations as high as 0.3 percent to act as an oxidation inhibitor. Presence of the inhibitor can enhance insulation life. It also changes the relationships of the oxidation products found in the oil.

In addition to their influence on basic fluid properties, poly-aromatic hydrocarbons or PAH's, may present a health concern. Recent study suggests naphthenic base oils with more than 2 percent PAH are potentially carcinogenic.

Characterization of the transformer fluid is the defining process that sets the stage for all future assessments by:

1. Determining how the fluid will interact with the rest of the system and establishing the basis for diagnostic evaluations.
2. Identifying residues of equipment manufacturing, fluid production, transformer processing and handling which provides source information for contamination and its potential consequences.
3. Identifying baseline values for the components that will change.

4. Confirming the condition of the fluid with regard to functionality as well as health, safety and environmental concerns.

The use of this information in conjunction with the information from an ongoing fluid testing program provides the basis for transformer life management.

The Fluid as a Part of the System

Many maintenance guides still consider the insulating fluid to be a separate component that can be monitored and treated separately from the fluid-paper insulation system or from the transformer as a whole. In fact, the fluid is an integral part of the transformer playing a dynamic role in the condition of the entire system.

Consider the role the fluid plays in the serviceability of the dielectric system. Aging tests were performed on transformer models in the Transformer Research Institute at Zaporozhye, Ukraine to evaluate the dielectric life and the mechanical life of the insulation system. These studies demonstrate that the dielectric life of the insulation system can be shorter than its mechanical life due to deterioration of the oil-paper system and the consequential deterioration of the dielectric withstand strength of the coil-to-coil insulation. As shown in the Table 4, at 100°C the conductor insulation life is 50 years based on mechanical properties and only 22 years due to deterioration of dielectric strength.

Table 4

Estimated Life of Transformer Winding Insulation Under the Influence of Temperature, Electrical and Mechanical Stresses[†]

Hot Spot Temperature, °C	Estimated Mechanical Life (Reduction of DP to 200), Years	Estimated Dielectric Life (Reduction of dielectric strength by 40%), Years
80	6229	124
100	50	22.1
110	17	10
125	4	3.3
140	1	1.16
160	0.19	0.32

† Tests performed in ZTZ – Service Material Lab

Water created from the degradation of the paper interacts with the paper-oil system to produce this effect. The increase of water available from the paper leads to an increased relative saturation of water in the oil and a reduction in dielectric strength. This in turn leads to an increased adsorption of water on particles that adsorb water, further reducing the dielectric strength of the fluid. When the relative saturation is sufficient, emulsion formation in the vicinity of surface-active substances further reduces the dielectric strength of the insulation. Studying the electrical models of the transformer paper-oil insulation system has shown that the dielectric safety margin of both the major and minor insulation contaminated with water is still determined by the dielectric withstand strength of the oil.

Water is usually present in the oil in a soluble or dissolved form but also may present as a form adsorbed by “polar” aging 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 two current transformers are shown in Table 5. After heating the oil at 100°C for 5 hours the water content in oil increased significantly. A similar phenomenon has been observed in bushing oils. Most likely, the dissolved polar compounds in the oil are the source of this additional water.

Table 5

Transformation of Bound Water to Soluble Water from Aged Oil
Not in Contact with Paper[†]

Type of oil	Properties	Water content ppm	
		Before heating	After heating at 100°C for 5 hours
Used oil from 750 kV CT	Acidity=0.064mg KOH/g IFT=32 dynes/cm PF ₉₀ =5.32%	26.3	85
Used oil from 750 kV CT	Ca=18% Acidity=0.064mg KOH/g IFT=32 dynes/cm PF ₉₀ =6.1%	23.5	132

