BY ORDER OF THE SECRETARY OF THE AIR FORCE

AIR FORCE HANDBOOK 32-1282V2
1 JULY 1999

Civil Engineering

Field Guide for Inspection, Evaluation, and Maintenance Criteria for Electrical Transformers

This handbook summarizes procedures and guidance to Air Force electricians for the inspection, evaluation, and maintenance of transformers and associated devices. It will also assist maintenance engineers and quality assurance evaluators in specifying and inspecting contractor performance.

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NOTE: Product and manufacturer names are included in this handbook for the purposes of illustration and do not carry the specific endorsement of the Air Force.

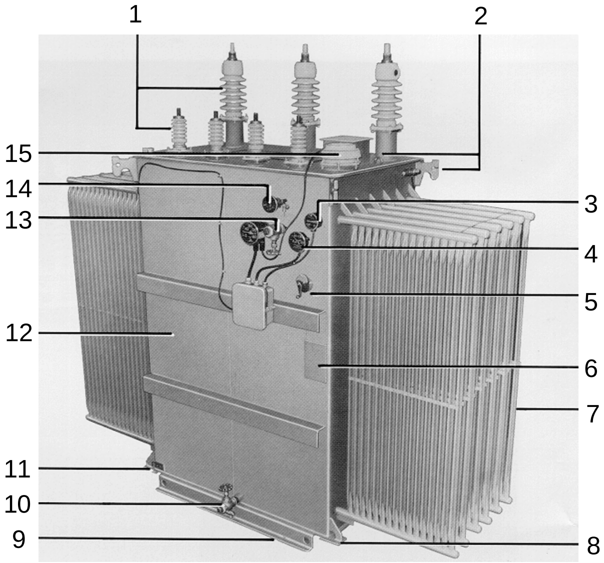
CHAPTER 1. OVERVIEW OF THE GUIDE

1-1. Scope. The condition of electrical transformers and related electrical power apparatus is crucial to the successful operation of all electrical power systems. Transformers and related equipment are significant components of the systems. This handbook identifies field procedures which allow early detection of transformer degradation and other defects which will adversely affect reliability. Appropriate corrective actions can then be accomplished.

a. Transformers and Related Equipment Covered. The transformers covered are constant-voltage power and distribution units and instrument transformers used in electric power systems. *Figures 1-1, 1-2, 1-3, 1-4, 1-5*, and *1-6* have been provided to remind the technician of similar and differing features of the various transformer types. Related equipment is discussed in AFH 32-1282(V1) (*Field Guide for Inspection, Evaluation, and Maintenance Criteria for Electrical Substations and Switchgear*).

(1) Operating and Protective Devices. Integral operating and protective devices which contribute to the correct operation of a transformer are covered. Also bushings used to connect transformers to the electric power system and surge arresters used for external protection of the transformer.

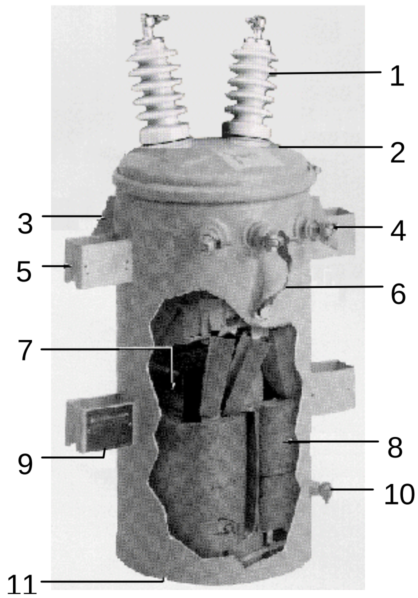
(2) Instrument Transformers. Instrument transformers which are classified as control apparatus rather than power apparatus are covered because their maintenance principals are similar to power transformers.



Note: See *Figure 2-2* for connections.

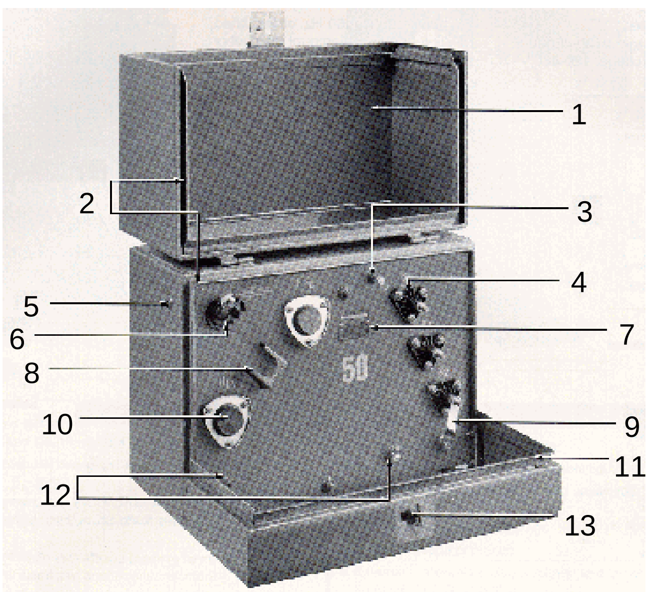
1. Bushings
2. Cover lifting loop and tank lifting hooks
3. Liquid-level gauge
4. Dial-type thermometer
5. De-energized tap changer
6. Nameplate
7. Coolers
8. Jack pads
9. Base
10. Drain valve
11. Grounding pad
12. Tank
13. Upper valve for filter press connection
14. Pressure-vacuum gauge
15. Pressure-relief device

Figure 1-1
Liquid-filled three-phase power transformer



1. High-voltage bushing
2. Cover and ring
3. Lifting lugs
4. Low-voltage bushing
5. Hanger bracket
6. Ground strap
7. Core
8. Coils
9. Nameplate
10. Ground boss
11. Recessed bottom

Figure 1-2
Liquid-filled single-phase distribution transformer



1. Door
2. Tamper resistant strips
3. Automatic pressure relief device
4. Low-voltage bushing
5. Lifting provisions
6. Bay-O-Net fusing
7. Nameplate
8. Standoff bracket
9. Ground strap
10. High-voltage bushing
11. Removable sill
12. Grounding provisions
13. Floating lock pocket

Figure 1-3

Liquid-filled single-phase compartmentalized padmount transformer

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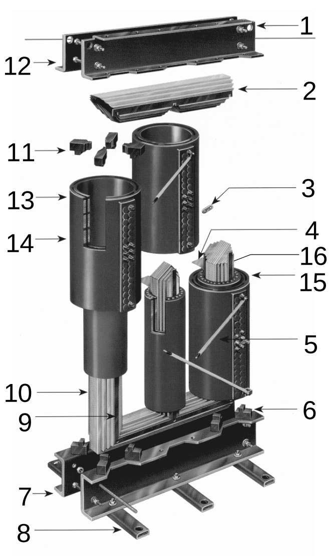
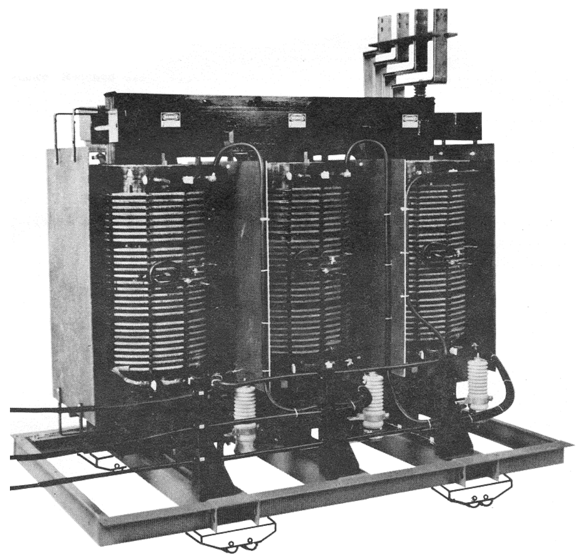


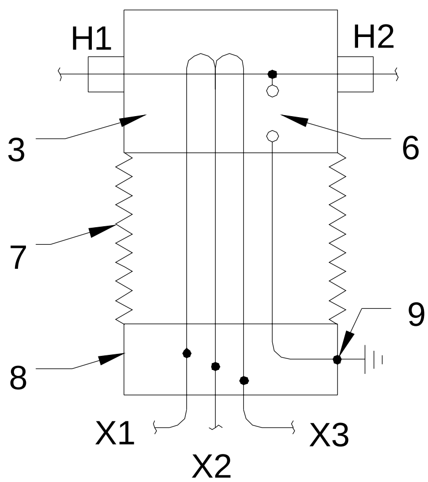
Cast Coil Unit

1. Lifting holes
2. Upper core yoke
3. High-voltage tap links
4. Low-voltage leads
5. High-voltage connections
6. Lower support blocks
7. Lower core clamp
8. Mounting feet
9. Core straps
10. Cruciform core
11. Upper support blocks
12. Upper core clamp
13. Primary conductors
14. Air ducts
15. Secondary conductors
16. Free-flowing ventilation



Conventional Unit

Figure 1-4
Dry-type three-phase power transformer



1. Oil filling cap
2. Oil level indicator
3. Tank containing primary core and secondary winding
4. Terminal H1
5. Terminal H2
6. Bypass protector (surge arrester)
7. Primary bushing
8. Secondary junction box (X1, X2, X3)
9. Ground pad on back of mounting bracket

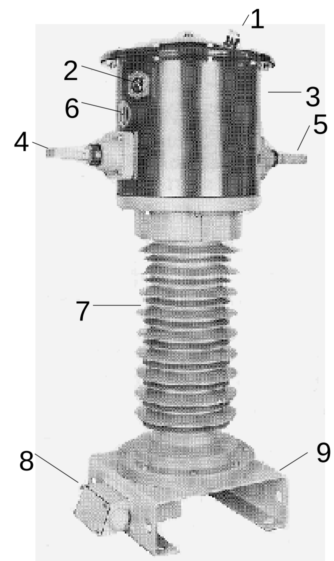


Figure 1-5
High-voltage current transformer

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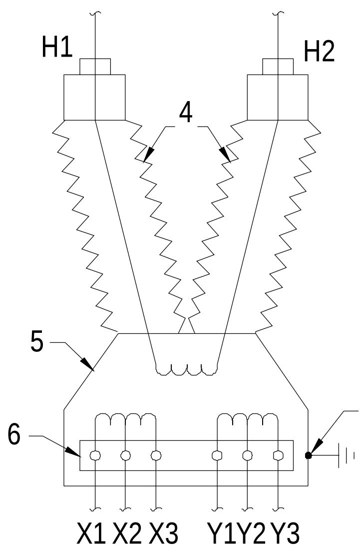

1. Terminal H1
2. Terminal H2
3. Oil level gage
4. Primary bushings
5. Tank containing windings
6. Secondary junction box
7. Ground pad

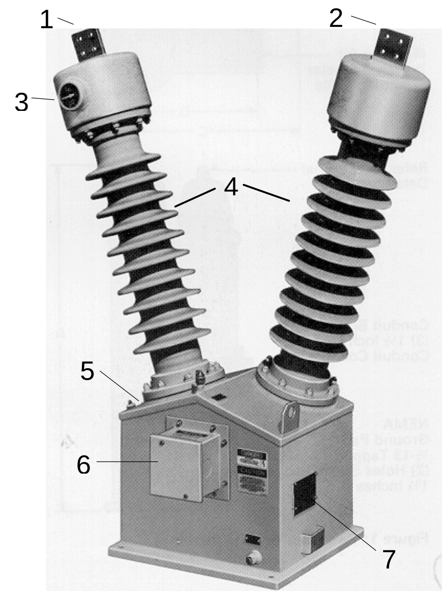

Figure 1-6
High-voltage potential (voltage) transformer

b. Equipment Not Covered. Electrical personnel with the appropriate knowledge may adapt the procedures for specialty, grounding, mobile, and mining transformers, and for step-voltage and induction voltage regulators which are specified under separate industry standards than those for power/distribution and instrument transformers. This handbook covers only apparatus typically found in Air Force transformer installations.

c. Purpose. Equipment deterioration needs to be identified before the equipment malfunctions or fails (that is, preventative maintenance). This handbook allows local preparation of electrical preventative maintenance (EPM) procedures. It does not cover catastrophic or operational failures. Its purpose is to prevent equipment failures resulting from a lack of proper preventative maintenance.

d. Technician Testing Limitations. The handbook is not a training guide. Air Force personnel should not use testing/metering/scanning devices around or on energized equipment unless they have been trained in their use and have satisfactorily demonstrated their knowledge of appropriate safety precautions.

1-2. Supplementary Information.

The maintenance technician should be familiar with and have available Air Force electrical design, maintenance, and safety manuals.

a. Design. Refer to the installation requirements of AFMAN 32-1180(I) *(Electrical Power Supply and Distribution)* which provides Air Force policy and guidance for design criteria and standards for electrical power supply and distribution systems.

b. Maintenance. Refer to AFMAN 32-1280(I) (*Facilities Engineering, Electrical Exterior Facilities)* which amplifies the maintenance and repair guidance of this handbook.

c. Safety. Refer to AFMAN 32-1185 *(Electrical Safe Practices)* which provide safety standards for the work being done. Maintenance work should be done only by workers in accordance with the electrical work classifications of AFMAN 32-1185, including AFSC 3E011 equivalent (helper), AFSC 3E031 equivalent (apprentice), AFSC 3E051 equivalent (journeyman), or AFSC 3E071 equivalent (craftsman). AFH 32-1285 (*Electrical Worker Safety Field Guide*) should be available to you to use in the field.

1-3. Basis for Developing Field Procedures.

This handbook is intended as summary guidelines and procedures. Actual maintenance/repair program requirements should be adjusted as appropriate for your specific electrical apparatus.

a. Handbook Information. This handbook covers generic apparatus performance, test data, and generally applicable component element checks. Use this handbook as a reminder of general maintenance requirements.

(1) Performance. Each component of major electrical apparatus performs essentially a simple operation. Complexity in maintenance is caused by the large and varied types of electrical components in the apparatus. This handbook provides figures and pictures to illustrate the most important of these components.

(2) Tests. Electrical equipment must be tested to ensure its continuing operating capability.

(a) Test Descriptions. Descriptions of the most commonly used tests are included in this handbook. Acceptable values of the tests are provided when possible. Reference to the manufacturer's literature may be required for other tests.

(b) Comparisons for Trends. All tests/readings should be compared to previous values (acceptance, preventative maintenance, or repair). This will assist in recognizing trends that indicate the need for more frequent testing. Permanent changes to equipment/devices that are overloaded, misapplied, or inadequate for the duty to which they are subjected may be required.

(3) Component Element Checks. Tables are included in this handbook which outline the most important components to be checked. Additional information on these components can be found in AFMAN 32-1280(I) and the manufacturer's literature.

b. Locally Developed Field Procedures. Each facility should maintain a copy of all applicable documents related to the installation, operation, and maintenance of electrical systems and equipment. Locally developed EPM procedures are essential to proper maintenance.

