Consideration of Standards and Recommendations for Selection, Installation and Maintenance of Substation Transformers_Final Draft_021120

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Abstract

This paper will discuss the key applicable North American Standards defining performance, testing, installation and routine field maintenance of liquid-immersed distribution substation transformers. These transformers, typically applied in commercial and industrial power systems, can be installed either in outdoor or indoor locations, applied as remote or close-coupled to either primary or secondary switchgear, or both. Recommendations based on these standards for selection, installation and factory/field testing industry users should specify to maximize reliability, operational efficiency and safety will follow.

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Abstract – This paper will discuss the key applicable North American Standards defining performance, testing, installation and routine field maintenance of liquid-immersed distribution substation transformers. These transformers, typically applied in commercial and industrial power systems, can be installed either in outdoor or indoor locations, applied as remote or close-coupled to either primary or secondary switchgear, or both. Typical ratings for these distribution substation transformers range from 112.5 kVA through 10,000 kVA three-phase, at 50 or 60 Hertz, with primary voltage at 34,500 volts and below and secondary voltage at 6,900 volts and below. Not included in the scope of this paper are dry-type distribution transformers, pad-mounted distribution transformers or power transformers with ratings up to 100,000 kVA and 230 kV. Recommendations based on these standards for selection, installation and factory/field testing industry users should specify to maximize reliability, operational efficiency and safety will follow.

Index Terms - Distribution substation transformers, industry standards, factory testing, field testing, routine maintenance

Introduction

Distribution substation transformers installed in industry for decades have served as the backbone of electrical power distribution systems. Manufacturing facilities in the process industries including petroleum & chemical, mining & metals, cement and pulp & paper will typically have quantities ranging from two or three to over one hundred of these installed, primarily serving medium-voltage and low-voltage motor loads. Typically, transformer primary voltages match the plant distribution voltage selected by the designer of the installed plant power system. In North America, the traditional plant distribution voltage has historically been 15,000 volts or 15 kV, but the trend moving forward is toward higher voltages including 27 kV and 34.5 kV. These two-winding transformers are used to step-down from a high-voltage or primary winding to the plant distribution voltage to a low-voltage or secondary winding to serve plant loads. Typically, secondary voltages in North America are either 4.16 kV or 2.4 kV serving primarily medium-voltage motor loads with these terminal voltages and 600 V or 480 V to serve low-voltage motor loads. Dry-type transformer designs including those with vacuum pressure impregnated (VPI) or cast coil windings are also available, but because these represent a minority of transformers installed and industry standards guiding selection, installation and maintenance of these are different than those for liquid-immersed designs, these are not considered in the scope of this paper.

Liquid-immersed or liquid filled distribution transformers can be installed in both indoor and outdoor locations. Typical outdoor installations include either cable terminations at the primary and secondary from an air terminal chamber or close-coupled primary protective device, either a load-break switch and fuse or vacuum circuit breaker switchgear assembly. Liquid filled transformers are typically installed in an outdoor vault including containment in case of fluid leaks and fire barriers isolating the transformer from an adjacent installed unit or a building. Indoor installations more typically are coordinated low-voltage or medium-voltage unit substations which include both primary medium-voltage switchgear at the primary bushings and secondary low-voltage switchgear close-coupled to the substation transformer at the secondary side-wall spade terminals. In this configuration, the primary bushings for phase and ground terminations may be contained in an air terminal chamber which is either removable or permanently attached to the tank. If switchgear is provided at the primary, it is manufactured with a transition bus and matching throat connection, allowing the two to be bolted together. The secondary connection to either bushings or secondary spades is on the opposite side of the primary terminations, also with a throat matched for connection to a bus transition at the secondary switchgear. Typically, a short length of flexible conductor to isolate vibration & noise is installed between the transformer secondary spade and the switchgear bus transition. The coordinated assembly consisting of primary medium-voltage switchgear, distribution substation transformer and secondary switchgear is often referred to as a unit substation.