† Tests performed in ZTZ – Service Material Lab

There are also other temperature driven dynamics of water including “bubble formation” and “rain”. EPRI sponsored projects in the late 1980s and early 1990s confirmed prior observation that bubbles could be generated from a sudden overload of the transformer. This type of bubble generation has been studied in more detail, and it now appears that these bubbles consist mostly of water vapor released from the cellulosic paper wraps on the hot conductor. The hot spot temperature is a critical factor, but the water content of the paper insulation is also important. Oil preservation systems, such as nitrogen-blanketed and conservator systems, showed very little difference at low moisture levels in the paper. If the insulation is very dry, eg., with 0.5% moisture, virtually no bubbles are formed. Aged transformers with 2.0% or more moisture could release bubbles at hot spot temperatures greater than 140°C. Since the dielectric strength of the bubbles is significantly less than the insulation system, their formation can result in discharge events ranging from partial discharge to flashover.

When a temperature drop within the transformer is sufficient to change the relative saturation of water from less than 100 percent to greater than 100 percent, an emulsion of oil and water will form. If an appropriate surface is available or the temperature drop is extreme enough, further condensation will occur forming water drops or “rain”. Both emulsified water and free water substantially reduce the dielectric strength of the insulation system. Transported by the fluid their movement through the transformer can cause numerous dielectric and mechanical problems both with the insulation system and adjacent cellulosic materials.

Finally, the presence of water in the cellulose participates in the degradation of the cellulose. Each doubling of moisture concentration doubles the rate of degradation. This process reduces the degree of polymerization (DP) of the cellulose thereby reducing its mechanical strength.

Like water, fluid oxidation products are instrumental in the degradation of the insulation system. The oxidation process culminates with the formation of sludge which:

- As a suspended impurity, reduces the fluid dielectric withstand strength in a manner similar to particles.
- As a semi-conductive sediment, reduces the insulation dielectric withstand strength and may provide for tracking.
- When extremely acidic, will aggressively age both the oil and the cellulose insulation.

The conditions under which sludge will form are not always readily apparent. In the presence of a strong electrical field sludge may form even though the acidity is low. A number of sludge deposits have been found on local insulation zones where the electric field strengths are quite high. These deposits were not apparent until the windings were dismantled.

The correlation between traditional aging characteristics such as color, acidity, interfacial tension, dielectric breakdown voltage, dissipation factor, resistivity and sludge appearance during oil stability tests may be quite different for different oils. These differences increase significantly when the fluids are aging in transformers, due to the effects of transformer materials, operating temperatures, dielectric stress and interaction of aging products with cellulose (See Table 6).

Table 6
Relationships of Aging Characteristics of Service Aged Oils
from Service-Aged Power Transformers

Sample	Acidity	IFT	Color	Infrared Absorbance	PF ₉₀	SN	Sludge
1	0.081	22.0	3.5	3	3.65		0.018
2	0.035	25.9	2.5	2	2.25		0.014
3	0.124	23.1	3.0	8	4.09		0.017
4	0.154	21.9	6.5		11.69		0.015
5	0.109	28.6	5.0	8	8.84		0.010
6	0.151	23.0	4.5		5.84	0.577	0.012
7	0.111	25.9	4.0	11	15.40	0.310	0.016
8	0.098	26.1	4.0	11	15.61	0.312	0.011
9	0.098	27.2	4.0	11	21.89	0.313	0.013
10	0.193	26.3	4.5	9.5	4.01		0.014

Figure 1 shows a correlation between acid number and interfacial tension test results of oil samples obtained from 25 power transformers, rated 138-13.8 kV, 12-60 MVA. The best correlation occurs in the least oxidized fluids. As the oxidation proceeds, the correlation begins to diverge.

