Chapter 5
Best Practices in Operation and Maintenance of Transformers

5.1 Power Transformer

5.1.1 Description

The transformer (Fig. 5.1) is static and is one of the most important devices in a power system network. It does step-up or step-down of the voltage and transfers power from one circuit to other AC circuits without any change in frequency. The transformer has primary and secondary windings housed in the main tank [1]. The transformer capacity is expressed in volt–ampere (kVA or MVA).

The transformers comply with IS0: 2026; fittings and accessories comply with IS 3639. A transformer of 33/11 kV rating should have a delta star winding connection. The favored ratings for 33/11 kV transformers should be 6.3, 8, 10, 16, 20 MVA for urban areas and 1, 1.6, 3.15, 5, 6.3 MVA for rural areas. Any standard ratings other than stated above may also be chosen depending upon technical and economic considerations.

The transformer ventilation can be of dry type, epoxy cast dry-type, or oil-filled depending on whether transformer installation is indoor or outdoor. The cooling should be ONAN or ONAF. The core is usually constructed with high-grade rolled grain-oriented steel. Transformers should withstand combined voltage, frequency, and fluctuations without injurious heating and produce over-fluxing conditions such as 125% for 1 min and 140% for 5 s. The tolerable increase in temperature rise of winding and oil should be 35 and 40 °C, respectively, over an ambient temperature of 50 °C.

The transformers should be provided with relays such as oil and gas actuated relays connected with trip contacts and alarm, if applicable. The tap changing switch is placed at a well-suited position for easy operation of the switch from ground level. For locking the switch, the handle equipped with locking is set up along with the tap position indication. For better voltage control of transformers of

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Fig. 5.1 Power transformer

3.15 MVA and above, the tap changing device in the onload circuit should be provided. Transformers with an onload tap changing device should have taps in steps of 2.5% ranging from (+)5% to (−)15% voltage variation on the 33 kV transformer winding [2].

5.1.2 Causes and Nature of Failure

In normal operation the power transformer is protected from various kinds of relays and protective devices. However, during analysis the reasons for failure of a power transformer mainly concentrate on the following.

- Oil degradation/leakage in the transformer tank
- Neutral shifting/disturbance due to failure of earthing or imbalance of the phasewise current
- Internal short-circuit due to failure of insulation inside transformer
- Increase in winding temperature due to internal short-circuit
- Failure of protective devices including temperature indicator, relay settings, and the like
- Overloading of power transformer without proper fuses/protective devices to cut down the load
- Fluctuation of voltage at incomer side
- Loose contact between live parts of the distribution system.

5.1.3 Primitive Maintenance of Power Transformer

Primitive maintenance to be taken depends upon the size of the transformer, operation of the protection relay, whether tripping of the relay makes a loud noise, smoke, or discharge of oil from the transformer, and so on. Visually inspect a transformer's physical condition for any type of damage to the bushings. Check the temperature of oil and oil level in the conservator tank. Use Megger for taking readings between the primary and secondary of the transformer and also of the individual side of windings to earth. If everything goes right, proceed as follows.

The failure may possibly be caused by sudden and heavy overload, or short-circuit. Check if its ampere rating is right or the fuse has dropped out; if wrongly placed, replace by the right size and energize the transformer, after switching off the load. If everything seems right, close the secondary circuit; if the fuse blows up again, the fault is surely in the outgoing lines, which should be mapped and rectified if possible. On the other hand, if the primary circuit fuse blows up, even when the load is not connected, an internal fault is indicated. This condition also applies, but only if an overcurrent relay has operated and tripped the circuit breaker.

When a transformer is first switched on and if a differential relay operates, it may be due to a switching surge. Check the harmonic control circuit and settings. However, if the relay operates when the transformer is in operation, it is surely because of an internal fault.

Any kind of tripping of the Buchholz relay requires careful examination. If the upper assembly of the relay has operated due to slow evolution of gas it is necessary to find its composition before jumping to conclusions. If, on the other hand, the lower relay assembly has tripped due to sudden release of a large quantity of gas, a major internal fault is to be surmised especially if differential or overcurrent or earth fault relay has operated. If it is only air, there is no reason for worry, as air can enter the transformer in many ways.

Thorough checking is necessary if there is an evolution of smoke or oil, or the earth fault relay has tripped or not, and also PRV has operated in the case of a large transformer. In such cases, reclosing the circuit breaker should not be permitted as it may cause further damage. Detailed testing of the transformer is to be carried out and the results compared with test certificate figures and the manufacturer consulted. In most cases, the cause of the fault can be found if the condition of the windings is carefully observed by lifting the core and coil assembly. The following explanations will help to detect the cause.

Lightning discharge or overvoltage: The occurrence of breakdown happens at the coil end turn near the line terminal. Also it has the possibility of appearing as a breakdown or flashing in the turn of the oil or lead end terminal and close-earthed part whereas the rest of the coil is healthy.

Sustained overloads: The sign of excessive heating present in one of the windings or all the phases would lead to weak insulation and it may lose its physical property.

Interturn short: As in sustained overloads similar signs can be observed, but this would appear on only one coil and rest is integral.

Dead short-circuit: The wrong coil displacement is distinguished in the dead short-circuit. The coil is twisted in loose fashion and also may cause an explosion under tension conditions.

5.1.4 Visual Checking of Transformer

- Check the silica gel color. If it is pink, reactivate or replace it. Also ensure proper quantity of oil in breather oil cup.
- Check oil level in conservator of main tank and OLTC. It should be >½ level marking.
- Check oil level in bushings.
- Check for any oil leakage and arrest if any.
- Check the working of Oil Temperature Indicator (OTI) and Winding Temperature Indicator (WTI) by taking hourly temperature readings. There should be changes in readings as per loading of transformer and atmospheric conditions.
- Check the cooling system by manually operating fans/pumps.
- Check the tap position of remote tap changer control (RTCC) and on-load tap changer (OLTC) panels. It should have the same position number.
- Check the humming noise and vibration of the transformer. If any abnormality is found, it is to be referred to the manufacturer concerned.

5.1.5 Preventive Maintenance Schedule of Power Transformer

The following three factors directly affect the life of the distribution transformer.

Excess heat: Excess heat, on account of overloading, loose connections, low oil level, blocking in oil circulation, and so on.

Moisture: The oil dielectric strength is reduced once moisture enters the transformer through the breather and contaminates the transformer oil.

Oxygen in the air: It oxidizes the oil to form sludge and acids that attack the insulation and make it brittle; it corrodes the surface of the inner and conservator tanks.

Maintenance work on the distribution transformer is intended to take care of the above three factors. The periodic maintenance checks to be carried out are given in Table 5.1.