Over the course of the last century, there have been countless changes in designs and manufacturers of distribution substation transformers. In the early 1900’s when transformers were first invented, Westinghouse
Electric Corporation and General Electric Company were the two dominant manufacturers of substation transformers, with industrialist George Westinghouse and inventor Thomas Edison as the original founders of these two businesses. Today, neither company manufacturers distribution transformers; Westinghouse is no longer in existence and General Electric has become a diversified conglomerate and changed the company name to GE. Over the past few decades, a host of mergers and acquisitions has changed the supplier base of transformers to now have a global footprint with leading transformer manufacturers in Europe, Latin America, the Asia Pacific Region and elsewhere. Because of this change, today there are few transformer manufacturers that design, assemble, test and field service distribution transformers in North America. Industry users must understand and rely upon standards to assure acceptable performance, reliability and maintenance of distribution transformers installed in their facilities.

**Substation Transformer Designs, Applicable Standards**

Liquid filled substation transformers consist of components and sub-assemblies including the core and coil, the tank and power/control connections along with gauges and protective devices. In most cases the core & coil is of a rectangular design with the primary coil made of wound insulated conductor and the secondary coil made of sheet wound conductor. Conductors can be either copper or aluminum and insulation between conductors consists of thermally upgraded insulating paper. Some of the ancillary insulation materials for transformer components such as gaskets and bushings may vary to ensure chemical compatibility with the fluid being utilized. The transformer core typically consists of grain-oriented silicon steel laminations assembled in either a stacked core or wound core fashion. There are many refined grain-oriented silicon steels available and also amorphous core designs with electrical resistivities two to three times higher than silicon metal alloys. These materials offer lower loss properties (watts/pound) due to the high magnetic permeability, but the trade-off is often higher first cost and a larger core assembly. Regardless of the core design, the basic principle remains the same, where primary current flow in the primary winding is transferred via magnetic flux in the core to induce a current in the secondary winding. Voltage and current relationships are as shown in Fig. 1 based a ratio of the primary number of turns N1 to the secondary number of turns N2.

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The transformer core and coil are mounted in a tank and filled with an insulating fluid such as mineral oil, high flash point silicone, hydrocarbon, or newer vegetable-based natural ester fluids. The tank is sealed to prevent contaminants from entering the oil. A gas space at the top of the transformer tank is filled with dry nitrogen, typically maintained at 3 pounds per square inch gauge (PSIG) at 25 degrees Celsius. With the tank above atmospheric pressure, contaminants are not able to enter. If pressure build occurs due to high ambient temperature or overheating, a pressure relief valve typically set at 8 ±1 PSIG is used to vent excess pressure from the tank. External primary and secondary bushings or spade connections allow for termination of three-phase conductors in the form of cable or bus. User connection to various gauge outputs and terminations for auxiliary components such as current transformers are made in an external tank-mounted control panel. Depending on the design and rating, external cooling fins circulating the insulating fluid and fans are also typically included. An image of a typical distribution transformer is shown in Fig. 2a, showing a transformer “in nature” which is not installed or connected to anything. This is instructive as the image shows the tank, cooling radiator fins, secondary throat connection with bushings and control terminal box. The image in Fig. 2b shows a similar liquid filled distribution transformer installed with a primary air terminal chamber with medium-voltage cables entering from the top and close-coupled low-voltage metal-enclosed switchgear which in turn feeds downstream plant loads.
Distribution Substation Transformers Standards

There are several industry standards outlining construction and performance requirements for distribution substation transformers. For specifications outlining construction and performance for new distribution substation transformers included in the scope of this paper, industry users should be familiar with IEEE Standard C57.12.36-2017 [1]. This document entitled “Standard Requirements for Liquid-Immersed Distribution Substation Transformers” includes rating data for transformer kilovolt-ampere (kVA), basic impulse level (BIL), primary voltage taps and impedance. Construction features for tap changers, various indicators and gauges, bushing current transformers, surge arrestors, etc. are also detailed here. Some details for transformer cooling such as ONAN – Oil Natural Air Natural and ONAF - Oil Natural Air Forced where natural cooled (i.e. by a radiator) and forced cooled (i.e. with a fan) and routine tests are defined in IEEE Std C57.12.00-2015 [2]. This standard titled “Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers” is a broader standard, with application for distribution, power and regulating transformers. User familiarity with this standard is less important as details in IEEE Std C57.12.36 refer to the broader IEEE C57.12.00 standard. Those developing the more specific document believed it was simply not necessary to duplicate content in both.