1-4. Preinspection Procedures. Prior to performing any field work, review historical EPM data and applicable safety requirements.

a. Apparatus Documentation. Assemble all documentation applying to the apparatus to be checked.

(1) Documentation Maintenance. The Base Civil Engineer (BCE) should ensure all documentation is maintained for each specific item of electrical apparatus which makes up the facility electrical power systems.

(a) Available From Design/Construction Files. The available data may include all of the inspection and testing procedures for the facility, copies of previous reports, single-line diagrams, schematic diagrams, electrical equipment plans, records of complete nameplate data, and manufacturer's service manuals and instructions.

(b) Locally Prepared. Prepare local EPM forms as necessary for installed equipment. Each item of apparatus should be shown on an equipment location plan. (*See Paragraphs 4-1, 5-1, 6-3, 7-3*, and *8-3*.) Provide unique apparatus designations along with a locally prepared safety electrical one-line diagram, and equipment location plan.

(2) Specific Assembling of Data. Assemble the following data, if available, for each specific item of apparatus.

- Locally prepared forms.
- As-built drawings for electric equipment layouts and elevations.
- Trend analysis data which should include:
  - (a) Installation acceptance data test results.
  - (b) Previous EPM reports including any previous systematic evaluations.

- Manufacturer's service manuals including practices and procedures for:
  - (a) Installation.
  - (b) Disassembly/ assembly (interconnection).
  - (c) Wiring diagrams, schematics, bills of materials.
  - (d) Operation (set-up and adjustment).
  - (e) Maintenance (including parts list and recommended spares).
  - (f) Software programs.
  - (g) Troubleshooting guidance.

(3) Systematic Evaluation of Apparatus Condition. Electric apparatus should receive a systematic evaluation of its condition after an EPM which indicates repairs were necessary beyond normal expected maintenance. The systematic evaluation should include:

- Reasons for the required repairs.
- Work required to complete the repairs.
- Assessment of the remaining service life.
- Determination of the need for a more frequent EPM.

b. Cleaning Precautions. Do not use a compressed air cleaner (in lieu of a vacuum cleaner) in medium and high voltage enclosures or other locations where dust could cause flashover.

c. Safety Requirements. Working on or near normally energized lines or parts requires observance of rules applying to safe working distances, work methods related to whether the line has been de-energized or left hot, and recognition of work hazards which require more than one worker for safety. Workers must be qualified for the work and use approved work methods and equipment. Refer to the requirements of AFH 32-1285 as amplified by AFMAN 32-1185. Always include a tailgate meeting to address existing site conditions and the procedures to be followed. Work will be done de-energized unless energized line work is specifically authorized.

(1) De-Energized Electrical Line Work. Follow the safe clearance (lockout/tagout) procedures given in AFH 32-1285. Remember lines are considered energized if the de-energized systems have not been provided with proper protective grounding. The safe clearance may require a job hazard analysis.

(2) Energized Electrical Line Work. Work on energized lines and equipment only when authorized by the electrical supervisor/foreman/lead electrician (per local organization) based on the need to support a critical mission, to prevent injury to persons, or to protect property. Insulating means must be provided to isolate workers from a source of potential difference. A job hazard analysis is required for energized line work.

d. Understanding Maintenance Frequencies. Frequency of maintenance should be locally adjusted based on the application of the equipment. See additional guidance in NFPA 70B (*Electrical Equipment Maintenance*). Adjust the frequency of inspection based on the criticality of the apparatus, the severity of the loading conditions, and an environment where unusual service conditions stress the equipment. Generally, usual service conditions extend only to elevations of not more than 3,300 feet (1 kilometer) and ambient temperatures of no more than 30 to 40 degrees C. Check with the manufacturer for other than normal service conditions.

e. Inspection Materials/Devices. Basic items needed for EPM include the following:

- A facility electrical truck
- Available documentation.
- EPM forms.
- Directions as to any input or approval needed from the appropriate using or operating agency

- Test equipment such as an
  - (1) Automatic insulation test set
  - (2) Dielectric test set
  - (3) Digital ground resistance test set
  - (4) Dissolved gas analyzer
  - (5) Infrared imager
  - (6) Corona tester
  - (7) Turns ratio test set
  - (8) Null balance (megometer) earth test set (megger®)
  - (9) Power factor test set
  - (10) True root-mean-square (rms) digital multi-electrical parameters meter
- Measurement instruments and miscellaneous devices such as a
  - (1) Cycle counter or timer
  - (2) Digital thermometer
  - (3) Multirange ac and dc voltmeters and ammeters
  - (4) Multirange noninductive load resistor
  - (5) Phase shifter
  - (6) Phase angle meter
  - (7) Three-phase sequence indicator
- Cleaning devices
  - (1) Vacuum cleaner
  - (2) Compressed air cleaner (*see caution of Paragraph 1.4.c*)
- Contamination washing devices such as a portable nozzle washer truck
- Miscellaneous tools such as
  - (1) Binoculars
  - (2) Flashlights (insulated)
  - (3) Insulated fuse puller
  - (4) Magnifying glass
  - (5) Tape recorder, tape and batteries
  - (6) Video camera and accessories
  - (7) Oil sample bottle and syringes and gas sample bottles
- Miscellaneous materials as necessary to clean, wipe, paint, insulate, solder, or for other small field-fix repairs.

CHAPTER 2. PERFORMANCE OF POWER/DISTRIBUTION TRANSFORMERS

2-1. Basics. A transformer utilizes electromagnetic induction between circuits of the same frequency, usually with changed values of voltage and current. All transformers covered in this handbook are constant-voltage type. That is, they maintain an approximately constant voltage ratio over loads from zero to the rated output.

a. Basic Transformer Theory. Assuming an ideal transformer (that is, one with no losses) then the alternating flux ι set up by the applied voltage Vp generates a secondary alternating voltage of Vs. For a perfect transformer the rate of change of flux in both windings is the same and the power output equals the power input. See *Figure 2-1*.

b. Requirement in the System. The requirement for electric power transfer will cause certain voltage levels to be more economical than others. The higher the voltage, the lower the current required to deliver the same electric power. A transmission system transfers energy in bulk between the source of supply (the utility) and the center for local distribution (the main electric supply station). A primary distribution system delivers energy from a main electric supply station to utilization transformers. A secondary distribution system delivers energy from a utilization transformer to points of utilization. Transformers provide a reliable method of converting voltage levels.

c. Classification as to General Construction. Transformer construction will vary dependant upon location such as indoors or outdoors, aerially, at grade, or below grade. Their cooling medium may be air or liquid as discussed in *Paragraph 2-4*. *Figures 1-1, 1-2, 1-3*, and *1-4* showed components of the various types most often encountered while *Pictures 2-1, 2-2, 2-3*, and *2-4* show actual installations.

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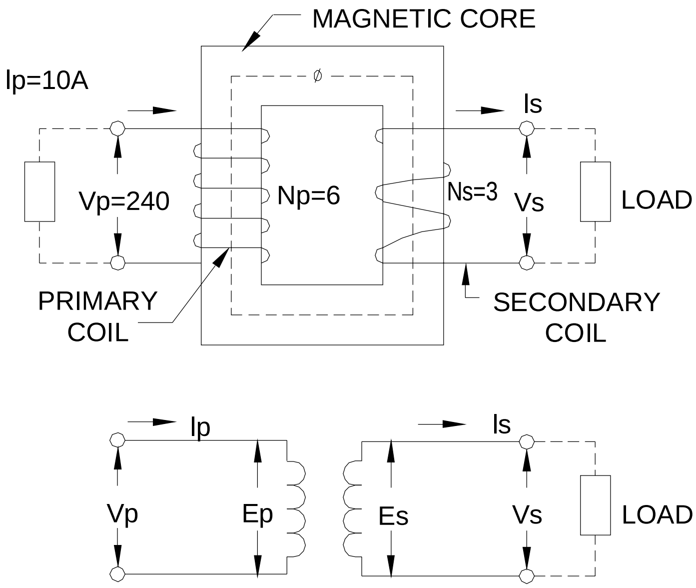


V = APPLIED VOLTAGE

E = FLUX GENERATED VOLTAGE

$$\frac{Es}{Ep} = \frac{Ns}{Np}$$

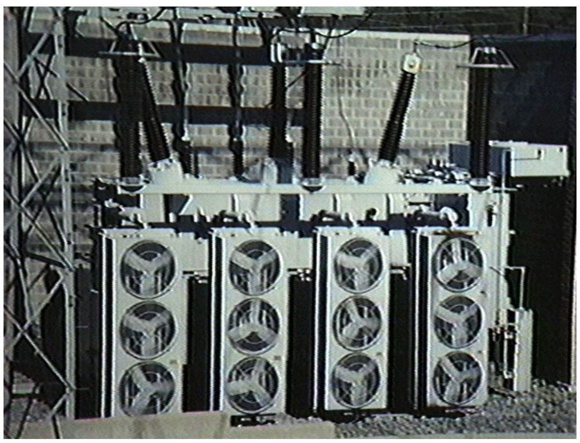
$Es = 240\ (3/6) = 120V$

$EpIp = EsIs$

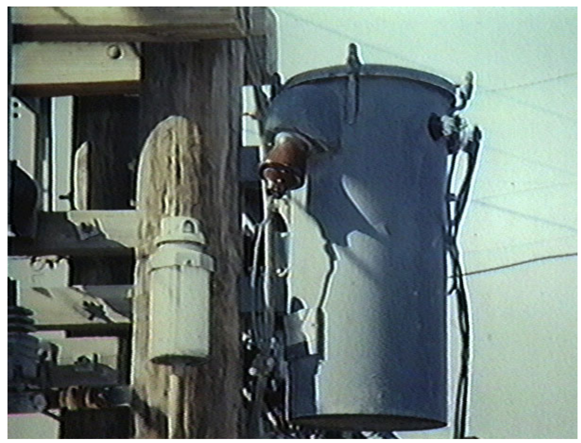
$$Is = \frac{240(10)}{120} = 20A$$

Figure 2-1

Connection and circuit diagram of an ideal transformer



Picture 2-1
Liquid-filled power transformer



Picture 2-2
Liquid-filled distribution transformers

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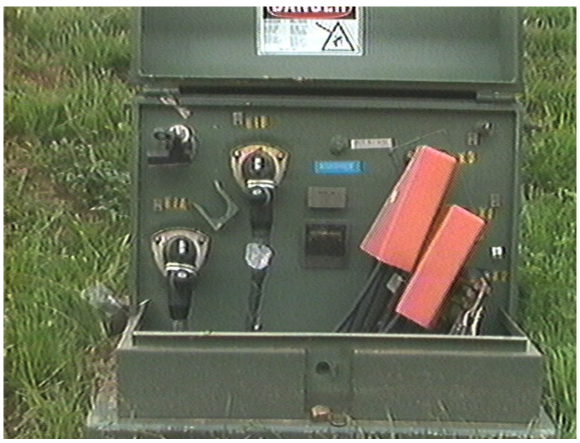
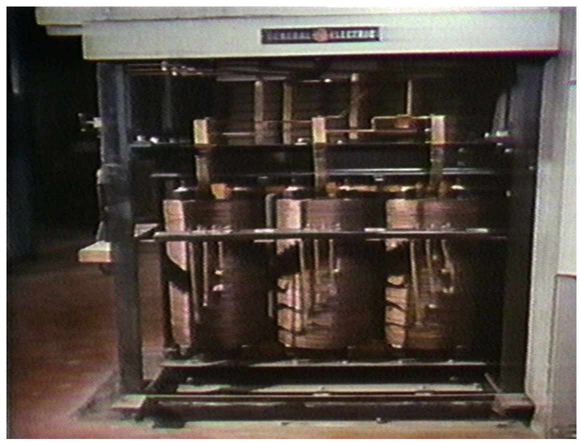


Picture 2-3
Liquid-filled compartmentalized padmount transformer



Picture 2-4
Dry-type power transformer

d. Classification as Power or Distribution Type. The industry classification of transformers as either a power or distribution type varies dependent upon the kVA rating of the transformer. Generally ratings of 5 to 500 kVA are considered distribution transformers while power transformers have ratings greater than 500 kVA. However, underground and compartmentalized padmount transformers of up to 2,500 kVA are also classified by industry standards as distribution transformers. The basic difference between power and distribution transformers is the general use of lower basic insulation level (BIL) for distribution transformers. Proper insulation coordination is not a maintenance responsibility. The transformer nameplate should list a specific transformer's BIL rating.

2-2. Principles. An ideal transformer does not consider the impedance elements which cannot be completely eliminated in actual transformers. This impedance represents the no-load losses and the load losses.

a. Turns Ratio. The turns ratio is the voltage ratio of the primary and secondary voltages as given on the transformer nameplate. A turns ratio measurement for all tap positions should compare with the calculated nameplate ratio to within plus or minus 0.5 percent. Thus:

Transformer connected delta-wye	Measured turns ratio
Primary voltage: Tap No. 1 14,400	$H_1 - H_2 / X_1 - X_2 = 3.455$
Secondary voltage: 4,160	$H_1 - H_3 / X_1 - X_3 = 3.456$
Calculated turns ratio: Voltage ratio = $\frac{14,400}{4,160} = 3.462$	$H_2 - H_3 / X_2 - X_3 = 3.457$

These measured ratios fall within plus or minus 0.5 percent of the calculated ratio.

b. Action Under Load. When a load is connected to the secondary of a transformer, the resultant inrush current in the secondary sets up a flux of its own in opposition to the primary flux. This reduces the overall flux through both windings, causing the flux generated voltages E_P and E_S to drop momentarily. The decrease in E_P lets the applied voltage V_p send more current through the primary winding. Connecting a load to the secondary has the effect of reducing the impedance seen by the applied voltage V_p. The increased primary current reestablishes the flux and provides the energy for the load.

c. Transformer Losses. Transformer losses include no-load and load losses.

(1) No-Load (Iron) Losses. Major losses result from the alternating flux created by the flow of no-load (exciting) current. Hysterisis losses come from the power necessary to magnetize the core in alternating directions. Eddy current losses result from circulating currents in the core iron. There are also small copper and stray flux leakage. Core loss is continuous on an energized unit.