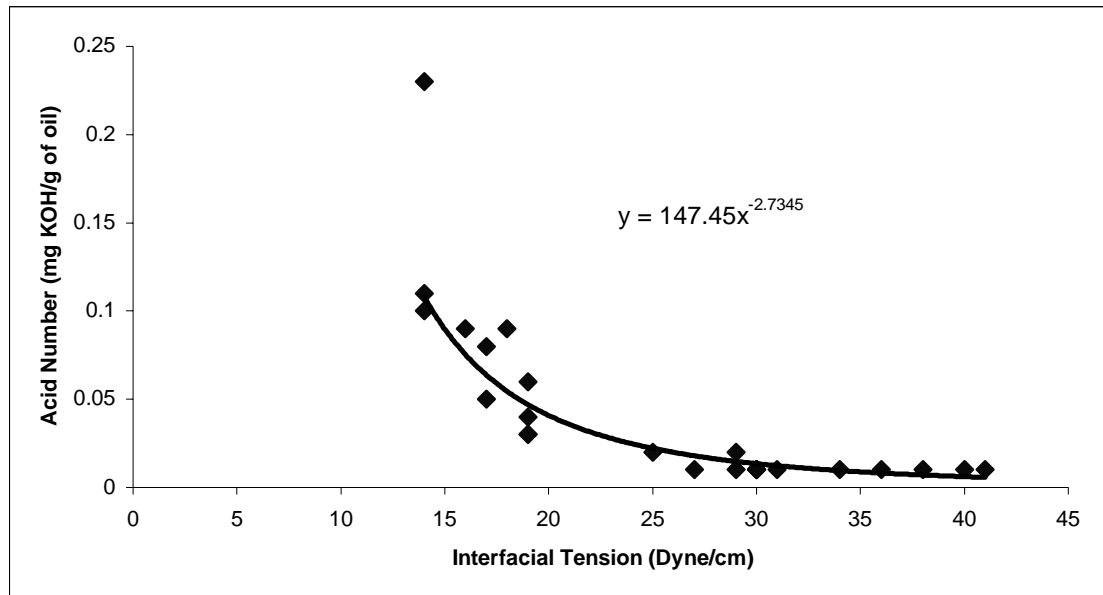


Figure 1
Correlation between acid number and interfacial tension test results.

Figures 2 and 3 show the correlation between the differential infrared absorbance of fluids at 1710 cm^{-1} versus their acid number and their interfacial tension, respectively. The discrepancy is more significant for acid numbers higher than 0.05 mg KOH/g and for IFTs lower than 20 Dynes/cm . The practical importance of such a discrepancy is that there may be oils in service with fairly acceptable IFT's and acid numbers that may contain a significant amount of non-acidic polar compounds detected by infrared spectroscopy.