Table 5.1 Condition monitoring of transformer

S. No.	Components	Test results	Condition evaluation	Remarks and required action
1.	Paper insulation on windings	• Recovery voltage meter (moisture content) • Tan-delta value • DGA (violation of standard value of different gases) • Insulation resistance value • Furan content	Whether paper insulation is dry or wet	The following test will detect whether drying out is necessary Internal checkup is required or not
2.	Transformer oil	• DGA test • Moisture content in oil • Color	Quality of oil is good or not	If it is bad, then replacement is required
3.	Winding mechanical integrity	FRA test vibration to be assessed	Mechanical integrity of winding is satisfactory. Clamping pressure and core tightness of winding is normal or not	Any repair is possible or not
4.	Transformer core	• DGA test • FRA test • Vibration assessment ratio test	Transformer core, core insulation, and core tightness are good or not	Any repair or replacement is required or not
5.	Bushings	• HV bushing tan-delta value • LV bushing tan-delta value	Whether the bushings are healthy or not	If not healthy, capacitance and tan delta test is to be performed again using the automatic test kit
6.	OLTC	• Winding resistance at each tap • Ratio test • Oil color check • Operation check	Whether it is healthy or not	If found unhealthy. this is to be repaired for rectification
7.	Other components	• PRD fine and fit • OTI or WTI fine calibration • Radiator banks: no blocking, multiple point leakages • Buchholz: healthy • Values: healthy, no leakages	All are healthy or not	If radiator bank is not in good shape, it is better to replace the bank. If PRD is not found healthy, modified kit is to be put on PRD to avert possible false tripping due to ingress of moisture

(continued)

Table 5.1 (continued)

S. No.	Components	Test results	Condition evaluation	Remarks and required action
		• Main gasket of transformer: in good shape • Gasket of MBS: in bad shape • Turrets: healthy • Cabling: some cables are cracked		Damaged gaskets and cracked cables are usually replaced with the new one
8.	General appearance	• Painting: check for repainting • Oil leakages: check for multiple leakage • Terminal connection: analyzed by thermovision scanning All foundations are checked properly. Analysis is also done to check if there are any requirements for oil pit cleaning	Whether the general appearance is good	The unsatisfactory cases are to be reanalyzed

5.1.6 Predictive Maintenance

Buchholz Relay: This relay is designed to detect a transformer internal fault in the initial stage to avoid major breakdown. An internal fault in the transformer generates gases by decomposition of oil due to heat and spark inside the tank. These gases pass towards the conservator tank, trapped in relay, and thereby causing the oil level to fall. The upper float rotates and the switches' contacts close, thereby giving an alarm signal. In the case of a serious fault, there is more gas generation, which causes operation of the lower float and trips the circuit breaker. The gas can be collected from a small valve fitted at the top of the relay for dissolved gas analysis (DGA).

Dissolved Gas Analysis (DGA): The transformer, in operation, is subjected to various thermal and electrical stresses, resulting in liberation of gases from the oil used as insulation media and coolant. The solid insulating materials such as paper, wooden support, and pressboard cause degradation and form different gases, which are dissolved in the oil. The most significant gases generated are hydrogen (H_2), methane (CH_4), ethylene (C_2H_4), acetylene (C_2H_2), propane (C_3H_8), propylene (C_3H_6), carbon monoxide (CO), carbon dioxide (CO_2), and ethane (C_2H_6). The gas connected in the relay will help to identify the nature of the fault. The greater the rate of gas collection, the more severe is the nature of the developing fault.

5.1.7 Condition Monitoring of Transformer

Based on the assessment of various test results, the health of the various components is encapsulated as shown in Tables 5.1 and 5.2.

5.2 Distribution Transformer

5.2.1 Description

The transformer should be in conformance with IS-1180, IS 2026, and IS-11171. Distribution transformers can be 33/0.4 kV, 22/0.4 kV, or 11/0.4 kV. The 33/0.4 kV distribution transformers generally have standard ratings of 500, 630, 1000, 1250, 1600, or 2000 kVA depending on necessities. In rural and urban areas where the population is not large lower rating transformers can be employed [3]. The usual standard ratings of 11/0.4 kV distribution transformers are given as 6.3, 10, 16, 25, 50, 63, 100, 250, 315, 400, 500, 630, and 1000 kVA.

The efficiency of 11/0.4 kV distribution transformers of 100 kVA and below should not be less than 98% at both 50 and 100% loading. The efficiency of 11/0.4 kV distribution transformers above 100 kVA should not be less than 98.8% at both 50 and 100% loading. The efficiency of 33/0.4 kV distribution transformers should not be less than 99% at both 50 and 100% loading.

The transformer can be classified as oil-filled or dry-type based on the requirements. Materials such as high-grade cold rolled grain-oriented (CRGO) steel and amorphous material are employed in the construction of energy-efficient and energy-saving types of instruments. The scrap CRGO materials are not incorporated in the construction of the transformer. Low-capacity transformers of rating 100 kVA and less should normally be used. The higher capacity transformers of rating larger than 100 kVA should be used where there are space constraints such as concentrated loads or areas with a high density of load.

Table 5.2 Gas color for finding affected material

S. No.	Color	Identification
1.	White	Decomposed paper and cloth insulation
2.	Yellow	Decomposed wood insulation
3.	Grey	Overheated oil due to burning of iron portion
4.	Black	Decomposed oil due to electric arc

Table 5.3 Interpretation of the faults according to the observed ratios of gases

S. No.	Characteristic Fault	Ration code			Diagnosis
		C_2H_2/C_2H_4	CH_4/H_2	C_2H_4/C_2H_6	
1.	No fault	0	0	0	Regular ageing
2.	Partial discharge of low-energy density gas	0	1	0	Discharge in gas-filled cavities due to incomplete impregnation
3.	Partial discharge of high-energy density gas	1	1	0	As above but leading to tracking or perforation of solid insulation
4.	Discharge of low-energy gas	1–2	0	1–2	• Continued sparking in oil between bad connections of different potential or to floating potential • Breakdown of solid material
5.	Discharge of high-energy gas	1	0	2	Discharge of power followthrough arcing. Breakdown of oil between winding or between coil to earth
6.	Thermal fault of low temp less than 150 °C	0	0	1	General insulated conductor overheating
7.	Thermal fault temp 150–300 °C	0	2	0	Flux influence causes overheating of core, increases hot spot; pyrolitic carbon deposition makes joints bad contacts and circulation of current over tanks
8.	Thermal fault temp 300–700 °C	0	2	1	
9.	Thermal fault >700 °C	0	2	2	

Depending on the type of supply transformer there can be three phases or a single phase. The ONAN cooling method is used for oil-filled transformers. Based upon technical and economic considerations, any standard rating other than the above could also be chosen.

Faults are shown in Table 5.3.

5.2.2 *Transformer Maintenance Management*

The major types of fault causing transformer failure are as follows.

- Insulation failure
- Design/material/workmanship
- Oil contamination
- Overloading
- Line surge
- Improper maintenance/operation

- Loose connection
- Lightning/flood
- Moisture.

5.2.3 *Causes of Failure of Distribution Transformers*

Table 5.4 lists some of the causes of failures of transformers in service and probable corrective measures have been highlighted to reduce the rate of failure, which are primitive alarming signals in current modern-day distribution transformer networks across the country [4, 5].