(2) Load (Copper) Losses. This is the additional power loss due to the load and the current in the primary and secondary windings of the transformer.

d. Regulation and Efficiency. Regulation is the change in output voltage as the load current is varied and is usually expressed in percent as shown by *Equation 2-1* while efficiency is the ratio of useful power output to total power input as shown by *Equation 2-2*.

$$\text{Percent regulation} = \frac{\text{No-load secondary voltage - Full-load secondary voltage}}{\text{Full-load secondary voltage}} \times 100 \qquad \text{Eq. 2-1}$$

$$\text{Percent efficiency} = \frac{P_{out}}{P_{out} + \text{iron losses} + \text{copper losses}} \times 100 \qquad \text{Eq. 2-2}$$

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(1) Regulation Ranges. Transformer regulation is a function of the design parameters, such as resistance of the primary and secondary windings, and it is also a function of the power factor. Approximate regulation for a 15-kilovolt insulation class, oil-insulated, three-phase transformer is between 3 and 4 percent at a 90 percent power factor.

(2) Efficiency Ranges. Transformers are the most efficient electrical equipment available. The efficiency of most transformers ranges from 95 to 99 percent when operated at rated capacity.

2-3. Connections.

Transformers are connected in an electric system to change voltages, generally three-phase voltages. In such connection the intent is to maintain as constant a secondary voltage as is practical. As a part of understanding transformer connections, review your understanding of correct transformer polarity and phase rotation connections. Examples of single-phase, three-phase, and polarity (relative instantaneous current directions of transformer windings) are shown on *Figure 2-2*.

a. Single-Phase Connections. Single-phase systems will generally only be found for housing loads. *Figure 2-2* shows terminal designations for secondary three-wire outputs based on whether primary-to-secondary voltage terminal connections would provide additive or subtractive polarity connections.

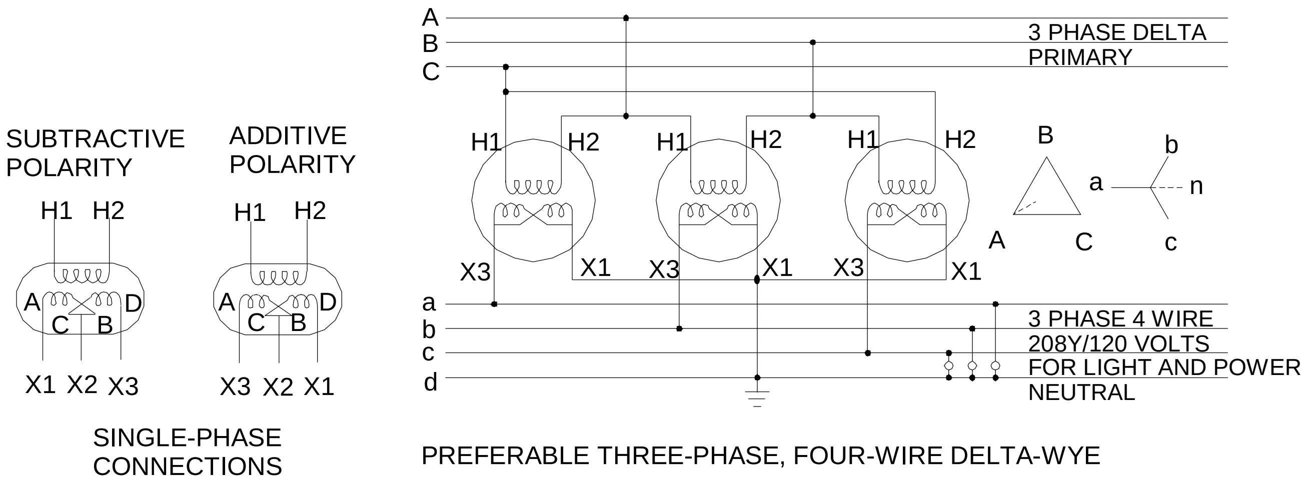

Figure 2-2
Transformer connections and polarities

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b. Three-Phase Connections. Superior operating characteristics are obtained with the delta-wye connection shown on *Figure 2-2*; therefore it is the most commonly used connection. The delta primary isolates the primary and secondary systems from third-harmonic currents. Such harmonic currents are increasing as more and more equipment is utilizing harmonic producing solid-state devices. A delta primary may be used without regard to whether the primary system is a three-wire or four-wire system. The wye secondary provides a convenient neutral point for grounding and for phase-to-neutral voltage loads.

c. Polarity. Polarity is the designation of the relative instantaneous directions of the currents entering the primary terminals and leaving the secondary terminals.

(1) Types. Connect primary terminal H1 and secondary terminal X1. Energize the connection and a voltmeter will read either the sum or the difference of the primary and secondary voltages depending on whether the transformer polarity is additive or subtractive. A conventional single-phase transformer with diagonal terminals of H_1 and X_1 is the designated method of indicating an additive polarity. Subtractive polarity locates H_1 and X_1 terminals on the same side. (See *Figure 2-2*.)

(2) Single-Phase Transformer Polarities. By industry standards, single-phase distribution transformers of 200 kVA and smaller, having high-voltage windings rated 8660 volts or less will have additive polarity. All other single-phase transformers will have subtractive polarity. This is because the potential stress between adjacent external (not internal) high- and low-voltage leads is less for subtractive polarities. This stress is only appreciable for transformers having high and/or medium voltages for both primaries and secondaries.

(3) Three-Phase Transformer Polarities. The polarity of three-phase transformers is fixed by their internal connections between phases as well as the relative location of leads. A vector diagram as shown on *Figure 2-2* should be shown on each transformer nameplate. The vector representing the voltage of a given winding is drawn parallel to that representing the corresponding phase voltage of the other winding with the use of a counterclockwise direction in the rotation of the vectors. The A, B, and C and the a, b, c, and n shown on the vector diagram are for three-phase transformer terminals rather than for a three-phase banked connection of single-phase transformers.

(4) Angular Displacement. Three-phase transformer connections provide a leading primary angular displacement of 30 degrees between primary and secondary voltages for delta-wye and wye-delta connections and zero degrees for delta-delta and wye-wye banks.

(5) Paralleling Transformers. Circulating currents occur if transformers to be paralleled do not match. The load will not be evenly divided between units and one unit can be overloaded. Matching characteristics include winding connections, impedances, turns ratios, primary voltages, and phase displacements. Polarities must be the same and similarly designated (H_1 to H_1) terminals must be connected to each other.

2-4. Construction. The basic elements of a transformer consist of the magnetic core, and the electrical windings or coils (see *Figure 2-1*). Other major components include the transformer tank or enclosure, the dielectric insulant/coolant, and the transformer bushings or provisions for connections to input and output electric power lines (see *Chapter 7*).

a. Core and Coil Construction. There are two basic core and coil constructions. One consists of the core type where the coils or windings surround the magnetic core (see *Figure 2-1*), generally used for small distribution transformers. The other is the shell type where the magnetic core surrounds the coils (see *Figure 1-4*) used for most large power transformers.

(1) Core Type (Form) Windings. There are three distinct classes of windings for core form units: helical, disk, and layer. Helical windings are the simplest and are typically used when only a few turns are required for a low voltage application. Disk windings have the capacity to withstand short circuit forces and are most often used in high voltage applications. Layer windings are very low in cost but have little mechanical strength. These transformers are likely to fail during a short circuit event.

(2) Shell Type Windings. The shell type is very strong mechanically and gives good protection against short circuits and lightning strikes, but it must be manually assembled. This makes the shell type uneconomical for most small and medium size transformers.

(3) Core and Coil Vibration. A transformer is a static device with no functional moving parts. But energized at 60 hertz, the continuously oscillating magnetic field generates 120 hertz mechanical vibration in the core laminations. This motion in turn generates audible sound or transformer hum.

b. Tanks or Enclosures. Transformer tanks are steel to provide protection for both the core and coil assembly and the coolant/insulant from moisture and other contaminants. Enclosures will vary dependant upon whether the coolant/insulant is nonliquid that is dry or liquid.

(1) Dry-Type Transformer Enclosures. The enclosure is steel and provides the protection against access to energized parts and contamination of the air as appropriate, to an indoor or outdoor location but allows inspection of the core and coil assembly. The transformers solid dielectric protects the assembly. Assemblies are provided with different insulations appropriate to the reliability required. Insulations range from a conventional solid insulation, a better vacuum-impregnated solid insulation, or the most superior cast-coil solid insulation.

(2) Liquid-Insulated Transformer Tanks. Various tank constructions are used to prevent exposure of the liquid to the atmosphere. The liquid insulation must be drained before inspection of the core and coil assemblies can be made. The various types are classified as:

(a) Free breathing, that is open to the atmosphere through a breather which may be equipped with a dehydrating compound. The free breathing construction is not usually a good choice for replacement transformers.

(b) Conservator-tank type partially filled with oil and the air space above vented to the atmosphere through a tube and a breather. See *Picture 2-5*.

(c) Conservator-tank type with an air bag. See *Picture 2-6*.

(d) Gas/oil sealed type with a two part expansion tank with oil below and an inert gas above. See *Picture 2-7*.

(e) Gas sealed type with an inert gas above the transformer tank oil and a gas cylinder to automatically maintain positive gas pressure above atmospheric pressure. See *Picture 2-8*.

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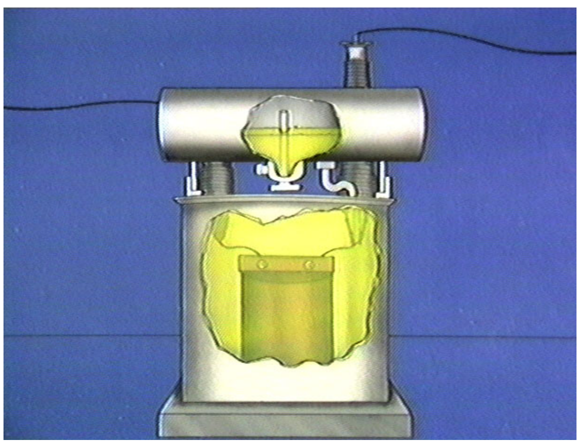
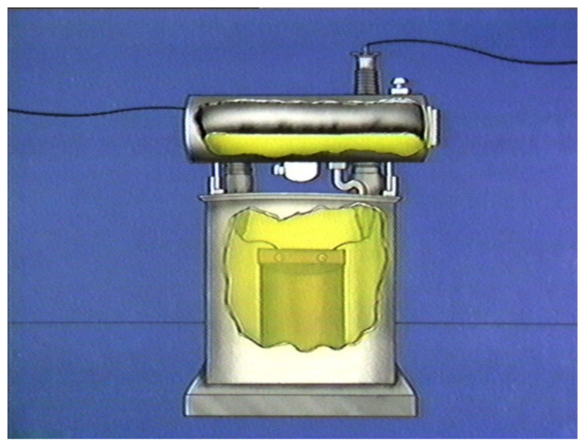
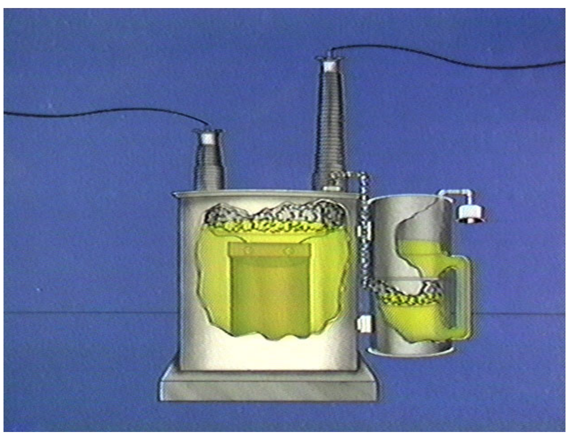


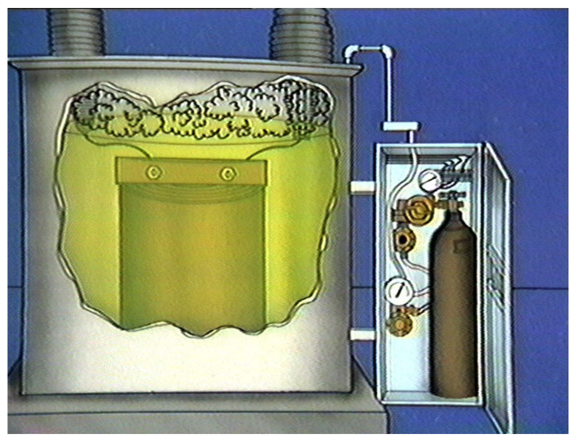
Picture 2-5
Simplified diagram of a conservator-tank type



Picture 2-6
Simplified diagram of a conservator-tank type with an air bag



Picture 2-7
Simplified diagram of a gas/oil sealed type



Picture 2-8
Simplified diagram of a gas-sealed type with a gas cylinder

c. Dielectric Insulants/Coolants. Electrical insulation is a medium or material which placed between conductors at different voltages permits only a small or negligible current in phase with the applied potential to flow through the insulation or dielectric. The dielectrics used to insulate a transformer consist of solid insulation used on the core and coil assembly and the nonliquid or liquid insulant/coolant medium surrounding the solid insulation and contained within the transformer tank. Transformers are generally classified as either nonliquid filled (dry-type) units or liquid-filled units.

(1) Dry-Type. Air as a nonliquid insulation and combinations of epoxy resin, porcelain, glass, and similar materials with various impregnating materials are generally used where the fire and environmental hazards of mineral oil make a dry type transformer a more desirable installation.

(2) Liquid-Cooled Type. Mineral oil liquid and cellulosic (Kraft) paper solid insulation combinations are the most widely used electrical-mechanical insulation systems as the least costly insulation although with the highest fire/environmental risks. Other liquid insulations used because of their fire-resistant characteristics are polychlorinated biphenyls (PCB) (now banned as environmentally hazardous) and silicon fluids whose cost generally eliminates their use. Fire-resistant synthetic transformer oils are also available but will shorten transformer life because they create higher temperature hot spots. Other solid insulation materials include enamel (low voltage applications only) and Nomex. Nomex is very strong but typically costs about 30 times more than Kraft paper. It is often used as insulation for high voltage leads and crimps, and in mobile transformers since these receive particularly high mechanical stresses during transport.

d. Mineral Oil. Transformer mineral oil provides dielectric strength and efficient cooling for the transformer. It protects the paper insulation and can be tested to predict the electric and mechanical strength of the insulation. Mineral oil can be produced from paraffin-based crude (paraffinic transformer oil) or from asphaltic-based crude (naphthenic transformer oil). Paraffinic transformer oil is not adequate for northern American winters (due to wax formation in the transformer) and was replaced by naphthenic transformer oil in the mid 1920's. Since 1973, there has been a critical shortage of naphthenic transformer oil. Only 100 percent paraffinic transformer oil and blends of paraffinic and naphthenic transformer oils are presently available.

(1) Oil Reclamation. Whenever possible, reclaim used transformer oil since it will be a better transformer fluid than new transformer oil. At least 80 percent of the hydrocarbons of even heavily used oil can be reused after oxidation products are eliminated. It will be necessary to add the oxygen inhibitor BHT (2,6-Ditertiary-Butyl-Para-Cresol (DBPC)) to reclaimed oil.