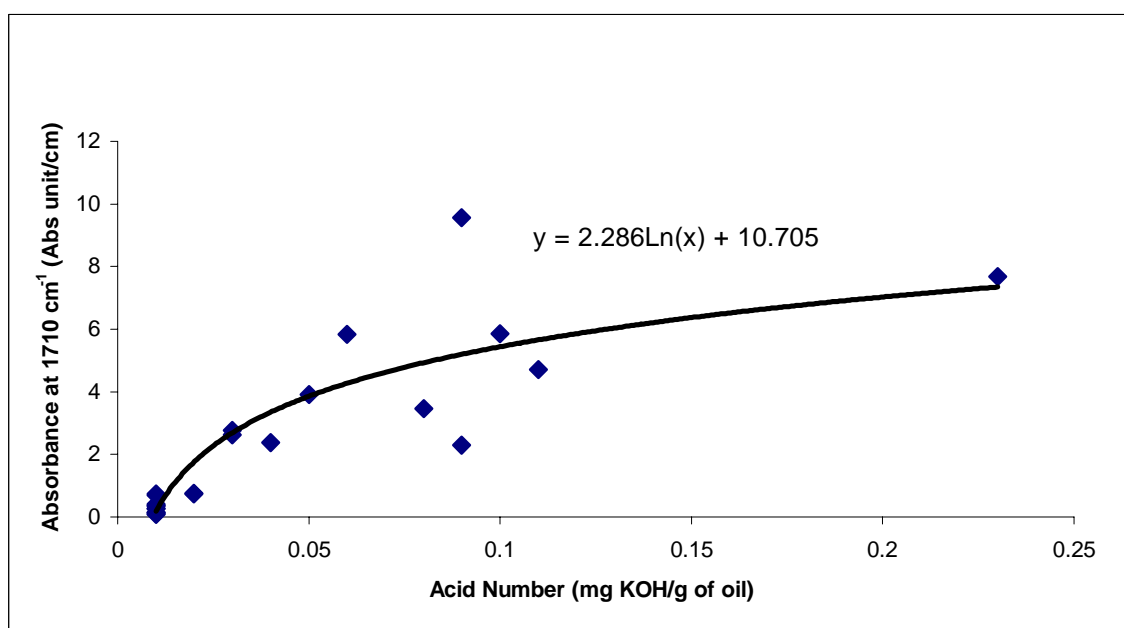


Figure 2
Correlation between the differential infrared absorbance at 1710 cm⁻¹ and the acid number

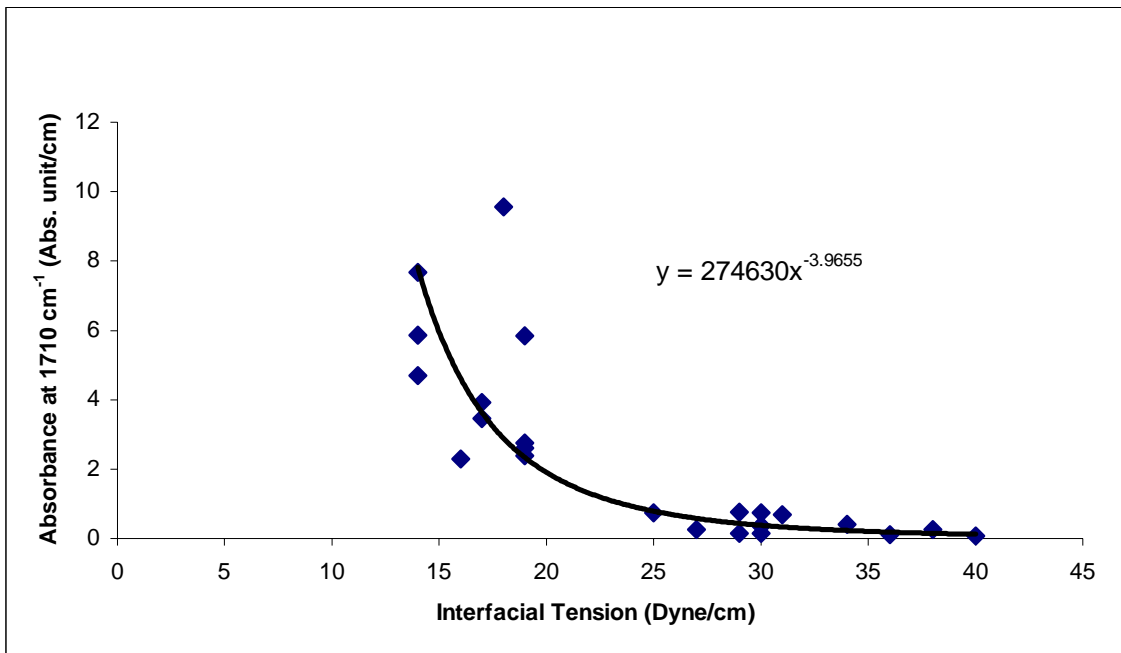


Figure 3
Correlation between the differential infrared absorbance of oils at 1710 cm⁻¹ and the interfacial tension

These examples demonstrate that the typical oil tests do not completely assess the progress of oil aging.

Gas formation occurs primarily in the oil. With the exception of bubble formation, gases are dissolved directly into the oil and distributed throughout the transformer. Changes in temperature will induce migration of gases between oil, cellulose and any gas spaces and may significantly change gas-in-oil concentrations, especially when the temperature changes are large (See Table 7).