Table 5.4 Causes of DT failure

S. No.	Reason on account of user	Probable cause	Preventive action
1.	Prolonged overloading	Selection of higher rating fuses	• Frequent measurement of peak load currents through tongue tester and fixing the correct rating of fuses on both HT and LT side. If overloading is 20% during peak load and persistence, then propose new transformer/ augmentation • Use correct size of fuse wire. Utilities should make the fuse wires available. Avoid using two wires in the fuse
2.	Unbalanced loading	Single-phase loading or additional heat on account of unbalanced current	• Avoid single-phase loading and unbalanced loading of distribution center. Measure and record the neutral current at regular intervals in distribution center history card • If neutral current exceeds 10% of load current, remedial measures should be taken to bring the neutral current down to within acceptable limits

(continued)

Table 5.4 (continued)

S. No.	Reason on account of user	Probable cause	Preventive action
3.	Faulty terminations	Once spark strikes the cable terminal because of loose connections it causes damage to busing sealing gaskets resulting in oil leakage on bushing top and causing failure of distribution transformer due to low oil level	Use proper termination connectors at both HV and LV sides by bimetal strips per ISS and REC standards
4.	Power theft and hooking	Results in overload/ unbalanced load and may cause failure in due course	• Meter the DTC to identify the pilferage • Regular energy audits, surprise raids, use of ABC conductor
5.	Wrong earth connections	High resistance will delay fault clearance	Solid earth is extremely essential. Earth at two diagonally opposite points of tank. Ensure that nut bolts are not painted at earthing
6.	Prolong short-circuit	If the fault persists for longer duration will result in melting, brazing, or brining of winding	Necessary protection devices may be installed properly such as OCB on HV and ACB on LV side; appropriate rating of HRC fuses for small transformers
7.	Less or no maintenance	–	Line workers should prepare their own maintenance charts as per the criticality (i.e., transformer rating, connected loads, type of installation, and place)
8.	Poor quality of LT cables and hanging against the terminal bushings without any support	PVC insulation causing dead short-circuit in the transformer. Also, its weight pulls the terminal down which may affect the leakage oil from the sealing gaskets of the bushing	–
9.	Improper installation of distribution center	No adequate clearance, missing breather, tree branches near terminals, explosion vent diaphragm, dielectric oil value of oil, and so on	Necessary precaution during replacement/ installation of transformer

5.2.4 *Preventive Maintenance Schedule*

The schedule is shown in Table 5.5.

Table 5.5 Transfer maintenance schedule

S. No.	Inspection frequency	Items to be inspected	Inspection checkpoint	Action required for unsatisfactory conditions
1.	Monthly	• Ambient temperature	• Note ambient temperature regularly	–
		• Oil level in transformer	• Check against transformer oil level	• If transformer oil level is low refill the oil and examine transformer
		• Relief diaphragm	• Check physical condition	• Replace if cracked or broken
		• Dehydrating breather	• Check that air passages are free. Check color of active agent	• If silica gel is pink, change by share change. The old gel may be reactivated for reuse
2.	Quarterly	• Bushing	• Examine for cracks and dirt deposits	• Clean and replace
		• Load (amp) and voltage	• Check against rated figures	• Shut down the transformer and investigate if current and voltage are higher than the normal value
		• Oil and winding temperature	• Check temperature rise is reasonable	• Shut down the transformer and investigate if the temperature is higher than the normal value
		• Oil in transformer	• Check for dielectric strength and water content	• Take suitable action
		• Cooler fan bearings, motors, and operating mechanism	• Lubricate bearing. Check gear boxes. Examine contacts. Check manual control and interlocks	• Replace burnt or worn contact or other parts
		• OLTC	• Check oil in OLTC driving mechanism	–

(continued)

Table 5.5 (continued)

S. No.	Inspection frequency	Items to be inspected	Inspection checkpoint	Action required for unsatisfactory conditions
3.	Half-yearly	• Earth resistance	• Measure earth resistance and record	• Replace with new earthing
		• IR value of lightning arrester	• Measure insulation resistance of lightning arrester	• Change lightning arresters immediately
4.	Yearly	• Oil in transformer	• Check for acidity and sludge	• Filter or replace
		• Oil-filled bushing	• Test oil	• Filter or replace
		• Gasket joints	–	• Tighten bolts evenly to avoid uneven pressure
		• Cable boxes	• Check for sealing arrangements for filling holes	• Replace gasket, if leaking
		• Surge diverter and gaps	• Examine for cracks and dirt deposits	• Clean and replace
		• Relay, alarms, and control circuits	• Examine relays and alarm contacts, their operation, fuse, and so on. Test relays	• Clean the component and replace contracts and fuses if required
		• AB switch	• Check the operation of AB switch	• Grease and check the operation
5.	Two yearly	Sampling and testing of acidity of oil	Take the sample and test for dielectric strength	Replace transformer oil
6.	Three yearly	Filtering of oil (Class B or mixture of Class A and B)	Take the sample and test for dielectric strength	Replace transformer oil
7.	Five yearly	Overhaul of transformer		Replacement every fifth year

5.3 Operation and Maintenance of Transformers and Reactors

5.3.1 Power Transformers and Shunt Reactors

Power transformers and reactors are critical components of the modern electrical power system. To provide reliable, extensive, and continuous services, it is very crucial that regular operation and maintenance of transformers/reactors and their parts are well planned and carried out. The frequency of O&M is dependent on environment, climate, service condition, and so on. A rigid preventive maintenance ensures the long life of transformers/reactors, as well as trouble-free service and low maintenance cost [6]. Table 5.6 lists the maintenance schedule of transformers/ reactors and maintenance consists of regular inspection, testing, and reconditioning where necessary.

Table 5.6 Recommended maintenance schedule for transformers

S. No.	Inspection frequency	Items to be inspected	Action required in case of undesired condition
1	Hourly	• Ambient temperature • Winding temperature • Oil temperature • Load (amperes) • Voltage • Tap position of tap changed	• To be compared with designed value • Refer to OEM in case of violation persistently higher than normal
2	Monthly	• Oil level in bushing, conservator, and OLTC conservator • Manual starting of oil pumps and fans • Checking of oil leak • Oil level in breather oil seal cup • Condition of silica gel • Changeover of supply in MB (to be checked manually if two parallel AC supplies are provided for auxiliary)	• Bushing needs to be replaced in case of oil leak to avoid any failure. In case of low oil level in main conservator or OLTC conservator, top up with dry oil at the earliest opportunity • In the case of oil leak, check tightness of bolts, cracks, and damage to oil sealing gaskets. In the case of a damaged gasket, gasket needs to be replaced • Regenerate or replace the silica gel if it is saturated/moist
3	Half-Yearly	• Dissolved gas analysis of oil • Oil parameter for BDV, PPM, tan-delta, resistivity, IFT • Operational checks on OLTC in charged but offload condition for all tap positions	• In case of violation of fault gases or oil parameter beyond the specified limit, monitoring schedule can be changed in consultation with OEM or based on the criticality of the transformer/reactor
4	Yearly	• Auto starting of fan and pumps • Measurement of BDV of OLTC oil • External cleaning of radiators, bushings, Buchholz, and gas collecting device, and so on • Maintenance of OLTC, driving mechanism, transformer MB • Online moisture measurement • Rust, damage, and repairing (if required) • Core insulation test • Bushing capacitance and tan-delta	• If any problem is encountered in OLTC such as OLTC balancing, problem in driving mechanism, same needs to be rectified per the procedure or as recommended by OEM