(2) New Oil. ASTM *D3487 (Standard Specification for Mineral Insulating Oil Used in Electrical Apparatus*) provides the current specification for new transformer oil. When specifying new transformer oil, specify naphthenic oil if the transformer could be subject to freezing temperatures. In warm climates, paraffinic oil is also acceptable. The manufacturer can supply oxygen inhibitor in the oil per ASTM D3487 Type I (0.08 percent maximum) or ASTM D3487 Type II (0.3 percent maximum). Type II should always be specified since it can be used in both newer and older transformers.

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(3) Precautions. Note that oil supplied with a level of inhibitor much over 0.3 percent is cause for concern since it may be intended to hide other problems in the oil. New oil should also have no PCBs and no combustible gases (combustible gases indicate the oil has been contaminated by gasoline). European transformer oils are provided as classes I, II, and III. Class II is similar to North American transformer oil, although the oxygen inhibitor is not included in the standard specification.

(4) Manufacturers. Currently available manufacturers of ASTM D3487 Type II oil include: Exxon (Univolt 61), Shell (Diala AX), Texaco (relabeled Exxon oil), Calumet (Cal-Tran 60-30), Pennzoil (Type II), Cross (Cross Trans 206), and Ergon (Hyvolt II).

2-5. Transformer Life Aspects. Maximum transformer life expectancy can be achieved by regular testing and maintenance. Loss of life can be limited to about 2 percent per year for transformers built since 1955 (prior to this date, very conservative safety factors were used in transformer design, and the transformers could better tolerate a neglect of regular maintenance). Loss of life cannot be prevented because the Kraft paper ages and decomposes at normal operating temperatures. Transformer life expectancy without maintenance has been reported by industry studies as averaging 9-11 years for very large units, and 14-22 years for most other units. Most transformers fail because of a breakdown in the insulation (85 percent). Other significant failure reasons include improper drying of the transformer during manufacture, damage during transportation, and damage during installation.

a. Evaluation of Transformer Materials. Materials utilized in transformer construction include conducting (copper or aluminum) magnetic (iron), structural (steel), and insulation systems. The first three materials can be readily evaluated as to their transformer durability. Thus, industry standards base life expectancy on the transformer's insulation as affected by temperature and time. Most data indicates that the majority of transformer failures are attributable to breakdown of the insulating system.

b. Transformer Maintenance Is of Paramount Importance. A properly maintained transformer is one where excessive voltages and loadings are not permitted, operational accidents are corrected to eliminate causes of premature failure where possible, and aging fluid insulation is reclaimed or replaced. Preventative and predictive maintenance will extend the practical life of a transformer from a possible unmaintained life of 20 years to 50 years.

c. Solid Insulation Is the Weak Link. Solid insulation is one part of the transformer whose aging characteristics are irreversible. The three characteristics which damage the cellulosic paper insulation found in oil-insulated transformers are:

- Vulnerability to excessive heat which is a result of overloading or short-circuit stress.
- Adverse reaction to oxygen from the atmosphere or oxygen liberated from solid insulation by heat or moisture.
- Affinity to water and oil decay products.

(1) Moisture by Dry Weight (M/DW). Some water is inherently present in new Kraft paper insulation (typically less than 0.5 percent M/DW). A transformer in service will typically have values of 0.5 to 1.0 M/DW. A wet transformer will show values of 3.0 percent M/DW or greater, and requires corrective action or replacement. Kraft paper is fully saturated with water at 17.0 percent M/DW, and has little insulating value. The M/DW value correlates well with the power factor test of IEEE 62, (*Guide for Diagnostic Field Testing of Electric Power Apparatus - Part 1: Oil-Filled Power Transformers, Regulators and Reactors*) up to about 3.0 percent M/DW.

(a) Replacement Specification. Be sure to specify a solid insulation power factor test by the manufacturer for a new transformer. (This test is repeatable in the field.)

(b) Replacement Acceptance. Do not energize a new transformer with the solid insulation power factor test reading above 0.5 percent without a complete internal inspection, consultation with the manufacturer, and possible corrective action such as drying. Generally, do not accept a new transformer with a solid insulation power factor test reading above 0.5 percent because otherwise many years of service life will be lost.

(c) Loss of Service Life. A new transformer with a power factor of 1.0 percent will have half the service life of one with a power factor of 0.5 percent. A solid insulation power factor test reading of 0.5-2.0 percent on transformers in service is generally acceptable because as transformers thermally age the Kraft paper insulation produces water. A reading above 2.0 percent is cause for further investigation. See *Paragraph 4.2.b.(4).*

(2) Moisture in the Oil. Water is frequently found at the bottom of transformer tanks but is relatively harmless at this point. Water is found in suspension in the oil (emulsified) but is usually only a problem when polar contaminants are dissolved in the oil that the water can cling to. Water is also found dissolved in the oil and this water will migrate into the cellulose depending on the temperature (and temperature depends on load). Migration of water between the oil and the cellulosic paper will eventually reach equilibrium. At equilibrium the moisture concentration in the paper will be hundreds of times greater than in the oil. Moisture content in the oil can be measured by laboratory test but does not by itself establish insulation dryness. However, 50 parts per million (ppm) of water from a top oil sample is critical as it indicates the paper insulation is wet.

(3) Sludge Formation. Oxidation begins as soon as the oil is placed in the transformer. Deterioration results from the effects of oxidation. Contamination results from moisture or other foreign substances and starts after the transformer is energized. Unstable hydrocarbons plus oxygen, moisture, heat, vibration, and electrical stresses result finally in the terminal stage of oil degradation as an insulating medium, that is the formation of sludge. Sludge is the first visible sign that oil needs to be reclaimed or scrapped. Sludge precipitates out of the oil where it attacks solid insulation and can reduce effective cooling. The sludge builds up in layers whose hardness depends on how the unit has been operated and how long maintenance has been ignored. Sludge formation depends on the presence of oxygen in an energized transformer. This oxygen may come from outside air, but also comes from the breakdown of the Kraft paper. The probability of sludge accumulation increases if the oil shows an increase in neutralization (acid) number, a drop in interfacial tension, and a deepening of color, as shown in *Table 2-1*.

Table 2-1. Oil condition based on ASTM D 1524 color comparisons

Color comparator number	Color	Oil condition
0.0-0.5	Clear	New oil
0.5-1.0	Pale yellow	Good oil
1.0-2.5	Yellow	Service-aged oil
2.5-4.0	Bright yellow	Marginal condition
4.0-5.5	Amber	Bad condition
5.5-7.0	Brown	Severe condition (reclaim oil)
7.0-8.5	Dark brown	Extreme condition (scrap oil)[1]

[1]Retest to confirm reading prior to scrapping oil.

2-6. Symptoms Indicating Possible Transformer Failure. Recognize that certain warning signs signal that transformers may need immediate shutdown to preclude transformer failure. Analysis of the causes may indicate need for shop repair or replacement. As an interim measure transformer removal for shop repairs may require a temporary replacement.

a. Danger Signals. The following symptoms are causes for concern.

- Smoke or evidence of burned insulation
- Excessive temperature or losses
- Incorrect operating parameters, such as voltage or frequency
- Noise indicating internal arcing or loose core and coil assemblies
- Observation of insulating oil leaking from liquid-insulated transformers or of moisture condensation on dry-type units
- Failure of oil insulating tests to meet minimum requirements
- Failure of transformers to meet testing requirements
- Tank wall bulge
- Oil with unnatural odor or darkened color

b. Transformer Replacement. The existing transformer will be disconnected and shipped for shop repairs or disposal as appropriate. The replacement transformer will be inspected, handled, installed, operated, and tested in accordance with its instruction manual and the site requirements for connection to the existing power input and output circuits.

(1) Existing Transformers. Check the instruction bulletin for approved methods of handling. Crane lifting is preferable; forklifts are not recommended. Rollers used must distribute stress so as to prevent tipping of the transformer base.

(2) Replacement Transformers. Ensure the manufacturer conducts factory tests as appropriate for the application. Insulation power factor, excitation current, and turns ratio tests should be performed at the factory for a benchmark. These tests are repeatable in the field and should be compared to the factory tests. Make visual and electrical checks to assure there was no shipment damage. Dry out transformers if necessary. Never energize a wet transformer. Make all necessary primary, secondary, and control connections and verify that the transformer is permanently and adequately grounded. Check correct operation of all devices such as fans, motors, relays, and auxiliary items.

(a) Tests. Provide acceptance tests in accordance with local policy but not less than those provided for the transformer that is being replaced or those considered necessary based on previous trend analyses. At a minimum, a core ground test and an inspection for visual damage should be performed on arrival or installation of the transformer as applicable. See *Paragraph 4-2* for additional information on testing.

(b) Liquid Insulation Addition or Sampling.

(i) Transformers requiring oil filling should have the work done under contract with an organization capable of providing the quality control necessary to prevent oil contamination. Such organizations are familiar with the various manufacturers' own field preparation instructions on fluid filling. Oil testing will be provided to assure that test limits meet the new mineral insulating oil for shipments as received from the refinery specified in ANSI/IEEE C57.106 (*Guide for the Acceptance and Maintenance of Insulating Oil in Equipment*). See *Paragraph 2-5* for additional information on replacement transformer oil.

(ii) Sampling. Sample the liquid insulation which must meet all test limits of new oil received in new equipment of ANSI/IEEE C57.106. (See *Paragraph 4-1*.) Sampling must be done in accordance with ASTM D 923 (*Standard Method for Sampling Insulating Liquids*). A one liter sample should be sufficient and an additional one liter sample should be kept in case of any problems encountered in the testing. Problems can occur if the following guidelines are not observed.

- Samples should be tested as soon as possible after removal and dates of sampling and testing should be noted.
- Sampling must be done in a relatively dry atmosphere (70 percent humidity or less) using dry and clean glass containers with nonrubber wax-sealed stoppers with sampling valves flushed to remove natural contaminants.
- Confirmation that a positive tank pressure exists should be made before attempting to obtain a sample. Failure to do so may introduce a gas bubble that could cause the transformer to explode, and kill or severely injure nearby personnel.

2-7. Characteristics. Industry standards define these characteristics. Transformer characteristics are standardized for most medium-voltage to low-voltage transformers. High-voltage to medium-voltage transformers have both standard requirements and other requirements which may be specified for some applications. All transformers provide the minimum information on their nameplates as required by industry standards. Some characteristics which are defined by industry standards are not required to be shown on transformer nameplates. The nameplate information usually required is shown in *Table 2-2*.

Table 2-2. Minimum transformer nameplate information[1]

Serial number	Polarity (single-phase transformers)
Class (OA, OA/FA, etc.)[2]	Phasor diagram (polyphase transformers)
Number of phases	Approximate total mass in pounds
Frequency	Connection diagram
kVA rating	Name of manufacturer
Voltage ratings	Installation and operating instructions reference
Tap voltages	The word *transformer* or *autotransformer* [4]
Temperature rise, degrees C[3]	Type of insulating liquid (generic name preferred)[3]
Percent impedance	Conductor material (of each winding)

[1]For dry-type transformers, the basic lightning impulse insulation levels (BILs) are required and there should be no listing of insulating liquid. Temperature rise by individual winding is required, if different.
[2]Applies to liquid-immersed transformers. Dry-type transformers are class (AA, AA/FA, etc.). For dry-type transformers larger than 500 kVA the nameplate shall state if the transformer is suitable for step-up operation.
[3]Applies to liquid-immersed transformers.
[4]The nameplate shall state “dry-type transformer.”

a. Capacity and Voltage Ratings. Capacity is the kVA rating which can be delivered continuously without exceeding the temperature rise limit. The temperature-rise is the difference between the temperature of the part under consideration and an ambient design temperature of 40 degrees C at the usual maximum altitude of 3,300 feet (1 kilometer). Above that elevation, transformer kVA must be derated in accordance with industry standards. There are several standard voltage ratings within the eight voltage insulation classes commonly encountered which are 600-volt, 5 kilovolt, 15 kilovolt, 25 kilovolt, 34.5 kilovolt, 46 kilovolt, 69 kilovolt, and 115 kilovolt.

b. Cooling. The standard kVA rating for transformers is based on the self-cooled ability of the transformer insulation either by a fluid or by air in combination with any transformer radiators. Additional higher ratings may be indicated when auxiliary cooling systems of fans and/or pumps are provided. Basic cooling classes are OA for liquid-immersed self-cooled units and AA for dry-type ventilated units. Forced air cooled units are the most often encountered when auxiliary cooling is provided and are denoted by either OA/FA or AA/FA. Other types of cooling are generally only provided for high-voltage to medium-voltage transformers and their instruction bulletins will cover the cooling equipment provided.

c. Impedance Level and Short-Circuit Capability. These are values the design engineer needs to know to properly protect transformers under short circuit conditions. The impedance level limits short-circuit flow and the short-circuit capability defines the transformer's ability to withstand without injury the stresses imposed by a short-circuit current for a time in seconds based on the short-circuit current magnitude.

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d. **Basic Impulse Level (BIL).** A BIL level indicates the crest value of the impulse voltage that the transformer is required to withstand without being damaged. BIL levels are intended to simulate conditions that may occur when transformers are subjected to lightning surges or to switching surges. BIL levels are required on nameplates of transformers rated more than 500 kVA and on transformers rated 500 kVA or less with a high-voltage BIL of less than 150 kV (15 kV insulation levels ratings and below).

e. **Voltage Ratio Tap Changers.** Load tap changers are automatically operated under load to maintain a constant secondary voltage with a variable primary voltage. Manual load tap changers (which cannot be operated with the transformer energized) allow adjusting the secondary voltage to compensate for primary voltages which are higher or lower than the transformer's rated voltage.

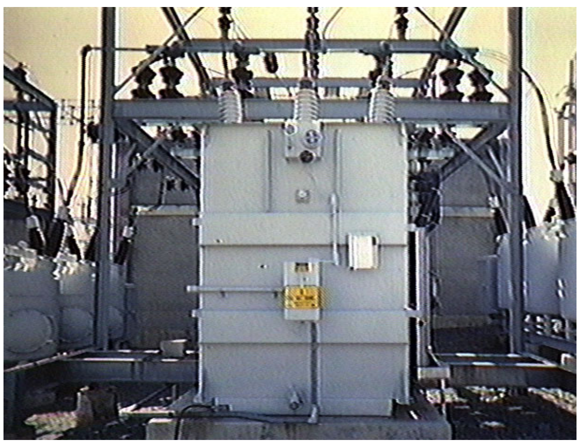
f. **Sound Level.** Transformer noise from the laminated core vibration can exceed Air Force regulations, especially for large high-voltage to medium-voltage units. Some installations may have provided sound-reducing enclosures or special designs. Alternately, the replacement transformer may be specified with an audible sound level tested in accordance with IEEE C57.12.90 *(Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers and Guide for Short-Circuit Testing of Distribution and Power Transformers*).

