प्रारूप भारतीय मानक

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Draft Indian Standard

Onsite diagnostic testing of power transformers for condition/health assessment

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BUREAU OF INDIAN STANDARDS

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BUREAU OF INDIAN STANDARDS

DRAFT FOR COMMENTS ONLY

Draft Indian Standard

ONSITE DIAGNOSTIC TESTING OF POWER TRANSFORMERS FOR CONDITION/HEALTH ASSESSMENT

Transformers Sectional Committee, ETD 16	**Last Date of Comments: 18 September 2023**

FOREWORD

This draft Indian Standard is proposed to be adopted by the Bureau of Indian Standards, after the draft finalized by the Transformers Sectional Committee had been approved by the Electrotechnical Division Council.

Today transformers constitute a major portion of the capital equipment of power utilities all over the world and the reliable power supply depend heavily on the fault free operation of transformers. The reliability of electrical power system depends on the performance and availability of its components such as power transformers and therefore there is a need to know the internal condition of these components. Due to disturbances/ transients from the power system as well as increasing age of the transformer population, onsite diagnostic testing and condition assessment are important to secure a reliable operation of the electrical power system. For this purpose, offline and online diagnostic methods for power transformers have been developed which offers the possibility of detecting incipient faults. Offline diagnostic methods are used mainly during scheduled inspections or when transformer trips and it is suspected that the transformer has failed whereas online methods are used during the operation and offer a possibility to record the parameters and monitor the condition under realistic operating conditions (e.g., electric field, load, and temperature).

NOTE —This standard specifies offline and online diagnostic methods for power transformers which help in reducing failure rate by detecting incipient faults thereby increasing life of the transformers and making a reliable power system network.

For the purpose of deciding whether a particular requirement of this standard is complied with, the final value, observed or calculated, expressing the result of a test or analysis shall be rounded off in accordance with IS 2: 2022 ‘Rules for rounding off numerical values (*second revision*)’. The number of significant places retained in the rounded off value should be the same as that of the specified value in this standard.

Draft Indian Standard

Onsite diagnostic testing of power transformers for condition/health assessment

1 SCOPE

This standard specifies the requirements and tests for on-site diagnostic testingfor condition/health assessment of power transformers of following types and ratingswith voltage class from 33kV up to and including 765 kV:

a) Three phase ratings from 10 MVA up to and including 500 MVA (both sealed and non-sealed type);
b) Single phase ratings from 10 MVA up to and including 500 MVA (both sealed and non-sealed type);

2 REFERENCES

Sl. No.	*IS/Other Standards*	*Title*
1.	IS 1866: 2017/ IEC 60422:2013	Mineral insulating oils in electrical equipment supervision and maintenance guidance (Fourth Revision)
2.	IEC 60076:18	Power transformers: Part 18 measurement of frequency response
3.	IEC 60599: 2013	Mineral oil - Filled electrical equipment in service - Guidance on the interpretation of dissolved and free gases analysis (Third Revision)

X TERMINOLOGY

3 REASONS FOR FAILURE

Failure of Transformer is defined as any situation which requires the equipment to be removed from service for investigation, remedial work or replacement.Major failures constitute events that require the transformer to be retired or removed from site for repair. Minor failures can be repaired on site.Transformer failures can be broadly classified as electrical, thermal and mechanical. The failures are also classified in a different manner as internal or external. Failure due to insulation degradation, PD, increased moisture content, overheating, winding resonance etc. fall under the internal category, whereas faults due to lightning strikes, switching over-voltages, system overloads etc. fall under the external category. So far as the location of the failure is concerned, it could be in the main tank, bushings, tap changers or in the transformers accessories.Transformer failures can also be grouped under three main headings:

a) Failures due to weak specification, design deficiencies, manufacturing weaknesses or material defects,
b) Failures due to system disturbances, operational factors, or interactions between the transformers and other equipment on the system,
c) Failures which result from maintenance operations, repairs or refurbishment that has or have not been undertaken.

Design and manufacturing related problems are major contributors for the failure of the transformer.

Failure of transformer can be caused due to a problem in any of its key component. In case of transformers; winding, tap changer and bushing related failures are the major contributors of failure, followed by lead exit related failures.For reactors, winding and bushing related failures are the major cause of failure.
Reason of failure in different components may be

a) Bushing-due to insulation failure, moisture ingress, etc
b) Oil – degradation due to aging, moisture content, reduction in dielectric strength
c) Insulation- due to highfaultcurrent, moisture
d) Failure of tapchanger

Transformers generally provide many years of service when well built and maintained.In general the failure rate of the transformer can be generalized using the bathtub curve as shown in Figure 1:

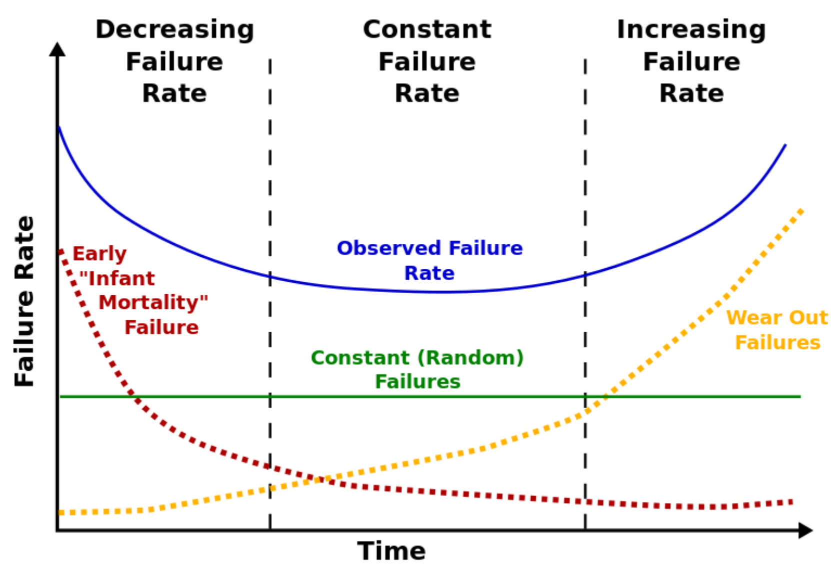


Figure 1 Typical transformer failure pattern

The life of power transformer includes manufacture, transport, installation, and in-service aging and maintenance. In general, the life of transformers roughly follows the classical “bathtub” curve, with a small number of units subjected to premature failure, followed by a long period with a low failure rate and then a period of increasing failures as they approach end of life. The set of tests described in product standards and this standard is intended to help detect and reduce failures during the first two periods and help the user to predict the outcome and take actions to delay the onset of the final stage.

4 DIAGNOSTIC TESTS TO BE CONDUCTED FOR CONDITION ASSESSMENT

Table 1 is a compilation of the 'Mandatory (M)', 'Optional (O)', and 'SOS' diagnostic tests typically performed on liquid-filled power transformers during their commissioning, while they are in service, and after protection trips caused by either a system fault or an internal fault.

TABLE 1 TESTS TO BE CONDUCTED
(*Clause*4)

Sl.No.	Name of Test	Voltage from 33kVupto 66 kV	Voltage from above 66 kVupto220kV	Voltage above 220 kV
(1)	(2)	(3)	(4)	(5)
i)	Core insulation tests	M	M	M
ii)	Insulation Resistance (IR) measurement	M	M	M
iii)	Capacitance and Tanδ measurement of bushings	O*	M	M
iv)	Capacitance and Tan δ measurement of windings	O*	M	M
v)	Turns ratio (Voltage ratio) measurement	SOS	SOS	SOS
vi)	Vector Group & Polarity	SOS	SOS	SOS
vii)	Magnetic Balance test	SOS	SOS	SOS
viii)	Floating Neutral point measurement	SOS	SOS	SOS
ix)	Measurement of Short Circuit Impedance	SOS	SOS	SOS
x)	Exciting/Magnetising current measurement	SOS	SOS	SOS
xi)	Operational checks on OLTCs	M	M	M
xii)	Tests/ Checks on Bushing Current Transformers (BCTs)	SOS	SOS	SOS
xiii)	Operational Checks on protection System	M	M	M
xiv)	Frequency Response Analysis (FRA) measurement	SOS*	SOS	SOS
xv)	Winding resistance	M**	M	M

	measurement			
xvi)	Dissolved Gas Analysis (DGA) of oil sample	SOS*	M	M
xvii)	Thermovision Scanning	SOS*	M	M
xviii)	Transformer Oil quality Testing	M	M	M
xix)	Furan analysis	SOS	SOS	SOS
xx)	Online Partialdischarge	SOS	O	O
xxi)	Moisture measurement in insulation/FDS for bushing & transformer	SOS	SOS	SOS
xxii)	Vibration measurement for reactors	SOS	SOS	SOS
xxiii)	Hot Spot measurement by fibreoptics	SOS	O	M

'Mandatory (M)' = Mandatorily required to be conducted by all utilities
'Optional (O)' = Optional for utilities to conduct
'SOS' = Tests which are to be conducted as and when required
*Mandatory for critical transformers; **Optionalfor transformers without tap changers

5 FREQUENCY OF TESTS TO BE CONDUCTED

Diagnostic tests are to be conducted as a part of condition based maintenance practice. Diagnostic testing and condition assessment of the transformer should begin from commissioning of the transformer. The first round of testing after commissioning may be time based within 2/3/4 years. Thereafter frequency should depend upon the assessed condition. Oil quality, DGA and Furan analysis may be carried out at regular interval starting from commissioning. All other diagnostic tests are to be conducted depending upon the assessed condition of the transformer in-service. Diagnostic testing during the service period of the transformer's life cycle is intended to identify adverse trends in the aging of the transformer and its accessories. Such testing may be time or condition based, depending on the recommendation of the transformer manufacturer and the philosophy of the user. Service period diagnostic testing may also be performed to validate the integrity of the transformer following exposure to normal and abnormal service events such as through faults and lightning surges or any event that causes actuation of the transformer's protective relaying.

The diagnostic testing frequency should be established by means of a cost/benefit evaluation based on life cycle analysis and risk assessment. For some owners this approach may indicate different testing frequencies from those indicated in Table 2. For instance, some electrical utilities may prefer not to perform this programme on to this type of transformer and small industries may prefer to include this type of transformer even in a higher category.

TABLE 2 FREQUENCY OF TESTS
(*Clause*5)

Sl.No. (1)	Name of Test (2)	Voltage from 33kVupto 66 kV (in years) (3)	Voltage from above 66 kVupto 220kV (in years) (4)	Voltage from above 220 kV (in years) (5)
i)	Core insulation tests	2-6	1-4	1-3
ii)	Insulation Resistance (IR) measurement	2-6	1-4	1-3
iii)	Capacitance and Tanδ measurement of bushings	2-6	1-4	1-3
iv)	Capacitance and Tan δ measurement of windings	2-6	1-4	1-3
v)	Turns ratio (Voltage ratio) measurement	2-6	1-4	1-3
vi)	Vector Group & Polarity	2-6	1-4	1-3
vii)	Magnetic Balance test	2-6	1-4	1-3
viii)	Floating Neutral point measurement	2-6	1-4	1-3
ix)	Measurement of Short Circuit Impedance	2-6	1-4	1-3
x)	Exciting/Magnetizing current measurement	2-6	1-4	1-3
xi)	Operational checks on OLTCs	2-6	1-4	1-3
xii)	Tests/ Checks on Bushing Current Transformers (BCTs)	At the time of commissioning	At the time of commissioning	At the time of commissioning
xiii)	Operational Checks on protection System	At the time of commissioning / after actuation of the protective relaying	At the time of commissioning/ after actuation of the protective relaying	At the time of commissioning/ after actuation of the protectiverelaying
xiv)	Frequency Response Analysis (FRA) measurement	2-6	1-4	1-3
xv)	Winding resistance measurement	2-6	1-4	1-3
xvi)	Dissolved Gas Analysis (DGA) of oil sample	2-6	1-4	1-3
xvii)	Thermovision	2-6	1-4	1-3

	Scanning			
xviii)	Transformer Oil Testing	2-6	1-4	1-3
xix)	Furan analysis	2-6	1-4	1-3
xx)	Online Partial discharge	2-6	1-4	1-3
xxi)	Moisture measurement in insulation/FDS for bushing & transformer	2-6	1-4	1-3
xxii)	Vibration measurement for reactors	2-6	1-4	1-3
xxiii)	Hot Spot measurement by fibre optics	2-6	1-4	1-3

6 ACCEPTANCE CRITERIA

Acceptance criteria for evaluation of diagnostic test results for condition assessment of transformer are listed in Table 3 below.

TABLE 3 ACCEPTANCE CRITERIA

(*Clause*6)

Sl.No.	**Name of Test**	**Voltage from 33kVupto 66 kV**	**Voltage from above 66 kVupto 220kV**	**Voltage from above 220 kV**
(1)	**(2)**	**(3)**	**(4)**	**(5)**
i)	Core insulation tests	>100 MΩ - Normal, 10 MΩ to 100 MΩ - Indicative of insulation deterioration and <10 MΩ - Needs to be investigated		
ii)	Insulation Resistance (IR) measurement	As recommended in Annex A	As recommended in Annex A	As recommended in Annex A
iii)	Capacitance and Tan δ measurement of bushings	Oil Impregnated Paper - 0.7% Resin Impregnated Paper - 0.7% Resin Bonded Paper-1.5%		
iv)	Capacitance and Tan δ measurement of windings	Change in capacitance should be within 5% of the bench mark value. Tan delta – below 1% at 20 °C.		

v)	Turns ratio (Voltage ratio) measurement	Within ±0.5% of the name plate value	Within ±0.5% of the name plate value	Within ±0.5% of the name plate value
vi)	Vector Group & Polarity	Comparable to name plate specifications		
vii)	Magnetic Balance test			
viii)	Floating Neutral point measurement	Voltage between Neutral and Earth should be zero or negligible (limited to the accuracy of the Voltmeter used)		
ix)	Measurement of Short Circuit Impedance	For three-phase transformers, the three-phase equivalent test results should be within ±3 % name plate values and the per-phase test results should be within ±3 % of the average value of all three phases. For single phase, the per-phase test results should be within ±3 % of the name plate value.		
x)	Exciting/Magnetisingcurrent measurement	Comparable within 10% for three similar single phase transformers or between the outer phases of three-legged, three-phase transformers.		
xi)	Operational checks on OLTCs			
xii)	Tests/ Checks on Bushing Current Transformers (BCTs)	As per relevant product standard requirements		
xiii)	Operational Checks on protection System	As per the relevant requirements of the protection scheme		
xiv)	Frequency Response Analysis (FRA) measurement	As recommended in Annex A		
xv)	Winding resistance measurement	Comparable to factory value or between the phases within ±5%		
xvi)	Dissolved Gas Analysis (DGA) of oil sample	As per IEEE Standard C57.104-2019 or IEC 60599-2013		
xvii)	Thermovision Scanning	As recommended in Annex A		
xviii)	Transformer Oil Testing	As per dual standard IS 1866: 2017/IEC 60422:2013		
xix)	Furan analysis	0 to 0.5 mg/kg - Normal deterioration, 0.5 to 1.0		

		mg/kg – Moderate deterioration, 1.0 to 2.5 mg/kg high deterioration, >2.5 mg/kg Severe deterioration
xx)	Online Partial discharge	Continuously increasing trend to be investigated and located with complementary DGA data
xxi)	Moisture measurement in insulation/FDS for bushing & transformer	0-2% Dry Paper 2-4% Wet Paper >4.5% Excessively Wet
xxii)	Vibration measurement for reactors	
xxiii)	HotSpotmeasurement by fibre optics	

ANNEX A

HEALTH ASSESSMENT OF POWER TRANSFORMERS

Factory tests (routine, design, and conformance) such as those described in product standard are intended to verify that the units are designed and manufactured to meet customer and industry specifications. Such tests are intended to reduce failures during every segment of the life curve. Diagnostic tests described herein are unique to each period in the unit's life cycle (transportation, installation, in-service aging, and maintenance).

The transportation phase in the life of a large power transformer is brief but may present significant structural and environmental challenges to the unit. Diagnostic tests sensitive to the shifting of internal components and those sensitive to adverse environmental exposure during shipment should be selected to identify changes to the unit's integrity since leaving the factory or other point of origin.

The installation phase of a transformer's life is also brief but requires certain select field testing (beyond that which confirms the lack of transportation damage) to validate the correct configuration of the transformer and its accessories, to confirm the proper processing and liquid filling of the tank, and to establish a baseline for future condition assessments.

Field testing during the service period of the transformer's life cycles intended to identify adverse trends in the aging of the transformer and its accessories. Service period diagnostic testing may also be performed to validate the integrity of the transformer following exposure to normal and abnormal service events such as through faults and lightning surges or any event that causes actuation of the transformer's protective relaying.

During the service period of the life cycle of a transformer, maintenance activities are performed to help preserve its integrity and prolong its useful life. Field testing following certain maintenance activities is not intended to identify aging but seeks to confirm that those activities achieved the desired result, to confirm that new or modified components or accessories are properly functioning, to verify that the unit is in its proper configuration prior to being returned to service, and to obtain data that serves as the new baseline for future evaluations.

Power transformers, regulators, and reactors are installed in a wide variety of applications. Users need to evaluate a number of parameters, whether selecting tests in response to a specific need for a single transformer or establishing a life cycle management program for an entire fleet. The goal of testing is to confirm the transformer's ability to continue functioning properly and to reduce the chance of failure.

Condition Monitoring for any device is defined as "A generic procedure / activities directed towards identifying and avoiding root cause failure modes". Condition monitoring activities for transformers can be described as the process of monitoring a parameter in the equipment, in order to identify a significant change which is indicative of a developing fault. It is a major component of predictive maintenance.

The condition monitoring activities of any Power transformers, regulators, and reactors can be classified as the following based on testing methodology:

a) Off Line Monitoring Activities
b) On Line Monitoring Activities

Table A.1 briefly describes the significance of the diagnostic tests.