(continued)

Table 5.6 (continued)

S. No.	Inspection frequency	Items to be inspected	Action required in case of undesired condition
5	Two yearly	• OTI and WTI setting checks • Alarm and trip test of WTI,OTI, PRD, Buchholz, MOG, and SPR • Earth pit resistance	–
6	Four yearly	• Winding capacitance and tan-delta • Calibration of OTI and WTI	
7	Ten yearly	• OLTC overhauling	
8	SOS	**All LV tests including** • Winding resistance measurement of winding • Magnetic balance test • Magnetizing current test • Voltage ratio at all taps • Frequency response analysis • Measurement of PI and DAI • Short-circuit impedance test • NGR winding and bushing capacitance and tan-delta • Vibration measurement for reactors • Furan measurement	Test results to be compared with test/results of transformer before its commissioning. Previous results to be used in case of major deviation
9	25 Years	• Residual life assessment of transformer/reactor	–

5.3.2 *Testing of Transformers/Reactors*

Testing is shown in Table 5.7.

5.3.3 *General Maintenance of Transformer/Reactor Accessories*

Silica Gel Breather Check: Breathers should be examined to ascertain if the silica gel requires changing. For better results it is advised to change the silica gel when half to two-thirds of the silica gel has become saturated [7]. The silica gel can be collapsed into a shallow tray or reactivated at the same time as in its charge container. Heating of the gel should be done in a well-ventilated oven at 110–130 °C for 8 to 10 h or 150–200 °C for 2 to 3 h and can be used again. Saturation of silica gel charge must occur from the bottom. In the case of silica gel desiccant saturated from

Table 5.7 Transformer/reactor health

S. No.	Name of test/checkpoint	Purpose of test/check
1.	Core insulation tests	Allows for investigating accidental grounds that result in circulating currents if there is more than one connection between the core and ground
2.	Earth pit resistance measurement	To check the resistance of earth pit provided for transformer. Proper treatment is to be given if the resistance of earth is more
3.	Insulation resistance (IR) measurement	Test result shows insulation strength, degree of paper insulation degradation, chemical adulteration in the oil, and damage inside the transformer tank
4.	Capacitance and tan-delta measurement of bushings	Measurement of C1 and C2 capacitance and tan-delta in UST mode. Any change in value of normal insulator capacitance indicates nonstandard conditions such as open circuits or short-circuits in the capacitance network, presence of moisture layer
5.	Capacitance and tan-delta measurement of windings	With the measurement of loss/dissipation factor and capacitance of winding the usual condition of the ground and interwinding insulation can be detected
6.	Turns ratio (voltage ratio) measurement	Measurement used to recognize any abnormal conditions in tapping changer or in shorted or open turns and so on
7.	Vector group and polarity	To determine the phase relationship and polarity of transformers
8.	Magnetic balance test	This test confirms any sort of variance in the magnetic circuit and is applicable only on three-phase transformers
9.	Floating neutral point measurement	This test is conducted to ascertain possibility of short-circuit in a winding
10.	Measurement of short-circuit impedance	This test is used to identify winding movement that usually occurs due to heavy fault current or mechanical damage during transportation or installation since dispatch from the factory
11.	Exciting/magnetizing current measurement	Measurement used for shifting of windings, locating any fault in magnetic core structure, problems in tap changers, or failures in turn-to-turn insulation
12.	Operational checks on OLTCs	To ensure smooth and trouble-free operation of OLTC
13.	Tests/checks on bushing current transformers (BCTs)	To ascertain the health of bushing current transformer at the time of erection
14.	Operational checks on protection system	Operational checks on cooler bank (pumps and fans), breathers (silica-gel or drycol), MOG, temperature gauges (WTI/OTI), gas actuated relays (Buchholz, PRD, SPR, etc.), and simulation test of protection system

(continued)

Table 5.7 (continued)

S. No.	Name of test/checkpoint	Purpose of test/check
15.	Stability of differential, REF of transformer/reactor	This test is performed to check the proper operation of differential and REF protection of transformer and reactor by simulating actual conditions. Any problem in CT connection, wrong cabling, or relay setting can be detected by this test
16.	Frequency response Analysis (FRA) measurement	Before commissioning, this test is required to make sure the transformer's active part has not suffered any severe impact/twitch during transport of transformer
17.	Winding resistance measurement	To verify any broken strings and high contact resistance, loose connections in tapping change devices
18.	Vibration test (for reactors only)	To check any abnormal vibration of shunt reactor during operation
19.	Dissolved gas analysis (DGA) of oil sample	Oil sample for DGA to be drawn from transformer main tank before commissioning for base data and after 24 h of charging subsequently to ensure no fault gas developed after first charging. DGA of oil sample helps in concluding the generation of gas and materials involved in the urgency of righteous measures to be taken by the operator

the top, proper tightening of the breather to the connecting pipe and condition of gasket is to be ensured.

Visual Check for Conservator's Oil Level: The transformer conservator consists of a magnetic oil-level gauge (MOG); each transformer conservator of the main tank is fitted with one MOG to indicate when the oil inside the conservator tank reaches minimum or maximum. The MOG dial has a scale from empty to full; it also has some intermediate divisions such as 1/4, 1/1, and 3/4. During full load condition, the temperature of the insulating oil increases accordingly, insulating expanded oil and the oil level goes up. After the full load, when the transformer load decreases the oil temperature reduces in turn reducing the volume of oil. But it is very essential to maintain the minimum oil level in the transformer conservator tank even at the lowest possible temperature. The entire transformer top of the conservator tank is fitted with a MOG. A lightweight hollow ball is floated on the insulation oil inside the conservator tank. The float arm is attached with bevel gear and the float goes up and down depending upon the oil level and consequently the float arm alignment changes. The MOG is float operated through the tank wall with the magnetically coupled float mechanism to the dial indicator. The float rotates a magnet inside the tank as the level increases beyond a certain level with the increase in level. The oil level indicated by the MOG and top oil temperature should be observed. The top oil temperature reading should be used to correct the oil-level gauge reading. The corrected oil level should be in the position corresponding to normal as mentioned in the OEM instruction manual (35 °C) range. If the level of oil is standard, there is no need to take extra action, but adding the oil and removal of oil from the conservator tank should be done if it is below or above the normal level, respectively.

Checks on Temperature Gauges: Oil temperature and hotspot temperature gauges are important for proper operation of the transformer. These gauges not only indicate temperature but also operate the fans and coolers by means of microswitches (mercury) that can be adjusted for various temperature settings. These gauges should be calibrated on a regular basis onsite with portable devices or in the laboratory.

Winding Temperature Indicator (WTI) Test: WTI is used to indicate the temperature of the winding based on the manufacturer heat run test. It does not have the temperature-sensing device which is fixed in the winding hotspot; as it gives only an approximate value of the temperature of the hotspot winding, it should not be an accurate value. But it can be used to activate the cooling system as well as the top oil thermometer. Winding temperature thermometers are placed near the top of the tank; it is similar to topping the oil thermometer which has a separate thermometer well without the bulb [8].