CHAPTER 3. ACCESSORIES AND COMPONENTS FOR DISTRIBUTION/POWER TRANSFORMERS

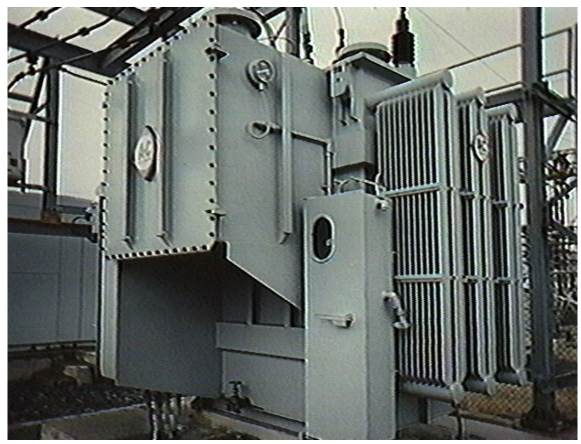
3-1. Accessories Improving Transformer Electrical Performance. Transformer cooling systems and tap changers are provided to increase transformer capacity and improve output voltage control respectively.

a. Cooling Systems. Transformer losses are power losses which are converted to heat. This heat must be dissipated into the surrounding atmosphere by the transformer's cooling system otherwise excessive insulation temperatures can occur. Cooling systems are self-cooled or fitted with auxiliary equipment to increase the self-cooled transformer capacity. *Pictures 3-1, 3-2, 3-3*, and *3-4* show actual cooling device installations.

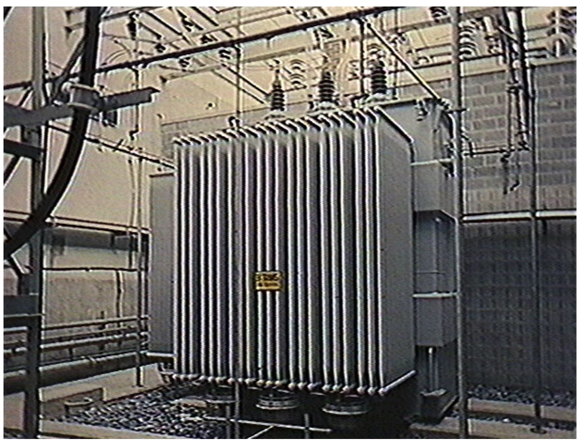
(1) <u>Liquid-Insulated Transformer's Self-Cooling Action</u>. The core and coil assembly heats the surrounding liquid which becoming less dense. The liquid rises and dissipates heat to the surrounding air. The air on being heated also rises causing both the internal oil and external air to naturally circulate within and without the transformer respectively. The oil flows alternately upward as it is alternately heated by the coils and then back down as it is cooled by the convection of the surrounding air. The transformer may be equipped with radiators to provide additional heat exchanger area. Radiators utilize hollow tubes connected to headers which allows the heated oil flowing in the upper header to cool and flow naturally through the lower header back into the transformer tank.



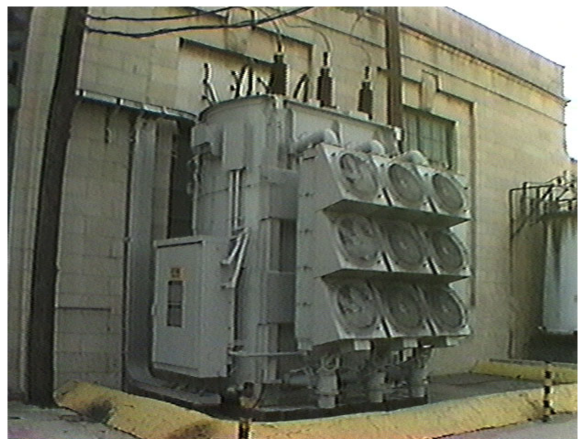
Picture 3-1
Self-cooled transformer without radiators



Picture 3-2
Self-cooled transformer with radiators



Picture 3-3
Transformer with cooling fans at base of radiators



Picture 3-4
Transformer with cooling pumps below cooling fans

(2) Nonliquid Cooled Transformer Self-Ventilating Action. The core and coil assembly is surrounded by air at atmospheric pressure and heat is removed by the natural convection of the surrounding air and radiation from the core and coil assembly.

(3) Auxiliary Cooling Systems. Cooling systems consist of various combinations which include controls, fans, pumps, heat exchangers, and oil system conservators for liquid-insulated transformers and controls and fans only for nonliquid cooled transformers.

(4) Conservators. Conservators act as reservoirs for the tank's oil as rising oil temperatures require them to act as expansion tanks. The various types are covered in *Chapter 2*. They are provided with breathers of either the open or dehydrating type. The open type exposes the oil to the atmosphere and its moisture. The dehydrating type prevent moisture from entering the tank.

(5) Procedures and Precautions. Recommended procedures and precautions applying to these devices are given in *Table 3-1*. However, always check manufacturer's procedures and precautions which take precedence if their directions differ from *Table 3-1*. Correct any deficiencies.

Table 3-1. Cooling system procedures and precautions

Self-cooled

Air-flow may be a problem. Any debris or contamination buildup lodged between fins or tubes of liquid-filled transformer radiators or between the ventilating channels and on the windings of dry-type transformers should be removed.

Cooling system controls

Determine type of cooling system

Check the manual control for sufficient voltage for each cooling system

Ensure proper operation of the applicable automatic control device. For temperature-controlled systems observe that the temperature control gauge is properly calibrated. For load-controlled systems check that the controlling current transformer (CT) is operating properly.

Running high speed pumps by manual control may result in transformer failure. Open-circuiting of the secondary of the load CT when the primary is energized can result in catastrophic results.

Cooling system fans

Observe that the rotation of the fans is in the proper direction preferably at the lower-than-normal speed at start-up or shut-down. Do not examine fans when they are rotating. Check that airways are not blocked or that blades and guards are not damaged or distorted.

Table 3-1. Cooling system procedures and precautions (cont.)

Cooling system heat exchangers

Water coolers. Check water flow and temperature for proper operation. Check to assure that no oil is present in the water. Oil in the water is an indication that the water-filled tubes (installed in the transformer's tank) are leaking.

Air coolers. Check for trapped debris or contaminated cooler fin surfaces.

Cooling system pumps

If a visual inspection of a pump is indicated, it should be done by contract personnel having precise knowledge of how the cooling system surrounding the pump can be effectively isolated from the rest of the equipment's cooling system.

Bearing wear is a cause of pump failure. Check the amount of shaft end-play to the manufacturer's requirement. This may indicate a need for visual inspection of the pump.

Consider providing a fault-gas analysis to check whether electrical problems have generated combustible gasses in the equipment's insulation liquid. Any significant imbalance of current between terminals (15 to 20 percent) indicates a pump problem. Differences of current ranges between like pumps on the same unit also indicates a problem.

Reversed pump rotation can occur after maintenance and is indicated by a sluggish movement of the flow gauge flag. If reversing two electrical leads speeds up the movement of the flow gauge flag, then the pump rotation direction is now correct.

Table 3-1. Cooling system procedures and precautions (cont.)

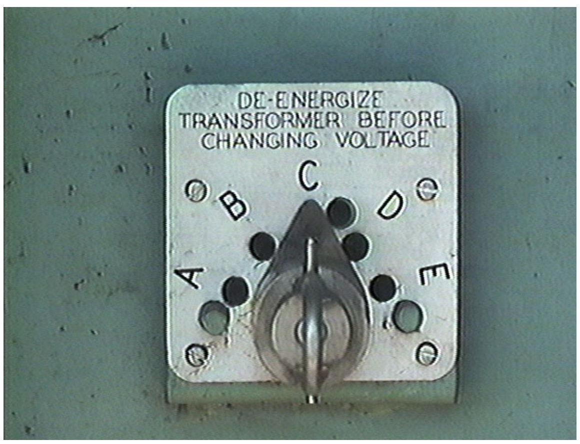
Conservators

Record oil temperatures: The oil level indicated on the liquid level gauge on the side of the conservator vessel should be made with respect to the 25 degree C mark on the gauge. The top oil temperature reading should be used to correct the oil level gauge reading. The resulting corrected level should be in the normal (25 degree C) range.

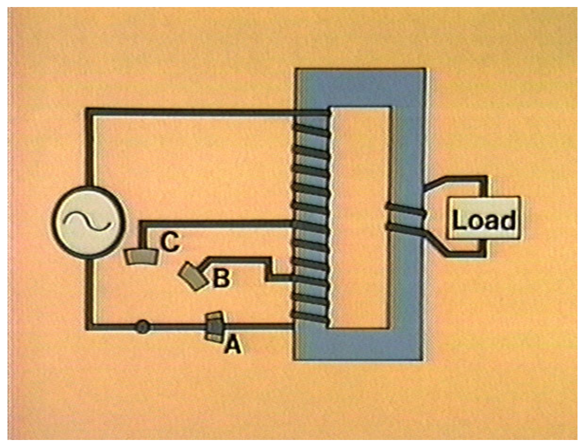
Recheck if the correct level is substantially above or below the normal level to be sure that it is necessary to add or remove some of the equipment's oil. The cause of any incorrect level should be determined and corrected prior to any other actions. Generally the corrected level should remain fairly constant unless there is an oil leak or other problems.

Oil diagnostic testing is normally sampled from an energized transformer. Otherwise, oil should never be added or removed from an energized transformer while performing EPM checks.

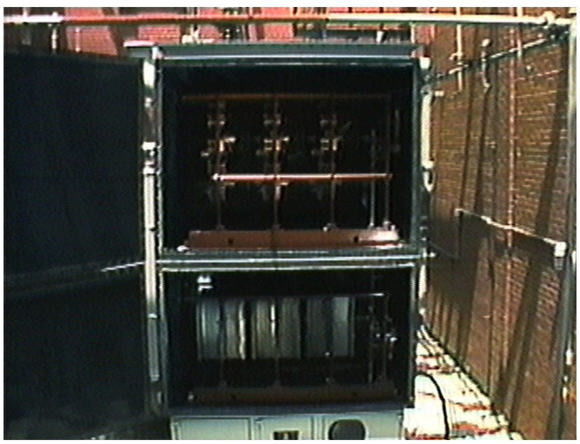
b. Tap Changers. Power transformers are generally supplied with either tap changers for de-energized operation or load tap changers. The transformer windings are tapped at the correct location and brought out to terminals and the appropriate method of connection provides the desired voltage. See *Pictures 3-5, 3-6, 3-7*, and *3-8* for actual tap changer installations and illustrations of operation principles.



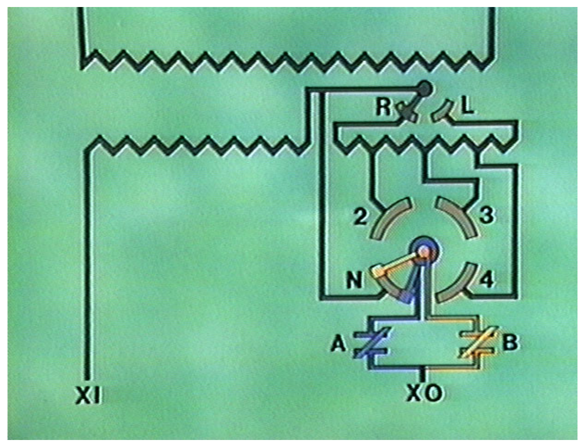
Picture 3-5
Manual tap changer



Picture 3-6
Simplified diagram of a manual tap changer



Picture 3-7
Load tap changer



Picture 3-8
Simplified diagram of a load tap changer

(1) Manual Tap Changers. Operate only with the tap changer de-energized as otherwise severe equipment damage, personal injury, and possible loss of life can occur.

(a) Dry-Type Units. Taps are accessible by removing a protective panel. Taps are changed by moving the flexible link from one terminal tap to another terminal tap. There are no moving parts. Correct contact pressure is necessary.

(b) Liquid-Filled Units. This unit is basically a switch used to adjust the turns ratio between the primary and secondary winding. Malfunction can be indicated by excessive combustible gasses in the oil. Since the tap changer is located within the tank the oil must be drained to a level that allows the tap changer to be inspected. Inspection should be done as a last resort when misalignment of the contacts or contact resistance is indicated as unacceptable. Connect a nulled transformer turns ratio tester to the high and low voltage windings. The tester loss of nulling is marked on both sides of the tap changer ON position as the operating handle is moved. If the ON position is found to be off center between the loss of the null mark found on either side then misalignment is indicated. Measured contact pressure resistance having any substantial deviation (increase over factory values) could be indicative of improper contact pressure. Procedures must be repeated for all tap settings.

(2) Load Tap Changers. Load tap changers (LTC) use a diverter switch to interrupt current during the load transfer operation. A transition impedance is used to control the circulating current where the taps are connected at their point of transfer. Current-interrupting devices require periodic inspection and maintenance in accordance with those specified by the manufacturer unless previous operational experience indicates more frequent inspections should be made. IEEE 62 recommends an initial inspection after the first year of operation and (regardless of contact wear) an inspection interval not to exceed 5 years. One large utility company recommends maintenance after approximately 30,000 operations.

(a) Operation Frequencies. Utility companies set frequencies based on the manufacturer and the service voltage load swings. Check recommended frequencies for your specific load tap changer with your local utility company.

(b) Types. The load diverter switch may be an arc-in-oil switch or a vacuum switch. Older designs use reactors as transition impedances. Later designs use resistors. The LTC may be located in a separate tank or located within the transformer tank.

(c) External Inspections. Inspect separate LTC compartments for external symptoms of potential problems. Such things as integrity of paint, weld leaks, oil seal integrity, pressure-relief device, and liquid level gauge are all items that should be inspected. While still in service, a separate LTC compartment may be inspected with an infrared scanner. Normally the temperature of the compartment may be a few degrees Celsius less than the main tank. Surface temperatures of the transformer and tap changer tanks can be checked by infrared measurements periodically. A monitoring system providing temperature comparison can be connected to the local/remote alarm system for under $3,000.00. Any temperature approaching or above that of the main tank indicates an internal problem.

(d) Internal Inspections. De-energize the transformer and drain appropriate compartments. Open the LTC compartment and inspect the door gasket for signs of deterioration. Any debris on the compartment floor may indicate abnormal wear. Sliding surfaces should be inspected for signs of excessive erosion. There should be only very minor amounts of carbon. The dielectric strength of the oil should be tested. The oil should be clear of contaminants if the LTC has been operating properly. Refer to the manufacturer’s instruction book for details on oil filling of the compartment. Most vacuum LTCs require oil filling under vacuum using degassed oil.

