

IEEE Guide for Diagnostic Field Testing of Fluid-Filled Power Transformers, Regulators, and Reactors

IEEE Power and Energy Society

Sponsored by the
Transformers Committee

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USA

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(Revision of
IEEE Std 62™-1995)

IEEE Guide for Diagnostic Field Testing of Fluid-Filled Power Transformers, Regulators, and Reactors

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Abstract: Diagnostic tests and measurements that are performed in the field on fluid-filled power transformers and regulators are described. Whenever possible, shunt reactors are treated in a similar manner to transformers. Tests are presented systematically in categories depending on the subsystem of the unit being examined. A diagnostic chart is included as an aid to identify the various subsystems. Additional information is provided regarding specialized test and measuring techniques. Interpretive discussions are also included in several areas to provide additional insight on the particular test or to provide guidance on acceptance criteria. These discussions are based on the authors' judgment of accepted practice. It should be noted that the results of several types of tests should be interpreted together to diagnose a problem. Manufacturers' acceptance criteria should also be consulted as it may take precedence over the criteria in this guide.

Keywords: bushing, core, diagnostic evaluation, field testing, fluid-filled transformer, IEEE C57.152™, insulating liquid, off-line testing, reactor, regulator, safety, tank, tap changer, winding

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Introduction

This introduction is not part of IEEE Std C57.152-2013, IEEE Guide for Diagnostic Field Testing of Fluid-Filled Power Transformers, Regulators, and Reactors.

Power transformers usually represent one of the most important and single most costly items in substations. Furthermore, particularly for large transformers, their failures usually result in lengthy outages or downgrading of electric service reliability. For these reasons, a high degree of care is required to properly field test this equipment to confirm equipment status and identify problems.

Because of these considerations, IEEE and other standards development organizations have published, since at least the early 1920s, various recommendations for testing and maintaining transformers. This guide replaces IEEE Std 62™-1995 [B33], since it primarily deals with power transformers, regulators, and reactors, which are devices covered by the Transformers Committee.^a

New sections have been added on safety; tank vacuum testing; visual inspection; a chart providing commissioning, routine, and after-fault testing guidance; and informational annexes. Also, new technologies have been identified that are available for use in field testing.

^a The numbers in brackets correspond to those of the bibliography in Annex J.

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1. Scope

This guide describes diagnostic field tests and measurements that are performed on fluid-filled power transformers and regulators. Whenever possible, shunt reactors are treated in a similar manner to transformers. The tests are presented systematically in categories depending on the subsystem of the unit being examined. A diagnostic chart is included as an aid to identifying the various subsystems. Additional information is provided regarding specialized test and measuring techniques.

Interpretive discussions are also included in several areas to provide additional insight on the particular test or to provide guidance on acceptance criteria. These discussions are based on the authors’ judgment of accepted practice. It should be noted that the results of several types of tests should be interpreted together to diagnose a problem. Manufacturers’ acceptance criteria and other standards in the IEEE C57™ series take precedence over the content of this guide.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 4TM, IEEE Standard Techniques for High-Voltage Testing.^{1, 2}

IEEE Std 510TM, IEEE Recommended Practices for Safety in High-Voltage and High-Power Testing.

IEEE Std C57.12.80TM, IEEE Standard Terminology for Power and Distribution Transformers.

IEEE Std C57.12.90TM, IEEE Standard Test Code for Liquid-Immersed Distribution, Power and Regulating Transformers.

IEEE Std C57.93TM, IEEE Guide for Installation and Maintenance of Liquid-Immersed Power Transformers.

3. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* [B32] and IEEE Std C57.12.80 should be consulted for terms not defined in this clause.^{3, 4, 5}

apparent charge (terminal charge): A charge that, if it could be injected instantaneously between the terminals of the test object, would momentarily change the voltage between its terminals by the same amount as the partial discharge (PD) itself. The apparent charge should not be confused with the charge transferred across the discharging cavity in the dielectric medium.

NOTE 1—Apparent charge, within the terms of this guide, is expressed in coulombs (C). One picocoulomb (pC) is equal to 10^{-12} C pulse charge transferred from the PD source to the terminals of the test object.⁶

NOTE 2—The **apparent charge** is measured in terms of picocoulomb (pC) using a calibrated PD measuring circuit as specified in IEEE Std C57.113TM-2010 [B41].

NOTE 3—The **apparent charge** is different from the PD charge because that charge originated at the PD site, which cannot be measured directly.

NOTE 4—The **apparent charge** is sometimes referred to as *terminal charge*.

partial discharge (PD): An electric discharge that only partially bridges the insulation between conductors, and which may or may not occur adjacent to a conductor.

NOTE—PD events may ignite in gaseous dielectrics due to a localized electrical field enhancement. Generally, PDs are caused by dielectric imperfections, such as gaseous inclusions in solid and liquid dielectrics as well as protrusions on electrodes in ambient air.

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³ *IEEE Standards Dictionary Online* subscription is available at:
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⁴ The numbers in brackets correspond to those in the bibliography in Annex J.

⁵ Information on references can be found in Clause 2.

⁶ Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

partial discharge (PD) level: Mean peak value of the apparent charge of PD pulses, whose magnitudes are randomly distributed and are evaluated by a PD measuring instrument specified in IEEE Std C57.113-2010.

NOTE—See IEEE Std C57.113-2010 [B41].

partial discharge (PD) measuring instrument: Analog or digital equipment for wideband measurement of the apparent charge as specified in IEEE Std C57.113-2010.

NOTE—See IEEE Std C57.113-2010 [B41].

radio interference voltage (RIV) level: Mean peak value of the RIV evaluated by an RIV measuring instrument specified in NEMA 107.

NOTE—See NEMA 107 [B57].

radio interference voltage (RIV) measuring instrument: Analog or digital equipment for narrowband measurement of the RIV of partial discharge (PD) events as specified in NEMA 107.

NOTE 1—See NEMA 107 [B57].

NOTE 2—**RIV measuring instrument** is sometimes referred to as an *RIV meter*.

4. Purpose of tests

Transformers are critical components within the overall architecture of a power system network and represent a substantial investment on the part of the user. The life cycle of such devices encompasses manufacture, transport, installation, and in-service aging and maintenance. Each period in the life of a transformer includes unique challenges to its integrity of which the manufacturer and user must be aware. Undetected damage or degradation of the transformer at any stage of this process can predispose the unit to failure. Because the premature loss of a large power transformer can impose significant fiscal, logistical and operational challenges, IEEE guides and standards have been developed to assist in its assessment during each life cycle period.

Large power transformers are devices that generally provide many years of service when well built and maintained. Collectively, the life of transformers roughly follows the classical “bathtub” curve, with a small number of units subject 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. Each set of tests described in IEEE guides and standards is intended to help detect and thereby 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 phase.

Factory tests (routine, design, and conformance) such as those described in IEEE Std C57.12.90 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. Field tests described herein can be divided into several categories associated with stressors that are unique to each period in the unit’s life cycle (transportation, installation, in-service aging, and maintenance). Such tests seek to identify deviations from the unit’s original condition at the factory. Therefore, optimum interpretation of the field tests described herein requires access to the original tests to quickly identify deviations or trends.

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. Such considerations include, but are not limited to the following:

- Cost of the transformer(s)
- Criticality of the connected load(s)
- Vintage of the unit(s)
- Loading
- Manufacturer(s)
- Service history of the unit(s) (or of units of similar design)
- Accessories
- Service environment (lightning exposure, through-fault exposure, etc.)
- Availability of a spare(s) or lead time to acquire a new replacement(s)
- Insurance costs

The transportation phase in the life of a large power transformer is brief but may present significant structural and environmental challenges to the unit (see IEEE Std C57.150™-2012 [B48]). Field 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 (see IEEE Std C57.93).