A wire is wrapped between the thermometer and temperature-sensitive bulb or a heater coil can be inserted into the thermometer in same way. A current transformer (CT) as in certain transformers has three leads of windings and gives current in proportion to the winding current directly to the heater coil. In other transformers, the CT gives current to the heater coil via an autotransformer. The bulb is slightly heated by the heater and the temperature is shown at the indicating dial although the value shown is not the true temperature of the hottest spot. Based on measured temperature rises, or data from tests of a thermally duplicate transformer, bias current to the heating coil of the winding temperature indicator is factory adjusted to simulate the same gradient in degrees Celsius over the top oil rise as will be experienced by the hottest spot in the transformer windings. The manufacturer makes adjustments in these devices by altering the taps on the autotransformer or CT, or by altering the calibration resistors in the control cabinet.

WTI normally cannot be field tested or calibrated other than testing the thermometer. Current in the heater circuit is adjusted by the transformer manufacturer; the magnitude of this current should be known to allow calibration of the unit to be verified. The calibration resisters can be adjusted in the field if the calibration curves of the heater current versus hottest spot gradient for the transformer available with the manufacturer are provided to user.

5.3.4 Cooler Control Setting, Alarm, and Trip Test

- Make sure transformer equipment is isolated, properly de-energized, and earthed.
- Temperature setting should be per standards. Only indicative values are furnished below. These values are to be taken seriously and confirmed with the instruction manual provided by the manufacturer.

- Use the local winding temperature indicator and move its pointer slowly to the first level of cooling value (say 65 °C).
- The cooler's fans which are set to the first level need to be checked in operation.
- Continue rotating the pointer to the second level cooling value (say 80 °C).
- Fans/pumps of those coolers which are set to the second stage need to be checked in operation.
- Continue rotating the pointer to the alarm preset value (say 100 °C).
- Check the alarm signal received in the control room is trustworthy.
- Set the tripping value (say 110 °C) by changing the indicating pointer.
- Whether trip signal has been received in the control room should be checked.

5.3.5 Calibration of the Winding Temperature Indicator

- The winding temperature indicator bulb needs to be removed from the transformer pocket placed in the tank cover.
- The bulb is inserted into a calibrated temperature-controlled bath.
- The temperature of the bath is raised in 5 °C steps and the response of the winding temperature indicator verified in a 10-min cycle up to a maximum temperature of 130 °C. The tolerance for the temperature indication is ±3 °C.
- Now the temperature of the bath is lowered by 5 °C steps and the response of the winding temperature indicator in the 10-min cycle is checked. In parallel verify the transducer output; the allowable tolerance limit is ±3 °C.
- Verify alarm and trip switch configuration by changing pointer to set temperature. Use a multimeter to indicate these settings and record the operational values.
- After completing return the bulb to the pocket in the transformer cover. Care should be taken for matching levels between temperature indicator and pointer.

5.3.6 Secondary Injection Tests

ONAN Rating

- Validate isolated cooler supply is in switched OFF state.
- Keeping constant temperature of 50 °C, change the winding temperature indicator bulb in the calibrated temperature-controlled bath.
- The rated current is injected into the winding terminal, a temperature indicator test kit is used for verification, and the result noted where the obtained result is same as the ONAN rating.

OFAF Rating

- A running pump is required to carry out these tests.
- Set the cooler isolator at ON position.
- Set the cooler switch to fans and pumps position.
- Ensure that pump is running.
- Turn on the heater coil and check the gradient for OFAF rating.
- Disconnect and set the cooler control switch to AUTO.

5.3.7 Oil Temperature Indicator (OTI) Tests

The thermometer consists of a cylindrical sensing body with a flange, capillary tube, and thermometer housing with dial and contact device. The measuring system is filled with a liquid that changes its volume at temperature variations and affects springy bellows [9]. The movements of the bellows are transferred to the pointer and signal contacts via a link system. The thermometer is provided with four microswitch-type signal contacts. The contacts can be set independently of each other. As to control and adjustment of the thermometer, see the instruction manual supplied by the manufacturer. This manual also gives settings recommended for the signal and start of the cooling equipment, respectively.

(a) Calibration of Top Oil Temperature Gauge

- Remove the OTI bulb and insert calibrated temperature-controlled oil bath from the pocket on the transformer lid.
- Increase the temperature of the oil from 0 to 120 °C step by step; increases in temperature should preferably be 5 °C or 10 °C intervals. Note the OTI, reading again the oil temperature range with tolerance ±3 °C.
- Note the oil temperature and instruct the alarm indicator (i.e., 95 °C) and the trip value pointer to 110 °C and check if they are operating using a multimeter across the said switches.

Interpretation: If the temperature difference between the reference temperature and dial indicator is more than 5 °C, it is suggested that it should be replaced with a healthy one. If it is impossible to replace the temperature gauge with a new one, or send the gauge for repair, put a temperature adjustment factor on the gauge to correct the error (addition or subtraction to the dial reading) to get the correct temperature reading.

Once the alarm lower turning on the settings of pump by the same correction factor mentioned above. These are pressurized systems and if out of calibration the indicator will read low. During field testing of the RLA it was observed that some of these gauges read 10–15 °C lower than normal temperature. The transformer gets in dangerous conditions as it allows continuous running in hotter than intended temperatures due to late activation of alarms and cooling. Transformer life may be shortened to failure if the thermometers are not properly tested and errors are corrected.

Checks on Gas Pressure Relay

There are two types of gas pressure relays commonly used in the transformer/reactor. The most common type is mounted under the oil and a similar type is mounted in the gas space. Internal arcing in liquid-filled electrical power equipment produces extreme gas pressure; it can severely damage the transformer and also pose severe danger to line personnel. The gas pressure relay is used to reduce the degree of damage by quickly activating the transformer protection system. The manufacturer's recommendations should be referred to for adjustment, repair, or replacement of an improperly operating device.

Pressure Relief Devices (PRDs): After the pressure release, the PRDs are spring-loaded valves that automatically reclose. When the PRD does not operate properly, the pressure inside the transformer is not relieved adequately. As a result, within a few seconds catastrophic rupturing of the tank occurs, spreading flaming oil over a wide area. Once a year, or as soon as possible after the internal fault, inspect PRDs and test the working condition. Switch the alarm circuits ON and make sure whether the correct communication point is activated.

Note: During operation if the PRD operates, then do not try to re-energize the transformer. All LV tests may be required to be carried out before re-energization and the oil sample sent for testing at DGA.

Sudden Pressure Relays (SPRs): A sudden pressure increase by arcing can be detected by SPR. The operating time is very fast and designed to operate before the PRD operation. Pressure is exerted at the bottom of the transformer tank; when a sudden excessive pressure develops this would move the spring operating pin. This operates like a switch generating further alarms and a breaker trip signal is generated. Once the relay responds successfully, the relay cap must be detached and the switch reset to normal by resetting the button.

Note: If this relay operates, then do not try re-energizing the transformer until the exact cause of operation is determined and corrective action taken.