Table A.1 Significance of Diagnostic Test

Sr. No.	Name of Test	Significance	Type of Activity
1.	Core insulation tests	Allows for investigating inadvertent core grounds which results in circulating currents if there is more than one ground connection exists between the core and ground.	Offline Testing
2.	Insulation Resistance (IR) measurement	Test reveals the condition of insulation (i.e. degree of dryness of paper insulation), presence of any foreign contaminants in oil and also any gross defect inside the transformer (e.g. Failure to remove the temporary transportation bracket on the live portion of tap-changer part)	Offline Testing
3.	Capacitanceand Tanδ measurement of bushings	For bushings, capacitance and tan δ of the C1 main insulation and C2 tap electrode insulation are measured. Short-circuited capacitor sections can be detected by an increase in capacitance. The presence of moisture and other contaminants can usually be detected by increase in tan δ.	Offline Testing & Online testing
4.	Capacitance and Tan δ measurement of windings	Capacitance and Tan δ measurement gives the overall condition of the insulation system. The tan δ is capable of detecting moisture and contamination within the transformer. The capacitance measurement can help in judging whether there has been bulk movement of the winding.	Offline Testing
5.	Turns ratio (Voltage ratio) measurement	Turns ratio can identify any abnormality in tap changers/ shorted or open turns etc.	Offline Testing
6.	Vector Group & Polarity	To determine the phase relationship and polarity of transformers.	Offline Testing
7.	Magnetic Balance test	This test is conducted only in three phase transformers to check the imbalance in the magnetic circuit	Offline Testing
8.	Floating Neutral point measurement	This test is conducted to ascertain possibility of short circuit in a winding.	Offline Testing
9.	Measurement of Short Circuit	This test is used to detect winding movement that usually occurs due to heavy fault current or mechanical damage	Offline Testing

	Impedance	during transportation or installation since dispatch from the factory.	
10.	Exciting/Magnetizing current measurement	To locate defect in magnetic core structure, shifting of windings, failures in turn to turn insulation or problems in tap changers. These conditions change the effective reluctance of the magnetic circuit thus affecting the current required to establish flux in the core	Offline Testing
11.	Operational checks on OLTCs	To ensure smooth and trouble free operation of OLTC during operation.	Offline Testing
12.	Tests/ Checks on Bushing Current Transformers (BCTs)	To ascertain the healthiness of bushing current transformer at the time of erection.	Offline Testing
13.	Operational Checks on protection System	Operational Checks on cooler bank (pumps & Fans), Breathers (Silicagel or Drycol), MOG, temperature gauges (WTI/OTI), gas actuated relays (Buchholz, Pressure Release Devices (PRD), SPR etc.) and simulation test of protection system	Offline Testing
14.	Stability of Differential, REF (Restricted Earth Fault) of Transformer/ Reactor	This test is performed to check the proper operation of Differential & REF protection of transformer and reactor by simulating actual conditions. Any problem in CT connection, wrong cabling, relay setting can be detected by this test.	Offline Testing
15.	Frequency Response Analysis (FRA) measurement	To assess the mechanical integrity of the transformer. Transformers while experiencing severity of short circuit current loses its mechanical integrity by way of deformation of the winding or core. During pre-commissioning this test is required to ascertain that transformer active part has not suffered any severe impact/ jerk during transportation.	Offline Testing
16.	Winding resistance measurement	To check for any abnormalities due to loose connections, broken strands and high contact resistance in tap changers	Offline Testing
17.	Dissolved Gas Analysis (DGA) of oil sample	DGA results indicate the normal and abnormal internal condition of the transformer.	Offline Testing & Online Testing
18.	Thermovision Scanning	Monitoring is done using thermovision camera to identify hotspot in the transformer terminals,main tank and radiator.	Online Testing
19.	Moisture	Moisture in oil can be measured and if required action can	Online

	Measurement	also be taken while the transformer is in service	Testing

The details of the major testing activities aredescribed below:

1. **Off Line Monitoring Activities for Transformers, Regulators and Reactors**

   a) **Low Voltage Conventional Tests**

   The low voltage conventional tests are described as the tests which are carried out at site and the test results are compared to the factory test results/pre-commissioning results.

a) Winding Resistance

Transformer winding resistances are measured in the field to check for abnormalities due to loose connections, broken strands, and high contact resistance in tap changers. The results are usually interpreted based on comparing measurements made separately on each phase of a wye-connected winding or between pairs of terminals on a delta-connected winding. Comparison may also be made with original data measured in the factory. The resistances between phases should be within 2% of each other. Agreement to within 5% for any of the above comparisons is usually considered satisfactory. It may be necessary to convert the resistance measurements to values corresponding to the reference temperature in the transformer test report. The conversions are accomplished by Equation (1):

$$R_s = R_m\left(\frac{T_s + T_k}{T_m + T_k}\right) \tag{1}$$

where
Rs= resistance at desired temperature *Ts*
Rm = measured resistance
Ts= desired reference temperature (°C)
Tm = temperature at which resistance was measured (°C)
Tk= 234.5 °C (copper)
= 225 °C (aluminum)
NOTE—The value of *Tk*may be as high as 230 °C for alloyed aluminum.

As the transformer resistance is Low resistance, the measurement has to be carried out with the help of **Kelvin Double Bridge / Transformer ohmmeter**. Normally winding resistance values 1 ohm or above is measured using Wheatstone Bridge and winding resistance values less than 1 ohm is measured using micro-ohm meter or Kelvin Bridge.

To reduce the high inductive effect it is advisable to use a sufficiently high current to saturate the core. This will reduce the time required to get a stabilized reading. It is essential that temperatures of the windings are accurately measured.Care shall be taken that self-inductive effects are minimized.Care also must be taken to ensure that direct current circulating in the windings has settled down before the measurement is done. In some cases this may take several minutes depending upon the winding inductance.

The winding resistance shall be preferably done when the difference in the top and bottom temperature of the winding (temperature of oil in steady-state condition) is equal to or less than 5°C.The winding resistance should preferable be carried out last after completion of all other LV tests, as after this test core gets saturated and tests like magnetizing current, magnetic balance etc. carried out after winding resistance test may be affected and indicate a misleading results, if the core is not de-magnetized before carrying out these tests.

As a check, Key gases increasing in DGA will be ethane and /or ethylene and possible methane of close connections to broken strands or OLTC contact problems.

b) Voltage Ratio Test

The turns ratio of a transformer is the ratio of the number of turns in a HV winding to that in a LV winding. The voltage ratio of a transformer is the ratio of the root mean square (rms) terminal voltage of an HV winding to the rms terminal voltage of an LV winding under specified conditions of no load.
The turns ratio of a transformer is the ratio of the number of turns in a HV winding to that in a LV winding. The voltage ratio of a transformer is the ratio of the root mean square (rms) terminal voltage of an HV winding to the rms terminal voltage of an LV winding under specified conditions of no load.

This ratio test is typically performed in the as-found tap positions. During field commissioning, if the transformer has taps for changing the voltage ratio, the voltage ratio should be determined for all taps. This means the voltage ratio test should be performed for all taps of the DETC and all taps of the LTC. It is considered best practice to perform the final (DETC) voltage ratio test in the as-left position and to test the voltage ratio after a DETC change.

A number of modern commercial transformer ratio measurement test sets are available from manufacturers serving the power industry. These instruments, when operated in accordance with the manufacturer's instructions, provide convenient and accurate readings of the following:

– Voltage ratio
– Polarity verification
– Phase angle
– Test meter current

The term “transformer turns ratio” (TTR) meter is commonly used to describe these instruments even though the actual turns ratio is not being measured.

The principle of operation is to apply a reduced voltage to the HV terminals and produce a resulting voltage at the LV terminals. The two voltages are accurately measured and used to calculate and display the transformer voltage ratio.

A continuous testing mode facilitates measurements on multi-tap windings and quickly measures, displays, and records the ratio and test meter current for each tap. Communication ports are helpful in automating testing and test data recording.

When a three-phase transformer voltage ratio test is performed on a single-phase basis, the proper connections and phase vector relationships should be considered. Detailed connection charts with corresponding formulas referring measured voltage ratio to nameplate voltage ratio are typically provided with the ratio measurement instrument for this method.

Results of the transformation turns or voltage ratio are absolute, and may be compared with the specified values measured during factory testing. The turns ratio tolerance should be within 0.5 % of the nameplate specifications. For three phase Y connected winding this tolerance applies to phase to neutral voltage. If the phase-to-neutral voltage is not explicitly indicated in the nameplate, then the rated phase-to-neutral voltage should be calculated by dividing the phase-to-phase voltage by $\sqrt{3}$.

If there are shorted winding turns, the measured ratio will be effected. Out-of-tolerance ratio measurements may be symptomatic of shorted turns, especially if there is an associated high excitation current. Out-of-tolerance readings should be compared with prior tests because in some instances, the design turns ratio may vary from the nameplate voltage ratio on some taps because of the need to utilize an incremental number of winding turns to make up the taps while nameplate voltage increments may not exactly correspond. This error may combine with measurement error to give a misleading out-of-tolerance reading.

Ratio measurements must be made on all taps to confirm the proper alignment and operation of the tap changers. It should be noted that, on transformers with OLTC that operate on positions bridging two tap contacts (check the nameplate chart for tap connections), there will be a circulating current in the tap section being bridged. This circulating current is limited in some manner, usually by a reactor or resistance device. The losses due to this circulating current will cause an increase in exciting current and some voltage regulation. It is therefore important to have prior data with the measurement system employed to properly analyze these transformers.

Open turns in the excited winding will be indicated very low exciting current and no output voltage. Open turns in the output winding will be indicated by normal levels of exciting current, but no or very low levels of unstable output voltage.

c) *Excitation/ Magnetization Current*

Exciting/ Magnetizing current is the current required to force a given flux through the core.This test should be done before DC measurements of winding resistance to reduce the effect of residual magnetism.Magnetizing current readings may be effected by residual magnetism in the core. Therefore, transformer under test is to be demagnetized before commencement of magnetizing current test.

The test comprises a simple measurement of single-phase current on one side of the transformer, usually the high-voltage side, with the other side left floating (with the exception of a grounded neutral). Three-phase transformers are tested by applying Single-phase 10 kV voltage to one phase (HV terminals) at a time. Keep the tap position alternatively in thelowest position, Normal position and highest position and all otherterminals open. Measure the voltages applied on each phase (Phase wise) on HV terminals and current is measured in each phase of HV terminal.

The usual approach to the analysis of the excitation current test results is to compare the results with the previous tests or with similar single-phase transformers or with phases of a given three-phase transformer. The difference in exciting current between the outer phases of the three phase transformer should not exceed 10%. This also applies when comparing with previous measurements. For the great majority of three-phase transformers, the pattern is two similar high readings on the outer phases and one lower reading on the centre phase. The recommended initial tests include measurements at half of the LTC positions, the neutral position, and one step in the opposite direction. The results may differ for various LTC positions, but the relationship between the phases is expected to remain unchanged. The understanding of how the LTC affects the current magnitude of individual phases is essential for developing proper analysis.
Three types of patterns can be easily described:

i) High-low-high (HLH) pattern
   – Expected for a three-legged core transformer.
   – Expected for a five-legged core (or shell) transformer with a delta-connected secondary winding.
ii) Low-high-low (LHL) pattern
   – Obtained on a three-legged core transformer if the traditional test protocols are not followed.
   – Neutral on high side wye-configured transformer is inaccessible.

– Obtained when the third terminal on a delta-connected transformer has not been grounded.

– Expected for a four-legged core transformer.

iii) All three similar patterns

– Expected for a five-legged core (or shell) transformer with a non-delta secondary winding.

If an out-of-tolerance reading is experienced while turns ratio, winding resistance, and impedance tests are normal, residual magnetism should be suspected.Residual magnetism may be eliminated or reduced by applying a dc voltage to the windings through a voltage divider. The voltage should be raised from zero to a maximum value that will yield a current of no more than 10 A through the winding and then returned to zero. Care must be taken not to break the circuit while dc current is flowing in the winding. The polarity should then be reversed and the procedure repeated. Repeat the process several times, each time reducing the magnitude of current and each time reversing the polarity. The excitation current test should then be repeated.

d) Insulation Resistance

Insulation resistance (IR) of windings is the simplest and most widely used test to check the soundness of transformer insulation. This test reveals the condition of insulation (i.e. degree of dryness of paper insulation), presence of any foreign contaminants in oil and also any gross defect inside the transformer (like failure to remove the temporary transportation bracket on the live portion of tap-changer part).Insulation resistance is measured by means of insulation resistance testers which are available in 500 V, 1000 V, 2500 V and 5000 V or higher ratings. For transformer windings with voltage rating 11 kV and above, 2.5 kV megger shall be used. IR value measurements of EHV transformers shall preferably be done with 5 kV motorized / digital insulation resistance tester.

IR measurements shall be taken between the windings collectively (i.e. with all the windings being connected together) and the earthed tank (earth) and between each winding and the tank, the rest of the windings being earthed. Before taking measurements the neutral should be disconnected from earth. Table A.2 gives combinations of IR measurements for auto-transformer, three -winding transformer & Shunt Reactor.

Table A.2 Combinations of IR Measurements

For Auto-transformer	**For 3 winding transformer**	**For Shunt Reactor**
HV + IV to LV	HV + IV to LV	HV to E

HV + IV to E	HV + LV to IV	
LV to E	HV + IV +LV to E	

Record date and time of measurement, serial number, make of insulation resistance tester, oil temperature, and IR values at intervals of 15 seconds, 1 minute and 10 minutes.

IR values may be compared with factory test results and these values may be used as bench marks for future IR monitoring in service. IR values vary with type of insulation (transformer oil or air), temperature, duration of application of voltage and to some extent applied voltage.

Insulation resistance varies inversely with temperature and is generally corrected to a standard temperature (usually 20 °C) using curve meant for this purpose as shown in Figure A.1.

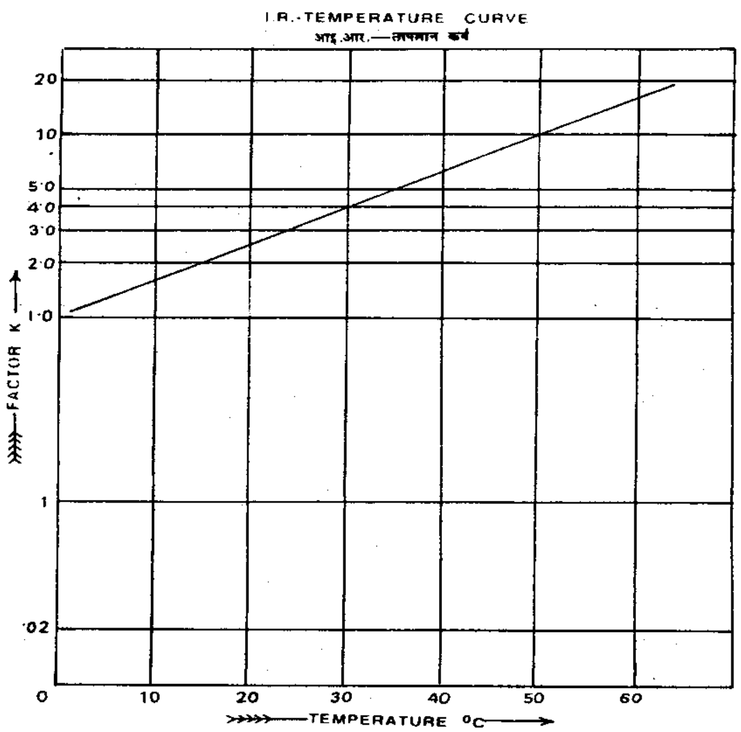


Figure A.1 IR Temperature Curve

An indicative minimum one minute insulation resistance value for transformers may be obtained by using the following empirical formula:

R = CE / √kVA, **(2)**

where

R = Insulation resistance, in MΩ

C = 1.5 for oil-filled transformers at 20°C, assuming that the transformer's insulating oil is dry, acid free, and sludge free

= 30.0 for untanked oil-impregnated transformers

E = Voltage rating, in V, of one of the single-phase windings (ph-to-ph for delta connected and ph-to-neutral for wye connected transformers)

kVA = Rated capacity of the winding under test (If the winding under test is three-phase and the three individual windings are being tested as one, the rated capacity of three-phase winding is used.)

IR test results below this minimum value may indicate possible insulation breakdown. Indication of zero or a very low value of ohms would indicate a grounded winding, a winding-to-winding short or heavy carbon tracking.

Unless otherwise recommended by the manufacturer as a thumb rule the IR values recommended in Table A.3 may be considered as the minimum satisfactory values at 30°C (one minute measurement) at the time of commissioning.

Table A.3 Minimum IR values for commissioning

Rated Voltage class of winding	**Minimum desired IR value at 1 minute (Meg ohm)**
11kV	300 MΩ
33kV	400 MΩ
66kV & above	500 MΩ

Even if the insulation is dry, IR values will be low if the resistivity of oil is poor.With the duration of application of voltage, IR value increases. The increase in insulation resistance is an indication of dryness of insulation.

The ratio of 60 second insulation resistance to 15 second insulation resistance value is called **dielectricabsorption coefficient or Index (DAI).** For oil filled transformers with class A insulation, in reasonably dried condition the absorption coefficient at 30°C will be more than **1.3.**

Polarization Index Test is ratiometric test, insensitive to temperature variation and may be used to predict insulation system performance even if charging currents (i.e. capacitive, absorption or leakage currents) have not diminished to zero. Since leakage current increases at a faster rate with moisture present than does absorption current, the insulation resistance value will not increase with time as fast with insulation in poor condition as with insulation in good condition. This results in a lower polarization index. An advantage of the polarization index is that all of the variables that can affect insulation resistance, such as temperature and humidity, are essentially the same for both the 1 min and 10 min readings. The polarization index test is performed generally by taking insulation resistance readings at the following intervals at a constant dc voltage: 1 min and then every minute up to 10 min. The **polarization index** is the ratio of the 10 min to the 1 min megohm readings.

$PI = R_{10} / R_1$ *(dimensionless)*(3)

Where PI is Polarisation Index and R is resistance

The following are guidelines for evaluating transformer insulation using polarization index values as listed in Table A.4:

Table A.4 Guidelines for PI Evaluation

Polarization Index	Insulation Condition
Less than 1	Dangerous
1.0-1.1	Poor
1.1-1.25	Questionable
1.25-2.0	Fair
2.0 – 4.0	Good
Above 4.0	Excellent

A PI of more than 1.25 and DAI of more than 1.3 are generally considered satisfactory for a transformer when the results of other low voltage tests are found in order. PI value less than 1 calls for immediate corrective action. For bushings, an IR value of above 10GΩ is considered satisfactory.

e) Capacitance and Tan delta of Winding Insulation

The tan delta (dissipation factor) has long been known as one of the most effective methods of assessing the overall condition of a transformer and is central to a transformer condition-based maintenance program. The ac capacitance test is a subset of the tan delta test because the capacitance value and associated charging current are required to calculate the tan delta. Both values are routinely evaluated together due to their close association. In fact, these two measured values should always be analyzed together to ensure that the condition of the transformer insulation is being properly assessed. Initial tan delta tests on new equipment as it arrives from the manufacturer determine the presence of contaminants and overall material quality. Depending on type of material, voltage class, and insulating liquid, it is possible to have different acceptance criteria for tan delta limits.

Tan delta and capacitance testing of transformers can help determine whether the level of contamination is above acceptable risk standards or whether there is a possibility of mechanical damage due to bulk coil movement. The tan delta itself is one of the leading methods for detecting moisture and contamination within a transformer, but it can also be influenced by the condition of the bushings and testing environment. The capacitance measurement (as part of the tan delta test) can help in judging whether there has been a bulk movement of the coil or whether a layer of insulation has been shorted. Periodic tests performed during the service life of the equipment can indicate that the insulation is either aging normally or deteriorating rapidly. Diagnostic tests on suspect or failed equipment may disclose the location of a fault or the reason for failure.

As a principle, insulation systems should not be evaluated in groups or sets; in other words, the test results that contain more than one set of test results should not be evaluated except to verify testing validity. It is possible that a good insulation system can mask poor test results from another insulation system, thus diluting the results.

Dielectric loss is usually determined by a bridge measuring instrument, such as the Schering bridge, tan delta bridge or transformer ratio-arm bridge. Instruments of this type normally have the means for determining the capacitance value as well as the loss factor of the insulation under test.

Along with the bridge, an ac power supply and standard capacitor (or equivalent) are required for measurement of loss factor. Portable test systems that include bridge, power supply, and capacitor in one enclosure are available for field testing. The operator of the test equipment should be completely familiar with the operation of the instruments and all safety procedures before attempting to perform these measurements. To obtain comparable benchmark test results, the instructions of the test device should be followed and the same instrument should be used.

Test voltages for a typical field test set range from below 100 V to as high as 12 kV. Field tests on most electrical equipment, however, are usually performed at rated voltage or a maximum of 10 kV. To provide comparability to factory tests, factory tan delta test results should also be available where the applied test voltage is no greater than 10 kV. Manufacturer’s instruction manuals and appropriate test standards should be consulted for operating procedures. Test voltage should not go beyond the safe withstand voltage for a winding or other apparatus to be energized during test.