The service period of the transformer's life cycle is the bottom of the bathtub curve, a long period having a low failure rate. Field testing during this period 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. When indicated, the user may elect to perform additional "special" tests to confirm the onset of significant aging. Such confirmation permits the user to take actions to refurbish select components or begin the process to procure replacement transformers (see IEEE Std C57.140™-2006 [B44]). Service period field 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.

The following subclauses describe the fundamentals of the individual tests and provide the user with guidance regarding their applicability and interpretation. Users should be aware that the described tests vary widely in the complexity and cost of the equipment involved and the skill of the operator. Users should carefully consider this data (and that in the references), as well as the condition of the transformer, to determine whether tests should be performed by in-house staff or by a testing service organization.

Given the critical nature of power transformers and the advanced age of many of those assets, significant efforts are underway to advance condition monitoring (see IEEE Std C57.143™-2012 [B45]) and diagnostic technologies. It is recommended that users keep abreast of such developments through other IEEE guides and standards, technical literature, and conferences. The accuracy of test results is critical when comparing them with the results of benchmark tests. It is imperative that the tests be conducted in a

manner consistent with previous tests and while following the instructions for the test device(s) being used to perform the tests.

5. Maintenance tests and information

5.1 Recommended, as-needed, and optional maintenance tests

Table 1 is a compilation of the recommended, as-needed, and optional maintenance 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—Maintenance test chart

Maintenance test	Liquid-filled power transformer			
	Commissioning ^a	In-service ^b	After protection trip due to system fault ^c	After protection trip due to internal fault ^d
Main tank				
Tank pressure	Opt	Opt	Opt	REC
Core ground test	REC	AN	AN	REC
Insulating liquid quality tests and dissolved gas analysis (DGA)	REC	REC	AN	REC
Furan test	Opt	Opt ⁵	Opt	REC
Vacuum	REC	Opt	Opt	REC
Insulation resistance	REC	AN	AN	REC
Winding resistance	REC	AN	AN	REC
Turns ratio (DETC taps)	REC	AN	AN	REC
Excitation current	REC	AN	AN	REC
PF/Tan-Delta	REC	AN	AN	REC
Partial discharge (PD)	Opt	Opt	Opt	Opt
Induced voltage	Opt	Opt	Opt	Opt
Frequency response analysis (FRA)	REC	AN	AN	REC
Dielectric frequency response (DFR)	Opt	Opt	Opt	Opt
Infrared	N/A	REC	N/A	N/A
Bushing				
Contact resistance	Opt	N/A	N/A	Opt
Infrared	N/A	REC	N/A	N/A
PF/Tan-Delta	REC	REC	AN	REC
Continuity	REC	N/A	N/A	REC

Table 1—Maintenance test chart (continued)

Maintenance test	Liquid-filled power transformer			
	Commissioning ^a	In-service ^b	After protection trip due to system fault ^c	After protection trip due to internal fault ^d
Load tap changer (LTC) and de-energized tap changer (DETC)				
Insulating liquid quality tests and DGA for LTC	REC	REC	AN	REC
Contact continuity for LTC	REC	AN	AN	REC
Infrared for LTC	N/A	REC	N/A	N/A
Motor current signature analysis for LTC	REC	AN	AN	REC
Vibration and acoustic measurement for LTC	Opt	Opt	Opt	Opt
Voltage dynamic testing for LTC	Opt	Opt	Opt	Opt
Ancillary equipment				
Gauges calibration	REC	REC	Opt	REC
Gas pressure relay calibration	REC	REC	Opt	REC
Pressure relief vent	REC	REC	Opt	REC
Cooling fan controls	REC	REC	Opt	REC
Cooling pump controls	REC	REC	Opt	REC
Arresters	REC	REC	REC	Opt
Bushing CTs	REC	AN	AN	AN

REC = Recommended

AN = As needed based on the REC Test results

Opt = Optional based on the AN test results

N/A = Not Applicable

^a Newly installed or repaired units prior to energization.

^b In-service transformers may need to be de-energized and properly set up, depending on the test to be performed. Condition-based maintenance practice—oil quality, DGA, and Furan tests—may be carried out at a regular interval and the necessity of other tests depend upon the assessed condition for power and distribution transformers. For hermetically sealed distribution transformers, the first round of tests after commissioning may be time based, and thereafter, the frequency should depend on the assessed condition.

^c After tripping of transformer due to system faults such as overcurrent.

^d After tripping of transformer due to internal faults such as differential tripping (before repair).

^e Furan Testing recommended for generator step-up (GSU) transformers and units operated above nameplate.

5.2 EPRI Power Transformer Maintenance and Application Guide

The EPRI Power Transformer Maintenance and Application Guide [B26] provides maintenance information pertaining to power transformers at nuclear plants. This public document incorporates a technical overview of transformers and a maintenance program designed to help plants avoid transformer failures. The guide covers component design and construction as background for personnel involved with transformers. It also provides warnings and precautions related to temperature rise, loss of cooling, low liquid level, low gas pressure, and static electrification mitigation to assist users in understanding how these factors affect transformer operability and life.

6. Safety

6.1 General

Considerations of safety in electrical testing apply not only to personnel, but also to the test equipment and apparatus being tested. The following guidelines cover many of the fundamentally important procedures that have been found to be practical. Since it is impossible to cover all aspects in this guide, test personnel should also consult IEEE Std 510; manufacturers' instruction manuals; and union, company, and government regulations.

Users of this guide are responsible for determining and complying with appropriate safety, security, environmental, and health and welfare practices, laws, and regulatory requirements applicable to their location, systems, equipment, and operations.

6.2 Types of hazards

6.2.1 Electrical hazards

There are three main electrical hazards—shock, arc flash, and arc blast—to which test personnel may be exposed, particularly if the transformer is not electrically isolated following proper procedures as mentioned in Clause 6.3. Other hazards may be present, and the user should take necessary precautions. Electric shock is contact with energized electrical equipment, conductors, or circuit parts that causes the flow of electrical current through the body. The severity of the shock is determined by the amount of electrical current, the total time that it flows through the body, and where it flows through the body. Humid or wet conditions or sweaty skin increase the potential for electrical shock. At a minimum, the shock hazard must be considered at any voltage greater than or equal to 50 V. Burns to the skin are also another result of an electrical shock. Internal damage caused by the electrical current flowing through the body is also possible; if shocked, the worker should report the incident and seek medical attention.

Electrical equipment that faults and creates an arc flash can expose a worker to extreme heat causing severe burn. Some secondary hazards related to an arc flash are the following:

- Fire
- Toxic smoke inhalation from vaporized copper
- Sound pressure that could damage hearing
- High intensity, ultraviolet, and infrared light that may damage eyesight
- Flying molten metal that may cause injury

Arc blast is associated with the release of tremendous pressures as a result of an arc fault where current flows through the air between two conductors or a conductor and ground. Vaporized copper, molten metal, pressure waves, shrapnel, intense noise, and toxic smoke/gases are some of the resultants of an arc blast. Dangers associated with an arc blast event are high pressures, sound, and shrapnel.

Users of this guide should follow fire safety and other safety requirements and precautions, including, but not limited to, personal protective equipment (PPE) and facility protections, in connection with any testing or evaluation of the transformer equipment.