Details outlining factory tests for distribution transformers including resistance measurements, polarity and phase-relation tests, ratio tests, no-load loss and excitation current measurements, impedance and load loss measurements, dielectric tests, temperature tests, short-circuit tests, audible sound level measurements, and calculated data are included in another standard, IEEE C57.12.90-2015 [3] “Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers”. The methods for performing these tests are once again included in the broader IEEE C57.12.00 standard.

Transformer Installation Standards

Installation of distribution transformers in the United States (U.S.) is dictated by the National Fire Protection Association (NFPA) 70 better known as the National Electrical Code (NEC) [4]. This installation standard is updated every three years with each U.S. state deciding when to adopt the newest edition of the NEC. As of this writing, the most current edition of the National Electrical Code is NEC 2020. Every country publishes installation standards which are unique to the region, state or province. An outline of considerations for substation transformers location and insulation requirements are outlined here.

NEC Article 450 Part II outlines specific requirements regarding the general location for each category of transformer. These location requirements can significantly affect the installation first cost of the selected transformer.

NEC Article 450.23(A) covers indoor installations of less flammable liquid-insulated transformers. These transformers must be insulated with a listed less flammable liquid with a fire point of not less than 300°C. NEC permits indoor locations without a vault for one of two options: (1) In Type I or Type II buildings, in areas where no combustible materials are stored, liquid confinement area is provided, and the installation complies with all the restrictions provided in the listing of the liquid; or (2) Any type of building with an automatic fire extinguishing system and liquid confinement area. Otherwise a code-approved vault per Article 430.26 as described for oil-insulated transformers is required. Typical examples of less flammable transformers available today meeting minimum 300°C fire point requirements include those filled with listed either High Temperature Hydrocarbon (HTM) fluid - typical fire point of 312°C, silicone fluid - typical fire point of 330°C, or natural ester/synthetic ester-based fluids with a typical fire point of 360°C.

NEC Article 450.26 outlines requirements for oil insulated transformers with flammable fluid with fire point typically at 160°C. This section applies to substation transformers with mineral oil insulating fluid and these must be located in a code-approved vault covered under Part III – Transformer Vaults, which generally have a minimum 3-hour fire rating. An exception allows the transformer vault to have a 1-hour fire rating when automatic sprinklers, water spray, carbon dioxide, or halon is provided. Note that halon is similar to freon and is considered an environmental pollutant causing depletion of the ozone layer. Article 450.26, Exception
5 permits substation transformers to be located in a detached building not complying with Part III if the building or its contents would not present a fire hazard to other buildings or property and it is used only in supplying electric service, with the interior accessible only to qualified persons. This exception would be applicable to a factory assembled and wired electrical room or e-House this includes different assemblies of electrical distribution and control equipment.

Outdoor less flammable liquid-insulated transformers are covered in NEC Article 450.23(B). Less flammable transformers with a fire point not less than 300°C are permitted to be installed outdoors attached to, adjacent to, or on the roof of buildings, where installed in accordance with either (1) For Type I or Type II buildings, the installation shall comply with all restrictions provided for in the listing of the liquid or (2) the same as defined in Article 450.27 which applies to oil-insulated substation transformers installed outdoors. This states that combustible material, combustible buildings, and parts of buildings, fire escapes, and door and window openings shall be safeguarded from fires originating in oil insulated transformers installed on roofs, attached to or adjacent to a building or combustible material. Space separations, fire-resistant barriers, automatic water spray systems, and enclosures that confine the oil of a ruptured transformer tank are recognized safeguards. One or more of these safeguards shall be applied according to the degree of hazard involved in cases where the transformer installation presents a fire hazard. Oil enclosures shall be permitted to consist of fire-resistant dikes, curbed areas or basins, or trenches filled with coarse, crushed stone. Oil enclosures shall be provided with trapped drains where the exposure and quantity of oil involved are such that removal of the oil is important – this typically always applies to outdoor installations of all oil-insulated substation transformers.