(e) Specific Internal Inspection Checkpoints for Separate LTC (Arcing-Type) Compartments

- Function of control switches
- LTC stopping on position
- Fastener tightness
- Signs of moisture such as rusting, oxidation, or free-standing water
- Mechanical clearances as specified by manufacturer's instruction booklet
- Operation and condition of tap selector, changeover selector, and arcing-transfer switches
- Drive mechanism operation
- Counter operation
- Position indicator operation and its coordination with mechanism and tap selector positions
- Limit switch operation
- Mechanical block integrity
- Proper operation of hand-crank and its interlock switch
- Physical condition of tap selector
- Freedom of movement of external shaft assembly
- Extent of arc erosion on stationary and moveable arcing contacts
- Inspection of barrier board for tracking and cracking
- After filling with oil, a manual cranking throughout the entire range
- Oil dielectric breakdown voltage.
- Finally, the tap selector compartment should be flushed with clean transformer oil. All carbonization that may have been deposited should be removed.

(f) Specific Internal Inspection Checkpoints for Separate LTC (Vacuum-Type) Compartments

- Items as given for arcing-type LTC
- Vacuum interrupter's wear (contact erosion) and presence of vacuum
- Vacuum monitoring system operation
- Coordination of vacuum bottles with selector mechanism

3-2. Integral Protective Devices. Integral protective devices vary dependent upon transformer capacity, voltage class, and use. Protective devices function to allow checking of a condition or an alarm indication for abnormal conditions.

a. Control Wiring Diagrams. Control wiring diagrams ensure correct operation and show alarm contact/switch connections. Always refer to the manufacturer's control wiring diagram in addition to the manufacturer's instruction book.

b. Liquid Level Condition. Maintain an acceptable liquid level over the entire temperature operating range of a liquid-filled unit to avoid loss of cooling and possible equipment damage.

(1) Operation. As the temperature of the liquid changes the liquid level will rise or fall. The level is indicated on a float type gauge having a round dial type face and alarm contacts to indicate a low level and, if supplied, a high level. The face is usually marked at the 25 degrees C (Normal) point and the High and Low points. The manufacturer's instructions will indicate the increase or decrease in liquid level for variations in temperature between High and Low. This information is also often indicated on the transformer's nameplate.

(2) Use. Read the oil level gauge and normalize the reading to 25 degrees C using the top oil temperature gauge reading. A liquid level gauge is never recalibrated or otherwise maintained. If the calibration is suspect, replacement should be made.

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c. Operating Temperature Condition. Two types of temperature gauges are used. A liquid temperature gauge is provided to indicate the top liquid temperature in liquid-filled transformer tank. Winding temperature gauges simulate either the hottest spot temperature of liquid-filled transformers or the average winding temperature of dry-type transformers. Temperature gauges do not measure temperature rise which must be determined by measuring the ambient temperature and subtracting that ambient temperature from the temperature gauge reading.

(1) <u>Operation</u>. Round dial-type gauges have their temperature sensitive elements mounted in leak-proof wells for liquid-filled transformers. They are mounted in a control panel with connections to the winding temperature sensors for dry-type units. Alarm contacts are provided for alarm activation of auxiliary cooling systems. Pointers with reset devices indicate the highest temperature attained since the last reset.

(2) <u>Temperature Rise.</u> For liquid-filled transformers read the ambient and top liquid temperature gauges. At 100 percent load, the top liquid temperature should not exceed the nameplate rated temperature rise (for example, 65 degrees C rise) over the ambient temperature. The hottest-spot winding temperature is normally described as 15 degrees C above the top liquid temperature at 100 percent load. A winding temperature gauge may be provided which estimates this temperature. At overloads of 125 to 150 percent, the actual hottest-spot winding temperature could be up to 50 degrees C above that of the top liquid temperature, and this may reduce the dielectric strength of the transformer oil. For dry-type transformers, the average temperature rise should not exceed the nameplate listed temperature rise.

(3) <u>Maximum Operating Temperature.</u> The normal top liquid temperature of a liquid-filled transformer should not exceed 60 degrees C for all ambient temperatures. This will maximize the useful life of the transformer by slowing breakdown of the oil and Kraft paper. Transformer oil life is

reduced by about half for each additional 10 degrees C above 60 degrees C. Corrective action should be taken to reduce the top liquid temperature of any transformer operating over 60 degrees C. An external forced-oil cooling system may be needed in warmer climates.

(4) Thermal Overload Relay. A thermal overload relay may be substituted for a "hottest-spot" winding temperature gauge. The relay indicates a percent thermal load rather than a simulated winding hot-spot temperature.

(5) Calibration. IEEE 62 recommends that gauges be calibrated on a regular basis. Calibration requires a controlled hot bath for liquid temperature gauges. Calibration curves of the winding temperature heating current to the winding temperature heating gradient are required for winding temperature gauges. The local installation must determine whether they can provide an effective recalibration method after determination that calibration is necessary. Otherwise no maintenance of gauges is required; suspect gauges should be replaced.

d. Pressure Condition. The internal pressure of a liquid transformer tank is indicative of its operating condition as it is affected by temperature, gas generation, and liquid insulation leaks.

(1) Pressure-Vacuum Gauge. The pressure-vacuum gauge indicates the tank gas space pressure relative to atmospheric pressure on a round dial-type face. The gauge is provided with alarm contacts to signal either excessive vacuum or pressure or both. Pressures vary dependent on both the barometric pressure and liquid temperature. Temperatures normally should be slightly positive. If a transformer is de-energized or operating at a light load under a low ambient the pressure may go negative. If the gauge does not change under load the gauge may be broken. If the gauge reads zero and does not change under load the transformer should be checked for a possible leak.

(2) Pressure Regulator and Relief Devices. A transformer may be furnished with a regulator which automatically bleeds off gas at a certain positive pressure or adds make-up air to the tank if the pressure reaches a certain negative level. Pressure relief device are normally furnished on transformers 2,500 kVA and larger. The device mechanically releases on excessive pressure utilizing a self-resetting spring-loaded diaphragm. When pressure returns to normal the diaphragm will reset and reseal the transformer. A mechanical operation indicator (needing manual reset) will signal diaphragm operation. Alarm contacts may be furnished on the relief device which must also be manually reset.

(3) Load Tap Changer Pressure. On an LTC compartment there should be a small positive pressure, relative to that in the separate transformer tank. If the LTC is of the vacuum-bottle type, there should never be any pressure buildup. In an LTC with a sealed compartment, pressure will build up with every tap change operation. These compartments are supplied with a pressure relief valve that opens at about 3 psi and re-seals at about 1 psi. This prevents any ingress of moisture into the tap changer compartment.

(4) Sudden (Fault) Pressure Relay. Sudden pressure relays may be mounted under the oil or in the gas space. Internal arcing in a liquid-filled transformer can generate a gas pressure that can be extremely damaging and present personnel hazards. The sudden pressure relay trips its protective device to minimize the extent of damage. The manufacturer's recommendations should be referred to for adjustment, repair, or replacement of improperly operating devices.

e. Miscellaneous Conditions. Fault gas detection and oil flow indication are protective devices found for specific types of transformers.

(1) Fault Gas Detection. Generally, only conservator-equipped power transformers are equipped with fault gas detector relays. The gas detector relay detects the presence of free gas liberated from the oil, indicating a level of gas generation beyond the dissolved gas saturation limits of the oil. Air leaking into the transformer, usually during extremely cold ambients, occasionally can also register on the gas detector relay. The accumulated gas should be analyzed in accordance with the manufacturer's instructions whenever the gauge indicates any value above zero. Dissolved gas-in-oil analysis would also be appropriate at this time.

(2) Flow Gauge Operation. Auxiliary cooling pumps are often equipped only with a flow gauge to indicate pump flow. Pump flow velocity or pump condition indicators may not be` provided. Lack of flow may be indicative of imminent pump failure. The sending unit or gauge may be defective if no flow is indicated when the pump is running or when flow continues to be indicated when the pump is turned off.

f. Condition Devices. *Pictures 3-9, 3-10, 3-11*, and *3-12* show protective device installations.

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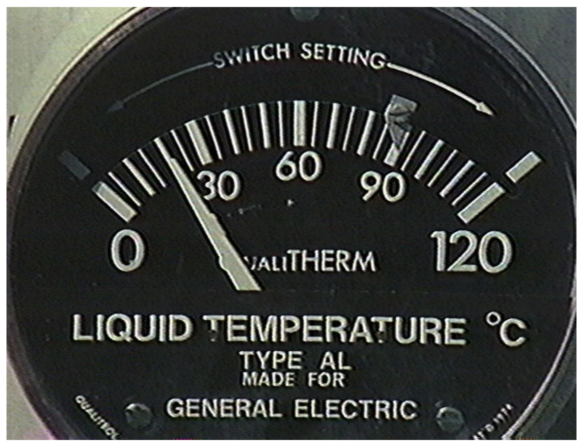
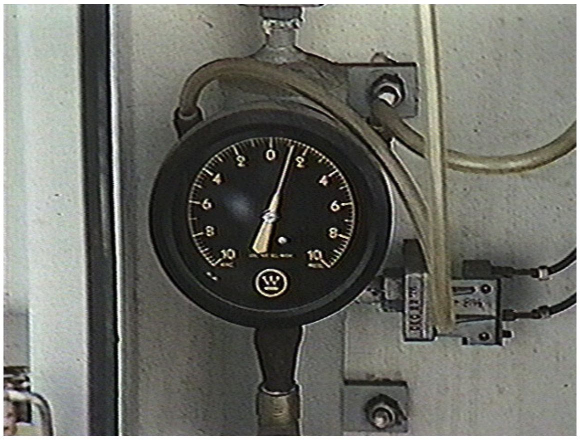
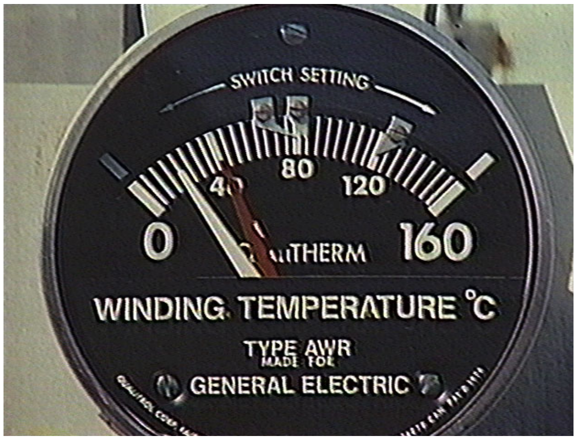
Picture 3-9
Liquid-level gauge



Picture 3-10
Liquid-temperature gauge



Picture 3-11
Pressure-vacuum gauge



Picture 3-12
Winding-temperature gauge

3-3. External Protective Devices. Basic transformer protection provided externally is not covered in this handbook, except for surge arresters which are covered in *Chapter 8*.

3-4. Termination Devices. Leads from the windings are connected to bushings, to terminal chambers, or to switchgear adapters, as appropriate to the unit allowing connections to be made to aerial or underground lines or to adjacent switchgear. Always check that exterior line connections are correct.

a. Bushings: Bushings can be cover mounted or wall mounted and may be provided with capacitance type voltage taps or integrated with current transformers for providing control inputs to alarms or relays (See *Chapter 7*).

b. Air Terminal Chambers. This is an air-filled metal enclosure mounted on the transformer for direct connection to power lines installed in conduit. It can be supplied for clamp type terminals or with potheads which can be protected by integral surge arresters (See *Chapter 8*). Chambers provide adequate electrical insulation to protect personnel from dangerous voltages. They must be sealed tight to maintain a clean dry atmosphere. A removable cover allows access to the terminal interior. Poor installation of the cover can allow water and other contamination to enter causing exposed terminal flashover, possible transformer failure, and put personnel in danger.

c. Switchgear Adapters. Switchgear adapters allow connection from switchgear buses to transformer throats either with flexible connectors or busway. Sealing is equally important for switchgear adapters.

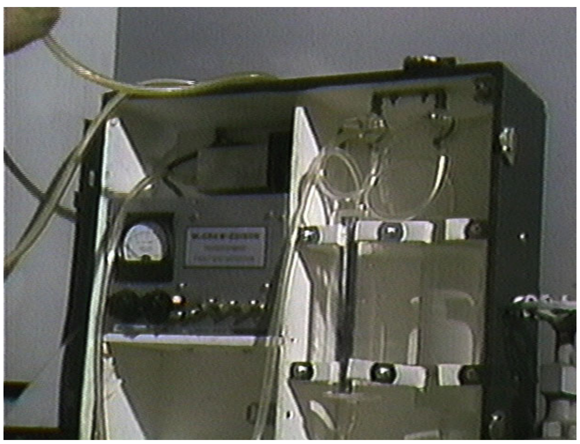
CHAPTER 4. POWER/DISTRIBUTION TRANSFORMER TESTING

4-1. In-Service Transformer Tests. These tests do not require that transformers be de-energized. Tests must be done in accordance with the safety requirements for energized electrical line work given in *Paragraph 1-4. Pictures 4-1, 4-2, 4-3,* and *4-4* show examples of various portable testers used in the field.

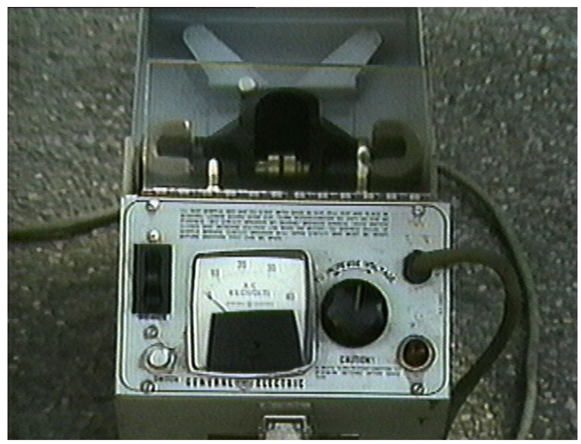
a. Transformer Readings. The following individual readings are to be taken whenever a transformer is inspected in accordance with AFMAN 32-1280(I) as adjusted to local requirements.

(1) Required Readings. Integral transformer indicators/gauges or secondary switchgear ammeters and voltmeters will be utilized for hourly readings. Compute the load kVA from measured maximum voltages and currents. Check to the wattmeter reading if a wattmeter is available. For critical transformers, utilize clamp-on recording voltmeters and ammeters to provide a minimum 24-hour record of all phases. Take current, voltage, and temperature readings at peak load hours if possible. Take the liquid level reading during low loads and low ambient temperatures. Use a digital thermometer to record ambient temperatures. Vacuum/pressure readings should be checked to manufacturer's instructions. See *Paragraph 3-2* regarding pressure conditions.

(2) Reading Results. *Table 4-1* indicates readings which require further action.