6.2.2 Other hazards

When working on a transformer, the following additional hazards should also be taken into account when planning the work and completing a Pre-Job Hazard Analysis:

- Falling from heights—Proper harness to provide fall protection should be considered.
- Confined space—Prior to entry, confirmation should be made that the atmosphere inside the tank is adequate to support life. This should be checked according to company guidelines and procedures or manufacturer's instructions.
- Outdoor and wet environments.
- Certain test procedures could result in fire; therefore, non-contaminating fire-fighting equipment should be available before beginning tests that apply dielectric stress to the transformer insulation system.
- The voltage may accidentally exceed the desired maximum during the conduction of high voltage (HV) tests. A sphere gap, adjusted to spark over at a voltage slightly above the desired maximum, may be connected across the voltage source (refer to IEEE Std 4). By selecting the proper value of series resistor, the gap may be used to provide a warning signal, to inhibit further rise in the test voltage, or to activate an overcurrent circuit breaker in the power supply circuit.
- Tests being performed on the transformer while the equipment is under vacuum should only be done with low applied voltages. The dielectric strength of the system is significantly reduced under these conditions. See 6.6.3 for more details.

6.3 Creating an electrically safe work condition

6.3.1 Generic safety principles

WARNING

Electrical equipment should be considered energized until it is proven de-energized and grounded. No person should begin work on de-energized parts until this verification has been completed.

To dissipate residual charges, all terminals should be discharged to ground after test voltages have been removed.

The following generic safety principles should be followed during the execution of transformer testing:

- Do not rush when planning or carrying out the testing work.
- No worker should begin any electrical work until the worker fully understands the instructions received, and in no circumstances should that person exceed those instructions. Should any person consider that the instructions given cannot be carried out safely, that person should refer the matter immediately to an appropriate supervisor.
- No worker should interfere with ground connections, locks, tags, danger or warning signs, safety barriers, flags or other safety devices.
- Do not work on any electrical equipment or circuit where the area is damp or wet until insulated rubber matting is put into place and the circuit is isolated and grounded.
- Only use tools that are properly insulated and approved.

- Conductive articles of jewelry and clothing (such as watchbands, bracelets, rings, keys, chains, necklaces, metalized aprons, cloth with conductive thread, or metal headgear) shall not be worn.
- Near misses and electrical incidents (arc flash and shock) shall be reported immediately. These incidents should be fully investigated, lessons learned, and recommendations implemented.
- During the execution of a task, if any changes are noticed from the planned procedures, then immediately stop the task, think and analyze, assess the risk, control the risk, and then resume work if appropriate.
- Safety signs, safety symbols, or accident prevention tags shall be used where necessary to warn personnel about electrical hazards that may endanger them. Non-conductive barricades shall be used in conjunction with safety signs where it is necessary to prevent or limit individual access to work areas exposing individuals to non-insulated energized conductors or circuit parts. If signs and barricades do not provide sufficient warning and protection from electrical hazards, a standby/signal person shall be stationed to warn and protect employees from entering the area.

6.3.2 Steps to be followed for creating an electrically safe work condition

Before any testing work is performed, an electrically safe work condition shall be evaluated in accordance with the following steps:

- Determine all possible sources of electrical connections to the specific transformer. Check applicable as-built up-to-date single line drawings, diagrams, and identification tags.
- After properly interrupting the load current, open the disconnecting device(s) to the specific transformer.
- Where it is possible, visually verify that blades of the disconnecting devices are fully open or draw-out circuit breakers are withdrawn to the fully disconnected position.
- Apply lockout/tagout devices in accordance with an established company procedure.
- Use an adequately rated voltage detector to test each phase conductor or circuit part to verify they are de-energized. Before and after each test, determine that the voltage detector is operating satisfactorily. Test-before-touch.
- Where the possibility of induced voltages or stored electrical energy exists, ground the phase conductors or circuit parts before touching them. Where it could be reasonably anticipated that the conductors or circuit parts being de-energized could contact other exposed energized conductors or circuit parts, apply portable ground connecting devices rated for the available fault duty.
- Use of working grounds should comply with established company guidelines. For further information, see ASTM F855-2009 [B20].
- The transformer owner should issue a Safe Work Permit to the maintenance and testing personnel.
- Before any test is performed on the transformer, there should be a meeting at the work site of the people who are involved or affected by the test. The test procedure should be discussed so there is a clear understanding of all aspects of the work to be performed. Particular emphasis should be placed on personnel hazards and the safety precautions associated with these hazards. In addition, procedures and precautions should be discussed to ensure the production of meaningful test results without subjecting the test specimen to unnecessary risks.
- Responsibilities for the various duties involved in performing the test should be assigned.

6.4 General practices for internal inspection

When it is necessary to work inside power transformers, the workers should be aware of the rules and requirements of their company and the local, state, and national codes with jurisdiction over the area in which the work is performed. The work should be done in accordance with such applicable rules, codes, and guidelines.

It is recognized that different organizations have interpreted such rules, codes, and guidelines for confined space entry in different ways and that workers may also interpret such codes in slightly different ways. In the absence of such guidance, or as a minimum level of safe practices, the following items are recommended:

- Only workers who have been trained and are familiar with confined space entry procedures should work inside transformers. Verification of the atmosphere is detailed in 6.5.4.
- Bushing terminals and the transformer tank must be securely grounded and current transformer leads shorted.
- A least one person should remain outside the transformer while others are working inside. This person should keep in visual or audible contact with the workers inside. If a worker inside loses consciousness, the outside worker should call emergency rescue workers and never go into the transformer to attempt to remove the fallen worker.
- Risks of engulfment should be eliminated. Entering a transformer tank without first completely draining it of insulating liquid is not recommended. If an inspection is carried out without the liquid removed, steps must be taken to eliminate the possibility of falling into the insulating liquid. If conservator tanks, radiators, coolers, pipes, or other sections of the transformer have been isolated by valves but not drained, and the quantity of liquid in these areas is sufficient to engulf the worker, the valves used to isolate these sections should be locked in the closed position.

6.5 Suggested general control measures

Consistent with the international and national standards on occupational health and safety management systems, the following principles should be practiced as preventive and protective control measures to help protect personnel from hazards of electricity:

- Eliminate the hazard—de-energize all possible sources.
- Use engineering controls wherever possible.
- Substitute safer work systems, e.g., other materials, processes, or equipment.
- Maintain the transformer following preventive, predictive, and reliability centered maintenance strategies.
- Provide administrative controls—electrical technical and safety training, permitting process, and safe work procedures.
- Provide PPE, including measures for its appropriate use and maintenance.

Electrical workers shall be shielded from injury due to electric shock and arc flash hazards by protective equipment rated for the work to be performed. Electrical-specific PPE and other protective equipment shall be of a safe design and constructed for the specific part(s) of the body to be protected. Electrical-specific PPE and other protective equipment should only be considered as a last line of defense when it comes to mitigating exposure to electrical hazards.

Overhead power lines may present a challenge when work is conducted in proximity to them. It is critical that workers understand that even close limits of approach can produce fatal shock hazards. With this understanding, it should be noted that overhead power lines should be considered energized until otherwise confirmed and directed by the electrical utility.

WARNING

Do not attempt to rescue a victim of an incident without de-energizing the electrical system first and suitably protecting the person who will attempt to rescue the victim.
Use of a rescue hot stick may be necessary.

Workers should regularly receive training in testing procedures. Training of personnel in approved methods of resuscitation, including cardiopulmonary, is needed.

6.5.1 List of potential standard operating practices of a single organization and reference codes

- Standard operating practice of a single organization on Information Handling System (IHS)
- Standard operating practices of a single organization on Electrical Specific Personnel Protective Equipment
- Standard operating practices of a single organization on Safe Work Permit
- Standard operating practices of a single organization on Lockout/Tagging of Equipment and Systems
- Standard operating practices of a single organization on Incident Reporting and Investigation
- National Electrical Code® (NEC®) (NFPA 70®, 2011 Edition) [B60]
- OSHA 29CFR1910, Occupational Safety and Health Standards [B64]
- NFPA 70E®-2012 Standard for Electrical Safety in the Workplace® [B61]
- Applicable ASTM standards

6.5.2 Precautions

When testing, precautions shall be taken to prevent personnel from contacting energized circuits. An observer may be stationed to warn approaching personnel and may be supplied with means to de-energize the circuit. The means may include a switch to shut off the power source and ground the circuit until stored charges are dissipated.