**FM Installation Standards**

One additional consideration regarding installation standards for substation transformers is the insurability of the installation. Global insurance provider Factory Mutual (FM), now known as FM Global Group, has developed standards for transformer designs based on the likelihood of fire or damage in the event of a transformer failure. One example of such standards is FM 3990 “Approval Standard for Less or Nonflammable Liquid-Insulated Transformers” [5]. Unlike a consensus industry standard, this is issued by a specific insurance carrier and outlines product design requirements to enhance the safety of the installed transformer. The standard requires the insurance provider to complete both examination and tests on production samples to evaluate 1) the suitability of the product; 2) the performance of the product as specified by the manufacturer and required by FM Approvals; and as far as practical, 3) the durability and reliability of the product. An examination of the manufacturing facilities and audit of quality control procedures is required to evaluate the manufacturer’s ability to consistently produce the product which is both examined and tested. A specific marking procedure by the insurance carrier is used to identify product conformance. This standard refers to the IEEE standards mentioned previously as “Normative References”, but in addition to these requirements, the manufactured product must be modified to include protection features. These include high fire point fluid, current limiting fuses with a maximum I^2t let through, ground fault protection, pressure relief devices of an adequate flow rate, special labeling, a calibration certificate for each piece of test equipment and a service provider’s accreditation certificate.

Although upgrading to a transformer that conforms to this standard will likely involve an additional cost, there are benefits based on reduction of long-term insurance premiums looking forward. There also are measurable first cost savings on the installation since conformance to FM 3990 Article 3.3.2 allows the transformers to be located 3 feet (0.9 meters) from building walls for both indoor and outdoor installations and 5 feet (1.5 meters) from doors, fire escapes and windows for outdoor installations. The stated exception to most in-country installation codes including NEC 2020 allows the user to reduce cabling costs without affecting building insurance premiums - a clear benefit.
Total Ownership Costs

Over the past several years, industry users have recognized that the first cost to purchase a transformer represents a significant investment, but the total ownership cost including installation and operating/maintenance costs over the transformer life is an important measure.

One element of ownership cost to consider is installation costs. Transformer direct installation costs will vary depending on NEC and/or the local in-country code special location requirements. For example, a mineral oil insulated transformer installed indoors in accordance with the NEC requires a code-approved transformer vault. A vault could add 40% to 80% of the first cost of the transformer to the installation costs for mineral oil insulated transformers installed indoors. Less flammable fluid insulated transformers, such as ester-based fluids would require liquid confinement (curbing), adding approximately 1 to 10% of the first cost to the indoor installation cost of these transformers. Some updated liquid filled transformer designs as shown in Fig. 3.
include containment as a part of the assembly as shipped from the factory. In most cases, specification of this feature will save installation cost versus the prospect of adding concrete curbing around the transformer base to account for containment.

One additional recommended area of focus is transformer efficiency. All transformer designs include both load losses and no-load losses. No-load losses are defined as steady losses which do not vary based on transformer load. These losses are caused by the magnetizing current needed to energize the transformer (a combination of eddy current and hysteresis losses). Transformer load losses are caused by the winding impedance and vary according to the load. The winding impedance is comprised of the resistance or heat losses (I²R) of the primary and secondary conductors of the transformer summed with the inductive reactance of the coils to form the total load loss value. Most transformer suppliers and/or manufacturers offer simple to use calculators to determine the annual operating cost of a transformer. Variables to consider include cost of energy and load factor; working and non-working hours plus total hours of operation. Total ownership costs include the first cost (including installation) plus operating cost, both for energy and maintenance. In some cases, paying a premium for high efficiency transformer design will pay off. An excellent review of calculations based on an actual example is included here [6]. It is important to note that similar to installation standards, many countries have adopted energy efficiency standards for substation transformers. In the case of the U.S. the Environmental Protection Agency (EPA) established the first standard for transformers in 2010. This has since been updated for transformers manufactured after January 2016 [7]. For liquid-immersed distribution transformers, these published minimum efficiency standards are compulsory for ratings up to and including 2500 kVA with input voltage of 34.5 kV or less and output voltage of 600 V or less.