It is important to record ambient conditions at the time of testing for reference when comparing test records. The loss factor of insulation can be sensitive to variations in temperature, in which case a correction factor needs to be applied to measured values. This is done to allow comparison of tests performed at different temperatures. The reference temperature used is 20 °C. Correction factors may be available from equipment manufacturers and test equipment manufacturers. Other environmental factors, such as relative humidity and precipitation at the time of testing, should also be recorded for future reference. A very small amount of water vapor on the surface of external insulation could increase the amount of leakage current and appears as increased loss in the test results. This is especially a factor for lower voltage equipment where the bushing creep distance is short. For this reason, testing during periods of high humidity or precipitation should be done with care; otherwise, it makes proper evaluation of the test results very difficult.

Each capacitor (insulation section) in a complex insulation system should be tested separately. Determining the characteristics of the individual components of a complex system is valuable in detecting and locating defective insulation in the system. Direct measurement should be made on each insulation system whenever possible.
The following are the recommended test procedures to be following during tan delta and capacitance testing:

i) The electrical apparatus to be tested shall be isolated.
ii) The apparatus should be visually inspected to identify external damage or unusual conditions.

iii) The appropriate test procedure should be selected that accounts for every winding (a tertiary winding is considered a winding; thus, an autotransformer with a tertiary is considered a twowinding transformer for testing purposes). If a transformer greater than one winding (e.g., autotransformer or reactor) is being tested, test equipment must be used that is capable of performing a grounded specimen test (GST) and an ungrounded specimen test (UST) test circuit. Calculation of individual systems is not acceptable.

iv) The desired measurements should be performed following the operating instructions supplied with the test equipment. The lead connections may have to be changed several times, depending on the complexity of the apparatus and the test equipment.

v) Apparatus nameplate data and all measurements should be recorded.

vi) Do not exceed withstand voltage of the winding or associated apparatus.

vii) If the unit is equipped with an LTC with a bypass resistor, the LTC should be placed off neutral.

viii) Ground test leads should be connected securely (metal to metal) to the grounding cable coming immediately from the transformer under test. If a transformer is not grounded (spare), the transformer must have a temporary ground installed.

ix) The terminals on a winding should be shorted together if possible. If the windings are not shorted together, stray leakage can occur, thus artificially raising the PF of the winding.

The test procedures listed in Table A.5, Table A.6, and Table A.7 indicate which winding should be energized at the prescribed test voltage. Connection for one or two LV leads is also included if testing a multiple winding transformer. Ground test leads are always connected to the ground cable coming immediately from the transformer. Insulation test systems are referred to as windings (C_H, C_L, C_T) and inter-windings tests (C_{HL}, C_{LT}, C_{HT}). Ground, guard, and UST refer to the various tan delta test circuit test lead connections. In some cases, test procedures contain validation checks. Validation checks allow for checking the final test results and determining whether test connections were made correctly. These are mathematical checks to see whether measured and calculated insulation values match (if available). In general, the measured capacitance and calculated validation check values should be within 5% of previous values.

Table A.5 One - Winding Transformer

Test	Energize	Measured	Notes
1	HV	CH	HV winding

Table A.6 Two - Winding Transformer

Test	Energize	Ground	Guard	UST	Measured	Notes
1	HV	LV	—	—	CH + CHL	Validation check
2	HV	—	LV	—	CH	HV winding
3	HV	—	—	LV	CHL	Inter-winding
4	LV	HV	—	—	CL+CHL	Validation check
5	LV	—	HV	—	CL	LV winding
6	LV	—	–	HV	CHL	Inter-winding

Validation check	Calculation	Results
1	Test 1 – Test 2	CHL (calculated)
2	Test 4 – Test 5	CHL (calculated)

Table A.7 Three - Winding Transformer

Test	Energize	Ground	Guard	UST	Measured	Notes
1	HV	LV	TV	—	CH + CHL	Validation check
2	HV	—	LV, TV	—	CH	HV winding
3	HV	—	—	LV	CHL	Inter-winding
4	LV	TV	HV	—	CL + CLT	Validation check
5	LV	—	HV, TV	—	CL	LV winding
6	LV	HV	—	TV	CLT	Inter-winding
7	TV	HV	LV	—	CT + CHT	Validation check
8	TV	—	HV, LV	—	CT	LV winding
9	TV	LV	—	HV	CHT	Inter-winding

Validation check	Calculation	Results
1	Test 1 – Test 2	CHL (calculated)
2	Test 4 – Test 5	CLT (calculated)
3	Test 7 – Test 8	CHT (calculated)

As shown in Table A.8, the normal in-service and new tan delta limit for mineral-oil-filled power transformers < 230 kV is 0.5% at 20 °C, and the normal and new limit for transformers ≥ 230 kV is 0.4%. To help reduce the risk of catastrophic failure, the limit for serviceability of all mineral-oil-filled transformers is 1.0% at 20 °C. Tan delta values between 0.5% and 1.0% at 20 °C require additional testing and investigation to confirm that a problem is not worsening. In some rare cases, selection of lower quality materials used in transformer manufacturing can lead to tan delta measurements greater than those previously mentioned. In these cases, end users need to discuss with manufacturers acceptable tan delta values.

Table A.8 Nominal and serviceability service-aged limit: power transformer insulation tan delta

kV Rating	Nominal/new tan delta limit	Serviceability aged limit
<230 kV	0.5%	1.0%
≥230 kV	0.4%	1.0%

Capacitance can be used to help assess the transformer for mechanical deformation. To properly analyse capacitance, a benchmark result is required. The first capacitance test performed serves as the benchmark. Subsequent tests are always compared to the benchmark results. To help ensure that this evaluation is valid, test conditions need to be consistent. Bushing or buswork changes can change the capacitance of the winding test because they are included in most field test cases. In the field, transformer insulation systems should not change by more than 5% from the benchmark results. If the results are above 5% and below 10% change, an investigation needs to be conducted to determine the extent or severity of the issue. If the capacitance has changed by more the 10%, the transformer should not be returned to service.

f) Capacitance and Tan delta of Bushings

Insulation power factor or dissipation factor (Tan δ) and Capacitance measurement of bushing provide an indication of the quality and soundness of the insulation in the bushing. For getting accurate results of tan delta and capacitance without removing the bushing from the transformer, a suitable test set capable of taking measurement by ungrounded specimen test (UST) method shall be used. Both tan delta and capacitance can be measured using the same set up.

Measurements shall be made at similar conditions as that of a previous measurement. The bushing insulation exhibits fairly constant tan delta over a wide range of operating temperature. Hence, effort is to be made for testing at temperature near to previous test and Correction factor need not be applied. The following precautions/ steps to be taken:

i) Porcelain of the bushings shall be clean and dry before test. Remove any dirt or oil with clean dry cloth.
ii) Test shall not be carried out when there is condensation on the porcelain. Preferably, tests shall not be carried out when the relative humidity is in excess of 75%.
iii) Terminals of the bushings of each winding shall be shorted together using bare braided copper jumper. These jumpers shall not be allowed to sag. Transformer windings not being tested shall be grounded.
iv) Measure and record the ambient temperature and relative humidity for reference. Record OTI and WTI during the measurement.
v) Do not test a bushing (new or spare) while it is in its wood shipping crate, or while it is lying on wood. Wood is not as good an insulator as porcelain and will cause the readings to be inaccurate. Keep the test results as a baseline record to compare with future tests.

Environmental factors like variation in temperature, relative humidity, surrounding charged objects etc. have great influence on measurement of dielectric dissipation factor. Care shall be taken to control the above factors during measurements. Testing during periods of high humidity or precipitation should be avoided; otherwise proper evaluation of test results becomes very difficult. A very small amount of water vapour on the surface of external insulation could increase the amount of leakage current and will appear as increased loss in the test result.

Tan delta limit for service-aged and new bushings and typical tan delta values are listed in Table A.9.

Table A.9 Bushing tan delta limit at 20 °C

Insulation	**Service aged**		**New typical values**
	IEEE C57.19.01	**IEC 60137**	
Oil Impregnated Paper	<0.5%	<0.7%	0.2% to 0.4%
Resin Impregnated Paper	<0.85%	<0.7%	0.3% to 0.4%
Resin Bonded Paper	<2.0%	<1.5%	0.5% to 0.6%

The main capacitance (C1) of the bushing i.e. the capacitance between high voltage terminal and test tap is not affected by the surrounding conditions and the accepted deviation from the values measured at factory tests should be less than 5%. The capacitance between bushing test tap and ground is largely influence by the stray capacitances to ground parts in the transformer and hence large deviation in the measured value shall be accepted when compared with the factory test value.

g) Short Circuit Impedance

The short-circuit impedance, or leakage reactance, of power transformers is often measured in the field to detect physical damage in transformer windings. During the service life of a transformer, a number of overcurrent events can occur. Winding deformation can result from high electro-mechanical stresses imposed by high currents. Transformers can perfectly function in the presence of deformation under normal load conditions. However, the mechanical integrity of such a unit is degraded, making it more likely to lead to an immediate failure during an overcurrent event. Furthermore, the winding damage can occur during transportation and installation. The leakage reactance test is sensitive to winding deformation and, as such, can be used to ascertain the presence of winding distortion and gauge the risk of failure.

Leakage reactance tests should be viewed in context with other tests that are sensitive or symptomatic to winding deformation. These tests are as follows:

– Frequency response analysis
– Low voltage impulse
– Capacitance (as part of tan delta testing)

There are two methods for performing short circuit impedance tests, as follows:

– Three phase equivalent test
– Per-phase test

For new or rebuilt three-phase transformers, the results of an initial three-phase equivalent test are compared with the nameplate value. A set of three per-phase tests is also performed for phase comparison and provides a benchmark for future analysis. For single-phase transformers, per-phase tests are performed and the results are compared with the nameplate values. To properly compare leakage reactance test results, it is essential that all tests be performed on the same DETC and LTC positions as indicated by the nameplate or benchmark results.

The measurement is performed in single phase mode. This test is performed for the combination of two winding. One of the winding is short circuited and voltage is applied to other winding. The voltage and current reading are noted.The test shall be conducted with a variable power supply of 0-280 V, 10 A, precision RMS voltmeter and ammeter. The conductors used for short-circuiting one of the transformer windings should have low impedance (less than 1mΩ or conductor size greater than No. 1 AWG) and short length. The contacts should be clean and tight.

Impedance test of a single-phase transformer

One of the two windings of the transformer (usually the LV winding) is short-circuited with a low impedance conductor, and voltage at rated frequency is applied to the other winding. The energizing voltage is adjusted to circulate current on the order of 0.5% to 1.0% of rated current in the windings or 2 A to 10 A, depending on the rating of the transformer under test.

The *%Z* of the single-phase transformer can be calculated using Equation (4):

$$\%Z \text{ single-phase} = (1/10) \cdot [(E_m/I_m) \cdot kVA_r/(kV_r)^2] \qquad (4)$$

where
E_m= measured test voltage
I_m = measured test current
kVA_r = the rating of the transformer in kilovolt-amperes
kV_r= the rating of the winding being energized in kilovolts

Impedance test of a three-phase, two-winding transformer

A three-phase transformer may be tested for impedance using a single-phase power source regardless of winding connection. The neutral terminals, if any, are not used. The test is made by short-circuiting the three line-leads of the LV windings and applying a single-phase voltage at rated frequency to two terminals of the other winding. Three successive readings are taken on the three pairs of leads, (e.g., H1 and H2, H2 and H3, H3 and H1), with the test current adjusted to the same level for each reading. Then the *%Z* of the three-phase transformer is given by Equation (5):

$$\%Z_{\text{three-phase}} = (1/60) \cdot [(E_{12} + E_{23} + E_{31})/I_m] \cdot [kVA_{3r}/(kV_{1r})^2] \qquad (5)$$

where

E_{12}, E_{23}, E_{31} = measured test voltages

I_m= measured test current

kVA_{3r}= the three-phase rating in kilovolt-amperes

kV_{1r}= the rated line-to-line voltage of the energized windings

For three-phase transformers, the three-phase equivalent test results should be within 3% of nameplate values. Analysis needs to consider the effects of different test setup, instrumentation, or tap changer position.

For three-phase transformers, the per-phase test results should be within 3% of the average value of all three phases. In some rare cases, it is possible that the three-phase equivalent measurement matches nameplate/benchmark results, but the per-phase measurement does not. This could be due to the influence created by the reluctance of the leakage flux path outside the leakage channel, thereby masking the changes in the leakage channel. In these cases, the results of the three-phase equivalent measurement should be used as a benchmark for future comparison. For single-phase transformers, the per-phase test results should be within 3% of the nameplate value.

h) Operational checks and Inspection of OLTC

On-Load Tap Changers (OLTCs) are designed to be operated while the transformer is energized. OLTCs may be located in either the high voltage winding or the low voltage winding, depending on the requirements of the user, the cost effectiveness of the application and tap changer availability. OLTC being a current interrupting device requires periodic inspection and maintenance. The frequency of inspections is based on time in service, range of use and number of operations.

Normally the temperature of the OLTC compartment may be few degrees Celsius less than the main tank. Any temperature approaching or above that of the main tank indicates an internal problem. Prior to opening the OLTC compartment, it should be inspected for external symptoms of potential problems. Such things as integrity of paint, weld leaks, oil seal integrity, pressure relief device and liquid level gauge are all items which should be inspected prior to entering the OLTC.

Following de-energization, close all valves between oil conservator, transformer tank and tap-changer head, then lower the oil level in the diverter switch oil compartment by draining of oil for internal inspection. Upon opening the OLTC compartment, the door gasket should be inspected for signs of deterioration. The compartment floor should be inspected for debris that might indicate abnormal wear and sliding surfaces should be inspected for signs of excessive wear.

The following check points/guide lines for inspection and maintenance should be addressed and the manufacturer's service engineer should be consulted for details of maintenance/overhauling activity to ensure the absence of problems and ensure proper operation in the future:

i) Function of control switches
ii) OLTC stopping on position
iii) Fastener tightness
iv) Signs of moisture such as rusting, oxidation or free standing water and leakages
v) Mechanical clearances as specified by manufacturer's instruction booklet
vi) Operation and condition of tap selector, changeover selector and arcing transfer switches
vii) Drive mechanism operation
viii) Counter operation
ix) Position indicator operation and its co-ordination with mechanism and tap selector positions
x) Limit switch operation
xi) Mechanical block integrity
xii) Proper operation of hand-crank and its interlock switch
xiii) Physical condition of tap selector
xiv) Freedom of movement of external shaft assembly
xv) Extent of arc erosion on stationary and movable arcing contacts
xvi) Inspect barrier board for tracking and cracking
xvii) After filling with oil, manually crank throughout entire range
xviii) Oil BDV and Moisture content (PPM) to be measured and recorded

Finally, the tap selector compartment should be flushed with clean transformer oil and all carbonization which may have been deposited should be removed.Minimum BDV should be 50 kV and moisture content should be less than 20

ANNEX B

OIL TESTS AND THEIR SIGNIFICANCE

A large number of tests can be applied to mineral insulating oils in electrical equipment. The tests discussed below are considered sufficient to determine whether the condition of the oil is adequate for continued operation and to suggest the type of corrective action required, where applicable.

B-1Colour and appearance

The colour of an insulating oil is determined in transmitted light and is expressed by a numerical value based on comparison with a series of colour standards. It is not a critical property, but it may be useful for comparative evaluation. A rapidly increasing or a high colour number may be an indication of oil degradation or contamination.
Besides colour, the appearance of oil may show cloudiness or sediment, which may indicate the presence of free water, insoluble sludge, carbon particles, fibres, dust, or other contaminants.

B-2 Breakdown voltage

Breakdown voltage is a measure of the ability of oil to withstand electric stress and has primary importance for the safe operation of electrical equipment. It is strongly dependent on the sampling temperature.
Dry and clean oil exhibits an inherently high breakdown voltage. Free water and solid particles, the latter particularly in combination with high levels of dissolved water, tend to migrate to regions of high electric stress and reduce breakdown voltage dramatically. The measurement of breakdown voltage, therefore, serves primarily to indicate the presence of contaminants such as water or particles. A low value of breakdown voltage can indicate that one or more of these are present. However, a high breakdown voltage does not necessarily indicate the absence of all contaminants.
The values of breakdown voltage are only significant when the oil has been sampled at the operating temperature of the transformer. Samples taken at <20 °C may give an optimistic view of the state of the transformer when analyzed at room temperature. The breakdown voltage of spare units that have been long out of service and are again energized should be monitored more often until the transformer has reached a steady state.

B-3 Water content

Depending on the amount of water, the temperature of the insulating system and the status of the oil, the water content of insulating oils influences:

a) the breakdown voltage of the oil,
b) the solid insulation,
c) the ageing tendency of the liquid and solid insulation.

The water content in the liquid and solid insulation thus has a significant impact on the actualoperating conditions and the lifetime of the transformer.There are two main sources of water increase in transformer insulation:

a) ingress of moisture from the atmosphere;
b) degradation of insulation.

Water is transferred in oil filled electrical equipment by the insulating liquid. Water is present in oil in a dissolved form and may also be present as a hydrate adsorbed by polar ageing products (bonded water). Particles, such as cellulose fibres may bind some water.

B-4 Acidity

The acidity (neutralization value) of oil is a measure of the acidic constituents or contaminants in the oil. The acidity of a used oil is due to the formation of acidic oxidation products. Acids and other oxidation products will, in conjunction with water and solid contaminants, affect the dielectric and other properties of the oil. Acids have an impact on the degradation of cellulosic materials and may also be responsible for the corrosion of metal parts in a transformer.

The rate of increase of acidity of oil in service is a good indicator of the ageing rate. The acidity level is used as a general guide for determining when the oil should be replaced or reclaimed.Generally, inhibited oil should show no significant increase in acidity from its original value provided that the inhibitor is present in sufficient amount.

B-5Dielectric dissipation factor (DDF) and resistivity

These parameters are very sensitive to the presence of soluble polar contaminants, ageing products or colloids in the oil. Changes in the levels of the contaminants can be monitored bymeasurement of these parameters even when contamination is so slight as to be near the limit of chemical detection.

Acceptable limits for these parameters depend largely upon the type of equipment. However,high values of DDF, or low values of resistivity, may deleteriously affect the dielectric lossesand/or the insulation resistance of the electrical equipment.

There is generally a relationship between DDF and resistivity, with resistivity decreasing as DDF increases. It is normally not necessary to conduct both tests on the same oil and generally DDF is found to be the more common test. Resistivity and DDF are temperature and moisture dependent.
The measurement of resistivity is also considered to be of value for monitoring oils in service, as it has been shown to be reasonably proportional to oxidation acids and to be affected by undesirable contaminants such as metal salts and water. Other compounds present in used oils, which can affect resistivity, include aldehydes, ketones and alcohols. An increase in temperature reduces the resistivity, as does water when precipitated at low temperature due to the saturation point being reached.

B-6 Sediment and sludge

This test distinguishes between sediment and sludge.

Sediment is insoluble material present in the oil.

Sediment includes:

a) insoluble oxidation or degradation products of solid or liquid insulating materials;
b) solid products arising from the conditions of service of the equipment; carbon and metalparticles, metallic oxides and sulfides;
c) fibres and other foreign matter of diverse origins.

Sludge is a polymerized degradation product of solid and liquid insulating material. Sludge issoluble in oil up to a certain limit, depending on the oil solubility characteristics and temperature. At sludge contents above this, the sludge is precipitated, contributing as an additional component to the sediment.