6.5.3 Warning signs and barriers

The test area may be marked off with signs and easily visible tape. Warning signs shall conform to the requirements of governing bodies such as the Occupational Safety and Health Administration (OSHA) in the United States. Danger, Warning, Caution signs should follow the format and convention provided by the NEMA Z535.4-2011 [B58] or OSHA 1910.145 rules [B64].

6.5.4 Atmosphere inside tank

Prior to entry, confirmation should be made that the atmosphere inside the tank is adequate to support life. This should be checked according to company guidelines and procedures or manufacturer's instructions.

WARNING

After the access/manhole cover is removed the transformer should not be entered until the shipping gas (including dry air) is completely purged with breathable dry air that has a maximum dew point of -45°C . The oxygen content must be between 19.5% and 23% before entering the tank. Carbon monoxide levels should also be monitored at a level less than 25 ppm. The lower explosive level should be less than 20%. The replacement of gas with dry air is necessary to provide sufficient oxygen to sustain life. If the unit was initially shipped in dry nitrogen, there is a possibility of trapped nitrogen pockets. In this case, a sufficient vacuum should be held for a predetermined period of time and vacuum released with and refilled with dry breathable air.

6.6 Apparatus

6.6.1 Fire-fighting equipment

Certain test procedures could result in fire; therefore, non-contaminating fire-fighting equipment should be available before beginning tests that apply dielectric stress to the transformer insulation system.

6.6.2 Overvoltage

The voltage may accidentally exceed the desired maximum during the conduction of HV tests. A sphere gap, adjusted to spark over at a voltage slightly above the desired maximum, may be connected across the voltage source (refer to IEEE Std 4). By selecting the proper value of series resistor, the gap may be used to provide a warning signal, to inhibit further rise in the test voltage, or to activate an overcurrent circuit breaker in the power supply circuit.

6.6.3 Testing under vacuum

Some users have a practice of taking dc resistance measurements under vacuum while performing dry outs to determine the insulation temperature. Caution should be used when tests are performed on the transformer while the equipment is under vacuum. The dielectric strength of the system is significantly reduced under these conditions—only sufficiently low voltage should be used; consult with manufacturer to obtain recommended voltage level or actions.

6.6.4 Surge arresters

If the test voltage is expected to approach or exceed the operating voltage of any transformer-mounted surge arresters, the arresters should be disconnected before energizing the transformer with test voltage. This avoids arrester damage and limitation of the test voltage due to arrester operation.

7. Tests and test techniques

7.1 Periodic general inspections

The purpose of a maintenance inspection is to evaluate the transformer's condition and make these findings known to appropriate personnel. Periodic inspection of power transformers and their accessories

contributes to their trouble-free operation. These procedures may identify potential problems before they become serious enough to cause equipment outages.

The following are the routine and scheduled inspection items for transformers and the associated equipment in the substation. Inspection frequencies vary based on manufacturer's suggested care, equipment risk and complexity, and the user's own maintenance practices and procedures.

WARNING

Some inspection items may be near the transformer line connections. Only electrically-qualified personnel should be allowed in this area.

7.1.1 Routine inspections

Check and record the following:

- Line voltage and load current
- Insulating liquid temperature, winding temperature, and ambient temperature, as applicable. Peak indicators should be recorded and reset.
- Insulating liquid levels of the main tank and liquid-filled compartments
- Nitrogen gas pressure for blanketed transformers
- Possible leaks in the transformer if the liquid level gauge remains at or near zero but the actual liquid level varies. This is an important maintenance check that verifies the integrity of the transformer seal.
- Radiators for cleanliness and freedom from obstructions
- Radiator connections, bolted pipe joints, bolted access ports, and valves for signs of insulating liquid leakage.
- Grounding and copper bus bars are still in place and have not been stolen
- Condition of controls, relays, and wiring
- Condition of desiccant gel
- Counter readings from load tap changer, circuit breakers, automatic reclosures, and disconnects
- Operation of cooling fans and insulating liquid circulating pumps, where installed. When automatic controls are installed they should be left in the automatic setting.
- Evidence of animal activity
- Results obtained from performing an insulating liquid combustible gas and *dissolved gas analysis* (DGA)
- Infrared temperature evaluation on tank, bushings, LTC, and control cabinet

7.1.2 Scheduled de-energized inspections

WARNING

Do not attempt any of the following with the transformer still in operation. Always de-energize the transformer and the auxiliaries (fans, pumps, and control cabinet) before conducting these inspections. Failure to follow these precautions may cause equipment damage and personal injury.

- Visually examine bushings, arresters, and interconnecting hardware for cracks, dirt, insulating liquid leaks, excessive corrosion, and signs of overheating or electrical tracking. Clean any contaminated areas with a soft cloth and suitable solvent. Then, wipe the area dry.
- Check radiators connections, bolted pipe joints, bolted access ports, and valves for signs of insulating liquid leakage. Tighten any loose fittings and repair any insulating liquid leaks.
- Examine the pump valves for evidence of leaking around the gland seals. Close and open the flapper operating arm. There should be some restriction to the flapper arm movement if the packing is properly tightened. Tighten the gland nut if necessary.
- If the transformer is equipped with a load tap changer, inspect the tap changer for proper operation. Detailed information for the inspection procedures and the frequency of inspection for the tap changer is usually supplied by the manufacturer.
- Inspect any breathers and small screen openings in pressure-relief valves or a pressure-vacuum breather to be certain they are clean and in operating condition.
- If the transformer is equipped with a conservator, or insulating liquid preservation system, remove the expansion tank breather and check for insulating liquid leakage into the bladder. The procedure for making this inspection is usually explained in the manufacturer's instructions.
- Examine the paint finish on the main tank (particularly around welded joints) and on accessory items such as radiators, coolers, and associated piping. Check for paint peeling or cracking and evidence of rust. Clean the affected areas by wire brushing, then wipe with a clean dry cloth. Paint the area with a touch-up primer and a suitable exterior finish coat.

7.2 Main tank (active part)

7.2.1 General

Almost all electrical equipment is contained in some type of tank. This tank provides mechanical protection for the equipment and also acts as a reservoir for the insulating liquid surrounding the equipment. Attached to the tank are a number of bushings, fittings, and associated devices. The types and number of these devices attached to the tank vary with the size, voltage class, and use of the equipment. Generally a device provides one of three or more functions. The most common of these are the following:

- A visual indication of a condition or state
- An alarm indication of some abnormality
- A benefit to the electrical performance of the equipment

7.2.2 Conservators

Conservators are vessels normally located at an elevation higher than the cover of the tank. They can, however, be located on a structure immediately adjacent to the tank. The bottom of the conservator is elevated above the top of the turrets and is connected to the tank by piping. This positioning allows the insulating liquid in the tank to remain at a positive pressure with respect to the atmosphere. There is usually a valve in-line with the transformer tank and a liquid level indicator on the side of the vessel. The oil level should be above turrets that have vent piping, or the tester should verify bushing turrets are bled to confirm no trapped gasses. A conservator provides a fluid reservoir for variations in the insulating liquid as the insulating liquid temperature rises. It functionally acts as an expansion vessel for the tank's insulating liquid.

There are basically three types of conservator systems. The “free-breathing” system is the oldest of these types. The liquid level rises and falls with the temperature of the equipment, and the insulating liquid is constantly exposed to the atmosphere. Some free-breathing conservators may employ dehydrating breathers of either the desiccant or refrigerant type. Both of the other two types of conservators prevent the insulating liquid from coming in contact with the atmosphere. The newer type uses an air cell (sometimes referred to as a *bladder*), which is a large balloon-like envelope located inside the conservator. As the liquid level in the conservator rises and falls, air is expelled or drawn into the air cell. The older type has a diaphragm attached to the inside of the conservator vessel wall that rises with the expansion of the equipment’s insulating liquid. Dehydrating breathers can be used to prevent moisture from collecting in the air space of the conservator with a bladder or diaphragm.