System Design Alternatives

As mentioned previously, one clear trend for industrial power systems is a move toward higher plant distribution voltages. First, electrical systems today are larger, some exceeding 100,000 kVA or 100 MVA of
total plant load. This in turn is driving larger transformer ratings and conductors feeding transformer loads. Higher ampacities have a significant impact on cable sizes. For example, the primary current for a substation transformer is defined by:

\[ I_{\text{PRIMARY}} = \frac{kVA}{\sqrt{3} \times V_{LL}} \] (1)

Using this formula for a 2500kVA transformer with a primary voltage at 13.8 kV yields a primary current of 2500/ (\(\sqrt{3} \times 13.8\)) or 105.9 amperes. The same transformer operating at a primary voltage of 34.5 kV yields 2500/ (\(\sqrt{3} \times 34.5\)) or 42.4 amperes. The increase in transformer cost for this higher primary voltage is negligible. Considering total installed cost, a nominal increase in first cost of the transformer is more than offset by the reduced cost of higher ampacity cables. An additional consideration in choosing a plant primary distribution voltage, is some larger systems such as open-pit mines require long cable runs where voltage drop and cable \(I^2R\) losses become a concern for systems utilizing lower primary voltages.

In an effort to reduce total ownership costs while also improving power distribution system reliability, another trend that many system designers are considering is radial versus loop-fed systems. The images in Fig. 4. outlined in [8] show two system configurations, a radial primary/radial secondary at the left and a loop primary/radial secondary at the right. Historically,
industrial power systems have been radial primary/radial secondary. As system voltages trend higher, these systems have become less practical. One issue is the cost of primary switchgear. Assuming the secondary substations shown for the radial/radial system are rated at 2500 kVA at 13.8kV as in the example above, the full load ampacity requirement for each substation would be 105 amperes. This causes underutilization of the primary switchgear vacuum circuit breaker which is typically available based on a 1200 ampere rating. If the primary voltage was 34.5 kV, the circuit breaker utilization would be compromised further. Conversely, for a loop primary design, a system using a primary voltage of 34.5 kV would allow over 25 low-voltage substations in the secondary loop (42.4 amperes X 25 = 1060 amperes), fed from a single 1200 ampere upstream circuit breaker. Note also that the system reliability of the loop secondary configuration is significantly improved since each substation can be fed from Primary Main Breaker 1 or Primary Main Breaker 2, or both. Provided Bus 1 and Bus 2 has sufficient MVA capacity to support the entire load, should one of the primary systems fail, the other would keep the plant running. Note the special configuration of the transformer as well. This shows an integral primary fuse to protect the primary winding, along with a sectionalizing switch to effectively include a given unit substation in the loop, or completely isolate it from the system. Each primary loop is typically configured such that one of the loop sectionalizing switches is kept open to prevent parallel operation of the two primary sources. In this configuration, any unit substation can be removed from service while the balance of the system is operational. For some liquid filled transformer designs, the configuration shown is available including a visible blade primary disconnect combined with a sectionalizing switch. Some newer substation transformer designs are available with a vacuum fault interrupter (VFI) at the primary. The VFI device can either replace the primary fuse in systems with lower system fault current, or be used in conjunction with a primary fuse, when fault currents exceed the interrupting rating of the vacuum interrupter. Several papers including [9] and [10] have outlined methods to add a vacuum circuit breaker at the primary of unit substations with both primary and secondary overcurrent protection, so that arc flash hazards at the substation secondary will be greatly reduced. IEEE 1584 [11] is the most current globally accepted document defining arc flash hazard calculations. Installation of a transformer including a VFI effectively duplicates this functionality, typically at a lower total installed cost. Fig. 5 shows one variation of a connection diagram for a liquid filled transformer configured with the associated protective devices. The sectionalizing switch, VFI, fuse and primary/secondary current transformers are mounted in the tank and are under oil. IEEE Std. C57.12.36 [1] today does not include reference to integral primary protection functionality described here, so in this case the industry standards will need to catch-up with
available commercial offerings.