The presence of sediment and/or sludge may change the electrical properties of the oil, and in addition, deposits may hinder heat-exchange, thus encouraging thermal degradation of the insulating materials.

B-7Interfacial tension (IFT)

The interfacial tension between oil and water provides a means of detecting soluble polar contaminants and products of degradation. This characteristic changes fairly rapidly during the initial stages of ageing but levels off when deterioration is still moderate.

The rate of decrease of IFT is strongly influenced by the type of oil; uninhibited oils usually show higher IFT rates of decrease than inhibited oils.

A rapid decrease of IFT may also be an indication of compatibility problems between the oil and some transformer materials (varnishes, gaskets), or of an accidental contamination when filling with oil.

With overloaded transformers, the deterioration of materials is rapid and IFT is a tool for detection of deterioration.

B-8Particle count

Particles in insulating oil in electrical equipment may have numerous possible sources. The equipment itself may contain particles from manufacturing and the oil may contain particles from storage and handling if not properly filtered. Metal wear and the ageing of oil and solid materials may produce particles during the service life of equipment. Localized overheating over 500°C may form carbon particles. The carbon particles produced in the on-load tapchanger diverter switch may migrate by leakage into the bulk oil compartment to contaminate the oil-immersed parts of the transformer. A typical source of metallic particles is wear of bearings of the pumps.
The effect of suspended particles on the dielectric strength of insulating oil depends on the type of particles (metallic, fibres, sludge, etc.) and on their water content.

Historically, some failures on HV transformers have been associated with particle contamination. Traditional dielectric breakdown voltage tests are not sufficient to identify the problem and particle counting methods have been advised as monitoring tools.

B-9Flash point

Breakdown of the oil caused by electrical discharges or prolonged exposure to very high temperatures may produce sufficient quantities of low molecular weight hydrocarbons to cause a lowering of the flash point of the oil.

A low flash point is an indication of the presence of volatile combustible products in the oil. This may result from contamination by a solvent but, in some cases, the cause has been observed to be extensive sparking discharges.

B-10Polychlorinated biphenyls (PCBs)

Polychlorinated biphenyls (PCBs) are a family of synthetic chlorinated aromatic hydrocarbons, which have good thermal and electrical properties. These properties combined with excellent chemical stability made them useful in numerous commercial applications. However, their chemical stability and resistance to biodegradation has given cause for concern in terms of environmental pollution. This increasing concern over the environmental impact of PCBs has progressively restricted their use since the early 1970s and their use in new plant and equipment was banned by international agreement in 1986. Unfortunately, the use of common handling facilities has led to widespread contamination of mineral insulating oil.

The PCB content of oil in new equipment should be measured to confirm that the oil is PCB free. Thereafter, whenever there is a risk of potential contamination (oil treatment, transformer repairs, etc.) the oil should be analyzed and if PCB content is found to exceed defined limits appropriate action should be taken.

B-11 Corrosive sulphur

The amount of sulphur in oil depends on oil refining processes, degree of refining and crude oil type; it is normally present as organo-sulphur, but elemental sulphur contamination can also occur. The presence of reactive compounds causing corrosion at normal operating temperatures is due to poor refining or contamination.

At relatively high temperatures, sulphur-containing oil molecules may decompose and react with metal surfaces to form metal sulphides. Such reactions may take place in switching equipment and will impact the conductivity of contacts.

Some sulphur containing molecules may also cause the formation of copper sulphide (Cu2S) deposition in the paper insulation of electrical equipment. This phenomenon leads to a reduction of the electrical insulation properties and has resulted in several equipment failures in service.

Cu2S deposition occurs preferentially in paper insulated electrical equipment where corrosive sulphur compounds are present in oil, unvarnished or unprotected copper is used, operating or/and ambient temperatures are high and the amount of oxygen in oil is limited.

B-12Dibenzyldisulphide (DBDS)

DBDS is potentially corrosive to copper surfaces at normal transformer operating temperatures and may form copper sulphide under certain conditions.

Among corrosive sulphur compounds DBDS appears to play a predominant role in the problem of corrosion.

B-13Passivator

The addition of a metal passivator is the mitigation technique that has been used to the largest extent in order to minimize the risk of corrosive sulphur.

B-14Evaluation of oil in service

Oil quality of the in service oil may be evaluated as per the Table 5- Application and interpretation of tests of dual standard IS 1866 : 2017/IEC 60442: 2013.

ANNEX C

DGA AT LABORATORIES

DGA is one of the most widely used diagnostic tools for transformer condition assessment because experience has proven it to be an effective tool.

The fundamental purpose of DGA is to discriminate between normal and abnormal conditions. More specifically, DGA aims to provide a reliable and economical method of detecting faults, which may present unacceptable possibility of damage or near-term failure. In transformers, a fault is revealed by the production of new gases.

Oil and oil-immersed electrical insulating materials decompose under the influence of thermal and electrical stresses and generate gaseous decomposition products of varying composition which dissolve in the oil. The nature, amount and rate of generation of the individual component gases that are detected are indicative of the type and degree of the abnormality responsible for the gas generation.Transformer mineral oils are mixtures of many different hydrocarbon molecules, and the decomposition processes for these hydrocarbons in thermal or electrical faults are complex. The fundamental steps of gas generation are the breaking of carbon-hydrogen and carbon-carbon bonds. Active hydrogen atoms and hydrocarbon fragments are formed. These free radicals can combine with each other to form gases, molecular hydrogen, methane, ethane, etc., or can recombine to form new, condensable molecules. Further decomposition and rearrangement processes lead to the formation of products such as ethylene and acetylene and, in the extreme, to modestly hydrogenated carbon in particulate form. These processes are dependent on the presence of individual hydrocarbons, on the distribution of energy and temperature in the neighbourhood of the fault, and on the time during which the mineral oil is thermally or electrically stressed.

The quantity of hydrogen formed can be relatively high and can be insensitive to temperature for some fault types, such as some stray gassing, partial discharges (PD) and catalytic faults. Formation of acetylene becomes appreciable only at temperatures nearing 1000 °C. Formations of methane, ethane, and ethylene also each have unique dependences on temperature. See Figure C.1.
The thermal decomposition of mineral oil-impregnated cellulose insulation produces carbon oxides and some hydrogen or methane from the mineral oil. The rate at which they are produced depends exponentially on the temperature and directly on the volume of material at that temperature.

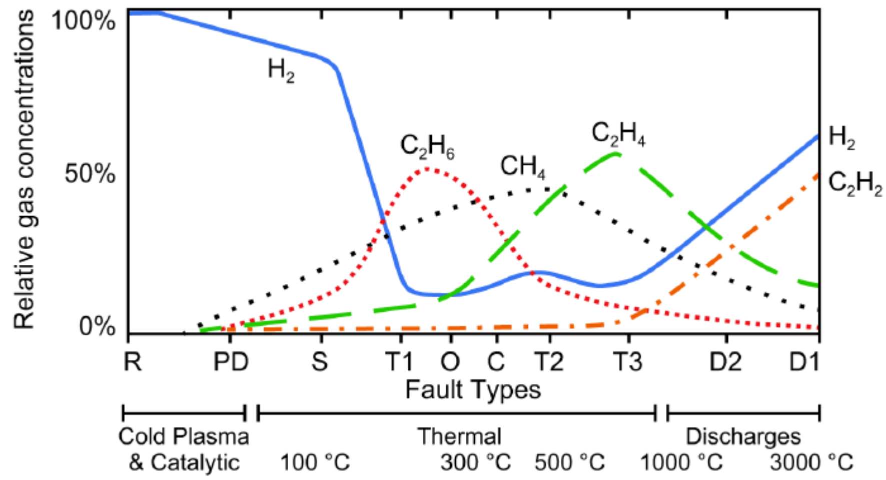


Figure C.1 Relative percentage of dissolved gas concentrations in mineral oil as a function of temperature and fault type

The transformer undergoes electrical, chemical and thermal stresses during its service life which may result in slow evolving incipient faults inside the transformer. Dissolved gas analysis (DGA) is the identification, measurement, and interpretation of the gases dissolved in the insulating liquid. The principal gases used in identification of faults (so-called "fault gases") are hydrogen (H2); methane (CH4); ethane (C2H6); ethylene (C2H4); acetylene (C2H2); carbon monoxide (CO); and carbon dioxide (CO2). Oxygen (O2) and nitrogen (N2) are also measured and used in the interpretation, although they are not fault by-products.

The gases containing both of the elements carbon (C) and hydrogen (H2) are called hydrocarbons, and the gases CO and CO2 are called carbon oxides. Hydrogen, the hydrocarbon gases, and carbon monoxide are combustible gases, while oxygen, nitrogen, and carbon dioxide are non-combustible gases. Other gases that may be dissolved in the insulating liquid, such as argon (Ar) and higher molecular weight hydrocarbon gases, are ordinarily ignored for transformer DGA.

The purpose of DGA is to detect the internal faults with in the oil-filled electrical equipment at an early stage and also to find incipient faults such as Arcing, Partial Discharge, low energy sparking, severe overloading, and overheating in the insulation system. The data obtained from this test is analyzed by DGA Interpretation guides such as IEEE.C57.104 and IEC-60599. Analysis and interpretation of the test results may give the type, severity and sometimes location of the fault.

Interpretation of DGA results

IEEE.C57.104 Guidelines
DGA data interpretation

The interpretation of DGA data begins with the detection of an abnormal condition. When found, it should be followed by severity assessment and fault identification. The fault detection and severity assessment part of DGA consists of comparing the gas levels and rates of change, to their respective norms and assigning a status condition according to which norms (if any) were exceeded. When there is an indication of a problem, a fault identification or diagnosis should be obtained by a reliable technique, such as the Duval Triangles and other methods. Graphical visualizations of the data in various ways often provides insights into fault identification, evolution, and severity. Other relevant information, such as maintenance activity records, electrical diagnostic test results, lightning strike occurrences, load history, etc., should be consulted to seek a better understanding of what may be causing the gassing activity, and to confirm or modify the DGA condition assessment.

C-1 Context of DGA data interpretation

From an operational point of view, it is important to establish the following priorities:

a) **Detection**: Detect the generation of any gases that exceed "normal" quantities and utilize appropriate guidelines, so the possible abnormality may be recognized at the earliest possible time to minimize damage or avoid a failure. If this analysis concludes that a fault exists, then proceed with evaluation.

b) **Evaluation**: Evaluate the impact of an abnormality on the serviceability of the transformer, using a set of guidelines or recommendations. Expert opinion, operator experience, and unit specific conditions should be part of the evaluation.

c) **Action**: Take the recommended action, beginning with increased surveillance and confirming or supplementary analysis. For example, if a thermal fault is suspected, which may be load sensitive, load reduction (if possible) may help with the diagnosis. If it is not possible, then alternatives, as drastic as removal of the unit from service, may need to be considered.

It is useful to look at graphs of gas levels over time for quick visual detection of suspicious changes, parallel long-term upward rates, or inconsistencies. Whenever a fault is suspected, past and present data should be analyzed and plotted, using one of the methods, such as the Duval Triangles and other methods.

The recommended action and resampling interval can be based on the fault diagnosis and the verified DGA status, plus the use of expert judgment. Because of the potentially serious consequences and high cost of misinterpreting transformer test data, an inflexible interpretation, based on an exclusively mechanical scoring approach, without the application of expert judgment, is highly inadvisable.

It is helpful to define DGA status levels to establish sampling intervals and maintenance activities on operational transformers.

a) **DGA Status 1:** Screening DGA results are acceptable. Continue routine operation

b) **DGA Status 2:** Incipient or modest recent gas production or moderately elevated gas level.

   i) Resample for confirmation and monitor possible gas evolution.

c) **DGA Status 3:** High gas levels or continuing significant gas production. Mitigative actions or other responses should be considered (i.e, continuous monitoring).

C-2 Initial verification test protocol

When a new transformer is added to a DGA program, or when DGA sampling is resumed for a transformer after several years without sampling, an initial verification is recommended. This is also applicable when there is no prior DGA history for the transformer, or when insulating liquid processing, repairs, or other factors "reset" the transformer's DGA history. In such cases, there may not be any prior DGA data providing a basis for calculating combustible gas increments or rates of change.
It is suggested to take a sample before and during commissioning procedures and several more samples over a short period of time (a few weeks to a few months) following energization to establish a DGA baseline and ensure that no abnormal gassing is taking place.
For new and repaired transformers, if any of the combustible gas concentrations are above their respective detection limits without a reasonable explanation (such as residual gas from an earlier fault diffusing into the insulating liquid from the paper insulation in a repaired transformer), it may be prudent to schedule another sample to be taken immediately to check for active gas production. A diagnostic method may be applied to see what the initial sample's pattern of gas concentrations matches, but the diagnosis cannot be considered unless a second sample confirms active fault gas production in a pattern that confirms the diagnosis.

The usual outcome of an initial verification test program would be either the assignment of DGA Status 1 with a recommendation to carry on with DGA periodic screening test protocol per company DGA policy, or the assignment of DGA Status 2 with a recommendation to sample more frequently to check for evidence of change and to discuss the test results with the manufacturer. If a resample confirms an elevated level of gases, contact the manufacturer to review the situation and evaluate the follow-up action.

C-3 Periodic screening test protocol

Most DGA results fall into this category.
The method of interpreting screening DGA data is explained in C.6 and in the Figure C.2 flowchart. If, the DGA status is 1, and there are no apparent reasons for concern, no fault

interpretation is necessary, and no special action is needed. The interpretation of the DGA data is complete and the next sample should be taken according to the DGA screening test protocol.

If analysis of a test result produces a DGA status of 2, or if any unusual shift in gas pattern suggests an anomaly, a fault diagnosis should be obtained using a reliable method.

If the fault diagnosis reveals an issue of a low temperature fault (T1), or stray gassing (S), this would be treated as a less urgent issue, however a low temperature fault (T1) may affect the future life of the insulation system.

If there is an indication of high-energy arcing (D2) or a high-temperature thermal fault (T3), or if paper insulation appears to be involved in the fault, another analysis step may be prudent. Some users will consider extra steps with increased surveillance, as recommended for a unit with a DGA status of 3.

If a DGA status of 3 is obtained, then a fault diagnostic and a DGA surveillance test protocol are warranted.

C-4 Surveillance test protocol

The purpose of the DGA surveillance test protocol is usually either:

a) To confirm the absence of suspicious gas activity
b) To characterize and diagnose suspicious gas formation
c) To provide early warning of dangerous changes or a fault reaching the pre-failure runaway stage

Gas history charts, a stacked chart showing all individual combustible gases, and the Duval Triangles with multiple samples are the most useful graphical tools for surveillance and monitoring.

A short-term rate of increase should be compared with their respective norms to obtain an updated status code. This may be increased if there is evidence of accelerating combustible gas formation. If there is evidence of a fault, a Duval Triangle or pentagon, with all surveillance data plotted on it, can be used to diagnose the fault and to watch for consistency or evolution of the fault type. For example, it could help to see if a thermal fault evolves toward a higher temperature fault.

If the results of a surveillance test indicate a serious or deteriorating situation, it will lead to a Status 3 evaluation. That should lead to consideration of starting a continuous monitoring test protocol.

It may be prudent at this point, that the user consult experts and the transformer manufacturer, as no two transformers are the same. What could be perfectly normal for a given transformer, could be a sign of a dangerous condition in another transformer. In such context, experience from experts is an invaluable tool.

C-5 Continuous monitoring test protocol

The continuous monitoring test protocol should be used when there is a clear indication that the transformer is not operating normally and is generating gas in a significant manner. This protocol should be considered for units with a DGA Status 3, although this should not be automatic. It should be implemented only after a complete review of the DGA results, together with all other available information. Monitoring may be started temporarily until further investigation is completed; or permanently, if the situation is deemed sufficiently serious to warrant it.
In continuous monitoring, the transformer is subjected to frequent sampling and tested at very short, time intervals (e.g., daily or several times per day) for accurate characterization of normal or abnormal gas formation, and very early warning of severely abnormal gas formation. This protocol may lead to the temporary or permanent installation of a suitable on-line monitoring device on the transformer.
The high sampling rate of on-line monitors permits early detection of abnormalities and accurate characterization of rates. Multiple readings may be combined using statistical methods to arrive at improved estimates of the dissolved gas concentrations, and to average over short-term cyclic gassing behavior. Because of the high volume of data generated by on-line monitoring, graphical visualization is essential. Time series graphs with rate values are useful in detection of the onset of increased gassing activity. The technique of plotting DGA results on a Duval Triangle or pentagon is useful in detecting changes in the nature of the fault. Also, since rates are obtained in real time over a short period, care should be taken to account for the intrinsic fluctuations of the DGA levels generated by the monitoring process. Gassing rates should be calculated using statistical methods and using trailing data spanning over a long enough time duration to control the likelihood of nuisance gas rate alarms.
In a continuous monitoring test protocol, the various norms used in screening DGA interpretations no longer apply, especially in regard to rates of gas generation. For on-line monitoring, it is not uncommon to use higher rate values than the ones used for laboratory DGA. Each situation is unique.

C-6 Suggested interpretation procedures for DGA results

This guide classifies DGA results into 3 groups, “DGA Status 1,” “DGA Status 2,” and “DGA Status 3,” using three tables of norms, as follows:

a) DGA Status 1: Low gas levels and no indication of gassing. (Unexceptional DGA)
b) DGA Status 2: Intermediate gas levels and/or possible gassing. (Possibly suspicious DGA)
c) DGA Status 3: High gas levels and/or probable active gassing. (Probably suspicious DGA)

Table C.1 and Table C.2 define low (below Table C.1), intermediate (between Table C.1 and Table C.2), and high (above Table C.2) gas levels. Table C.3 defines possible gassing. Table C.4 defines probable active gassing.

Figure C.2 is a flow chart that provides a suggested process to review the DGA results.

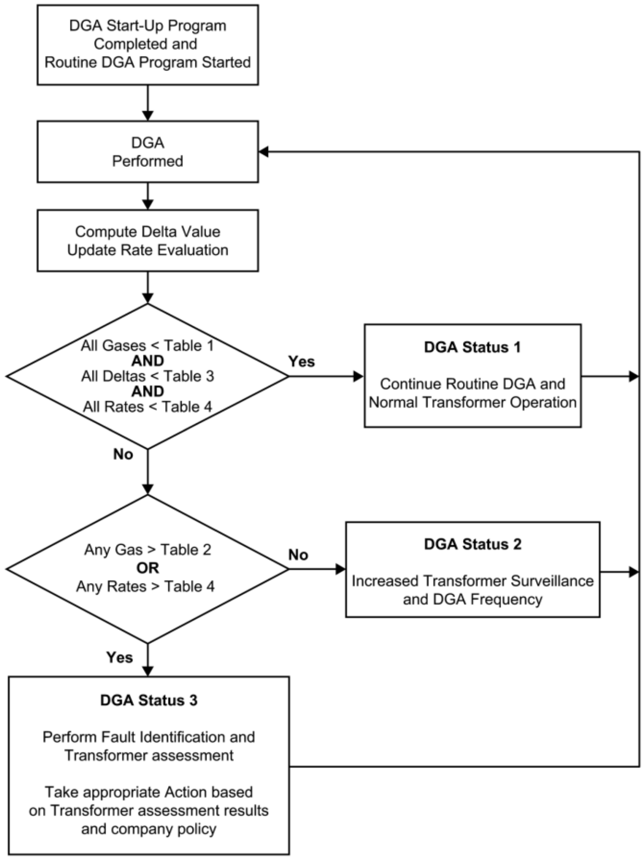


Figure C.2 Flow Chart for Interpreting DGA

Table C.1 is based on the 90th percentile of the population of DGA results (gas levels).
Table C.2 is based on the 95th percentile of the population of DGA results (gas levels).
Table C.3 is based on the 95th percentile of deltas between two consecutive laboratory DGA results [Δ µL/L, (Δ ppm)], without any adjustment due to time (no normalization per year). This is dominated principally by DGA result fluctuations caused by the analysis process itself. Table C.3 is used to decide when a difference between the latest DGA result and the previous one is above the normal DGA fluctuations and might indicate a gas increase. In such cases, a confirmation sample is suggested.