Picture 4-1
Combustible gas tester



Picture 4-2
Oil dielectric test set

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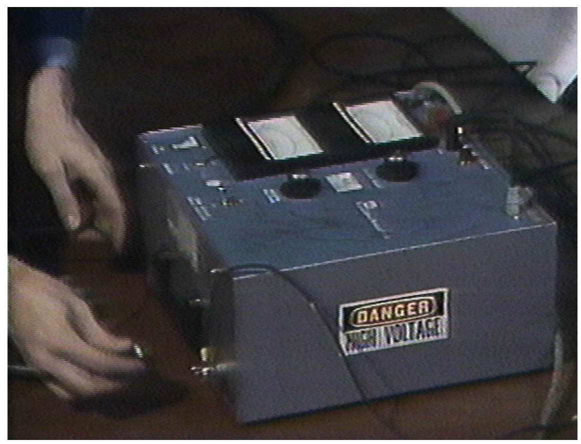
Picture 4-3
Turns-ratio tester



Picture 4-4
Megohmeter

Table 4-1. Transformer deficiency indications

Value	Deficiency	Action
Phase current unbalance	Over 10 percent	Rebalance single-phase loads
Phase voltage unbalance	Over 2 percent	Investigate for cause. May affect motor and solid-state equipment operation.
Low or high voltage	Exceeds tap changer corrective ability	Investigate as to cause
kVA	Exceeds 110 percent of nameplate rating	May need to drop some load especially if the liquid temperature reading is too high
Liquid temperature	Exceeds ambient temperature plus nameplate temperature rating	May need to drop some load

b. Infrared (Thermographic) Tests. An infrared (IR) temperature measurement test locates high-resistance or hot spot thermal variations due to component failure, fatigue, and mechanical misalignment.

(1) Precautions. The object being examined will radiate both emitted and reflected IR energy. Only the emitted IR energy is a measure of the object's temperature. Measurements will vary as the geometry of observation varies the angle of incidence. Changing the angle of incidence changes the reflected IR energy. The IR equipment used should be capable of detecting at least a 1 degree C temperature difference between the object and the at 30 degrees C reference area by detecting emitted radiation and converting it to a visual signal. The IR equipment should allow the user to mathematically compensate for reflected energy. Correction may be made by entering an estimated emmissivity value provided by the IR equipment manufacturer or based in the installation's experience.

(2) Action. Scan all current-carrying equipment and conductor connections during periods of maximum possible loading. Generally a reading for an equipment/conductor load below 40 percent of its rating will not locate any hot spots. Always measure the IR temperature from several different positions to minimize errors from reflected IR energy or from solar gain for outdoor installations.

(3) Interpretation. Infrared hot-spot temperature gradients indicating possible deficiencies are given in AFMAN 32-1280(I) for transformers and *Paragraph 3-1* for load tap changers. *Table 4-2* lists temperature rises above ambient which have been found practical in regard to equipment problems.

Table 4-2. Recommended maintenance based on IR temperature rises

Temperature rise above ambient (degrees C)	Recommendation
<10	Repair in regular maintenance schedule; little probability of physical damage.
11-39	Repair in near future. Inspect for physical damage.
40-75	Repair in the immediate future. Disassemble and check for probable damage.
>76	Critical problem; repair immediately.

c. Insulating Liquid Tests. Transformers with external sampling valves may have the liquid taken when the transformer is energized. Otherwise take an internal sample on a de-energized (and temporary grounded) transformer. Take samples from the bottom for mineral oil-insulated units and from the top for less flammable liquid-insulated units. Samples should be laboratory tested. Tests can only be as accurate as the validity of the sample so follow the procedures listed in *Paragraph 2-6*. See *Table 2-1* on the relative condition of the oil based on its color. The various tests required by AFMAN 32-1280(I) should be performed in a laboratory as soon as possible to avoid contamination from exposure to direct sunlight. Acceptable test limit values for new and service-aged oil are given in IEEE 57.106 *(IEEE Guide for Acceptance and Maintenance of Insulation Oil in Equipment*). Store tightly sealed containers in a refrigerator's freezing compartment overnight. Check the next day as a cloudy sample indicates free water in the sample. Recheck cloudy samples by taking a second sample to verify that the water did not come from the container.

d. Dissolved Gas Analysis. Low-energy faults in transformers with a nitrogen seal or conservator system invariably generate combustible gases. An analysis of such gases is invaluable in detecting the early stages of such faults. First remove an oil sample and then analyze the sample using a dissolved gas analysis test set with a direct reading scale. A method to evaluate test results is given in *Table 4-3.*.

Table 4-3. Dissolved-gas evaluations

Percentage of combustible gas	Gas evaluation
0-1	Satisfactory operation indicated. Excessive aging may be indicated if the percentage is above 0.5 percent. If so, analyze more often.
1-2	Equipment shows some indication of contamination or slight incipient fault. Readings in this range should be followed immediately with a laboratory dissolved gas analysis. Take more frequent readings and watch trends.
2-5	Begin more frequent readings. If trend continues upward, prepare to investigate cause, preferably by internal inspection.
Greater than 5	Remove transformer from service as soon as possible. Investigate by internal inspection. Be prepared to move equipment to a service shop for repairs.

4-2. De-Energized Transformer Tests. These tests require that transformers be de-energized and grounded. Tests must be done in accordance with the safety requirements for de-energized electrical line work given in *Paragraph 1-4*. Convert measured insulation resistances and power factors from the test temperature to the reference temperature of 20 degrees C (see AFMAN 32-1280(I)).

a. Permanent Transformer Grounding. Transformers have two types of grounds, an equipment ground and a core ground.

(1) Equipment Ground. The equipment grounding connection should be tested as a part of the transformer's substation ground mat testing as covered in AFH 32-1282VI to assure safe potential differences for personnel and equipment.

(2) Core Ground. A single point ground connection from the transformer core is connected to the substation ground mat to prevent a voltage rise from occurring on the core during operation. The core ground should be checked to determine if an inadvertent core ground exists. Heating may occur due to circulating currents if the core is grounded at more than one point. The laminations that make up the core are insulated from each other at a value which prevents damaging eddy currents but permits grounding of all laminations by one connection. Also the core insulation resistance to ground should be checked to determine its adequacy. Make the tests using a megohmeter (megger). The test voltage should not exceed 1000 volts dc.

(a) Inadvertent Core Ground Causes. Insulation damage can result in inadvertent core grounds when a transformer is improperly shipped or installed. Inadvertent core grounds are also often caused by debris which shorts a core lamination to the tank wall. This typically occurs during movement of the transformer. In core-form transformers, this may lead to excessive circulating currents and an unbalanced flux distribution (in the shell-form transformer design, multiple grounds are not an important problem). Correction of an inadvertent core ground may often be accomplished by hitting the tank of the transformer to cause vibration. It also may be possible to burn off the debris using a direct current-type welding machine.

(b) Inadvertent Core Ground Test. Make a test between the ground strap and its grounding point to determine if there is an inadvertent ground which will register a resistance (use a dc high-resistance meter). Connect a 12-volt battery (or equivalent dc source) from side to side across the core to bridge all core laminations. Connect the negative lead of a dc voltmeter to an internal tank ground point. Move the positive lead of the voltmeter across the core laminations at right angles until a zero point appears. This is the location of the inadvertent ground. Examine to determine the inadvertent ground source is readily visible and repairable. Contact the manufacturer to determine whether moving the core ground strap to this point is recommended. The relocation will not eliminate the inadvertent core ground but may reduce circulating ground currents in the core to an insignificant level.

(c) Core Insulation-to-Ground Resistance Measurement. Disconnect the core grounding strap from the transformer frame or tank. Secure all noncaptive fastener hardware. Insulation resistance ranges indicate service-aged insulation conditions as shown on *Table 4-4.*

Table 4-4. Typical insulation resistance ranges for various conditions of core insulation

Core insulation resistance in megohms	Condition of insulation
Greater than 100	Normal
Between 10 and 100	Indicative of insulation deterioration
Less than 10	Sufficient to cause the generation of destructive circulating currents and need to be investigated

b. Transformer Winding Insulation Tests. These tests determine if degradation of the insulation has affected its quality. Three types of tests are commonly used. The reliability of each test varies dependant upon the time the measurements are made and whether the test utilizes dc or ac voltage.

(1) Time and Voltage Effects. The application of voltage to insulation causes a current consisting of three components whose values vary according to time as shown on *Figure 4-1* for dc high voltages. Winding insulation resistance is measured by connecting windings as shown on *Figure 4-2*. Where ac high voltages are applied, the capacitance charging current will recharge and discharge as the voltage changes at 60 hertz. Therefore megohmeters are used for dc resistance testing while ac tests are limited to the use of power factor test sets.

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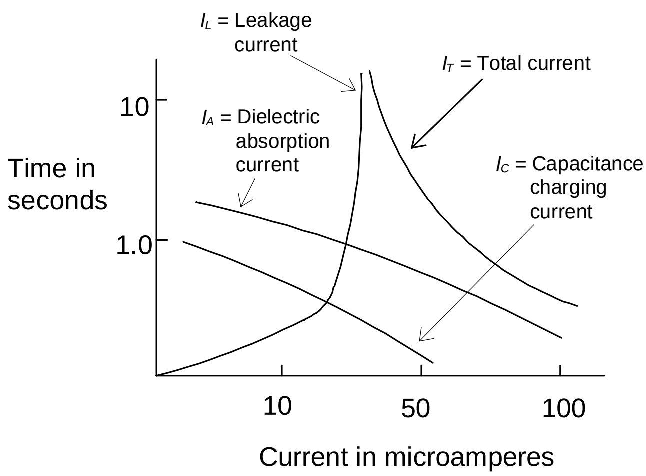
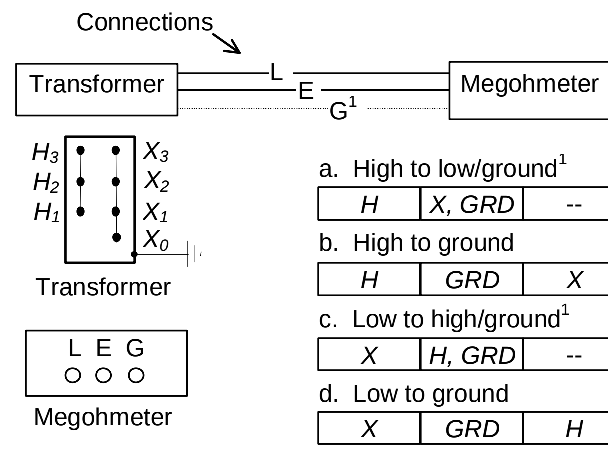


Figure 4-1
Insulation currents



Winding Connections		
Line	Earth	Guard
L	*E*	*G*

a. High to low/ground[1]

H	*X, GRD*	--

b. High to ground

H	*GRD*	*X*

c. Low to high/ground[1]

X	*H, GRD*	--

d. Low to ground

X	*GRD*	*H*

e. High to low

H	*X*	--

[1]Provide internal ground connection

Figure 4-2
Insulation resistance test connections

(a) Short-Time Resistance Tests. These are usually compared at the one minute reading and need to be temperature corrected with humidity effects considered. They are the simplest test but can only be evaluated as for a rough check of the insulation condition. Use them to establish a trend.

(b) Insulation Resistance Ratio Test. The polarization index test compares the short time value to the 10-minute value. It is a dimensionless value and does not require temperature or humidity sensitivity. Again trends should be evaluated.

(c) Power Factor Tests. The high dielectric strength of oil may prevent a dc insulation test from detecting a problem until the transformer is about to fail. This test is the most reliable for tracking insulation quality but is also the most difficult (thus the most costly) to perform.

(2) Winding Insulation Resistance Tests. Ground the tank and core iron and verify grounding. Short circuit each winding at each transformer bushing. Resistance measurements are then made between an individual winding and all other windings. Windings are never left floating. Remove the ground on a solidly grounded winding when measuring its resistance to other grounded windings. Make tests from windings as shown on *Figure 4-2*. Take the transformer ambient temperature during measurements. Correct the measured insulation resistance and record. Compare with acceptance and previous test values. A gradual decline in resistance with age is normal; however, a sudden decline means insulation failure is imminent. A continued downward trend indicates insulation deterioration, even though measured resistance values are above the minimum acceptable limits. See *Table 4-5* for test voltages and minimum insulation resistances.

Table 4-5. Transformer winding insulation-resistance test values

Transformer coil rating	Minimum dc test voltage	Recommended minimum insulation resistance in megohms	
		Liquid-filled	**Dry**
0-600 Volts	1000 Volts	100	500
601-5000 Volts	2500 Volts	1000	5000
5001-15000 Volts	5000 Volts	5000	25000

(3) Polarization Index (PI) or Dielectric Absorption Tests. Follow the directions given for use of a megohmeter and apply to windings as covered for an insulation test. Apply voltage for 10 minutes. The 10-minute reading divided by the 1-minute reading is the PI index. For good insulations, the resistance increases with time. Cleaning and drying may increase the reading if the value compares unfavorably with previous tests. See *Table 4-6.*

Table 4-6. Meaning of PI ratios

PI ratio	Insulation condition
Less than 1	Poor
Between 1 and 2	Questionable[1]
2 to 4	Good
Above 4	Excellent

[1]Evaluate as smaller transformers may exhibit a polarization index between 1 and 1.3.

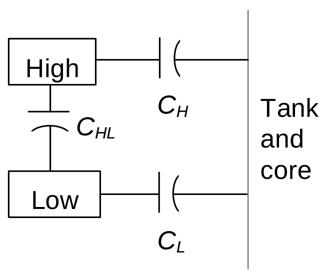
(4) Insulation Power Factor Tests. Use a power factor test set in accordance with the test set's instructions. The use of the set requires previous training and the set manufacturer should supply test-data forms. Limit test voltages to the line-to-ground voltage rating of the selected transformer winding. Take measurements as shown on *Figure 4-3*. These measurements allow the test set to compute the power factor based on the measured insulation watts loss divided by the volt-amperes applied. Power factor test results should evaluated on the basis of previous results but should be expected to be about or less than the values of *Table 4-7* for good insulation.

Table 4-7. Recommended maximum transformer insulation power factors

Type	Mineral oil	Silicone	High fire point hydrocarbon	Dry type[1]
Power	2.0%	0.5%	2.0%	3.0%
Distribution	3.0%	0.5%	3.0%	5.0%

[1]For C_{HL} insulation between high-and-low winding. C_H and C_L will vary due to support insulators and bus work utilized on dry-type units.

c. Transformer Turns Ratio (TTR) Test. This test is used to detect shorted and open turns. A change in TTR can result from short circuits, switching surges, deteriorated oil, wet insulation, depolymerization of cellulose insulation, physical movement of the transformer, and problems in the tap changer. Use a turns ratio test set in accordance with the manufacturer's instructions for all load taps on a manual tap changer and for all positions of an LTC set in the neutral position. The turns ratio tolerance should be within 0.5 percent of the nameplate ratings. For wye-connected windings the tolerance applies to the phase-to-neutral voltage.