A 750 kV Shunt Reactor with a source of localized overheating was stored for 1 year. Tests were performed before and after heating the unit for 3 days

Table 7
Effect of Temperature Distribution of Gases

	H ₂ ppm	CH ₄ ppm	C ₂ H ₄ ppm	C ₂ H ₂ ppm	C ₂ H ₆ ppm	CO ppm	CO ₂ ppm	O ₂ %	N ₂ %
20 °C, before heating	trace	172	78	ND	56	923	1929	0.08	2.9

64 °C, after heating	56	269	147	1.3	90	1163	2654	0.09	5.5
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Gas bubbles may be produced in transformers from severe fault conditions, a sudden release of pressure in gas saturated systems or an overload condition. Only a serious fault condition is expected to release large quantities of fault gases that do not get absorbed into the oil immediately. Nitrogen or air blanketed transformers may develop negative pressure in the gas space during rapid cool down. If the pressure differential between the gas in the oil and gas in the gas space is appreciable, spontaneous release of bubbles is possible. Transformer failures from a “cold start” of a stagnant transformer from bubble release in the supersaturated oil is one of the causes of sudden transformer failures. Therefore, it is necessary to ensure that such extreme pressure differential does not occur. Modern transformers with conservator tanks avoid this problem. As mentioned earlier, an overload condition with sufficient moisture and heat will produce bubbles of water vapor. Bubbles from any of these phenomena can lead to discharge events ranging from PD to flashover.

All of these examples illustrate that obtaining the best information from oil testing requires an understanding of the dynamics of the transformer as a system including the distribution of water, gases, contaminants and decomposition products between the fluid, solid insulation and gas spaces.

The Fluid as the Diagnostic Field

The possible benefits from using oil testing are indicated on Table 8, the Transformer Functional Failure Model suggested by the Cigre workgroup on Transformer Life Management, Cigre WG12.18. One may observe that for this collection most of the problems indicated could, in principle, be detected by means of oil analysis.

Table 8
Functional Failure Model
Possible detection of typical defects and faults through oil tests.

SYSTEM, COMPONENTS	DEFECT	Detection Through oil	FAULTS	Detection Through oil
<u>Dielectric</u> Major Insulation Minor Insulation Leads	Excessive water Oil contamination Surface contamination Abnormal aged oil cellulose aging static electrification PD of low energy	Yes Yes No Yes Yes Yes Yes	Destructive PD Localized tracking Creeping discharge Heated cellulose Flashover	Yes No Yes Yes Yes
<u>Magnetic circuit</u> Core insulation Clamping Magnetic shields Grounding circuit	Loosening clamping Short/open-circuit in grounding circuit circulating current Floating potential Aging lamination	No Yes Yes Yes No	Localized hot spot Sparking/ discharges Gassing	Yes Yes Yes
<u>Mechanical</u> Windings Clamping Leads support	Loosening clamping	No	Winding distortion radial axial twisting Insulation Failure	No Yes
<u>Electric circuit</u> Leads Winding conductors	Poor joint Poor contacts Contact deterioration	Yes Yes Yes	Localized hot spot Open-circuit Short-circuit	Yes No Yes

A selection of parameters to achieve the information goals is suggested in Table 9. The diagnostic use of oil-based information may be assisted by creating functional test/information groups such as:

- Characterization – which gives parameters that can be used to identify the oil
- Aging status – which gives parameters relevant to the aging process
- Dielectric status – which gives parameters used to determine the dielectric safety margin and dielectric characteristics of the insulation spaces.
- Degradation status – which gives parameters relevant to faults, failure and wear.

Table 9
A Functional Classification of Oil-Based Information

Classification of Oil-Based Information for Transformer Life Management			
Characterization	Aging Status	Dielectric Status	Degradation status
Fluid Composition Carbon Types Specific Gravity Viscosity Refractive Index Permittivity PAH content Inhibitor Content Total sulfur Corrosive Sulfur PCB Content BTA Content	Free Radicals Visible Spectrum Acidity Saponification Number Inhibitor contents IFT IR spectroscopy Dissipation factor Resistivity Polarization Index Turbidity Insoluble sludge Sludge content Oxidation stability tests Furanic compounds	Water content Percent saturation Bound water Particle profile Breakdown voltage Impulse strength Charging Tendency Resistivity Dissipation factor Insoluble sludge Gas tendency PD intention voltage	DGA Extended DGA Furanic compounds Phenols Cresols Dissolved metals Particle profile