Checks should be carried out according to the following procedure:

Procedure: The liquid level indicated on the liquid level gauge on the side of the conservator vessel should be recorded. This reading should be made with respect to the 25 °C mark on the gauge. The top oil temperature of the equipment should then be recorded. The top oil temperature reading should be used to correct the liquid level gauge reading. The resulting corrected level should be in the normal (25 °C) range. If gauges are not available, a “dipstick” method to use an external site gauge can be used to confirm the oil level. When dipsticking the conservator bag, there should be no oil present on the air side or the outside of the bladder. If this exists, the bladder is breached and should be replaced.

Interpretation: If the corrected level is normal, no additional action should be required. If the corrected level is substantially above or below the normal level, the measurements and calculations should be rechecked. If the results are the same, it may be necessary to add or remove, as the case may be, some of the insulating liquid of the equipment. The user should refer to the manufacturer’s recommendations. In addition, the cause of any incorrect level should be determined and corrective steps should be taken prior to taking any other action. Generally the corrected level should remain fairly constant unless there is an insulating liquid leak, etc.

Precautions: Insulating liquid for diagnostic testing is typically sampled on an energized transformer. Otherwise, insulating liquid should never be added or removed from an energized transformer, except in the most extreme circumstances, and then only with great knowledge and care.

7.2.3 Tank vacuum testing

7.2.3.1 General

Transformer tanks are designed to withstand a specified level of vacuum. This level of vacuum withstand depends on the type and size of the unit. Prior to the factory tests, transformer tanks are subjected to vacuum during the fabrication stage and again verified during the final insulating liquid filling stage. Large transformers shipped with dry air or nitrogen again need vacuum application when received at the site and as part of the energizing processing. The principal function of vacuum application is to remove the trapped air and moisture from the insulation and enable the insulation to attain its full dielectric strength. Before vacuum application, the manufacturer’s instruction manual should be referred to and necessary precautions followed as suggested.

7.2.3.2 Precautions

Ensure that the tank, including fittings (including conservator tank, radiators, pumps, associated valves, and monitoring equipment), are suitable for vacuum application. If any fittings are not designed to withstand vacuum, they need to be removed and blanked off.

Ensure the suitability of LTC application or pressure equalization. LTCs with separate barrier boards, if not suitable for full vacuum, should also be pressure equalized to avoid any damage to the barrier boards.

Make sure that no rigid connections have been made to bushings, insulators, and lightning arresters.

7.2.3.3 Vacuum leak rate test

After all parts have been assembled, seal the tank so that there are no leaks during vacuum application. Apply vacuum as specified by the manufacturer; large units may be subjected to a vacuum level of 1 torr or below. Hold the vacuum for 4 h. Secure the vacuum valve at the transformer tank. Wait 5 min and record any rise in pressure. At 10 min, measure the change in tank pressure. If the vacuum rise exceeds the manufacturer's limits or the operating company limits, the leaks should be corrected and the test repeated. After a successful vacuum leak rate test, continue with the designated vacuum time for liquid filling.

At the end of 4 h, the tank plate walls should not have any appreciable deflection. If observed, deflection should be discussed with the manufacturer.

7.2.4 Dew point

Dew point is covered in Annex D.

7.2.5 Insulating liquid

7.2.5.1 General

The insulating liquids used in transformers, regulators, and reactors act as both an insulating fluid and a heat transfer medium to carry off excess heat generated by the losses of the power equipment. The tests listed in Table 2 measure the properties used to determine a liquid's condition. ASTM publishes a summary of these tests and their usefulness (see ASTM D117 [B1]). The IEEE publishes guides that use the results of these tests to determine the condition of service-aged mineral oil, silicone, less-flammable hydrocarbon, and natural and synthetic ester insulating liquids and the diagnosis of power equipment based on insulating liquid condition (see IEEE Std C57.106™ [B39], IEEE Std C57.111™ [B40], IEEE Std C57.121™ [B42], IEEE Std C57.147™ [B46]).

Sampling techniques for these test methods (see ASTM D923 [B3]) should ensure that the specimen taken is representative of the insulating liquid contained within the equipment. Natural contaminants exist within the body of sampling valves; therefore, to maintain sample integrity, the valves should be flushed before the extraction is performed.

The existence of a positive tank pressure should be confirmed before attempting to obtain a sample. Failure to do so may result in a gas bubble entering the tank and creating an immediate dielectric breakdown while moving upward or a latent breakdown by becoming lodged in the windings. This condition may result in the premature and violent failure of the equipment.

A sufficiently large sample should be withdrawn so that enough insulating liquid is available to perform the desired tests. Typically 1 quart (0.95 L) is enough. Table 2 gives the insulating liquid volumes needed for individual tests. Proper sample containers and sampling procedures should be used to ensure a representative test sample (see ASTM D923 [B3]).

Table 2—Minimum volume of liquid for each test

Property	ASTM standard test	Quantity of insulating liquid (mL)
Visual examination	D1524 [B10]	10
Sediments and sludge	D1698 [B12]	50
Color	D1500 [B9]	125
Dielectric breakdown voltage	D1816 [B13]/D877 [B2]	500
Dissipation factor	D924 [B4]	250
Water content	D1533 [B11]	50
Acid number	D974 [B6]	20
PCB content	D4059 [B16]	10
Interfacial tension	D971 [B5]	20
Relative density	D1298 [B8]	125
Furan	D5837 [B17]	40
Particle count	D6786 [B18]	100
Corrosive sulfur	D1275 [B7]	500
Oxidation inhibitor	D2668 [B14]	20
Dissolved gases	D3612 [B15]	50
		Total: 1870
NOTE—The quantities listed have generally been found to be needed for the test procedures. Since some equipment manufacturers make larger containers, the test laboratory should be consulted prior to sampling to ensure that the sample volume is adequate.		

In most cases, the sample should be transported to the laboratory in a clean, dry container. Prolonged exposure to direct sunlight or contamination by excessive atmospheric moisture should be avoided. Many of the liquid volumes for measurements specified in Table 2 are not standardized. However, the values listed have been found to be practical and are commonly used.

Mineral oil in service may be placed into the following groups based on the evaluation of the characteristics; more details are in 7.2.5.2 through 7.2.5.11:

- Group I—Mineral oil that is in satisfactory condition for continued use
- Group II—Mineral oil that requires only reconditioning for further service
- Group III—Mineral oil in poor condition (such insulating liquid should be reclaimed or disposed of depending on economic considerations)
- Group IV—Mineral oil in such poor condition that it is technically advisable to dispose of it

Tests should be performed at least annually, but more often if the equipment is strategically located in the system.

7.2.5.2 Acid number

The acid number test (ASTM D974 [B6]) determines the acidic degradation constituents in service-aged insulating liquid.

This test should be used to indicate the relative change in an insulating liquid during use under oxidizing conditions. Acidity is gauged by the acid (neutralization) number, expressed as the number of milligrams of potassium hydroxide required to neutralize the acid in a gram of insulating liquid. Transformer grade insulating liquids contain only trace levels of acidic constituents when new; the acid number increases as the insulating liquid degrades. A used insulating liquid having a high acid number indicates that the insulating liquid is either oxidized or contaminated with materials such as varnish, paint, or other matter. In some insulating liquids, this condition may be indicative of sludge formation. There is no direct correlation between the acid number and the corrosive tendency of the insulating liquid towards metals in electrical

power equipment. Short chain acids are detrimental to insulation systems and can induce oxidation of metals when moisture is also present. Changes occur over long periods of time. Elevated levels are not indicative of a problem in the equipment, but of a potential threat to the internal components of the equipment.