5.3.8 Checks on Buchholz Relay

(a) **Alarm Checks**

- Connect the tubes of the "bomb" to the copper pipe from the relay test cock (top of the relay) and foot pump.
- Charge the Buchholz pressure bottle with the foot pump to a pressure of 4 bar (60 psi). Measure the volume of gas trapped inside the window and mark.

- Keep the valve on the tank side closed. Open the relay test cock. Alternatively open the drain valve/plug of the relay.
- Very slowly release the valve of the Buchholz pressure bottle to allow air into the relay.
- Check the control room to ensure that the gas alarm has indicated once a sufficient amount of air has entered the relay.
- Check for correct operation using a multimeter (continuity of alarm contacts) connected across the alarm contacts in the relay.
- Close the relay test cock. Close the valve on the Buchholz pressure bottle.
- Vent all air from the gas and oil relay; close when a steady stream of oil is discharged into the bucket.

(b) **Trip Check**

- Charge the Buchholz pressure bottle to a pressure of 2 bar (30 psi).
- Keep the valve on the tank side closed.
- Open the relay test cock.
- Open the drain valve/plug of the relay.
- Quickly open the valve on the Buchholz pressure bottle to allow a full surge of air to enter the relay.
- Check the control room to ensure the surge trip relay flag has operated.
- Check correct operation of relay trip switch contacts using a multimeter (continuity of trip contacts) connected across the trip terminals.

(c) **Gas and Oil Relay Surge at Pump Activation**

Check the status and conditions of the alarm and trip contacts of the Buchholz relay as soon as the oil pump starts. This check is carried out manually and automatically so that any spurious alarms and trips do not result in a faulty condition.

(d) **Results**

If the relay operates correctly close the bomb valve, disconnect from copper pipe work, and vent all air from the relay petcock. If the relay fails to operate repeat the alarm check at successive incremental pressures of 0.25 bar (3.5 psi) up to 4 bar (60 psi) until the relay operates. Operating pressure is to be recorded.

If the relay fails to operate, isolate the relay from the expansion vessel and the tank using the valve (see the concerned valve on the general arrangement drawing). Drain the oil from the relay mechanism.

Blank off each open flange while investigating the relay fault to ensure that no contamination enters the system. If the switches in the relay are faulty replace them. Alternatively, if the relay mechanism is faulty replace that. Refit the relay into the pipe work using new gasket material. Vent all air from the relay. Open the relay test petcock and vent all air from the system after completion of test.

5.3.9 Checks on Cooling System

Large power transformers are fitted with some type of cooling system. Cooling systems generally consist of combinations of radiators, pumps, and fans. The cooling surfaces should be inspected regularly and cleaned of foreign particulates. This is especially important in the case of fan cooling. The cleaning should be performed with high-pressure water flushing and proper safety measures such as by covering the fan motor, so that the high-pressure water does not enter it [10]. During flushing, it is likely that the radiator fins get bent. They should be straightened immediately after cleaning. Finally dry cloth and cleaning solutions are used in the cleaning process. Normally, no measures are necessary for keeping the internal cooling surfaces clean as long as the oil is in good condition. If, however, sludge formation has set in, the sludge may deposit on horizontal surfaces in radiators and coolers. If that occurs, the radiators and coolers should be internally flushed by new clean oil in connection with the oil exchange.

The cooler bank should be inspected regularly. Cleaning of coolers is carried out by pulling off the tube packets and making them accessible for cleaning. This activity is to be carried out in consultation with the manufacturer. Generally all the fan motors have permanent lubrication in their bearings and also have dual sealing rings. The motor bearings are axially clamped with spring washers. If the noise level of the fan increases, all mounting supports should first be retightened.

5.3.10 Cooling System—Fans

(a) Visual inspection should be done when the transfer is onload to ensure fans are operated at the rated speed and their airways are not barren, thus saving the blades from damage. Any fan that is running at less than its design speed will be obvious to the naked eye. For more precise measurements, a tachometer may be used.
(b) The rotation of the fan blades should be observed to ensure that the air flow is in the proper direction for the type of device involved. The observation may be facilitated if it is performed at a lower than normal speed either during startup or immediately after switching off. Corrections to rotation should be made as indicated by inspection.
(c) All fans that are not running at design speed should be replaced. After stopping fans, any obstructions to air flow should be removed and any damaged fan guards or blades should be replaced or repaired.
(d) If the motor is fitted with heaters they should be switched on whenever the motor is standing. Check for buildup of moisture in the motor. Drain holes are provided at the lowest part of the motor and are fitted with plugs on totally enclosed motors (wherever applicable). These plugs should be removed to allow any moisture to drain away.

(e) Regular greasing of the bearings should be carried out and as a general guide, one or two shots from a grease gun should be sufficient at intervals of 1000 running hours. It will only be necessary to maintain the grease in the bearings.
(f) It is recommended that at least every two years the bearings and housings be flushed out in white spirit and inspected for wear. Worn parts should be replaced where necessary and repacked with grease.

Cooling Fan Controls: The cooling fan manual and automatic control system can be operated; however, automatic operation is associated with the load and energization.

Manual Control: This turns ON for a brief period to ensure that each stage has sufficient voltage to operate. Fan operation should be observed and the oil pumps' operation and their flow gauges checked. Refer to the manufacturers' recommendations for any malfunctions.

Temperature Control: Remove the temperature bulb from its well on the top of the transformer; put the master control in automatic position. Using a calibration instrument slowly raise the temperature of the bulb and observe for proper calibration/operation.

Load Control: Verify the CT controlling secondary current operation. Remove the secondary lead after shorting out the CT secondary (if the transformer is energized); further current should then be injected in the control circuit and its level varied to observe proper operation.

Caution: Extreme care should be observed when performing operations with the secondary of an energized CT; otherwise if the CT secondary is left open by mistake, catastrophic results may occur without warning.

5.3.11 Cooling System—Pumps

(a) Cooling pumps are generally centrifugal-type pumps and as such will pump some oil regardless of their direction. The pump has a direction and flow gauge/indicator fitted on the top of the pump. The pumps should be manually turned ON and OFF and the action of each pump's flow gauge should be observed while the pump is coming ON. The oil flow should cease or be at a bare minimum before energizing the circuit.
(b) If the movement of the flow gauge flag is sluggish where 3-ph motors are used, there is an indication of reverse rotation. Reverse any two electrical leads supplying the suspect pump and re-energize. The movement of the flow gauge flag should now be more prompt.
(c) To determine excessive bearing wear remove the pump for visual inspection. After removing the pump from the system, the end play of the shaft should be measured. The impeller and impeller housing should be examined for any wear. The manufacturer's guide should be consulted to determine if excessive bearing wear exists as indicated by the amount of shaft end-play observed. Any

indication of wear on the impeller and impeller housing is indicative of excessive thrust-bearing wear.

(d) Partially shorted motor windings and other electrical problems with the pump motor will cause generation of combustible gases in the transformer oil DGA because oil directly flows through the pump motor during normal operation. Routinely or after detecting an abnormal level of combustible gas in the transformer oil DGA, the current flowing in each electrical terminal of each pump motor should be accurately measured at the running condition of the pump.