Assessing the Transformer Condition for Life Management

The assessment begins with a compilation of information about the transformer. This includes information about the ratings, the core and coil such as their weights and configuration, the preservation system, the cooling system, the presence and configuration of a load tapchanger, the presence of a no-load tapchanger, and the full characterization of the fluid. This information should be collected and compiled in a manner that allows it to be available whenever an assessment is performed.

Summary operation, event, and maintenance activity data should also be compiled and available for assessments. As was illustrated above, isolated test data may imply one cause but be the result of a different one. Only with a completely integrated set of information can a thorough assessment be achieved.

We are proposing, for functional purposes, that the commentaries on the assessment address the topics of aging, dielectric and degradation. Note that there is an overlap of information between these topics and that these functional groupings are not intended limit a diagnostic testing program.

Assessing the Ageing Status of a Transformer

The test information for aging status specified in Table 9 was chosen to answer the following questions:

- What is the remaining inhibitor content?
- What is the non-acidic polar content?
- What is the acid content?
- What is the water content?
- What is the amount of esterification?
- What is the amount of sludge?
- What is the amount of insoluble sludge?
- What is the degree of polymerization of the paper?

The answers to these questions integrated with the compiled transformer information provides the basis for assessing the stages of aging and potential consequences. From the assessment a set of conditions such as:

- Presence of water, acids and non-acid polars which accelerate cellulose decomposition
- End of the induction period indicating a trend of accelerated degradation
- Appearance of sludge may be chosen to initiate a course of actions like those shown in Figure 4.

Assessing the Dielectric Status of a Transformer

The condition assessment of the dielectric system of a transformer incorporates quantification of those factors that may reduce the dielectric safety margin of insulation under operating and through fault conditions. This information is used to answer the following basic questions:

- ⟨ *What is the contamination with water, particles, acid, sludge?*
- ⟨ *Will there be a substantial reduction in the dielectric margin at operating temperatures?*
- ⟨ *What is the dielectric withstand capability?*
- ⟨ *What is the amount of water in the solid insulation?*
- ⟨ *Will there be bubble evolution at any allowable amount of loading?*
- ⟨ *What is the amount of insulation surface contamination?*
- ⟨ *What is the remaining mechanical strength of the solid insulation?*
- ⟨ *Does this provide adequate withstand capability?*

Similar to the aging status, the answers to these questions integrated with the compiled transformer information provide the basis for assessing the stages of dielectric strength and withstand potential. From the assessment a set of conditions such as:

- Potential reduction of dielectric strength from conductive particles

- Potential reduction of dielectric strength from sediment or surface active substances
- Potential reduction of dielectric strength from water
- Potential reduction of mechanical withstand capability may be chosen to initiate a course of action.