Maximum recommended values of acid number for different types of insulating liquid are given in Table 3.

Table 3—Acceptable acid number values for new and in-service insulating liquids by voltage class

Type of insulating liquid	Voltage class (kV)	Acid number (mg KOH/g), maximum			
		Mineral oil ^a	LFH ^b	Silicone ^c	Natural ester ^d
New insulating liquid in new equipment	—	0.015	0.03	0.01	0.06
Service-aged insulating liquid	—	—	0.20	0.2	—
	≤ 69	0.20	—	—	0.3
	> 69 to < 230	0.15	—	—	0.3
	≥ 230	0.10	—	—	0.3

^a See IEEE Std C57.106-2006 [B39].

^b See IEEE Std C57.121-1998 [B42].

^c See IEEE Std C57.111-1989 [B40].

^d See IEEE Std C57.147-2008 [B46] (some of these values are provisional; see standard for additional information).

7.2.5.3 Visual inspection and color

Visual inspection and color tests cover estimating, during a field inspection, the color and condition (free water or sediment such as metal particles, insoluble sludge, carbon, fibers, dirt, etc.) of a sample of insulating liquid (ASTM D1524 [B10]) and a more precise laboratory determination of color (ASTM D1500 [B9]).

The observation of cloudiness, particles of insulation, products of metal corrosion, or other undesirable suspended materials, as well as any unusual change in color, should be followed up with a laboratory examination and analysis for proper diagnosis. If insoluble contaminants are present in the insulating liquid, valuable information concerning the condition of the transformer and its components may be obtained by filtering the insulating liquid and identifying the residue. Ultimately, a number of other tests may be incorporated to help in the diagnosis of the potential problem.

Color is used to indicate the relative change in insulating liquid during use and is expressed by a numerical value or color description based on comparison with a series of color standards. There should be no direct correlation between a change in the color of the insulating liquid and a specific problem within the equipment. Changes normally occur over long periods of time. A rapidly increasing number should be indicative of a dramatic change in operating condition and generally precedes other indications of a problem. A high color number occurs in combination with the presence of insulating liquid deterioration or contamination, or both.

The color interpretation for mineral insulating oil is given in Table 4.

Table 4—Relative condition of mineral oil based on color

Color comparator number	ASTM color	Mineral oil condition
0.0 to 0.5	Clear	New
0.5 to 1.0	Pale yellow	Good
1.0 to 2.5	Yellow	Service-aged
2.5 to 4.0	Bright yellow	Marginal
4.0 to 5.5	Amber	Bad
5.5 to 7.0	Brown	Severe (reclaim)
7.0 to 8.5	Dark brown	Extreme (scrap) ^a

^a Retest to confirm reading prior to scrapping oil.

7.2.5.4 Dielectric breakdown voltage

Dielectric breakdown voltage tests (ASTM D877 [B2], ASTM D1816 [B13]) determine the dielectric breakdown voltage of service-aged insulating liquid. Table 5 lists acceptable breakdown values.

Table 5—Acceptable dielectric breakdown values for new and in-service insulating liquids by voltage class

Test method	Voltage class (kV)	Dielectric breakdown strength (kV), minimum			
		Mineral oil ^a	LFH ^b	Silicone ^c	Natural ester ^d
ASTM D 1816 [B13]—1 mm gap					
New insulating liquid in new equipment	≤ 34.5	—	20	—	—
	> 34.5	—	25	—	—
	≤ 69	25	—	—	25
	> 69 < 230	30	—	—	30
	> 230 < 340	32	—	—	32
	≥ 340	35	—	—	35
Service-aged insulating liquid	Not specified	—	23	—	—
	≤ 69	23	—	—	23
	> 69 < 230	28	—	—	28
	≥ 230	30	—	—	30
ASTM D 1816 [B13]—2 mm gap					
New insulating liquid in new equipment	≤ 34.5	—	40	—	—
	> 34.5	—	50	—	—
	≤ 69	45	—	—	45
	69 < 230	52	—	—	52
	≥ 230 < 340	55	—	—	55
	≥ 340	60	—	—	60
Service-aged insulating liquid	Not specified	—	34	—	—
	≤ 69	40	—	—	40
	> 69 < 230	47	—	—	47
	≥ 230	50	—	—	50
ASTM D877 [B2]					
New insulating liquid in new equipment	Not specified	—	30	30	—
Service-aged insulating liquid	Not specified	—	24	25	—

^a See IEEE Std C57.106-2006 [B39].

^b See IEEE Std C57.121-1998 [B42].

^c See IEEE Std C57.111-1989 [B40].

^d See IEEE Std C57.147-2008 [B46] (some of these values are provisional; see standard for additional information).

The recommended method to determine the dielectric breakdown voltage of insulating liquid (ASTM D1816 [B13]) uses spherical capped electrodes of the Verband Deutscher Elektrotechniker (VDE) type in its test cell. Contamination and products of deterioration generally reduce the dielectric strength of insulating liquid. The dielectric breakdown voltage of insulating liquid indicates the insulating liquid's ability to withstand electrical stress without failure. High dielectric strengths do not indicate the absence of

contaminants. There should be no direct correlation between a certain breakdown voltage and failure, except in extreme cases.

This test may be satisfactorily performed in the field but is more controllable in a laboratory environment. A visual test should be performed to verify that the sample does not contain free water or air bubbles caused by agitation during transport.

7.2.5.5 Dissolved gas

The dissolved gas test (ASTM D3612 [B15]) determines the dissolved gas components in service-aged insulating liquid.

This test should be used to determine the amount of specific gases generated by a liquid-filled in-service transformer. Certain combinations and quantities of these generated gases are frequently the first indication of a possible malfunction that may eventually lead to failure if not corrected. Arcing, PD, low-energy sparking, severe overloading, and overheating in the insulation system are some of the mechanisms that can result in chemical decomposition of the insulating materials and the formation of various combustible and noncombustible gases dissolved in the insulating liquid. Normal operation may also result in the formation of some gases, but not to the same extent as when a malfunction exists.

Precautions: The sample should preferably be obtained using a clean, moisture-free, gas-tight container to isolate it from excessive atmospheric moisture and to maintain its quantity of dissolved gases. Care should be taken to purge the container of atmospheric gases but retain all gases from the equipment at the time the sample is taken. See [B6] for additional guidance.

After determining the quantities of key dissolved gases from the sample using this procedure, a prescribed diagnostic routine to assist in interpretation of the analysis should be followed (IEEE Std C57.104™ [B38], IEC 60599 [B30]).

It can be difficult to determine whether or not a transformer is operating normally if it has no previous dissolved gas history. Also, considerable differences of opinion exist for what is considered a “normal transformer” with acceptable concentrations of gases. Many techniques for the detection and measurement of gases have been established. However, it should be recognized that analysis of these gases and interpretation of their significance at this time is not an exact science but an art subject to variability.

7.2.5.6 Interfacial tension

The interfacial tension (IFT) test (ASTM D971 [B5]) determines the IFT of service-aged insulating liquid against water.

This test method should be used to indicate the IFT between an electrical insulating liquid and water. This is a measurement of the molecular attractive force between their unlike molecules at the interface. This test provides a means of detecting soluble polar contaminants and products of deterioration in the insulating liquid. There is a unique relationship between IFT and acid number in that the acid number of the insulating liquid increases and the IFT decreases as a liquid oxidizes. To a certain extent, the IFT is a measure of the remaining useful life of the insulating liquid, short of its being reclaimed. Decreased levels are not indicative of a problem in the equipment, but of a potential threat to the future operating condition of the equipment.