(e) The oil flow gauge shows only whether there is oil flowing through the pump. It is not indicative of the velocity of the oil or the condition of the pump. After making sure that the oil cooling pumps are ON, the flow gauge should be observed for indication of flow. If the pump is ON and no flow is indicated, the sensing unit may be defective. If the pump is turned OFF and the flow gauge continues to indicate, the gauge is probably stuck in the flow position and the sending unit or the entire gauge may need to be replaced. It is normal for a gauge to continue to indicate flow for a brief period before indicating OFF (no flow), following the turning off of a pump. This is due to conservation of momentum with respect to oil.

5.3.12 Operational Checks on OLTC

Tap Changer Handle Operation: Move the tap changer handle up as well as down over its entire range; check the operation before trying to attempt electrical operation. Also keep in mind that while the handle is inserted, the interlock switch of the said handle will not allow electrical operation. In addition to this, check tap positions for the single-phase tap changers and make sure that they reached together at the motor drive unit head. Continuity and discontinuity of the tap-changing operation is verified by connecting a multimeter across the high- and low-voltage sides and changing the position from minimum to maximum.

Maintaining Circuit: The correct sequence of the maintaining circuit needs to be checked by hand, winding the units to halfway through a tap and then removing the handle. Power up the drive motor and also make sure that the motor runs to drive the tap changer handle in the same direction.

Limit Switches: Limit switches' operation needs to be thoroughly checked at both ends.

Drive Motor: Put tap changer in the middle position and verify the rotational direction. Measure the starting and running currents in both the higher and lower modes of operation and also measure and record these values. Set the motor's overload to 10% above normal running current.

Raise and Lower Control: (1) Step-by-step relay operation; (2) move tap changer one tap at a time.

Out of Step Relay: Shift the first tap changer in a three-phase bank to be one position out of step with respect to the other two phases. Check the alarm's condition to ensure it is activated properly. In the same way repeat this process for the other two tap changers.

- First check the suitable operation of the local/remote switch.
- Using local control, raise and lower the tap changer over its full operational range.
- Repeat the above using the remote raising and lowering facility over the full range.
- Check that neither the local nor remote switches can operate the tap changer when it is in the other mode and vice versa.
- Hold the raise and lower pushbuttons in following a tap change to ensure it only moves one tap at a time hence checking the step-by-step relay.

Tap Change Position Indicator: Check the mechanical position indicator to ensure accurate indication in all positions. Also check that the remote instrument operates in the same sequence to the same accuracy. With the remote instrument unconnected, operate the tap changer and measure the output from each binary coded matrix.

Tap Change Incomplete Alarm: Check whether the operation of the tap changer is incomplete by keeping the winding unit on hand halfway through a tap changing, including alarm working, flag relay, and also monitoring if their operation is right as well as time of operation.

Operation Counter: Ensure that the tap changer counter operates and reads correctly.

Remote Indication: Check the remote indication switch and control facility to prove that the output terminals of the said arranging kiosk are working fine.

Tap Changer Protective Relay: Verify the tripping characteristics of the relay by opening the cover and pressing the "Trip" button to check the operation of the transformer CB; ensure proper working function and then close the cover. The following checkpoints/guidelines 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.

The following checks are to be carried out on OLTC.

(a) Manual operation on all taps and handle interlock switch.
(b) Local and remote operation and L/R switch.
(c) Matching of tap changer positions and tap position indicator.
(d) Check the working order of the tap selector handle; exchange the selector and arcing transfer switches.
(e) Drive operations.
(f) Counter, position indicator, and its co-ordination with mechanism operations.
(g) Limit switch operation.

(h) Mechanical blocks integration.
(i) Proper movement of the hand-crank and its interlock switch.
(j) Physical wear and tear of tap selector.
(k) Free movement of the external shaft assembly.
(l) Extent of arc erosion on motionless and variable arcing contacts.
(m) Inspect the end boards for tracking and cracking the faults.
(n) After filling with oil, manually crank during entire range.
(o) Oil BDV and moisture content (PPM) to be recorded and measured to a minimum BDV of 40 kV and moisture content of 10 PPM.

5.3.13 Checks on Bushings

After one month of service and on a yearly basis, make sure that the porcelain bushings are free of dust and dirt; otherwise proper cleaning is required. Particularly in the areas where there is high air pollution, salt regions, cement dust, or chemical substances, cleaning is required regularly at short intervals. If the bushing is damaged/highly polluted, it causes excessive leakage current and a visible mark appears as treeing (carbon tracking) on the surface of the bushing and may cause flashovers if the bushings are not cleaned and replaced properly.

By looking in the oil-sight glass, check the oil level in the bushings because the level does not change with varying temperature. Stuck oil gauge pointers coherent with an oil leak can cause a collapse in the bushing and possible damage in the transformer and switchyard equipment. If the oil level is low, and the external leakage not visible, there might be internal leakage around the lower seal of its tank. In that case refill the bushing with the same oil as per the standard. An old bushing is replaced when it has more than 25% of bushing oil capacity; the bushing is sent for repair or it may be completely scrapped, if unrepairable at the site.

Inspect the bushing using an infrared camera regularly after one month of service and on a yearly basis. In the case where any of the phases shows an eccentrically high temperature, there is a possibility of poor connection; line personnel have to verify the top connection first, however, a poor connection inside the transformer tank leads to higher temperatures at the top also. Furthermore these faulty connections should be detected by finding the hot metal gases such as the ethane and ethylene ratio in the DGA.

Caution: When the temperature is high don't open the oil fill plug of any bushing because pressurized hot oil gush may result in a burn injury. Generally a safe temperature range is between 15 and 35 °C. Some bushings may have gases such as nitrogen in the form of a blanket on top of the oil layer which pressurizes it as the oil expands due to temperature. Check with the manufacturer while topping up oil or opening the bushing. Also see the directions in the special information documents about bushings that are included in the transformer instruction manuals at delivery.

5.4 Connectors

In order to avoid extreme temperature rises at the electrical connections of the transformer, check screw joints and retighten the screws according to the manufacturer's manual. For transformers in service, a thermovision camera may be used.

5.5 Maintenance of Insulating Oil

Mineral oil is used as an insulating fluid in transformers/reactors. In addition to acting as an insulating fluid, it also acts as a heat transfer medium to carry off excess heat generated by the losses of power transformers. Tests cover the determination of certain quantities, primarily degradation constituents in in-service transformers and the diagnosis of these results wrt the power transformer condition [11, 12].

A sampling technique should ensure that the specimen taken is representative of the insulating oil contained within the equipment. Natural contaminants exist within the body of sampling valves; therefore valves should be flushed before extraction is performed in order to ensure that sample integrity is maintained. A sufficiently large sample should be withdrawn to cover all tests as listed below. Typically 1 L oil is enough for carrying out the following tests to ascertain continued serviceability of any insulating oil filled in the transformer/shunt reactor or any other electrical apparatus. The tests explained above are carried out at specific time intervals. However, for carrying out DGA, syringe sampling is recommended.

- Dielectric strength sampling
- Water content sampling
- Specific resistance sampling
- Dielectric dissipation factor
- Flashpoint sampling and recoding
- Total acidity sampling
- Interfacial tension sampling
- Sludge content (for aged oils only)

The following tests are generally performed to determine the various properties of oil meeting certain conditions.