Table C.4 is based on 95th percentile of rate computed with multi-point (3 to 6) linear regression [µL/L/year (ppm/year)]. As the number of points increase, fluctuations caused by the laboratory DGA analysis process cancel each other (average out), and this table is dominated principally by transformer gas evolution. Table C.4 is used to decide when a sequence of DGA results indicates probable active gassing.
The following procedure explains the Figure 2 flowchart and refers to Table C.1 through Table C.4.
Step 1: After completion of a start-up DGA program, periodic DGA are performed as per company routine policy.

Step 2: Compute the O2/N2 ratio. Compute the absolute variation [delta µL/L (ppm)] for each gas from the previous routine sample. Update multipoint rate values using the last 3 to 6 data points over the last 4 to 24 months period, if available. If more than 6 data points are available, use the six most recent data points, not exceeding two years, to compute the rates.

NOTE—Rates will not be available if the transformer is sampled only once per year.

Step 3: If age is known, compare all gas values to the applicable column of Table 1, according to the O2/N2 ratio and age. If age is unknown, use the values in the column “Unknown” (under “Transformer age year header) of the applicable table. If the O2/N2 ratio is not available, the O2/N2 ratio >0.2 section should be used.

NOTE—When the O2/N2 ratio is near 0.2, it could happen that successive DGA test results change back and forth between <0.2 and >0.2 due to intrinsic DGA variability. In such cases it is recommended to use the >0.2 section.

Step 4: If all gas levels are below the applicable values in Table C.1, compare the delta values to the applicable sections of Table C.3. Compare rate values to the applicable sections of Table C.4, if available.

Step 4a: If all gas delta values are below the applicable section of Table C.3, and all rates values are below the applicable section of Table C.4 (if available), then a DGA status of 1 is indicated. Continue routine sampling as per company policy.

Step 4b: If any delta is greater than the value in the applicable sections of Table C.3, or any calculated generation rate is greater than the applicable sections of Table C.4, perform a confirmation DGA within a month and then perform Step 4c.

Step 4c: Compute the absolute variation (delta) between the reference sample (the one used as reference in Step 4b) and the confirmation sample. Compute rates with the confirmation sample replacing the previous value.

Step 4d: If the confirmation sample does not indicate an increase from the previous sample (i.e., all gas variations delta are below the applicable section of Table C.3 and all rates below the applicable section of Table C.4 norms), and all gas level values are also still below the applicable section of Table C.1, DGA status is 1. Continue routine sampling per the company policy or manufacturer requirements.

Step 4e: If the second sample confirms an increase (Delta) has occurred but all gas level values are below the applicable section of Table C.1 and all multi-point rates are below the applicable section of Table C.4 values, then a DGA status of 2 is indicated.
Step 5: If any one gas level is between the values in the applicable sections of Table C.1 and Table C.2 with no gas levels above the applicable sections of Table C.2, and all multi-point rates are below the applicable section of Table C.4, then a DGA status of 2 is indicated.

If only 1 sample per year is taken, there will not be enough samples to calculate the multipoint gas generation rates for comparison to Table 4, so only Table 3 would be used in such cases. If Table C.3 values are exceeded, a confirmation sample is required, which will allow the computation of the rates (e.g., 3 samples in 2 years).

Step 6: If any one gas level is above the applicable section of Table C.2, or if any rate is above the applicable section of Table C.4, a DGA status of 3 is indicated.

Step 7: For DGA in status 3, gas evolution should be monitored for a significant period of time. If during that period of time there is no significant positive rate observed, then a lower DGA status could be considered, after consultation with a DGA expert.

Step 8: For extremely high concentrations, deltas, or rates, consult a DGA expert.

Table C.1 **90th percentile gas concentrations as a function of O_2/N_2 ratio and age in µL/L (ppm)**

		O_2/N_2 Ratio ≤ 0.2				O_2/N_2 Ratio > 0.2			
		Transformer Age in Years				Transformer Age in Years			
		Unknown	1 – 9	10 – 30	>30	Unknown	1 – 9	10 – 30	>30
Gas	Hydrogen (H_2)	80	75		100	40	40		
	Methane (CH_4)	90	45	90	110	20	20		
	Ethane (C_2H_6)	90	30	90	150	15	15		
	Ethylene (C_2H_4)	50	20	50	90	50	25	60	
	Acetylene (C_2H_2)	1	1			2	2		
	Carbon monoxide (CO)	900	900			500	500		
	Carbon dioxide (CO_2)	9000	5000	10000		5000	3500	5500	

Table C.2 95th percentile gas concentrations as a function of O2/N2 and age in µL/L (ppm)

		O_2/N_2 Ratio ≤ 0.2				O_2/N_2 Ratio > 0.2			
		Transformer Age in Years				Transformer Age in Years			
		Unknown	1 – 9	10 – 30	>30	Unknown	1 – 9	10 – 30	>30
Gas	Hydrogen (H_2)	200	200			90	90		
	Methane (CH_4)	150	100	150	200	50	60		30
	Ethane (C_2H_6)	175	70	175	250	40	30	40	
	Ethylene (C_2H_4)	100	40	95	175	100	80	125	
	Acetylene (C_2H_2)	2	2		4	7	7		
	Carbon monoxide (CO)	1100	1100			600	600		
	Carbon dioxide (CO_2)	12500	7000	14000		7000	5000	8000	

Table C.3 95th percentile values for absolute level change between successive laboratory DGA samples in µL/L (ppm)

		Maximum µL/L (ppm) variation between consecutive laboratory DGA samples	
		O_2/N_2 Ratio ≤ 0.2	O_2/N_2 Ratio > 0.2
Gas	Hydrogen (H_2)	40	25
	Methane (CH_4)	30	10
	Ethane (C_2H_6)	25	7
	Ethylene (C_2H_4)	20	
	Acetylene (C_2H_2)	Any Increase	
	Carbon monoxide (CO)	250	175
	Carbon dioxide (CO_2)	2500	1750

Table C.495th percentile values from multi-points (3-6 points) rate analysis of laboratory DGA samples with all gas levels below Table 1 values, in µL/L/year (ppm/year)

		Maximum µL/L/year (ppm/year) rate in function of the period between first and last point of the laboratory DGA series (3 to 6 samples)			
		O_2/N_2 Ratio ≤ 0.2		O_2/N_2 Ratio > 0.2	
		Period between first and last point of the series			
		4-9 Months	10-24 Months	4-9 Months	10-24 Months
Gas	Hydrogen (H_2)	50	20	25	10
	Methane (CH_4)	15	10	4	3
	Ethane (C_2H_6)	15	9	3	2
	Ethylene (C_2H_4)	10	7	7	5
	Acetylene (C_2H_2)	Any increasing rate		Any increasing rate	
	Carbon monoxide (CO)	200	100	100	80
	Carbon dioxide (CO_2)	1750	1000	1000	800

C-7 Fault type identification from DGA results

All fault identification methods (Rogers Ratios, Doernenburg Ratios, Key gas, Duval Triangles 1-4-5 and Pentagons 1-2) can be used only if µL/L (ppm v/v) values are reliable and accurate enough.

Hydrogen (H2) is created primarily from corona partial discharge and stray gassing of oil, also from sparking discharges and arcs, although C2H2 is a much better indicator in such cases. It can also be caused by chemical reaction with galvanized steel.

Methane (CH4), Ethane (C2H6), and Ethylene (C2H4) are created from heating of oil or paper.

Acetylene (C2H2) is created from arcing in oil or paper at very high temperatures above 1000 °C. Transformers without internal fuses, switches or other arcing devices that may have operated should not create any C2H2 under normal operating conditions. It is not uncommon to find increased levels of H2 or C2H4 when C2H2 is detected.

The ranges of temperatures where these gases are mostly produced in oil can be seen in Figure C.1. It can also be seen in Figure C.1, that mixtures of these gases are always formed at any temperature. By looking at their relative proportions in oil, it is possible to identify the faults that have produced them, using one of the methods (Rogers Ratios, Doernenburg Ratios, Key gas, Duval Triangles 1-4-5 and Pentagons 1-2).

Carbon Monoxide (CO) and Carbon Dioxide (CO2) are created from heating of cellulose or insulating liquid.

C-8 Key Gas method

The Key Gas method is summarized in Table C.5:

Table C.5—Key Gas method

Key Gas	Fault type	Typical proportions of generated combustible gases
Ethylene (C_2H_4)	Thermal mineral oil	Predominantly Ethylene with smaller proportions of Ethane, Methane, and Hydrogen. Traces of Acetylene at very high fault temperatures.
Carbon-Monoxide (CO)	Thermal mineral oil and cellulose	Predominantly Carbon Monoxide with much smaller quantities of Hydrocarbon Gases Predominantly Ethylene with smaller proportions of Ethane, Methane, and Hydrogen
Hydrogen (H_2)	Electrical low energy partial discharge (PD)	Predominantly Hydrogen with small quantities of Methane and traces of Ethylene and Ethane.
Hydrogen and Acetylene (H_2, C_2H_2)	Electrical high energy (arcing)	Predominantly Hydrogen and Acetylene with minor traces of Methane, Ethylene and Ethane. Also, Carbon Monoxide if cellulose is involved.

When the main gas formed in DGA results is one of the four key gases in column 1, together with the secondary gases in column 3, the type of fault is provided in column 2.

The limitation of the Key Gas method is that it results in many inconclusive or wrong fault identifications (typically 50%) when applied automatically with software. This is because often it is not clear which is the main gas formed, also because the main gas formed may not be one of those used in the Key Gas method. Furthermore, CO is not always a good indicator of a fault in paper.

When applied manually by experienced DGA users, the number of wrong fault identifications with the Key Gas method is lower (typically 30%) but still high.

C-9 Rogers Ratios Method

The Rogers Ratios Method is summarized in Table C.6. It uses three gas ratios indicating five different types (cases) of faults, depending on the values of the ratios in column 2 through column 4 of Table C.6.

Table C.6Rogers Ratios Method

Case	C_2H_2/C_2H_4	CH_4/H_2	C_2H_4/C_2H_6	Suggested fault diagnosis
0	< 0.1	0.1 to 1.0	< 1.0	Unit normal
1	< 0.1	< 0.1	< 1.0	Low-energy density arcing—PD[a]
2	0.1 to 3.0	0.1 to 1.0	> 3.0	Arcing—High-energy discharge
3	< 0.1	0.1 to 1.0	1.0 to 3.0	Low temperature thermal
4	< 0.1	> 1.0	1.0 to 3.0	Thermal < 700 °C
5	< 0.1	> 1.0	> 3.0	Thermal > 700 °C

[a] There is a tendency for the ratios C_2H_2/C_2H_4 and C_2H_4/C_2H_6 to increase to a ratio above 3 as the discharge develops in intensity.

The limitation of the Rogers Ratios Method is that it cannot identify faults in a relatively large number of DGA results (typically 35%), because they do not correspond to any of the cases in column 1 of Table 5, even when μL/L (ppm) values are high and there is obviously a fault.

C-10 Doernenburg Ratios method

The Doernenburg Ratios method is illustrated in Table C.7:

Table C.7Doernenburg Ratios method

Suggested fault diagnosis	Ratio 1 (R1) CH_4/H_2 Extracted from mineral oil | gas space		Ratio 2 (R2) C_2H_2/C_2H_4 Extracted from mineral oil | gas space		Ratio 3 (R3) C_2H_2/CH_4 Extracted from mineral oil | gas space		Ratio 4 (R4) C_2H_6/C_2H_2 Extracted from mineral oil |gas space	
1 – Thermal decomposition	> 1.0	> 0.1	< 0.75	< 1.0	< 0.3	< 0.1	> 0.4	> 0.2
2 – Corona (low intensity PD)	< 0.1	< 0.01	Not significant		< 0.3	< 0.1	> 0.4	> 0.2
3 – Arcing (high intensity PD)	> 0.1 < 1.0	> 0.01 < 0.1	> 0.75	> 1.0	> 0.3	> 0.1	< 0.4	< 0.2

It is a historic method less used today. It has the same limitation as the Rogers Ratios method.

C-11 Duval Triangles 1, 4 and 5 methods

The Duval Triangle 1 Method is illustrated in Figure C.3:

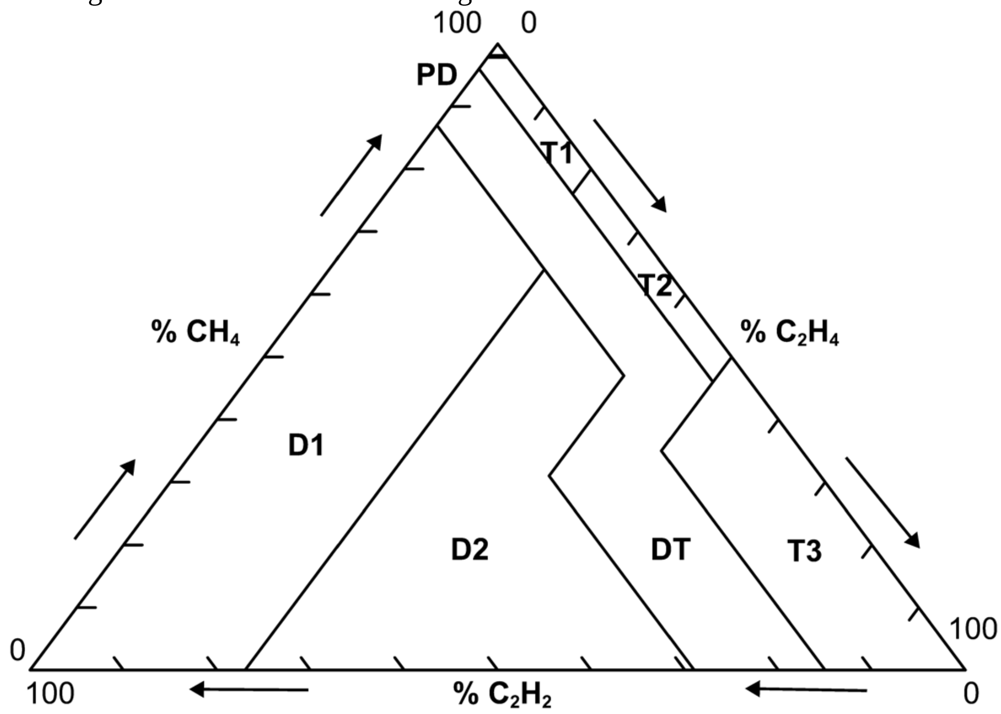


Figure C.3 DUVAL TRIANGLE 1

The Duval Triangle 1 Method uses three gases corresponding to the increasing energy content or temperature of faults: methane (CH4) for low energy/ temperature faults, ethylene (C2H4) for high temperature faults, and acetylene (C2H2) for very high temperature/energy/arcing faults. On each side of the triangle are plotted the relative percentages of these three gases.

This method allows identification of the six basic types of faults (PD, D1, D2, T1, T2 and T3) plus mixtures of electrical/ thermal faults in zone DT. Table C.8 gives the numerical values for fault zone boundaries of Duval Triangle 1 Method expressed in (%CH4), (%C2H4), and (%C2H2).

Table C.8Fault zone boundaries for Figure C.3

Gas% / Fault	% CH_4	% C_2H_4	% C_2H_2
PD	≥ 98	—	—
T1	< 98	< 20	< 4
T2	—	≥ 20 and < 50	< 4
T3	—	≥ 50	< 15
DT	—	< 50	≥ 4 and < 13
	—	≥ 40 and < 50	≥ 13 and < 29
	—	≥ 50	≥ 15 and < 29
D1	—	< 23	≥ 13
D2	—	≥ 23	≥ 29
	—	≥ 23 and < 40	≥ 13 and < 29

The advantages of the Duval Triangle 1 Method are that it always proposes a fault identification (it is a “closed” system as compared to 2-gas ratios methods), with few erroneous diagnosis (it is based on a large number of inspected cases of faulty transformers in service), and it allows the ability to visually and rapidly follow the evolution of faults with respect to time in a transformer. Conversely, because it always gives a diagnostic, it should be used only to identify a fault when other information indicates that a fault is likely to exist. The fact that a possible fault type is identified is not in itself a confirmation of the presence of a fault.

The Rogers Ratio Method and Duval Triangle 1 Method should not be used on samples with very low gas levels, which can be unreliable and inaccurate.

The general methodology as Triangle 1 is applied to obtain interpretations with Triangle 4 and Triangle 5 and is as follows:

In a DGA report, if (C2H2) = x; (C2H4) = y; (CH4) = z, in µL/L (ppm), first calculate the sum (x+y+z), then the relative % of each gas %C2H2 = 100x/(x+y+z); %C2H4 = 100y/(x+y+z); %CH4 = 100z/(x+y+z).

These relative % values are the coordinates of the DGA point in Duval Triangle 1. As illustrated, for example, in Figure C.3 where x = 25 µL/L (ppm) of CH4, y = 15 µL/L (ppm) of C2H4 and z = 10 µL/L (ppm) of C2H2.

Relative % values are CH4 = 50%, C2H4 = 30% and C2H2 = 20%; in zone D2.

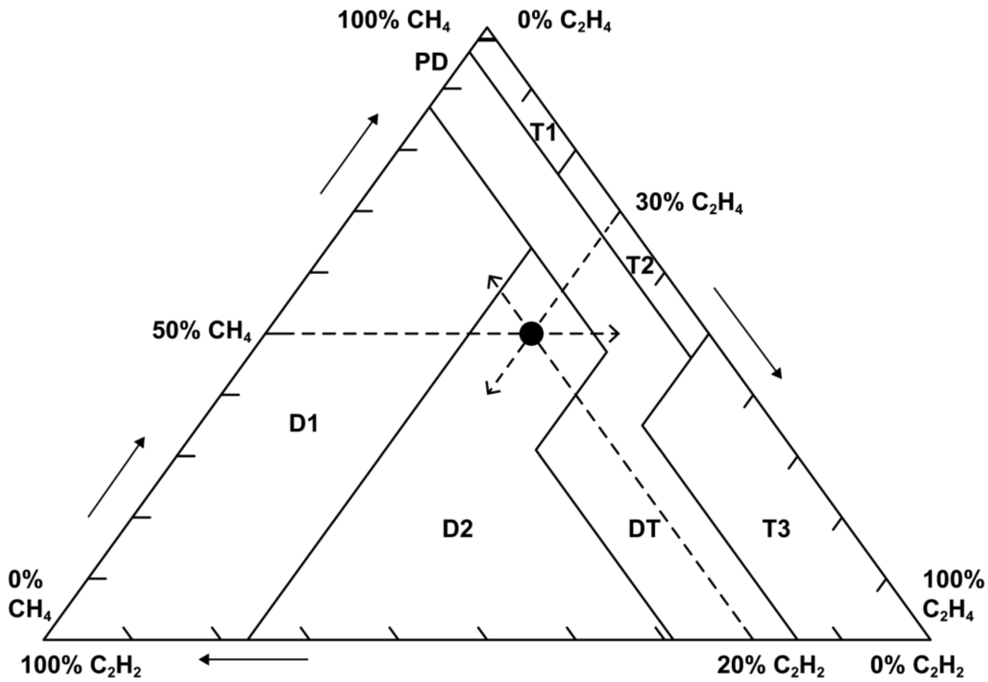


Figure C.4—Example of Duval Triangle 1 representation

Duval Triangles 4 and 5 are built and used in the same manner but use different gases and zones. Duval Triangle 4 uses H2, CH4 and C2H6 and Duval Triangle 5 uses CH4, C2H4 and C2H6.