This test may be satisfactorily performed in the field, as well as in a laboratory environment.

Interpretation: Recommended acceptable values of IFT for different conditions of insulating liquids are shown in Table 6.

Table 6—Acceptable interfacial tension values for new and service-aged insulating liquids by voltage class

	Voltage class (kV)	Interfacial tension (mN/m), minimum			
		Mineral oil ^a	LFH ^b	Silicone ^c	Natural ester ^d
New insulating liquid in new equipment	All	38	—	—	—
	Not specified	—	38	—	—
Service-aged insulating liquid	Not specified	—	24	—	60% of original value
	≤ 69	25	—	—	—
	> 69 ≤ 230	30	—	—	—
	> 230	32	—	—	—

^a See IEEE Std C57.106-2006 [B39].

^b See IEEE Std C57.121-1998 [B42].

^c See IEEE Std C57.111-1989 [B40].

^d See IEEE Std C57.147-2008 [B46]. The limit values are provided for reference purposes and more long-term experience is needed to validate the test applicability to alternative liquids.

7.2.5.7 Particle count

The particle count test (ASTM D6786 [B18]) determines the number and size of particles present in mineral insulating oil. Particles in insulating oil may have an impact on the dielectric strength or power factor (PF) of the insulating oil. The source of the particles can be from internal material of the equipment such as carbon, cellulose fibers, metals, and oil degradation. Other external sources are possible when contaminants are introduced when processing the oil or when the equipment is open to the environment.

Particle counts will provide a general sense of the degree of the contamination and may be used to determine the effectiveness of oil filtration. Water in the oil greater than 10 ppm may contribute to increase particle count.

Particle counts may be undertaken to help in the determination of the cause of degradation of standard oil tests. The IEEE has not established a guide with any limits for particle count for insulating oil however, CIGRE [B21], and at least one manufacturer (Service Handbook for Power Transformer [B69]) have suggested points at which further action may be required for in-service insulating mineral oil. At least one manufacturer of transformers has particle count limit requirements for placing a transformer into service and in-service limits.

Particle counting has evolved over time and an interpretation of the present methods used is essential to insure proper interpretation of the reported results. The preferred method is the use of Automatic Particle Counters (APC) calibrated using the ISO Medium Test Dust (MTD). The calibration is performed according to ISO 11171:2010 [B52]. The laboratory conducting the particle count is responsible to report the calibration method used and insure that the repeatability and reproducibility criteria of the test method are in conformance to the test method.

Collecting a sample for particle count is an important aspect to obtain proper results. The test method (ASTM D6786 [B18]) requires a particle clean bottle of at least 100 ml and cleaned to contribute less than 1% of the total particles expected in the sample. Sample collection using a bottle is to be conducted according to ASTM D923 [B3].

An informative description of the methods used for calibration, interpretation, and suggested action points for in-service mineral insulating oil is provided in Annex I.

7.2.5.8 Dissipation factor

The dissipation factor (DF) test (ASTM 924 [B4]) determines the DF of new and service-aged insulating liquid.

This test should be used to indicate the dielectric losses in insulating liquid when used in an alternating electric field and to indicate the energy dissipated as heat. The DF is the ratio of the power dissipated in the insulating liquid in watts to the product of the effective voltage and current in volt-amperes, when tested with a sinusoidal field under prescribed conditions. A low DF indicates low dielectric losses. It is useful as a means to maintain sample integrity and as an indication of changes in quality resulting from contamination and deterioration in service or as a result of handling. Insulating liquid samples that are defective often pass other standard electrical and chemical tests, yet fail this test.

This test may be satisfactorily performed in the field, as well as in a laboratory environment. A visual test should be performed to verify that the sample does not contain air bubbles due to agitation during transport. After allowing the specimen to settle in the test cell, ASTM 924 [B4] should be followed in a laboratory. In the field, the recommendations of the test equipment manufacturer should be followed.

Interpretation: The recommended acceptable values of percentage DF for different categories of new and service aged insulating liquids are shown in Table 7.

The DF limits given for an insulating liquid are based on the understanding that DF is an indicator test for contamination by excessive water (in combination with particulate matter) or polar or ionic materials in the liquid.

High levels of liquid DF are of concern because contaminants may collect in areas of high electrical stress and concentrate in the winding, making transformer cleaning difficult and masking changes in winding PF due to other causes such as changing water content. A very high liquid DF may be caused by the presence of free water, which could be hazardous to the operation of a transformer. Whenever there is high liquid DF, the cause should be sought. Oxidation, free water, wet particles, contamination, and material incompatibility are possible sources of high liquid DF.

Table 7—Acceptable dissipation factor values for new and service-aged insulating liquids

Status of insulating liquid	Dissipation factor (%), maximum							
	Mineral oil ^a		LFH ^b		Silicone ^c		Natural ester ^d	
	25 °C	100 °C	25 °C	100 °C	25 °C	100 °C	25 °C	100 °C
New insulating liquid in new equipment	0.05	0.40	0.1	1	0.1	—	0.5	—
Service-aged insulating liquid	0.5	5.0	1	—	0.2	—	0.5	—

^a See IEEE Std C57.106-2006 [B39].

^b See IEEE Std C57.121-1998 [B42].

^c See IEEE Std C57.111-1989 [B40].

^d See IEEE Std C57.147-2008 [B46] (some of these values are provisional; see standard for more details).

7.2.5.9 Polychlorinated biphenyl content

The polychlorinated biphenyl (PCB) content test (ASTM D4059 [B16]) determines the PCB content of service-aged insulating liquid.

PCBs are regulated substances in many countries. For this reason, it is important to know the present condition of power equipment with regard to its PCB concentration. A transformer having a PCB concentration of < 50 mg/kg (ppm) is classified as non-PCB-contaminated equipment; however, the insulating liquids may still require proper disposal. A PCB concentration ≥ 50 mg/kg but < 500 mg/kg

results in a classification of contaminated. A concentration of ≥ 500 mg/kg is considered PCB material. Because most laws deal with the PCB concentration of the involved insulating liquid, it is most important to be aware of the PCB concentration of the insulating liquids on any given system. National, state or local governmental regulations may require specific actions, records, and disposal methods for values of even < 50 mg/kg.

This testing may be performed in the field prior to laboratory testing. In the field, there are a number of commercially available screening kits. Check the expiration date and the compatibility of the insulating liquid with the kit. These types of tests only estimate the PCB concentration and do not give exact numerical values. It is essential that the manufacturer's recommendations be followed precisely when performing the field screening test. This type of test gives a positive indication for chlorinated compounds, whether they are PCB or not. Therefore, care should be taken not to introduce other chlorinated compounds into the procedure. Laboratory testing is required to obtain an actual PCB concentration.

Interpretation: PCB regulations vary by location. Local regulators should be consulted for appropriate guidelines.

7.2.5.10 Sludging condition

The sludging condition test covers the determination of pentane-insoluble sludge present in service-aged insulating liquid. For mineral oil, this test is generally not performed unless IFT is < 26 mN/m or the acid number is > 0.15 mg KOH/g liquid.

Sludge is a resinous, polymeric substance that is partially conductive, hygroscopic, and a heat insulator. If there is water in the transformer, it is attracted to the sludge. The presence of soluble sludge should be an indication of deterioration of the insulating liquid, presence of contaminants, or both. It serves as a warning that there may be formation of sediment.

This test is intended to determine the extent to which the insulating liquid has begun to sludge, see ASTM D1698 [B12]. The test has value in determining the proper procedure for performing maintenance on a transformer. If the insulating liquid has not started to sludge or is only sludging slightly, the transformer's insulating liquid may be circulated through a reclaiming system, thus extending the life of the insulating liquid and the transformer. If the insulating liquid has progressed into sludging such that sediment exists, more dramatic maintenance procedures may be required, including removing the transformer from service and thoroughly washing down the insulation system, tank, and cooling system. This is necessary since sludge (sediment) and moisture become trapped in cooling systems, thereby reducing effective cooling. There is also a possibility that the moisture-laden sludge will collect in critical regions of electrical stress and result in premature failure or, at the least, reduced heat transfer efficiencies.