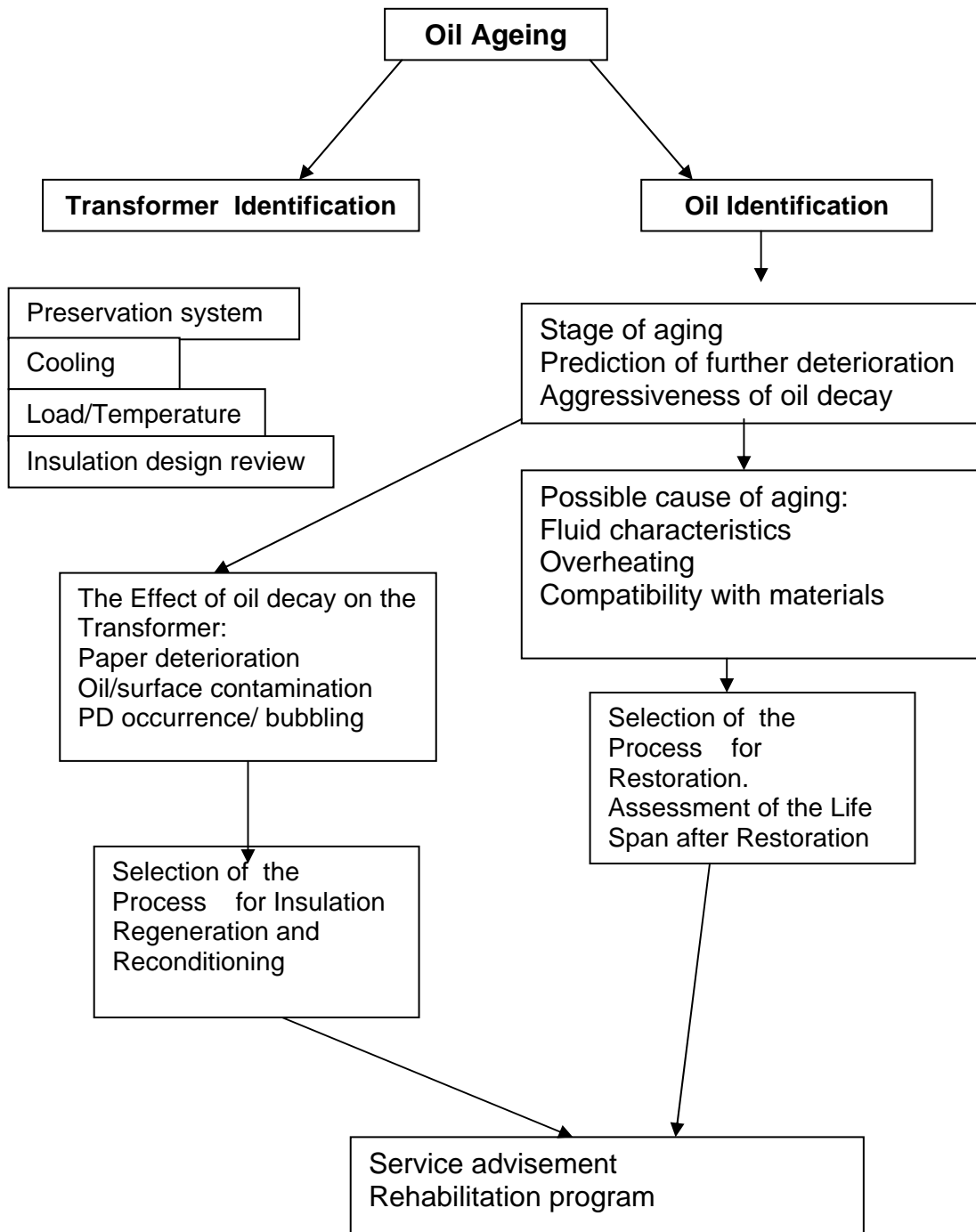


Figure 4
A flow chart of actions for fluid ageing

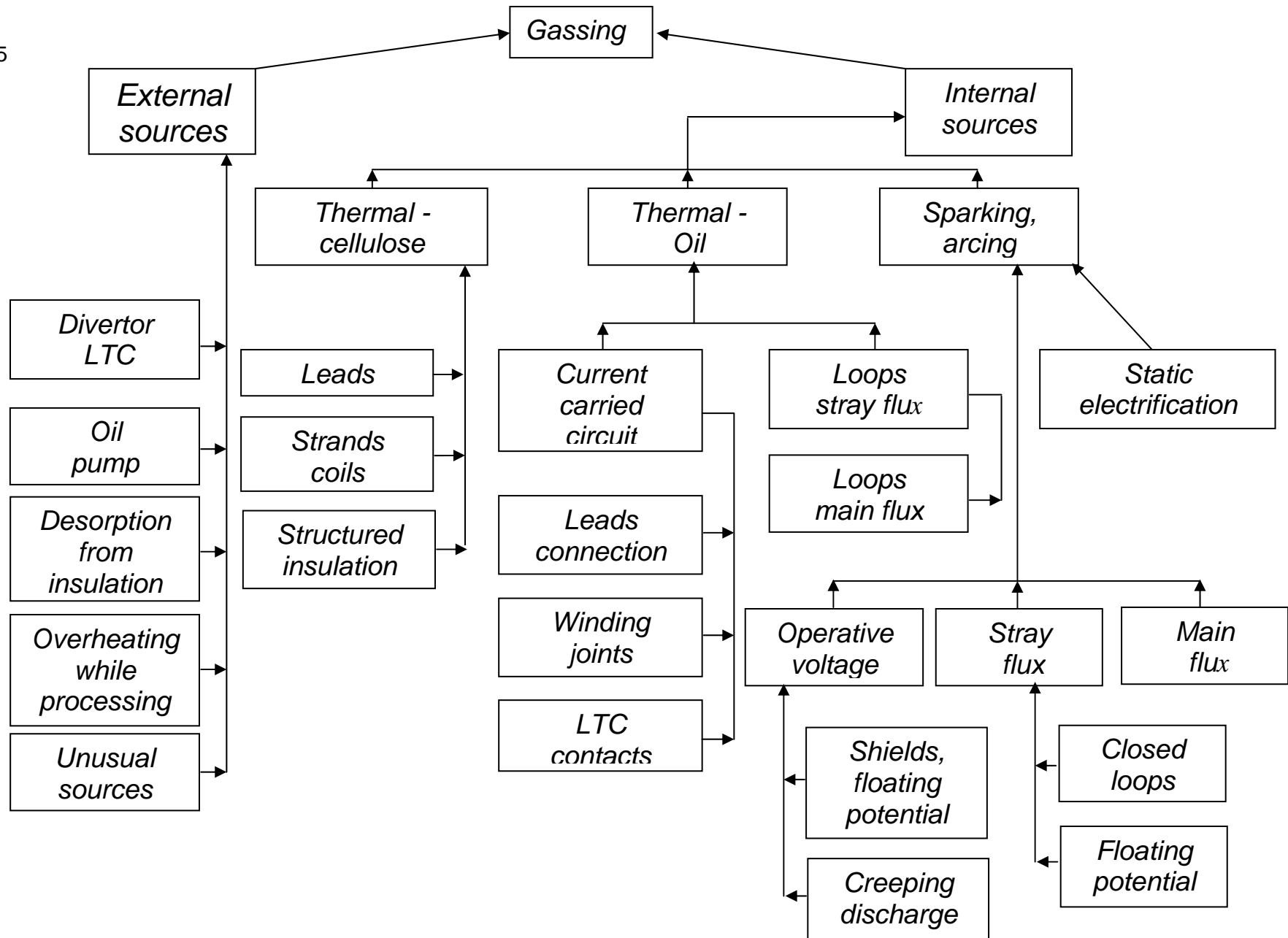
Assessing the Degradation Status of a Transformer

Degradation by-products such as gases, furans, phenols, cresols, dissolved metals, and metal particles are effective indicators of degradation processes. Once indicated, the challenge is to identify the source and seriousness of the process. The scheme in Figure 5 shows how gas information can be used to begin to locate the source of several degradation processes. Combined with the additional information available for the transformer, the success of identifying the source and severity is greatly enhanced.

Conclusion

Transformer life management requires comprehensive condition assessments to be made from a system's perspective. Because the transformer fluid is systemic, a large amount of this requisite information is available from fluid testing. In order to obtain the most complete and therefore useful information from fluid testing, an understanding of the dynamics of the transformer as a system, including the distribution of water, gases, contaminants and decomposition products between the fluid, solid insulation and gas spaces, is required. Using this understanding and the test information obtained, a diagnostic assessment can be made. This diagnosis coupled with an effective set of action plans provides the asset manager with the ability to choose the course of action best suited to the utility's needs.

Fig. 5



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