Duval Triangles 4 and 5 can be utilized to obtain more information about sub-types of thermal faults (S, O, C, T3-H and R).

When low energy or low temperature faults are identified using the Duval Triangle 1 (PD, T1 or T2), more information can be obtained with Duval Triangle 4.

When high, or very high, temperature faults have been identified with Duval Triangle 1 (T2 or T3), more information can be obtained using the Duval Triangle 5.

The Duval Triangle 4 method is illustrated in Figure C.5.

The Triangle 4 method allows for distinguishing between faults S, O, PD, R which are of relatively minor concern in transformers, and potentially more dangerous faults C, which involve possible carbonization of paper. Faults R will appear at the very top of Triangle 4 (H2 only).

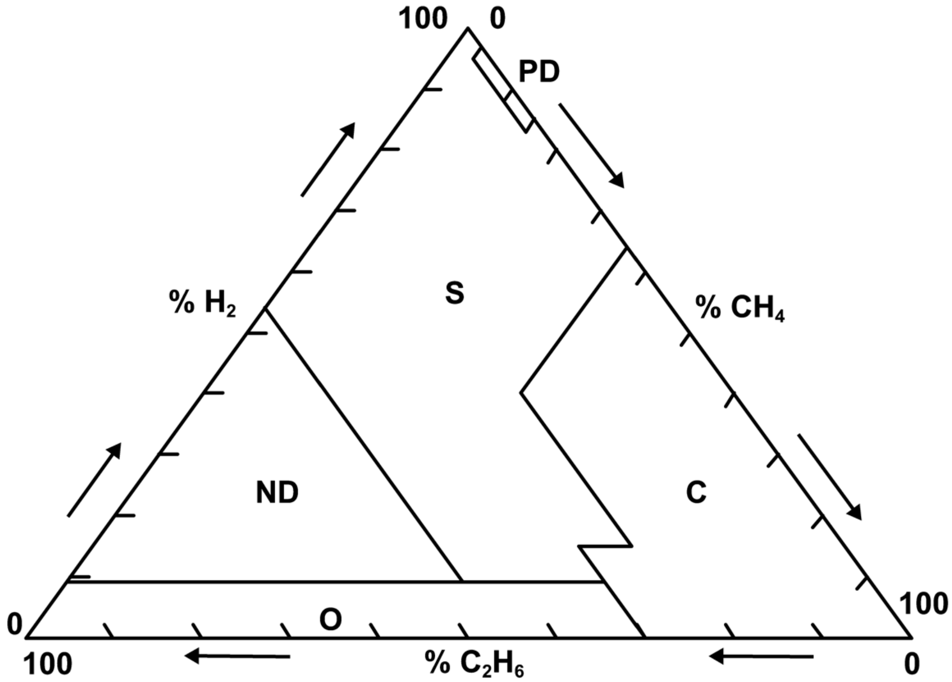


Figure C.5—Duval Triangle 4 method for low temperature faults

Numerical values for fault zone boundaries of Duval Triangle 4 method are the following, expressed in %H2, %CH4 and %C2H6:

Table C.9 Fault zone boundaries for Figure C.5

Gas% / Fault	% H_2	% CH_4	% C_2H_6
PD	—	≥ 2 and < 15	< 1
S	≥ 9	—	≥ 30 and < 46
	≥ 15	—	≥ 24 and < 30
	—	< 36	≥ 1 and < 24
	—	< 36 and ≥ 15	< 1
	—	< 2	< 1
O	< 9	—	≥ 30
C	—	≥ 36	≥ 24
	<15	—	≥ 24 and < 30
ND	≥ 9	—	≥ 46

The Duval Triangle 5 method is illustrated in Figure C.6:

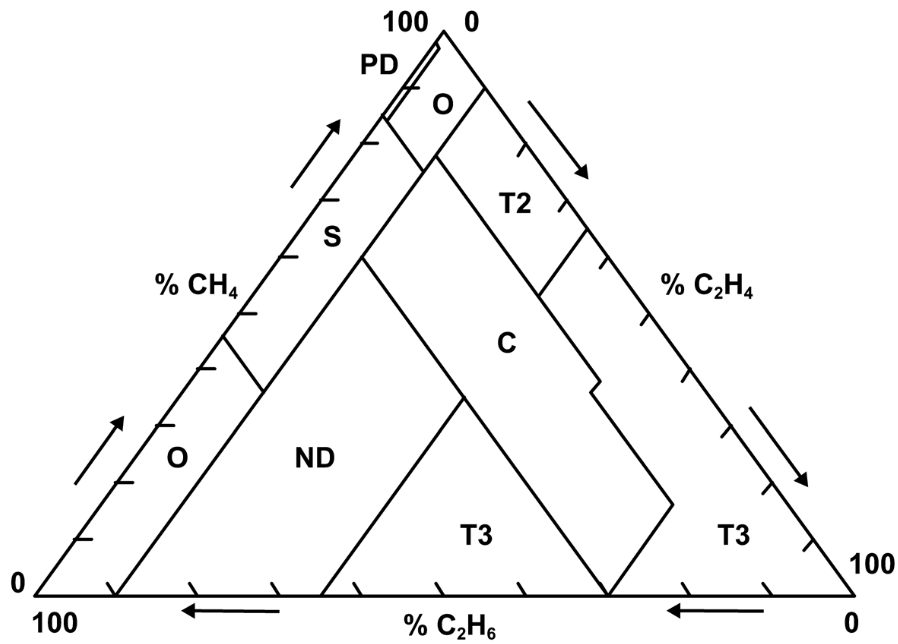


Figure C.6—Duval Triangle 5 method for high temperature fault

The Triangle 5 method allows a user to distinguish between high temperature faults T3/T2 in mineral oil only, of lesser concern in transformers, and potentially more dangerous faults C involving possible carbonization of paper.
Numerical values for fault zone boundaries of Duval Triangle 5 method are the following, expressed in %CH4, %C2H4 and %C2H6:

Table C.10—Fault zone boundaries for Figure C.6

Gas% / Fault	% CH_4	% C_2H_4	% C_2H_6
PD	—	< 1	≥ 2 and < 14
O	—	≥ 1 and < 10	≥ 2 and < 14
	—	< 1	< 2
	—	< 10	≥ 54
S	—	< 10	≥ 14 and < 54
T2	—	≥ 10 and < 35	< 12
T3	—	≥ 35	< 12
	—	≥ 50	≥ 12 and < 14
	—	≥ 70	≥ 14
	—	≥ 35	≥ 30
C	—	≥ 10 and < 50	≥ 12 and < 14
	—	≥ 10 and < 70	≥ 14 and < 30
ND	—	≥ 10 and < 35	≥ 30

Note that:

a) Triangles 4 and 5 should never be used for faults identified first with Triangle 1 as electrical faults D1 or D2.
b) Triangle 4 should be used only in case of faults identified first as faults PD, T1 or T2 in Triangle 1.
c) Triangle 5 should be used only in case of faults identified first as faults T2 or T3 in Triangle 1.
d) DGA points occurring in zones C indicate a possibility of carbonization of paper, not a 100% certainty, and further investigations with carbon oxides and furans should be undertaken.

C-12 Duval Pentagon 1 method

The Duval Pentagon 1 method is illustrated in Figure C.7.

The Duval Pentagon 1 uses all five hydrocarbon gases (H2, C2H6, CH4, C2H4 and C2H2). The order of gases at the five summits of Pentagons 1 and 2 correspond to the increasing energy or temperature of the faults producing these gases (from H2 to C2H2).

The six basic types of faults of (PD, D1, D2, T1, T2 and T3 can be detected with Duval Pentagon 1, as in the case of Duval Triangle 1, as well as stray gassing of mineral oil (S).

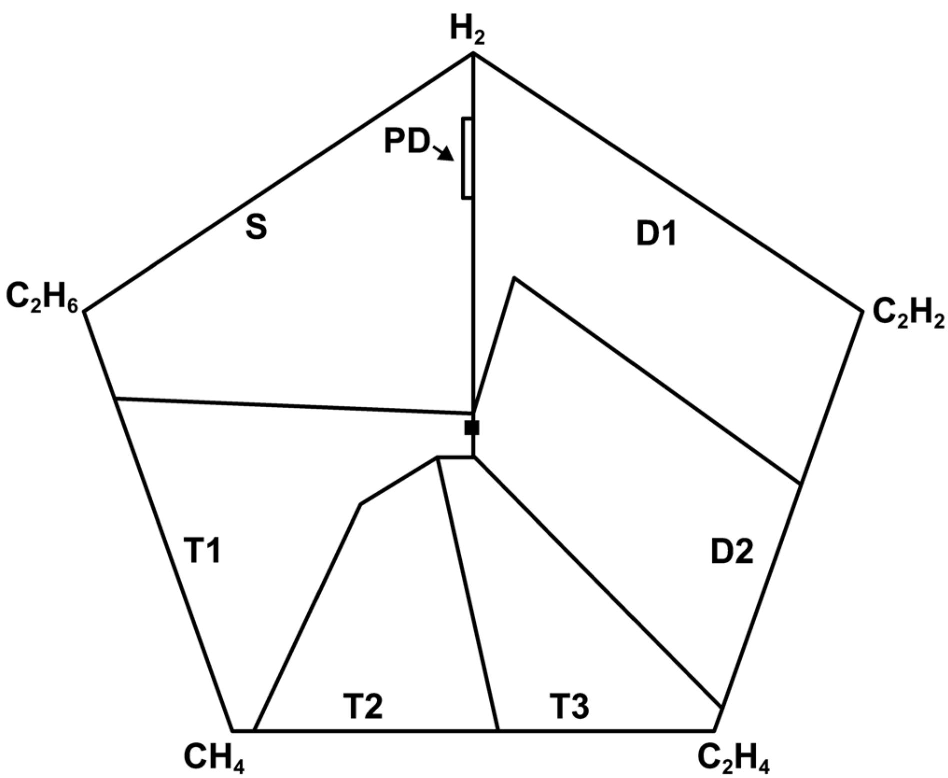


Figure C.7—Duval Pentagon 1 method

The numerical values of the (x, y) coordinates of zone boundaries in Pentagon 1 are indicated below [the dot of Figure C.7 is at coordinates (0,0) and the apex H2 is at coordinates (0, 40)]:
PD: (0, 33), (–1, 33), (–1, 24.5), (0, 24.5);
D1: (0, 40), (38, 12), (32, –6.1), (4, 16), (0, 1.5);
D2: (4, 16), (32, –6.1), (24.3, –30), (0, –3), (0, 1.5);
T3: (0, –3), (24.3, –30), (23.5, –32.4), (1, –32); (–6, –4);
T2: (–6, –4), (1, –32.4), (–22.5, –32.4);
T1: (–6, –4), (–22.5, –32.4), (–23.5, –32.4), (–35, 3), (0, 1.5); (0, –3);
S: (0, 1.5), (–35, 3.1), (–38, 12.4), (0, 40), (0, 33), (–1, 33), (–1, 24.5), (0, 24.5);

C-13Duval Pentagon 2 method

If thermal faults (T1, T2, and T3) have been identified with Duval Pentagon 1, more information can be obtained on these faults with Duval Pentagon 2, as in the case of Duval Triangles 4 and 5.
The Duval Pentagon 2 method is illustrated in Figure C.8.

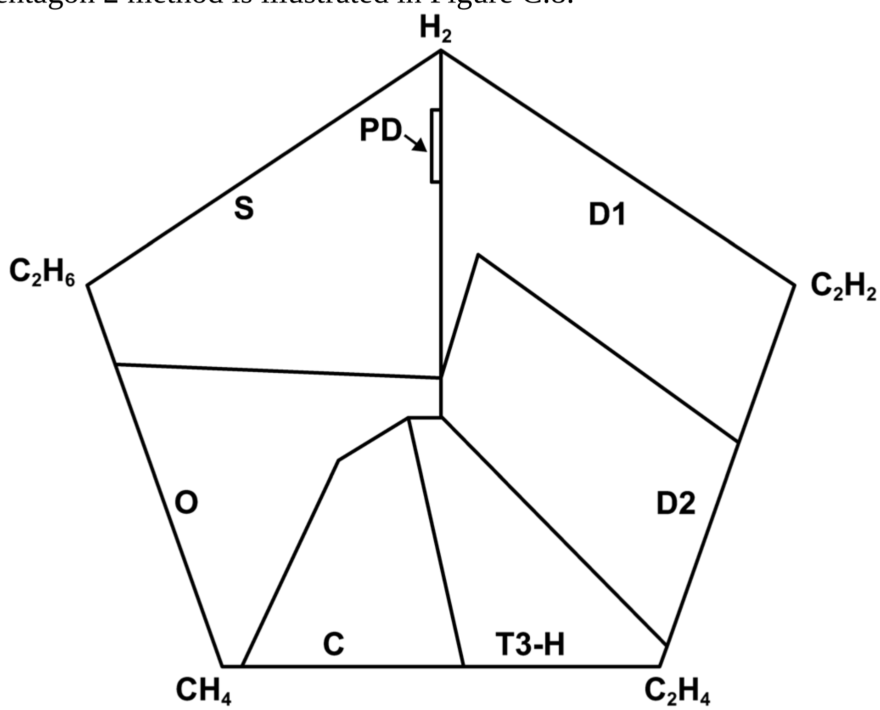


Figure C.8—Duval Pentagon 2 method

The Pentagon 2 method allows for detection of the 3 basic types of electrical faults (PD, D1 and D2) as in Duval Pentagon 1, and to further distinguish between the 4 additional sub-types of thermal faults (S, O, C and T3 in mineral oil only).

In Duval Pentagon 2, faults T3 in mineral oil only are indicated as T3-H, where H is for “Huile” or “oil” in French.

NOTE—DGA points occurring in zone C indicate a possibility of carbonization of paper, not a 100% certainty, and further investigations with carbon oxides and furans should be undertaken.

The numerical values of the (x, y) coordinates of zone boundaries of Pentagon 2 are indicated below:

PD: (0, 33), (–1, 33), (–1, 24.5), (0, 24.5);
D1: (0, 40), (38, 12), (32, –6.1), (4, 16), (0, 1.5);
D2: (4, 16), (32, –6.1), (24.3, –30), (0, –3), (0, 1.5);
S: (0, 1.5), (–35, 3.1), (–38, 12.4), (0, 40), (0, 33), (–1, 33), (–1, 24.5), (0, 24.5);
T3-H: (0, –3), (24.3, –30), (23.5, –32.4), (2.5, –32.4), (–3.5, –3);
C: (–3.5, –3), (2.5, –32.4), (–21.5, –32.4), (–11, –8);
O: (–3.5, –3), (–11 ,–8), (–21.5, –32.4), (–23.5, –32.4), (–35, 3.1), (0, 1.5), (0, –3).

C-14 Mixtures of faults

Duval Triangles 1, 4, 5 and Pentagons 1, 2 methods, as well as all other diagnosis methods (Key Gas, Rogers Ratios, Doernenburg Ratios), were initially developed for detecting single faults only.

However, multiple faults (mixtures of faults) often occur rather than single faults and may be more difficult to identify with certainty. For instance, actual mixtures of faults T3+D1 may sometimes appear in terms of gas formation as faults D2 in Triangle 1, Pentagon 1, and other diagnosis methods (Rogers Ratios, etc.), while actual mixtures of faults T3 in mineral oil (T3-H) and O may appear as faults C in Triangle 5 and Pentagon 2.

Mixtures of faults may be suspected when fault identifications provided by Duval Triangles 1, 4, and 5 and Pentagons 1 and 2 for the same DGA results are different. This is because each graphical representation is more sensitive to some gases and some faults than to others. For example, Triangle 4 and the Pentagons are more sensitive to H2 and faults S and PD, while Triangle 1 and Triangle 5 are more sensitive to C2H4 and faults T3.

If the position of the DGA point changes with time in the Triangles and the Pentagons, this indicates that a new fault has formed over the old one or another source of gas formation (a different type of fault has become active) exists. To get a better identification of this new fault, gas concentrations from the previous DGA results may be subtracted from the most recent ones. The subtracted (delta) values will thus be due only to the new fault. If delta values are negative for some gases, this means that no additional amounts (zero μL/L) of these gases have been formed because of the new fault since the previous sample, and that some of those gases previously formed have started to escape from the transformer. When identifying the new fault, negative delta values should, therefore, be replaced by zero μL/L.

C-15When to use the Duval Pentagons and Triangles

If interest is only in the six basic types of faults (PD, D1, D2, T1, T2 and T3) and by single faults, the display of DGA points would be done using the Pentagon 1 or Triangle 1.

If there is also an interest in the additional sub-types of faults (S, O, C, T3-H AND R), Pentagon 2 and Triangles 4 or 5 should be used.

C-16Interpretation of CO and CO2

Until recently, CO and CO2 were considered as good indicators of paper involvement in faults. Recent investigations at CIGRE, and in preparation of IEC 60599 revision, however, have shown that this is not always the case. The present view on the interpretation of CO and CO2 is the following.

a) High concentrations of CO (> 1000 µL/L (ppm)) and/or low CO2/CO ratios (< 3), WITHOUT the formation of significant amounts of hydrocarbon gases, are NOT an indication of a fault in paper, particularly in closed transformer, but are rather due to mineral oil oxidation under conditions of limited supply of O2.

b) High concentrations of CO (> 1000 µL/L (ppm)) and low CO2/CO ratios (< 3), TOGETHER WITH the formation of significant amounts of hydrocarbon gases, may be an indication of a fault in paper. This should be confirmed, however, by Pentagon 2 and Triangles 4, 5, and other observations (e.g., furans and degree of polymerization).

c) High concentrations of CO2 (> 10 000 µL/L (ppm)), high CO2/CO ratios (> 20) and high values of furans (>5 µL/L (ppm)) are an indication of the slow degradation of paper at relatively low temperatures (<140 °C), down sometimes to very low degrees of polymerization (DPs) of paper (e.g., 150 to 100). In the very large majority of cases, however, this does not prevent the transformer from operating normally, even in the presence of an external short circuit. However, there are concerns that the low DP paper may not always withstand strong transient over-currents or short circuits.

d) Concentrations of CO and CO2 below Table 1 of this guide, corresponds to normal gassing in transformers without faults.

e) Zero or very low rates of change of CO and CO2 do not necessarily mean the absence of a fault in paper. Localized faults in small volumes of paper often do not produce detectable amounts of CO and CO2 compared to the usually high background of these gases in service. However, they often produce significant amounts of the other hydrocarbon gases, allowing the detection of faults in paper with Pentagon 2 and Triangles 4 or 5.

C-17Other useful gas ratios for fault identification

The O2/N2 ratio

Decreasing values of this ratio indicate overheating and oxidation of mineral oil and can be used to confirm thermal faults.
Increasing values may indicate leaks in the air preservation system of transformers (membrane or nitrogen blanket).