**Ongoing Maintenance of Substation Transformers**

Most liquid-type transformers should be inspected on a periodic basis (normally once a month the first year and once a year thereafter) with routine inspections of installed gauges to make sure proper liquid level, temperature, and pressure are maintained.

IEEE Standard C57.152-2013 “Guide for Diagnostic Field Testing of Fluid-Filled Power Transformers, Regulators, and Reactors” [11] is a comprehensive standard outlining suggested routine maintenance. Similar to IEEE Std. C57.12.00, this document of recommended testing applies across a broad range of transformers, regulators and reactors. Perhaps the most useful part of this standard is informative Annex A through Annex I which describes individual test procedures as follows:


Most of the test procedures are based on American Society for Testing and Materials (ASTM International) standards. This organization develops and publishes voluntary consensus technical standards for a wide range of materials, products, systems, and services. These are referenced in Annex J, the bibliography. In addition to the Annex sections defining specific tests, Article 5.1 Table I Maintenance Test Chart outlines a list of field tests that are recommended at first commissioning, as routine in-service maintenance and following a protection trip due to a system or internal fault. This section is useful and all-encompassing.

Article 7.2.5 is dedicated to substation transformer insulating liquids and dissolved gas analysis (DGA). The value of DGA for a liquid-immersed substation transformer derives from the fact that certain gasses are produced by and abnormal release of thermal and/or electrical energy. Formation of these gasses within an operating transformer is caused by either thermal or electrical stresses and the analysis of combustible gasses may indicate the existence of one or a combination of thermal, electrical or partial discharge faults. The most prevalent gases generated during electrical arcing in an ester-based liquid-immersed transformer are hydrogen, methane, ethane, ethylene, acetylene, carbon monoxide and carbon dioxide. Liquid-immersed transformers using mineral oil produce gases at different rates and different proportions. DGA is actually only one of
multiple liquid tests defined in the Standard. Article 7.2.5.1 Table II includes details on extraction of the
minimum volume of liquid required for fifteen (15) different tests such as visual examination, water content,
acid number, dielectric breakdown voltage, corrosive sulfur and others. This comprehensive reference clearly
defines all liquid tests and supporting details regarding interpretation of results. A number of variables
are identified for field testing. For instance, acceptable dielectric breakdown values for new and in-service
transformers for various insulating liquids by voltage class is outlined in Table 5. Also, environmental
factors can impact test results (i.e. for this test, “The temperature of the windings and insulating liquid
should be near the reference temperature of 20°C and under no circumstances shall tests be made while
the transformer is under vacuum”.
The DGA liquid test ASTM D3612 “Standard Test Method for Analysis of Gases Dissolved in Electrical Insulating Oil by Gas Chromatography” is only one of 15 tests. Which
liquid tests are the most important? Which can be performed in-house and which require an outside lab?
Regarding DGA, Article 7.2.5.5 of the text says “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.”

Because of the complexities in understanding which field testing is relevant and in proper interpretation of
DGA results, the recommended approach is to require that any new transformer purchased includes a factory
test report. This report can 1) identify the manufacturer’s testing based on requirements as outlined in the
product performance standard for the actual transformer purchased and 2) serve as a baseline for comparison
for future field testing including DGA, performed during routine rotational outages. When specified by
the user, transformer manufacturers will perform factory DGA testing for either oil-immersed or natural
ester/synthetic ester-immersed transformers in accordance with IEEE Std C57.104 [13] or IEEE Std C57.155
[14] respectively. Regarding field DGA testing, in most cases, industry users do not have the time, resources
or technical expertise to perform routine service of substation transformers including proper extraction of
fluid from the tank, proper storage and transport of the fluid to a lab, and interpretation of a DGA sample.
For reference, Appendix A includes an example of standardized routine field tests typically performed by the
field services organization of one transformer manufacturer. In addition to specification of factory tests for
new transformers, the authors recommend a clear and consistent specification of required field tests, using
both factory and previous field tests as a baseline to determine additional required maintenance to assure
product integrity.