NOTE—Tiny, solid particles may not be sludge. They could be clay fines or artifacts.

7.2.5.11 Water (moisture)

Some moisture is always present in any transformer. In addition, since the paper in the insulation system has a great affinity for water, most of the moisture present is in the paper.

The dielectric strength of the paper is very sensitive to the presence of moisture, as is the insulating liquid. Therefore, it is important that the moisture content be known and its concentration controlled.

Water migrates between the solid and liquid insulation in a transformer with changes in load and, therefore, temperature. Consequently, the concentration of water in the insulating liquid alone, expressed in mg/kg (ppm), does not provide sufficient information to obtain an adequate evaluation of the insulation system dryness. Relative saturation provides a better evaluation under a wide range of operating conditions and temperatures. Even using relative saturation to evaluate insulation system dryness has some inherent biases

due to the fact that water never reaches equilibrium between the solid and liquid insulation. The further from equilibrium the system is when the sample is taken, the greater the bias. The bias may be either positive or negative and can be affected by short-term transients at solid/liquid surfaces or by longer-term transitions within the thicker insulation.

7.2.5.11.1 Water content

Table 8 shows the suggested limits for moisture in insulating liquids as determined by Karl Fischer analysis (ASTM D1533 [B11]). Liquids at delivery prior to processing should have moisture content at or below the specification limits for the liquid.

With regard to insulating liquid moisture levels, solubility equations have been used to assess the solubility limit of moisture in insulating liquid. The solubility limit is the maximum amount of moisture that is soluble in the insulating liquid at a specific temperature. It is also referred to as the *moisture in insulating liquid saturation limit* or simply *100% saturation* and is determined when the calculation of the percent saturation equals 100%. The equation is $[(\text{mg/kg water in insulating liquid})/(\text{mg/kg of water in insulating liquid at saturation})] \times 100$.

Table 8—Acceptable water content values for new and in-service insulating liquids by voltage class

Status of insulating liquid	Voltage class (kV)	Water content ^a (mg/kg), maximum			
		Mineral oil ^b	LFH ^c	Silicone ^d	Natural ester ^e
New insulating liquid in new equipment	Not specified	—	25	50	—
	≤ 69	20	—	—	300
	> 69 < 230	10	—	—	150
	≥ 230	10	—	—	100
Service-aged insulating liquid	Not specified	—	35	100	—
	≤ 69	35	—	—	400
	> 69 < 230	25	—	—	200
	≥ 230	20	—	—	150

^a These values are for insulating liquids not insulation dryness or dielectric integrity.

^b See IEEE Std C57.106-2006 [B39].

^c See IEEE Std C57.121-1998 [B42].

^d See IEEE Std C57.111-1989 [B40].

^e See IEEE Std C57.147-2008 [B46] (note some of the values are provisional; see standard for additional information).

7.2.5.11.2 Discussion

IEEE Std C57.106 [B39] discusses the absence of thermodynamic equilibrium in an operating transformer. This leads to the conclusion that a quantitative correlation of moisture in liquid to moisture in paper is not currently feasible. This conclusion is based on the following conditions in an operating transformer:

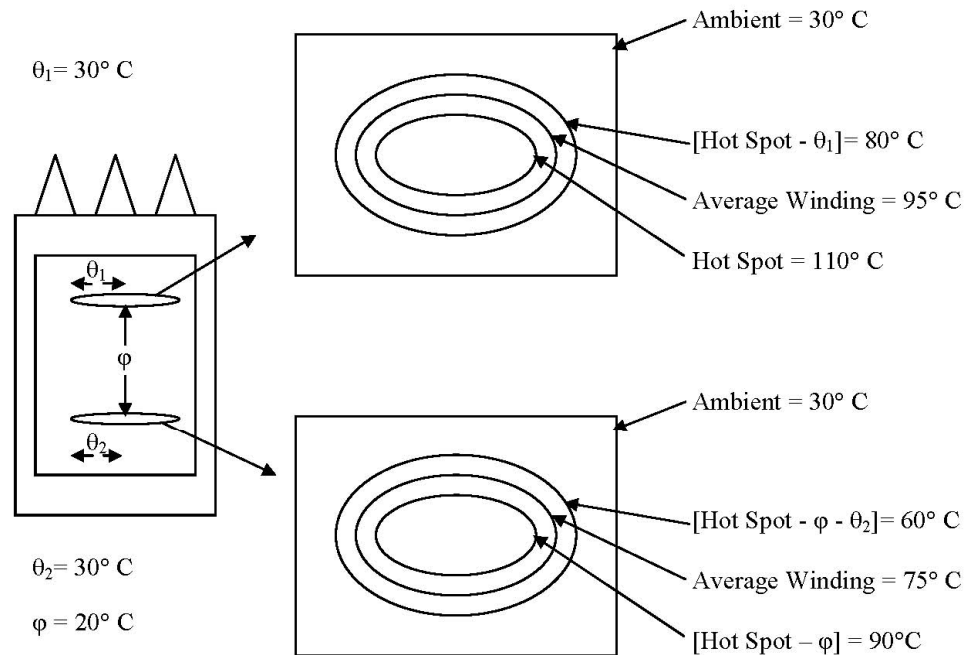
- Temperatures and moisture concentrations vary significantly with location
- Temperatures and moisture concentrations vary significantly with time
- Time variation is rapid for temperature and slow for moisture diffusion
- Solubility of moisture in liquid is not the same for the various insulating liquids

The first three statements can be evaluated quantitatively by using the solid insulation time constants for moisture diffusion and temperature. A model using this evaluation (Thompson [B70]) shows that the moisture diffusion time constants are on the order of magnitude of weeks and months, whereas typical temperature time constants from the IEEE loading guide IEEE Std C57.91™ [B37] for transformers are on the order of magnitude of hours. In addition, in this model, using curves for a flat sheet of paper Oommen [B62], gives an approximate range of 1% to 3.5% for a temperature gradient of 40 K.

CAUTION

Once the water content in insulating liquid reaches the solubility limit (100% relative saturation), free water droplets form, which adversely affects the dielectric strength of the insulating liquid and may result in transformer failure.

Next, considering the thermograph model in Figure 1, there is an even greater temperature gradient (50 K). This hypothetical model serves the purpose of showing possible temperature gradients in an operating transformer that is at constant load and constant ambient conditions (temperature and wind velocity). This model also indicates that the prediction of any single homogeneous moisture-in-paper value is invalid. While an accurate model can be attempted only with temperature probes, nonetheless it is clear here that moisture curves predict a range of moisture values whenever there are temperature gradients. Also, after the publication of moisture equilibrium curves for paper-mineral oil systems, cautions have been issued to not use these curves to determine the dryness level of the solid insulation in an operating transformer (Oommen [B63]). Finally, adding the conditions of changing load and ambient conditions further complicates any quantitative analysis.



$$\phi = (\text{Hot Spot Temp.}) - (\text{Maximum Temp. in Horizontal Plane at bottom of Coil})$$

$$\theta_1 = 2 \cdot [(\text{Hot Spot Temp.}) - (\text{Avg. Winding Temp at Top Coil})]$$

$$\theta_2 = 2 \cdot [(\text{Hot Spot Temp.}) - (\phi)] - (\text{Avg. Winding Temp at Top Coil})$$

Figure 1—Model of isothermal lines and temperature gradients for mineral-oil-filled 65 K rise transformer at constant full load and constant ambient conditions