The C2H2/H2 ratio

Values of this ratio >3 may indicate leaks or contamination from the tap-changer compartment into the main tank. If such contamination is suspected, it should be investigated.

IEC 60599 Guidelines

C-18Types of faults

Internal inspection of hundreds of faulty equipment has led to the following broad classes of visually detectable faults:

Partial discharges (PD) of the cold plasma (corona) type, resulting in possible X-wax deposition on paper insulation;

discharges of low energy (D1), in oil or/and paper, evidenced by larger carbonized perforations through paper (punctures), carbonization of the paper surface (tracking) or carbon particles in oil (as in tap changer diverter operation); also, partial discharges of the sparking type, inducing pinhole, carbonized perforations (punctures) in paper, which, however, may not be easy to find;

Discharges of high energy (D2), in oil or/and paper, with power follow-through, evidenced by extensive destruction and carbonization of paper, metal fusion at the discharge extremities, extensive carbonization in oil and, in some cases, tripping of the equipment, confirming the large current follow-through;

Thermal faults, in oil or/and paper, below 300 °C if the paper has turned brownish (T1), and above 300 °C if it has carbonized (T2);

Thermal faults of temperatures above 700 °C (T3) if there is strong evidence of carbonization of the oil, metal coloration (800 °C) or metal fusion (>1 000 °C).

C-19Basic gas ratios

Each of the six broad classes of faults leads to a characteristic pattern of hydrocarbon gas composition, which can be translated into a DGA interpretation table, such as the one recommended in Table 1 and based on the use of three basic gas ratios:

$$\frac{C_2H_2}{C_2H_4} \qquad \frac{CH_4}{H_2} \qquad \frac{C_2H_4}{C_2H_6}$$

Table C.11 applies to all types of equipment, with a few differences in gas ratio limits depending on the specific type of equipment.

Table C.11 – DGA interpretation table

Case	Characteristic fault	$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_4}{C_2H_6}$
PD	Partial discharges (see notes 3 and 4)	NS [a]	<0,1	<0,2
D1	Discharges of low energy	>1	0,1 – 0,5	>1
D2	Discharges of high energy	0,6 – 2,5	0,1 – 1	>2
T1	Thermal fault *t* <300 °C	NS [a]	>1 but NS [a]	<1
T2	Thermal fault 300 °C < *t* <700 °C	<0,1	>1	1 – 4
T3	Thermal fault *t* >700 °C	<0,2 [b]	>1	>4

NOTE 1 In some countries, the ratio C_2H_2/C_2H_6 is used, rather than the ratio CH_4/H_2. Also in some countries, slightly different ratio limits are used.

NOTE 2 Conditions for calculating gas ratios are indicated in 6.1 c).

NOTE 3 CH_4/H_2 <0,2 for partial discharges in instrument transformers. CH_4/H_2 <0,07 for partial discharges in bushings.

NOTE 4 Gas decomposition patterns similar to partial discharges have been reported as a result of stray gassing of oil (see 4.3).

[a] NS = Non-significant whatever the value.

[b] An increasing value of the amount of C_2H_2 may indicate that the hot spot temperature is higher than 1 000 °C.

Some overlap between faults D1 and D2 is apparent in Table 1, meaning that a dual attribution of D1 or D2 must be given in some cases of DGA results. The distinction between D1 and D2 has been kept, however, as the amount of energy in the discharge may significantly increase the potential damage to the equipment and necessitate different preventive measures. Table 1 applies to transformers.

NOTE Combinations of gas ratios that fall outside the range limits of Table 1 and do not correspond to a characteristic fault of this table can be considered a mixture of faults, or new faults that combine with a high background gas level.

In such a case, Table C.11 cannot provide a diagnosis, but the graphical representations Duval's triangle 1 can be used to visualize which characteristic fault of Table C.11 is closest to the case.

The less detailed scheme of Table C.12 can also be used in such a case in order to get at least a rough distinction between partial discharges (PD), discharges (D) and thermal fault (T), rather than no diagnosis at all.

Table C.12 – Simplified scheme of interpretation

Case	$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_4}{C_2H_6}$
PD		<0,2	
D	>0,2		
T	<0,2		

CO2/CO ratio

The formation of CO2 and CO from oil-impregnated paper insulation increases rapidly with temperature. High values of CO (e.g., 1 000 ppm) and CO2/CO ratios less than 3 are generally considered as an indication of probable paper involvement in a fault, with possible carbonization, in the presence of other fault gases.

However, in some recent transformers of the closed-type or open (free breathing) transformers operating at constant load (i.e., with low breathing), CO can accumulate in the oil, leading to ratio CO2/CO <3, without any irregularities or faults if no other gases such as H2 or hydrocarbons are formed.

High values of CO2 (>10 000 ppm) and high CO2/CO ratios (>10) can indicate mild (<160 °C) overheating of paper or oil oxidation, especially in open transformers. CO2 can accumulate more rapidly than CO in open transformers operating at changing loads because of their different solubilities in oil. This, and the long term degradation with time of paper at low temperatures (<160 °C), can lead to higher CO2/CO ratios in aged equipment.

In some cases, localized faults in paper do not produce significant amounts of CO and CO2 and cannot be detected with these gases (the same for furanic compounds).

Involvement of faults in paper therefore shall not be based only on CO and CO2, but shall be confirmed by the formation of other gases or other types of oil analysis.

In order to get reliable CO_2/CO ratios in the equipment, CO_2 and CO values should be corrected (incremented) first for possible CO_2 absorption from atmospheric air, and for the CO_2 and CO background values, resulting from the ageing of cellulosic insulation, overheating of wooden blocks and the long term oxidation of oil (which will be strongly influenced by the availability of oxygen caused by specific equipment construction details and its way of operation).

Air-breathing equipment, for example, saturated with approximately 9 % to10 % of dissolved air, may contain up to 300 μl/l of CO_2 coming from the air. In sealed equipment, air is normally excluded but may enter through leaks, and CO_2 concentration will be in proportion of air present.

When excessive paper degradation is suspected, it is recommended to ask for further analysis (e.g., of furanic compounds) or a measurement of the degree of polymerization of paper samples, when this is possible.

O_2/N_2 ratio

Dissolved O_2 and N_2 are found in oil as a result of contact with atmospheric air in the conservator of air-breathing equipment, or through leaks in sealed equipment. At equilibrium with air, the concentrations of O_2 and N_2 in oil are ~32 000 and ~64 000 ppm, respectively, and the O_2/N_2 ratio is ~0.5.

In service, this ratio may decrease as a result of oil oxidation and/or paper ageing, if O_2 is consumed more rapidly than it is replaced by diffusion. Factors such as the load and preservation system used may also affect the ratio, but with the exception of closed systems, ratios less than 0.3 are generally considered to indicate excessive consumption of oxygen.

C_2H_2/H_2 ratio

In power transformers, on load tap changer (OLTC) operations produce gases corresponding to discharges of low energy (D1). If some oil or gas communication is possible between the OLTC compartment and the main tank, or between the respective conservators, these gases may contaminate the oil in the main tank and lead to wrong diagnoses. The pattern of gas decomposition in the OLTC, however, is quite specific and different from that of regular D1s in the main tank.

C_2H_2/H_2 ratios higher than 2 to 3 in the main tank are thus considered as an indication of OLTC contamination. This can be confirmed by comparing DGA results in the main tank, in the OLTC and in the conservators.

If contamination by gases coming from the OLTC is suspected, interpretation of DGA results in the main tank should be made with caution by subtracting background contamination from the OLTC, or should be avoided as unreliable.

Recommended method of DGA interpretation (see Figure C.9)

a) Reject or correct inconsistent DGA values. Calculate the rate of gas increase since the last analysis, taking into account the precision on DGA results.

If all gases are below typical values of gas concentrations and rates of gas increase, report as "Normal DGA/healthy equipment".

If at least one gas is above typical values of gas concentrations and rates of gas increase, calculate gas ratios and identify fault using Table 1. Check for eventual erroneous diagnosis.

If necessary subtract last values from present ones before calculating ratios, particularly in the case of CO, CO2.

If DGA values are above typical values but below 10 × S (S = analytical detection limit).

b) Determine if gas concentrations and rates of gas increase are above alarm values. Verify if fault is evolving towards final stage. Determine if paper is involved.

c) Take proper action according to best engineering judgment and/or with the help of Figure C.9.

It is recommended to:

a) increase sampling frequency (quarterly, monthly or other) when the gas concentrations and their rates of increase exceed typical values;
b) consider performing complementary tests (acoustic, electrical, infrared) or reduce loading;
c) consider removing the transformer from service for inspection or repair depending on results of complementary and other tests and on advice of transformer experts;
d) consider immediate action when gas concentrations and rates of gas increase exceed alarm values.

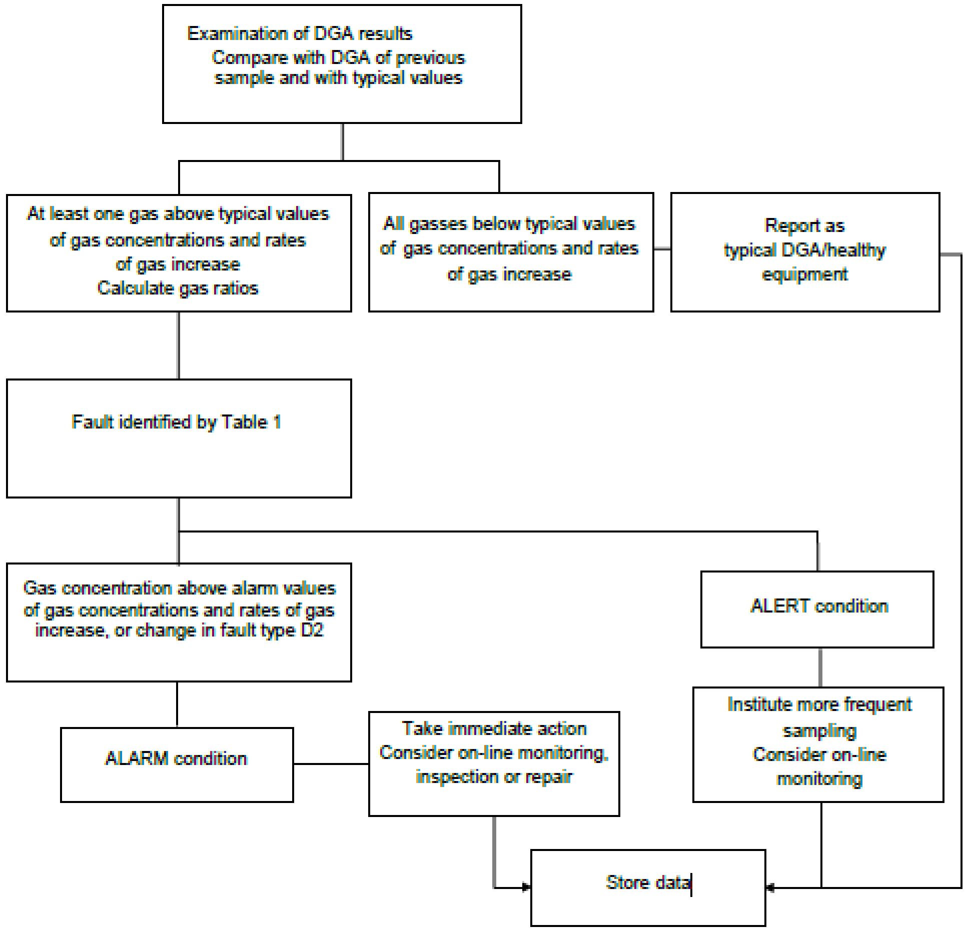


Figure C.9 Method of DGA Interpretation

Typical faults in power transformers

Table C.13 Typical faults in power transformers

Type	Fault	Examples
PD	Partial discharges	Discharges in gas-filled cavities resulting from incomplete impregnation, high-humidity in paper, oil super saturation or cavitation, and leading to X-wax formation
D1	Discharges of low energy	Sparking or arcing between bad connections of different or floating potential, from shielding rings, toroids, adjacent disks or conductors of winding, broken brazing or closed loops in the core Discharges between clamping parts, bushing and tank, high voltage and ground within windings, on tank walls Tracking in wooden blocks, glue of insulating beam, winding spacers. Breakdown of oil, selector breaking current
D2	Discharges of high energy	Flashover, tracking, or arcing of high local energy or with power follow-through Short circuits between low voltage and ground, connectors, windings, bushings and tank, copper bus and tank, windings and core, in oil duct, turret. Closed loops between two adjacent conductors around the main magnetic flux, insulated bolts of core, metal rings holding core legs
T1	Thermal fault $t < 300$ °C	Overloading of the transformer in emergency situations Blocked item restricting oil flow in windings Stray flux in clamping beams of yokes
T2	Thermal fault 300 °C $< t <$700 °C	Defective contacts between bolted connections (particularly between aluminium busbar), gliding contacts, contacts within selector switch (pyrolitic carbon formation), connections from cable and draw-rod of bushings Circulating currents between yoke clamps and bolts, clamps and laminations, in ground wiring, defective welds or clamps in magnetic shields Abraded insulation between adjacent parallel conductors in windings
T3	Thermal fault $t > 700$ °C	Large circulating currents in tank and core Minor circulation currents in tank walls created by a high uncompensated magnetic field Shorting links in core steel laminations

Typical concentration values

Ranges of 90 % typical gas concentration values observed in power transformers, from about 25 electrical networks worldwide and including more than 20 000 transformers, are given in Table A.2. For hydrogen, for example, one network reported a typical value of 50 µl/l, another one 150 µl/l and the 23 others reported values between 50 µl/l and 150 µl/l. These ranges of values have been reported by CIGRE SC D1 and A2 (TF11) and approved by IEC TC 10 and TC 14.

Table C.14 – Ranges of 90 % typical gas concentration values observed in power transformers, in µl/l

	C_2H_2	H_2	CH_4	C_2H_4	C_2H_6	CO	CO_2
All transformers		50 – 150	30 – 130	60 – 280	20 – 90	400 – 600	3 800 – 14 000
No OLTC	2 – 20						
Communicating OLTC	60 – 280						

"Communicating OLTC" in Tables C.14 and C.15 means that some oil and/or gas communication is possible between the OLTC compartment and the main tank or between the respective conservators. Gases produced in the OLTC compartment may contaminate the oil in the main tank and affect concentration values in these types of equipment. "No OLTC" refers to transformers not equipped with an OLTC, or equipped with a tap changer not communicating with or leaking to the main tank. Typical values in Table C.14 apply to both breathing and sealed transformers, and correspond mostly to core-type transformers. Values in shell-type transformers are likely to be higher.

Typical rates of gas increase

Ranges of 90 % typical rates of gas increase observed in power transformers, from four electrical networks and including more than 20 000 DGA analyses, are given in Table A.3. These ranges of values have been reported by CIGRE SC D1 and A2 (TF11) and approved by IEC/TC 10 and TC 14.

Table C.15 – Ranges of 90 % typical rates of gas increase observed in power transformers (all types), in µl/l/year

	C_2H_2	H_2	CH_4	C_2H_4	C_2H_6	CO	CO_2
All transformers		35 – 132	10 – 120	32 – 146	5 – 90	260 – 1 060	1 700 -10 000
No OLTC	0 – 4						
Communicating OLTC	21 – 37						

Typical values in Table C.15 are valid for large power transformers with an oil volume>5 000 l. Values in small transformers (<5 000 l) are usually lower. Values in the early and late years of the equipment tend to be higher than the average values of Table C.15. Values of Table C.15 may be converted into ml/day when the transformer oil volume is known.

Typical concentration values for industrial and special transformers (furnace transformers, rectifier transformers, railway transformers, distribution transformers below 10 MVA, submersible distribution transformers, wind farm transformers) are listed in Table C.16

Table C.16 – Examples of 90 % typical concentration values observed in industrial and special transformers, in µl/l

Transformer sub-type	H_2	CO	CO_2	CH_4	C_2H_6	C_2H_4	C_2H_2
Furnace	200	800	6 000	150	150	200	[a]
Distribution	100	200	5 000	50	50	50	5
Submersible	86	628	6 295	21	4	6	<S [b]

NOTE The values listed in this table were obtained from two individual networks. Values on other networks may differ.

[a] The data are influenced by the design and assembly of the on-load tap changer. For this reason, no statistically significant value can be proposed for acetylene.

[b] < S means less than the detection limit.

Typical faults in bushings

In a number of instances, partial discharges result in increased dielectric losses, thermal runaway and final breakdown. Most frequent final failures are related to the breakdown of core insulation between shortcircuited layers (as a result of partial discharges or thermal runaway), flashovers along the internal surface of the porcelain (often resulting in explosions) and flashovers along the core surface.

Table C.17 – Typical faults in bushings

Type	Fault	Examples
PD	Partial discharges	Discharges in gas-filled cavities resulting from humidity in paper, poor impregnation, oil supersaturation or contamination, or X-wax deposition. Also in loose insulating paper displaced during transportation with puckers or folds in paper
D1	Discharges of low energy	Sparking around loose connections at capacitive tap Arcing in static shielding connections Tracking in paper
D2	Discharges of high energy	Localized short-circuits between capacitive stress grading foils, with high local current densities able to melt down foils (see definition of D2 in 5.3), but not leading to the explosion of the bushing
T2	Thermal fault 300 °C < t < 700 °C	Circulating currents in paper insulation resulting from high dielectric losses, related to contamination or improper selection of insulating materials, and resulting in thermal runaways Circulating currents in poor connections at bushing shield or high voltage lead, with the temperature transmitted inside the bushing through conduction by the conductor

Identification of faults by DGA in bushings
A simplified table of interpretation is proposed as shown in Table C.18.

Table C.18 – Simplified interpretation scheme for bushings

Fault	$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_4}{C_2H_6}$	$\frac{CO_2}{CO}$
PD		<0,07		
D	>1			
T			>1	
TP				<1, >20

In cases where a single characteristic fault cannot be attributed using this simplified table, or when a more precise diagnosis is required, the general Table 1 should be used.

Typical concentration values

The following 95 % typical values are proposed.
The values given in Table C.19 are for information only.

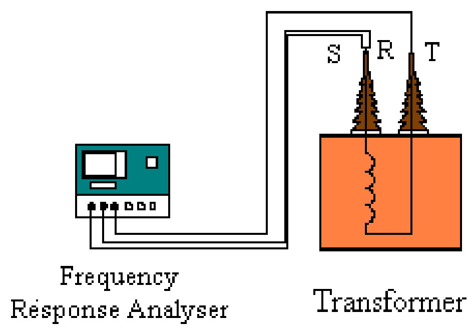
Table C.19 – 95 % typical concentration values in bushings, in µl/l

H_2	CO	CO_2	CH_4	C_2H_6	C_2H_4	C_2H_2
140	1 000	3 400	40	70	30	2

ANNEX D

SWEEP FREQUENCY RESPONSE ANALYSIS

Frequency Response Analysis (FRA) is conducted to assess the mechanical integrity of the transformer. Transformers while experiencing severe short circuit currents,suffer deformation of the winding or core. These changes cannot be detected through conventional condition monitoring techniques. Sometimes even transportation without proper precaution may cause some internal mechanical damages. FRA measurement provides vital information of the internal condition of the equipment so that early corrective action could be initiated. IEC 60076-18, IEEE C57.149 and CIGRE Technical Brochure 812 provide the guidelines for a comprehensive SFRA measurement.