Conclusions

Distribution substation transformers are universally applied across all process industries. Because these
assemblies are not “active” elements of power distribution systems like other assemblies such as drives and
motor controls, they are often overlooked when specified, installed and maintained. Although transformer
performance is critical in assuring system reliability, a shortage in availability of technical resources with
expertise in product design, manufacturing, testing and field maintenance leaves these assemblies vulnerable
to failure, due in part to misunderstanding of proper specification and field testing by facility engineers.
Industry standards offer guidance in defining performance requirements along with best practices in routine
maintenance to ensure performance and reliability of these components of site power distribution systems.
Consideration and understanding of the applicable standards are key to assuring safe, reliable and efficient
operation of substation transformers applied in commercial and industrial power systems.
Liquid-Immersed Transformer with No-Load Tap Changer

Maintenance Testing Guideline

Necessary Equipment

- Personal protective equipment (PPE)
- Project folder or note book
- Product line contacts and phone numbers
- Torque wrench
- Insulation resistance test set 1000 VDC minimum
- RMS Multimeter
- TTR
- Dry Nitrogen, Gauges & Hose
- Oil Sample bottle
- Dielectric test set
- CT tester (if required)
- AC/DC Power Supply
- Portable generator (if required)

Prior to Testing

1. Procure and review:
2. Drawings associated with the device being tested
3. Instruction books
4. Safe working procedures and MSDS forms that apply to this task
5. Site safety rules and emergency procedures
6. Install safety locks and tags and safety grounds as required to provide for a safe working environment
7. Verify:
   8. That the transformer nameplate information is compatible with the drawings
9. Suitability and calibration dates of test sets
10. Record on the test form:
11. Customer and job information
12. Field data
13. As found conditions in the comment area
14. Test equipment data
15. Service engineer/technician name

**Inspection and Test Procedures**

**Report serious deficiencies immediately to the responsible customer contact**

1. Examine transformer for:
2. Tank, flanges and cooling fins for alignment, dents, scratches, fit, and missing hardware
3. Loose or obviously damaged components
4. Proper identification
5. Compliance to the drawings
6. Leaks
7. Verify:
8. The correct liquid level in all tanks, bushings and cooling fins
9. That positive pressure is maintained on nitrogen-blanketed transformers
10. That equipment grounding is correct
11. Cooling fan blades turn freely and appropriate safety guards are in place
12. That fan motors have correct overcurrent protection
13. That alarm, control, and trip settings on temperature indicators are as specified

**Electrical Tests**

1. Perform insulation-resistance tests winding-to-winding and each winding-to-ground
2. Perform a turns-ratio test at all tap positions
3. Verify that winding polarities are in accordance with nameplate
4. Using temporary control power, verify that cooling fans operate correctly and verify that control and alarm settings on temperature indicators are as specified
5. Test operation of all alarm, control, and trip circuits from temperature and level indicators, pressure relief device, and fault pressure relay
6. Take an oil sample and perform a Dielectric Breakdown test
7. Collect an oil sample and DGA to be sent to a company certified test lab for analysis of the following
8. Acid neutralization number
9. Specific gravity
10. Interfacial tension
11. Parts per million water
12. Visual condition
13. Color
14. Dielectric breakdown
15. Combustible Gas in Oil
16. Before energizing:
17. Verify that the as-left tap connections are as specified
18. Thoroughly clean the equipment before energizing
19. Check tightness of accessible bolted electrical connections with a calibrated torque-wrench
20. Make certain all components and wiring are installed and secure
21. Remove and account for all test equipment, jumper wires, and tools used during testing
22. Remove and account for safety grounds and tools
23. Replace all barriers and covers, close all doors, and secure all latches
24. Remove safety locks and tags
25. Verify correct secondary voltage phase-to-phase and phase-to-neutral after energization and prior to loading
26. If a fan control transformer is mounted in the transformer control panel, verify correct secondary voltage
27. Verify that the temperature indicator and sudden pressure relay is functioning properly

**After Testing**

1. Finish recording data on the data form, completely filling in all the appropriate blocks
2. Note corrective actions taken, deficiencies and recommendations, and any general comments
3. Apply field services test sticker to the equipment
4. Review and organize all test results and forms
5. Contact a customer representative to report results and follow-up actions