- Kinematic viscosity
- Pour point sampling
- Carbon type composition
- Oxidative ageing
- PCB content and density
- Oxidation stability and SK value

The diagnosis of the equipment containing oil is evaluated with the following tests; they do not check the quality of the oil.

- Dissolved gas analysis (DGA)
- Furfur-aldehyde analysis (FFA)

Give special attention to diagnostic tests, for the oil-filled equipment, and not the oil itself. The DGA evaluates the composition of gases dissolved in transformer oil and estimates most probable incipient faults in the transformer using various interpretation techniques per standards such as IS9434, IEC 60599, IEC 60567, and IEEE C57.104. The furfur-aldehyde analysis is generally for checking the health of the paper insulation in the windings by measuring the 2-furfur-aldehyde released in the oil when the insulation paper degrades. It is to be understood that these two tests are diagnostic and trend related and not analyzed on absolute values of results. Normally insulation oil is checked against dielectric and moisture content in an onsite test to determine the transformer oil condition.

5.5.1 Tests for Dielectric Strength (BDV)

To do the BDV test, a 2.5-mm gap is maintained between the electrodes; a further six tests are performed on the oil to check its breakdown voltage. The six-digit value in the result is taken into account to check the acceptance condition for 70 kV. Refer to IS-6792 or IEC-60156 for the detailed testing procedure.

Tests for Moisture Content (Measured in ppm): Inject a sample of the oil in an automatic moisture content test kit. Depending on the type of test kit, the moisture may be measured by µg H_2O and the measured figure could be divided by weight of the injected oil sample in grams, thus giving parts per million units. Generally moisture content would be maintained less than 10 ppm when the transformer is in service condition [13, 14]. As this test is highly operator- and kit-maintenance dependent, it is advisable to send the sample to an authorized laboratory only.

Note: DGA frequency for new equipment under commissioning should be just before charging, after 24 h of charging, 7 days, 15 days, one month, and three months after charging; thereafter six monthly DGA to be followed. The frequency of sampling can be changed depending on test results.

Frequency Response Analysis (FRA): The FRA test is conducted on transformers and reactors to determine the frequency response of windings. The reference frequency responses obtained during laboratory testing serve as "fingerprints" to monitor the condition of the transformer or reactor during service.

The frequency response of an electrical winding is obtained by application of sweep frequency (sinusoidal). The winding will have a characteristic frequency response for the applied signal at different frequencies. The response is uniquely determined by the winding arrangement involved and any winding movement or other fault will modify the frequency response due to changes in inductance and capacitance. The sweep frequency voltage is applied through network analyzers. The frequency response of the winding is determined between the frequency ranges of 10 Hz to 2 MHz.

The FRA test is performed on one winding of the electrical equipment at a time. The transformer/reactor should be electrically isolated from any other electrical connections or systems, including earth connections during the FRA test. The two end terminals of each winding should be made available for measuring the frequency response across the winding.

- For star-connected winding, the response should be measured across the terminal and neutral.
- For delta-connected winding, the response should be measured across two line terminals and in the case of open-delta, across individual winding.
- For autoconnected winding, the response of series and common windings should be measured separately.

For a transformer, it is normal practice to earth one end of every winding that is not being tested, leaving the other end open. Alternatively, all other windings may be left unconnected from each other and from earth. In every case, the termination of each winding for each test should be recorded. The frequency response of the winding is determined by plotting the ratio of the output from the winding to the input in the frequency range of 10 Hz to 2 MHz.

Alternatively frequency ranges specified by the customer can be selected. The test is normally conducted at maximum, mean, and minimum taps, in the case of windings having tapping. While making measurements at mean tap, care should taken to move the tap from higher voltage taps for proper comparison of FRA results of different phases of the same or different transformers.

The FRA results are analyzed for:

- Changes in response of the winding
- Significant difference between the FRA records of different phases of the same transformer
- Significant difference between same phase of identical transformers

The FRA test is primarily a condition assessment test and can be used in conjunction with other diagnostic tests for detailed analysis and interpretation of the transformer.

Dielectric Frequency Domain Spectroscopy (FDS): In frequency domain spectroscopy (FDS), the frequency sweep measures the dissipation factor of the insulation components. The frequency versus tangent delta measurements method is called frequency domain spectroscopy. In this method, the frequency range is much enhanced, especially to low frequencies.

Figure 5.2 shows the S-shaped curve where the dissipation factor is plotted in the *y*-axis and the frequency is in the *x*-axis. The temperature and ageing curve move towards the higher frequency scale when the moisture content increases.

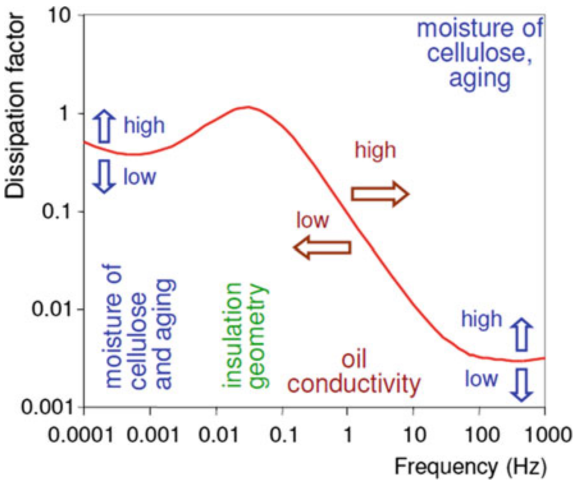

Fig. 5.2 Dielectric frequency domain spectroscopy

Table 5.8 Moisture content in paper

S. No.	Insulation condition	Source: IEEE standard 62-1995	
		% Moisture by dry weight in paper (Wp)	% Saturation of water in oil
1.	Dry (at commissioning)	0.5–1.0	<5
2.	Moderate to wet (lower number indicates fairly dry whereas large number indicates moderately wet insulation)	<2	6–20
3.	Wet	2–4	21–30
4.	Extremely wet	>4.5	>30

Source CIGRE DOC. No. 227. Life Management Technique for Power Transformer

Moisture content has greater influence in the lower and higher frequency ranges; the steep gradient shows oil conductivity in the midrange of the curve. The "hump" left side of the steep gradient curve data helps to calculate moisture content.

Table 5.8 may be considered for determining the level of wetness and taking necessary action for dryout.

Partial Discharge Measurement: PD techniques for detection and location are important for diagnostics, as they not only help to identify the inception of damage caused, but also assist in monitoring the evolving and deteriorating situation affected by the various stress factors existing in the service condition. There can be various reasons for PD inception. It can be the result of electrical stress caused by mechanical deformation, overheating of an insulated conductor, or can even be the result of inherent defect. The PD detection at the site can be done by various techniques such as

- Dissolved gas analysis
- Conventional IEC 60270
- Acoustic measurement
- RFI measurement
- UHF measurement

All these techniques have their strengths and weaknesses in terms of sensitivity and accuracy. The sensitivity and effectiveness of these techniques depends upon the type of defect and location of the fault.

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