Sinusoidal signal output of approximately 10 V peak to peak from the Frequency Response Analyzer is applied and one measuring input (R1) is connected to the end of a winding and the other measuring input (T1) is connected to the other end of the winding. The voltage is applied and measured with respect to the earthed transformer tank. Two different types of response analysis is done – driving point impedance method and transfer function method. Transfer function method is used in all the commercial instruments. The voltage transfer function T1/R1 is measured for each winding for nine or fifteen standard frequency scans from 20 Hz to 2 MHz, as prescribed by IEC 60076-18, and amplitude and phase shift results are recorded. In general, the low frequency regions reveal core defects, the medium frequency regions revealstructural defects of the winding and inter winding displacements and high frequency regions reveal lead displacements.

It is ensured that winding which is not under test is terminated in open condition in order to avoid response difference among the three phases. The same procedure is followed on subsequent tests on the same or similar transformer, to ensure that measurements are entirely repeatable.

Interpretation of the test results is based on subjective comparison of FRA responses taken at different intervals. If changes are observed in the later FRA spectrum with respect to the reference FRA spectrum, it is left to the experience of the analyst for quantitative condition assessment of the transformer.

However, one should check for any significant shift in the resonance frequencies and emergence of new resonant frequencies in the later FRA response, which could be the result of any mechanical deformation in the transformer winding. As FRA is signature analysis, data of signature of the equipment when in healthy condition is required for proper analysis. Signatures could also be compared with unit of same internal design or with other phases of the same unit. Normally measured responses are analyzed for any of the following:

a) Changes in the response of the winding with earlier signature.
b) Variation in the responses of the three phases of the same transformer.
c) Variation in the responses of transformers of the same design.

IEEE standard distinguishes between axial and radial displacement of the winding by considering the frequency range of variation. In all the above cases the appearance of new features or major frequency shifts are causes for concern. The phase responses are also being recorded but normally it is sufficient to consider only amplitude responses.

The traces in general will change shape and be distorted in the low frequency range (below 5 kHz) if there is a core problem. The traces will be distorted and change shape in higher frequencies (above 10 kHz), if there is a winding problem. Changes of less than 3 decibels (dB) compared to baseline traces are normal and within tolerances. An accuracy of ±0.3 dB is required by IEC 60076-18. In general, changes of ± 3 dB (or more) in a frequency range may indicate a probable type of fault as shown in Table D.1 below:

Table D.1 Probable fault from FRA data

Frequency Range	**Probable Fault**
5 Hz to 2 kHz	Shorted turns, open circuit, residual magnetism or core movement
50 Hz to 20 kHz	Bulk movement of windings relative to each other
500 Hz to 2 MHz	Deformation within a winding
25 kHz to 10 MHz	Problems with winding leads and/or test lead placement

CIGRE Technical Brochure 812 summarises the recent developments in interpretation of SFRA results – mainly by the use of statistical parameters termed as numerical indices. The application of machine learning algorithms to numerical indices, is proposed as the future of SFRA interpretation.

D-1 Frequency Domain Spectrometry

Capacitance and dissipation factor (Tanδ) measurement at 50Hz is a very common diagnostics technique used for insulation condition assessment of the bushings since many decades. The moisture in paper, ageing of paper and other polar impurities in insulation can be detected by this measurement. However relation between insulation condition (e.g. moisture and ageing) and diagnostic quantities are sometimes uncertain. In many cases it has been observed that an initial developing fault in bushing may not always be reflected by Tan δ values at 50Hz. Problems like partial discharge in bushings, development of bridging of grading layer generally do not reflected in substantial change in capacitance value at 50Hz. In all such cases, Capacitance and dissipation factor (Tanδ) measurement in variable frequency and DGA is proven to be supplement diagnostic tools for condition assessment of OIP bushings. It has been observed that Capacitance and Tan δ measurement in frequency domain (15Hz to 400 Hz and 1 mHz to 1kHz) have correlated very accurately to bushing DGA and visual inspection upon dismantling.

Capacitance and Tan δ measurements are also used for winding insulation condition assessment. Frequency Domain Spectroscopy is also used for the same purpose.

Dielectric losses measured in the frequency domain FDS (Frequency Domain Spectroscopy) reflect the same fundamental polarization and conduction phenomena in transformer insulation, the special feature of which is a combination of oil gaps and solid insulation and as a consequence are influenced strongly by both solid insulation moisture content and oil condition and less influenced by the geometry of the solid and liquid insulations.

The complex permittivity can be used to characterize the insulation. It is a dimensionless quantity consisting of a real part representing the energy stored in the electric field within the sample and an imaginary part representing the energy losses. FDS response of an oil paper composite insulation represents the frequency and temperature dependent permittivity and dissipation factor of composite insulation.In addition, faults like voids in paper, partial discharge and deposition of X-Wax in the bushings leading to high dielectric loss, high moisture content in paper insulation can be detected by the above measurement.

The measurement in high frequency region can be conducted in minimum time while sweeping across the low frequency range can be time consuming. Hence PDC (polarisation depolarisation current) measurements can be carried out and a frequency domain transformation of the response can be utilised to estimate the response in low frequency region.

Inputs in the form of X-Y factors, corresponding to the dimensions of the barriers and the spacers in the transformer are required for data analysis, but there are algorithms which can produce the best fit in the absence of this data.

The FDS response of the insulation may be interpreted in the manner as suggested in Figure D.1 below:

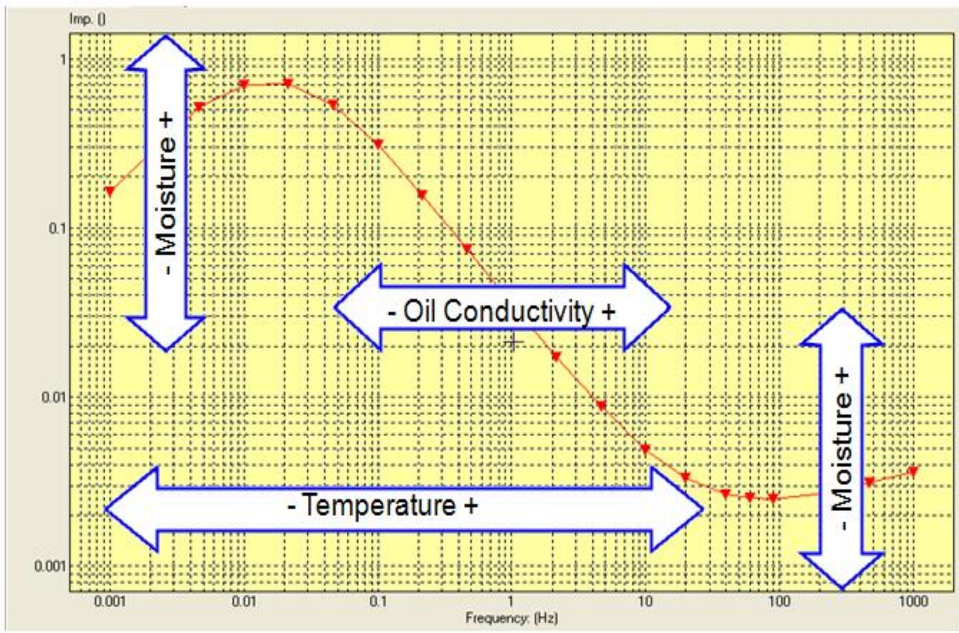


Figure D.1 Frequency domain spectroscopy obtained on transformer paper oil insulation system

An Example of the result comparison of a faulty bushing is as shown below:

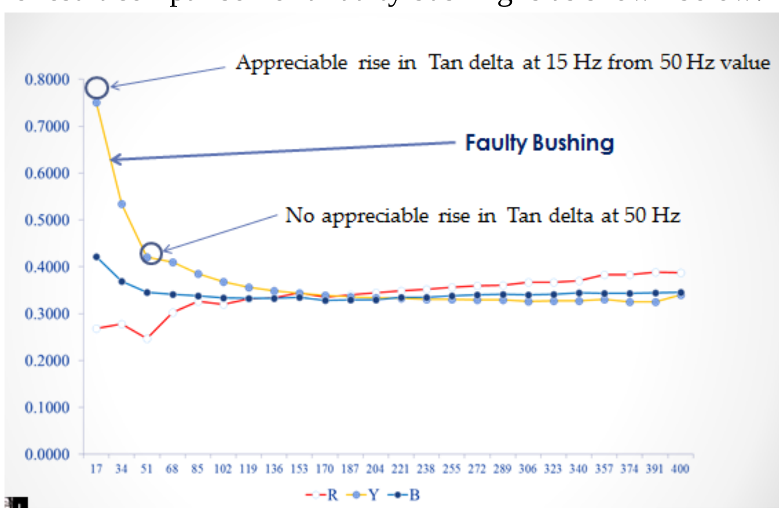


Figure D.2 Frequency domain spectroscopy obtained on oil impregnated bushings

ANNEX E

ON LINE MONITORING ACTIVITIES FOR TRANSFORMER/ REACTOR

ONLINE-DGA

Continuous On-Line Monitoring of DGA is very important monitoring technology for transformers and reactors. Several sensors technologies are available in the market using different detection techniques - fuel cell, chromatography, semiconductor,photo-acoustic spectroscopy, thermal conductivity. Depending on the technology and its implementation, the online DGA measurement systems available in the market vary from two gas models (hydrogen and moisture) to ten gas models (all Gases used in conventional DGA).

One of the major advantages of on-line monitors is that alarm can be raised in the event of absolute level or Rate of Change (ROC) of fault gases exceeding their thresholds.If asset manager responds to these alarms and prompt action is taken on time then major failures and damage to associated equipment can often be prevented. By communicating the on line DGA data to remote center on continuous basis, suitable actions to each possible alarm could be formulated and could be made available with Asset Manager for responding to each incidence. Further, it can be helpful in health indexing as well as monitoring dynamic change of condition of the equipment on continuous basis.

The disadvantage of single gas online DGA monitoring systems, which often use hydrogen is that hydrogen is considered as a stray gas. Further, hydrogen may also be generated by reaction of steel and galvanized steel with water as long as oxygen is available from the oil nearby. Large quantity of hydrogen may also be generated due to presence of trapped air due to improper vacuum in the transformer tank. Hence, based on only hydrogen concentration in the oil, it is difficult to take decision for further course of action. However, if the multi gas online DGA monitors are provided, then taking decision becomes easier based on the rising trend of all other fault gasses.

E-1 Online Partial Discharge Measurement

Online Partial Discharge (PD) monitoring is a method for detecting the weak spots in the insulation of the transformer under testing. These weak spots can be due to any void, metallic particles which may cause uneven voltage distribution in the insulation. Online PD monitoring test is presently done using two methods – Acoustic & Ultra High Frequency (UHF) Testing method.

In Acoustic testing, acoustic response of PD inside a transformer/reactor is typically measured by a piezo-electrical sensor (which is attached on the outside wall of the transformer) in the frequency range of some 10 kHz, up to 300 kHz. Using the difference in arrival time of the acoustic PD signal at multiple sensors, algorithms compute the location of the PD source. The measurable direct signal in oil at the sensor position depends on the intensity of the PD event and on the damping in the propagation path. Therefore, the attenuation by core, winding, transformer board, flux shielding etc. should be as low as possible. For that reason, the search for sensor positions that ensure good signal quality is essential during the measurement procedure. Thus, the measurement method may be vulnerable to noises both internal & external. The knowledge about the inner structure of the transformer/reactor is helpful for good positioning and repositioning of the sensors.

In UHF testing, Sensors (UHF antenna) are inserted via the transformer oil drain valve vent of size 40/50/80 NB. The UHF sensor mounted on the Transformer is able to detect the UHF signals generated by a partial discharge inside the transformer. It then passes the UHF signals generated by a partial discharge within the transformer tank with low attenuation. The System is sensitive to partial discharge signals throughout the frequency range 200-1500 MHz. The signal can then be processed by a PD Monitoring system which is able to triangulate the source of the PD inside the transformer. Since the sensor is inside of the transformer so the possibility of noise affecting the reading can be ruled out.

E-2 Bushing Tan delta measurement

Changes in bushing capacitanceand power factor are indicativeof insulation deterioration. Normally bushing tan delta is measured during shutdown period but in many cases where there was a very rapid deterioration of insulation, sudden and catastrophic failures have occurred. To rule out these possibilities online monitoring of bushing tan delta can be undertaken.

Several online bushing monitoring technologies are currently available in the market using different detection techniques - sum of leakage current method, phase shift method etc. Depending on the technology and its implementation, the systems are able to measure either relative change in capacitance and Tan δ or absolute capacitance and Tan δ.

The PD sensors can also be used to monitor the Partial Discharge in the bushings. For partial discharge measurement, the signals from the sensors and rogowski coils are used. The sensors provides primary diagnostic information for the system while the signals from the rogowski coils are used to assist in identifying whether the partial discharge activity being measured was positive or negative and whether it was coming from inside the transformer/reactor or from outside sources.

PD generally occurs as the voltage stress increases and PD patterns are repeatable. Often the same pattern can be seen on the positive and negative half of the sine wave and over multiple data plots. These are fundamental characteristics of the activity to be classified as partial discharge.

E-3 Moisture Measurement and Control

Moisture in the transformer oil can be measured and also controlled using the online dry-out system. The system is permanently installed which continuously keeps on removing the moisture while transformer is in energized condition.During the filtration process moisture level in ppm is continuously monitored.This process does not only remove moisture from transformer oil but from the insulation as well.

The transformer oil is circulated through a series of cylinders filled with specially designed cartridges that absorbs moisture as well as removes solid contaminations from the oil. However this may not be suitable for wet transformers/reactors which may require offline dry-out.

ANNEX F

HOT SPOT TEMPERATURE

Transformers can be fitted with fibre optic sensors which can be used to monitor the temperature at identified points. The sensor's locations are based on the design of the transformer to monitor the temperatures at the various identified temperature hotspots.

F-1 Thermovision Scanning

A thermovision camera determines the temperature distribution on the surface of the tank as well as in the vicinity of the jumper connection to the bushing. The information obtained by thermographs (as given below) is useful in predicting the temperature profile within the inner surface of tank and is likely to provide approximate details of heating mechanism.The temperature comparisons shown in Table F.1 between similar components under similar loading andtemperature rises above ambient have been found to be practical during IRinspection:

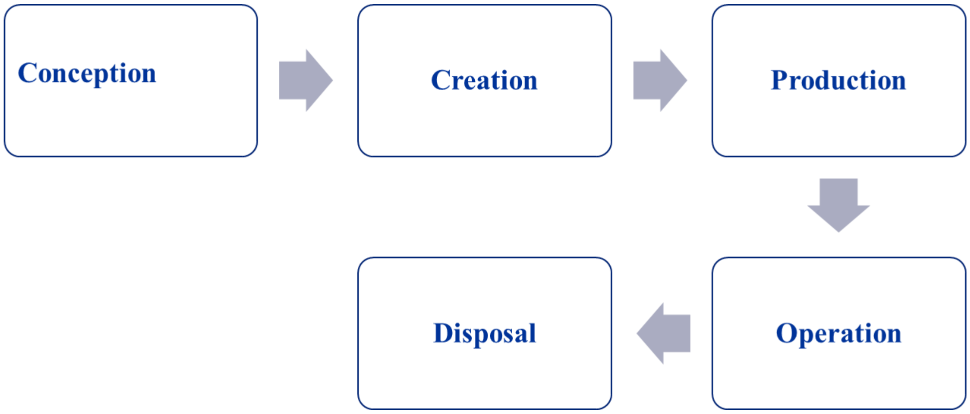
In order to avoid prohibited temperature rises in the electrical connections of the transformer, all screw-joints included should be checked and re-tightened based on readings from thermovision camera.

Table F.1Temperature comparisons between similar components

Temperature difference (ΔT) based on comparisons between similar components under similar loading in °C	Temperature difference (ΔT) based on comparisons between components and ambient air temperatures in °C	Recommended action
1 to 3	1 to 10	*[Normal to]* possible deficiency; warrants investigation
4 to 15	11 to 20	Indicates probable deficiency; repair as time permits
Greater than 15	21 to 40	Monitor until corrective measures can be accomplished
Greater than 15	Greater than 40	Major discrepancy; repair immediately *[For top liquid temperature rises of 65 °C there may be cases where up to 65 °C is normal]*

F-2 Life Cycle Management of Transformer/Reactor

Life Cycle Management is an integrated, information driven approach to all aspects of a product's life from its design inception, through its manufacture, deployment and maintenance, and culminating in its removal from service and final disposal. The entire process can be summarized as shown:



The conventional approach to Life Cycle Management can however be updated to include feedback from the Asset Manager. By giving a feedback (based on the accurate measurements along the lines of the method described above), the operation of the equipment can be optimised and the life can be extended.

a) Asset Health Indexing

Asset Health Indexing is an approach for assessing the health of the transformer/reactor and ranking it based on all of the following or a combination of parameters such as, Dissolved Gas Analysis (DGA), moisture in oil, Partial Discharges (PD) in main tank and bushings, bushing leakage currents, hot spots, load, apparent power, temperatures, through fault currents, high energy events, etc.The purpose is to combinethem into an informative and intuitive parameter, called a Health Index. Further, the on-linedata can be combined with historical offline data, as well as transformer visual inspection results,in order to provide a more detailed and refined condition assessment and trend analysis.

A health index/reliability index provides an indication of the probability of failure or remaining useful life while a repair or refurbishment index provides a ranking of the transformers based on the expected benefits from repair/refurbishment. Formulation of index from the available data, is convoluted process having profound implications for the utility of the index. Numerical methods are usually utilized while machine learning algorithms are being explored for the process. There is no standard way to express the condition of a transformer in existing IEC, IEEE or CIGRE literature. However, 2003 CIGRE TB 227 attempted a qualitative assessment of thehealth of a transformer identifying five categories as shown:

Condition	Definition
Normal	No obvious problems, No remedial action justified. No evidence of degradation.
Aged? Normal in service?	Acceptable, but does not imply defect-free
Defective	No significant impact on short-term reliability, but asset life may be adversely affected in long term unless remedial action is carried out.
Faulty	Can remain in service, but short-term reliability likely to be reduced. May or may not be possible to improve condition by remedial action.
Failed	Cannot remain in service. Remedial action required before equipment can be returned to service (may not be cost effective, necessitating replacement).

CIGRE TB 761 and 858 have built upon the previously available work and has provided good insights on the formulation of assessment indices for transformers. TB 761 gives six categories based on the severity from A to F while TB 858 gives five categories, from 1 to 5.

The approach is to define groups of parameters andthresholds in order to evaluate the condition ofeach transformer/reactor. Both on-line and off-lineparameters can be used for evaluating the score. A validity criterion should also be setup: very old data should not be considered, soa time based criterion can be used for each parameter to understand if the data is valid or not.Additional criteria can be used to address the parameter validity by considering the quality of the data. Finally we can map out the parameters and scores, assign weightages and calculate a score statistically which shall define the overall health of the unit.

For defining the score we may use a logical approach, technical limits, past experience or standards. For example, the tan delta limits can be varied as per past experience to define the condition in the group,Standards (CIGRE TB443 or IEEE C57.104 or Customized Methodology) can be used to assess the scores.

Evaluation of the score on a continuous basis shall also deliver the trend of the health of the equipment. This will help the Asset manager in seeing if the condition is improving or declining and the effect of a major or minor maintenance. Based on these facts a decision can be taken on run, refurbish, and replacement in respect of old and aged transformer.

Disposal of the main tank and accessories of the replaced unit is to be done through an authorized party only such as M/s MSTC Ltd. However, handling and disposal of transformer Oil should be done in a manner that shall not be detrimental to the environment.