Test	Energized	Grounded	Guarded	Measure
1	*H*	*L*	--	$C_H + C_{HL}$
2	*H*	--	*L*	C_H
3	*L*	*H*	--	$C_L + C_{HL}$
4	*L*	--	*H*	C_L
5		Test 1 minus Test 2		C_{HL}
6		Test 3 minus Test 4		C_{HL}

- C_H refers to all insulation between the high-voltage conductors and grounded parts, including bushings, winding insulation, structural insulating members, and oil.
- C_L refers to the same parts and materials between the low-voltage conductors and grounded parts.
- C_{HL} refers to all winding insulation, barriers, and oil between high- and low-voltage windings.

Figure 4-3

Power factor test measurements

d. Core Excitation Current. Use a power factor test set in accordance with the test set's instruction. The use of the set requires previous training and the manufacturer should supply test-data forms. Tests should be performed at the highest test voltage possible without exceeding the voltage rating of the excited winding. Exciting current is measured by applying single-phase voltage to one phase at a time. The voltage is applied on the high-voltage side with the other side left floating (with the exception of the grounded neutral). Recommended tests include measurements on one-half the tap changer positions, the neutral position, and one step in the opposite direction. Although the results may be different for various tap changer positions, for each position there should be similar readings on the outer phases and a lower reading on the center phase.

(1) Comparisons. These results should be compared with previous tests. Differences in previous measurement comparisons exceeding 10 percent may indicate magnetic core defects, turn-to-turn insulation failure, winding shifts, or tap changer problem. Residual magnetism may cause higher than normal exciting currents requiring tests to be made again after demagnetizing the transformer core.

(2) Core Demagnetizing. Apply a direct current voltage of alternate polarities to the transformer core to neutralize the core iron's magnetic alignment. The usual method is to apply the voltage to the phase having the highest exciting current level. After a short interval reverse the polarity of the voltage. If at the next reversal the demagnetizing current has reached a slightly lower level than the previous level again reverse the voltage polarity. Continue until the current level is zero.

4-3. Special Tests. These are tests which should be done by trained personnel. Some tests (induced potential and ac high-potential) can be destructive and are usually limited to factory proof tests. Other tests require test techniques beyond the usual knowledge of Air Force technical staff. IEEE 62 covers in greater detail these test techniques. Tests should be done by contract personnel who have been currently certified in electrical power distribution system testing by recognized electrical industry testing associations. Technical staff should be familiar with the type of tests available, acceptable measurements, and what equipment abnormalities may be indicated by unacceptable values.

a. Winding Conductor Resistance Tests. Winding conductor resistance test comparisons larger than 5 percent may indicate loose connections, broken winding strands, or high tap-changer contact resistance. Winding conductor resistance is measured between each phase of a wye-connected winding or between pairs of terminals on a delta-connected winding. Results are compared with the measured transformer's other phase windings, to the same winding as measured previously, or the original factory measurements. If comparison is made to previous or original factory measurements correction must be made for different test temperatures. Temperature correction is not normally required for comparisons made between phases done at the same time.

b. Short-Circuit Impedance Tests. Short-circuit impedance is used to detect winding movement due to heavy fault current or transportation/installation mechanical damage. Short-circuit impedance is measured by short-circuiting the three line-leads of the low voltage windings. Then apply a single-phase voltage variable from 0-280 volts and with at least a 10 ampere current at rated frequency to two terminals of the high-voltage windings. Provide three separate voltage readings on three pairs of leads. The computed impedance (See *Equation 4-1*) from these readings should be compared to the nameplate rating. Changes of more than plus or minus 3 percent are indicative of problems.

$$\%\text{ of } Z \text{ three-phase} = \frac{1}{60} \times \frac{(E_{12} + E_{23} + E_{31})}{I_m} \times \frac{kVA_{3r}}{(kV1_{1r})^2} \quad \text{Eq. 4-1}$$

where E_{12}, E_{23}, E_{31} are measured test voltages, I_m is the current,
kVA_{3r} is the three-phase rating in kilovoltamperes, and
kV_{1r} is the rated line-to-line voltage of the energized windings.

CHAPTER 5. POWER/DISTRIBUTION TRANSFORMER EVALUATIONS

5-1. Power/Distribution Transformer EPM Reports. Each installation should prepare local blank EPM report forms to be filled out by the inspecting technicians. (See *Paragraph 1-4*.) The following tables indicate data which may need to be recorded. Evaluate the extent of data required based on your installation needs and maintenance ability.

a. Basic Power/Distribution Transformer Information To Be Determined Before the Inspection. Provide a suitable record header with blank spaces for insertion of the following data given in *Table 5-1*.

Table 5-1. Power/distribution transformer general data

General	**Liquid-filled**
Designation	Free breathing
Date of inspection	Conservator
Location	Sealed
Serial no.	Cooling system, if any
Year installed	Fluid type
Last inspection date	Gallons of fluid
Manufacturer	
Instruction manual	
KVA	**Dry-type**
Voltage/taps	Cooling system, if any
Phase	Core type

b. Basic Inspection Items To Be Checked. Provide an EPM inspection report with column headings covering items to be checked off for each listed item number as given in *Table 5-2.*

Table 5-2. EPM column headings

Item no. (for easy referral)
Inspection item (name)
Operating mode (in-service or de-energized and grounded)
Passing criteria (list)
Inspection method (visual, test, or other)
Corrective action (if necessary)

c. Inspection Items To Be Covered. List inspection items to be covered. *Table 5-3* indicates transformer readings and appropriate evaluation paragraphs for passing criteria. *Table 5-4* indicates transformer components and appropriate inspection actions. See *Chapter 7* for bushing requirements.

Table 5-3. Transformer readings

Gauge reading or test value		Evaluation reference paragraph
1.	Ambient temperature	--
2.	Primary and secondary phase a, b, and c currents	4.1.a
3.	Maximum current unbalance	4.1.a
4.	Primary and secondary phase a, b, and c voltages	4.1.a
5.	Maximum voltage unbalance	4.1.a
6.	Computed kVA load	4.1.a
7.	Liquid level condition	3.2.b
8.	Operating temperature condition	
	Liquid temperature	4.1.a/3.2.c
	Winding temperature	3.2.c
9.	Pressure condition	
	Pressure/vacuum	3.2.d
	Relief operation	3.2.d
	LTC pressure	3.2.d
10.	Infrared temperature rise[1]	4.1.b
11.	Insulating liquid	4.1.c
12.	Dissolved gas analysis	4.1.d
13.	Core-insulation resistance/inadvertent core ground	4.2.a
14.	Winding-insulation resistance	4.2.b(2)
15.	Polarization index	4.2.b(3)
16.	Insulation power factor	4.2.b(4)
17.	Turns ratio	4.2.c
18.	Core excitation current	4.2.d

[1]Readings should identify location or be provided with such identification in a separate report.

Table 5-4. Transformer components

Component Inspection	Component Inspection
1. Liquid-filled transformer tank and radiator	4. Cooling systems
a. Paint condition	a. Controls, fans, pumps operating condition
b. Liquid leaks	b. Filter cleanness[1]
c. Gasketing or other sealing adequacy	5. Electrical connections
d. Concrete pad connection adequacy	a. Tightness
e. Ground connection	b. Hot spots[2]
2. Dry-type transformer enclosure and windings	6. Protective device operation/calibration
a. Paint condition	a. Control circuits
b. Cover tightness	b. Relays
c. Gasketing adequacy	c. Alarms
d. Winding cleanness and dryness	d. Gauge
e. Concrete pad connection and winding support adequacy	e. Relief devices
f. Ground connection	7. Liquid insulation
3. Tap changers[1]	a. Filling
a. General condition	b. Filtering
b. LTC automatic operating condition and number of operations	c. Sampling

[1]May require lubrication, cleaning, adjusting, and aligning.
[2]For infrared checking see *Paragraph 4.1.b*.

d. Corrective Action. Describe corrective actions taken. Deficiencies requiring action beyond the capability of the technicians at the site should be indicated as “see note X.” “Note X” should explain reasons. Such a note might indicate that an oil leak needs to be repaired requiring a shut down of the transformer and appropriate welding materials.

5-2. Transformer Handling Actions. Treat with special caution transformers which have been identified as containing polychlorinated biphenyls (PCBs). De-energized transformers can acquire moisture in the insulation and need drying out before being energized.

a. PCB Handling. Transformers with PCB insulation should have been identified as PCB-contaminated and scheduled for a priority removal to meet a 31 December 1998 target date in accordance with ETL 96-2 (*Elimination of Liquid Polychlorinated Biphenyls (PCBs) Prioritization Guidelines*).

(1) Function. PCB (askarel) provided a nonflammable insulation and was distributed by several equipment manufacturers under such trade names as Inerteen, Pyranol, Chlorextol, Saf-T-Kuhl, and No-Flamol.

(2) Emergency Treatment. Nontrained workers are not permitted to dispose of PCB contamination, therefore emergency treatment applies only to accidental spills. The EPM record should indicate a PCB transformer and who to contact if there is a spill. A worker trained to contain PCB spills, in accordance with EPA regulations, must be used. Minimum safety requirements for PCB spills are given in AFMAN 32-1185.

b. Drying Out Transformers. Never energize a wet transformer. Drying may be needed for dry-type transformers shut-down for more than 24 hours during a period of humidity which is sufficiently high enough to cause condensation. Excessive moisture in shut-down liquid filled transformers can be checked by cooling a test tube sample of oil in an ice bath. A cloudy appearance in the test tube at a temperature above 0 degrees C indicates a need for drying out. The cloudy appearance will occur as the sample cools to the cloud point temperature. The sample will become clear again as the sample continues to cool below the cloud point temperature.

(1) <u>Power Off Internal Field Method Treatment</u>. Connect a power source to one winding with the other winding short-circuited. Sufficient voltage at normal frequency should be applied to the other winding to circulate approximately normal current. For dry-type units the winding temperature should not be allowed to exceed the manufacturer's temperature rise limits (use 100 degrees C if the manufacturer's limits are not available). For liquid-filled units the winding temperature should not exceed its rated maximum (see *Paragraph 3-2.c*.)

(2) <u>Drying by External Heat Methods</u>. Dry-type transformers can have moisture removed by directing heated air into the bottom of the transformer case and following the manufacturer's instructions for heater requirements. It is possible to dry liquid-filled transformers by the circulation of hot oil but this can be very slow. Hot-air drying should not be used for liquid-filled transformers due to the possibility of creating an explosive oil-air mixture.

CHAPTER 6. INSTRUMENT TRANSFORMERS

6-1. Performance. An instrument transformer is designed to reproduce in its secondary circuit (in a definite and known proportion) the current or voltage of its primary circuit with the phase relations and waveform substantially preserved.

a. Importance in the System. An instrument transformer provides secondary low current and low voltage values whose magnitudes are suitable for relays, meters, and instruments. The instrument transformer provides safety to personnel and simplifies the connected device construction by providing insulation between the power (primary) circuit and the control (secondary) circuit.

b. Current Transformers. A current transformer is a current source device which reduces line currents to proportional secondary currents. Secondary currents are designed to usually not exceed 5 amperes. Any change in the primary current is reflected in the secondary current.

(1) Construction. A wound current transformer has two separate windings on a magnetic core (see *Figure 1-5).* The primary winding consists of a few turns of heavy wire around the core or a bus bar extending through the core and many turns of small wire for the secondary winding. The window (through or doughnut) type consists of an insulated hole centered in the magnetic core through which the primary system's power conductor passes to become the current transformer's primary winding. This window type of construction is used for bushing and split core current transformers. An air core is substituted for a magnetic core where saturation of a magnetic core could result from expected high fault currents.

(2) Short-Circuiting Dangers. A current transformer, having a primary current input, requires that the secondary circuit always be closed. As long as there is current in the primary winding, there will be current in the secondary winding. On an open circuit the secondary voltage will be the secondary current multiplied by an extremely high open-circuit secondary resistance. This high voltage can damage insulation and prove dangerous to life. Under no circumstances should the secondary of a current transformer be opened while the primary circuit of the transformer is energized, unless the terminals of the current transformer are of the short-circuiting type.

c. Voltage (Potential) Transformers. A voltage transformer is a unit which reduces line voltages usually to 120 volts.

(1) Construction. A voltage transformer has a relatively large number of turns of fine wire for the primary winding and a fewer number of turns of heavier wire for the secondary winding . Both are installed on a common magnetic core (see *Figure 1-6*). The primary winding is connected in shunt or parallel to the power circuit voltage to be measured or controlled. The secondary winding insulates control devices connected to the secondary terminal from the power circuit.

(2) Open-Circuiting. Unlike current transformers the secondaries of voltage transformers should always be open circuited when no load is connected. Short circuiting any voltage transformer secondary will burn it out if carried for much more than one second. Primary fuses are installed to protect against partial short circuits in the primary winding and against a secondary short circuit.

d. Outdoor Features. Outdoor units must be protected against possible contaminated environments. The addition of skirts on outdoor units provides a greater creepage distance from the primary terminal (line potential) to the secondary (ground) terminals and base plate. Creepage is the shortest distance between two conducting parts measured along the surface of the insulating material between them. Outdoor units which must also have noncorrosive hardware and nonarc-tracking insulation.

e. Polarity Marks. In instrument transformers the flow of current in the secondary winding is in a direction opposite to that in the primary winding, that is, 180 degrees out of phase with the primary winding current. At any instant when the current is flowing into one of the primary terminals it will be flowing out of one of the secondary terminals. (See *Paragraph 3-2* also.) Terminals HI and XI have the same polarity and are defined by white dots or letter/number designations. In any application which depends on the interaction of two currents it is essential that the correct polarity relationships be maintained. Examples are wattmeter and directional overcurrent relay connections.

(1) Determining Polarity. If polarity markings have been obscured or need to be verified, connect a dc permanent magnet instrument (meter) across the instrument transformer terminals as shown on *Figure 6-1*. The plus side of meters and the plus side of two dry cell batteries in series are each connected to the appropriate winding of the instrument transformer terminal having a polarity mark (if marks are available). Otherwise assume the location of polarity marks.

(a) Voltage Transformers. Connect a voltmeter (150 volt range) across the voltage transformer's primary terminals. Correct the plus side of the battery to the voltage transformer's secondary terminal having the polarity mark. Make an instantaneous contact between the other terminal of the voltage transformer's secondary winding and the minus side of the battery. A deflection in an upscale direction upon making (not breaking) the circuit will indicate that the voltage transformer terminals are marked correctly.

(b) Current Transformers. Connect an ammeter (5-ampere range) across the current transformer's secondary terminals. Connect the minus side of the battery to the current transformer's primary terminal which does not have the polarity mark. Make an instantaneous contact between the other terminal of the current transformer's primary winding and the plus side of the battery. A deflection in an upscale direction upon making (not breaking) the circuit will indicate that the current transformer terminals are marked correctly.

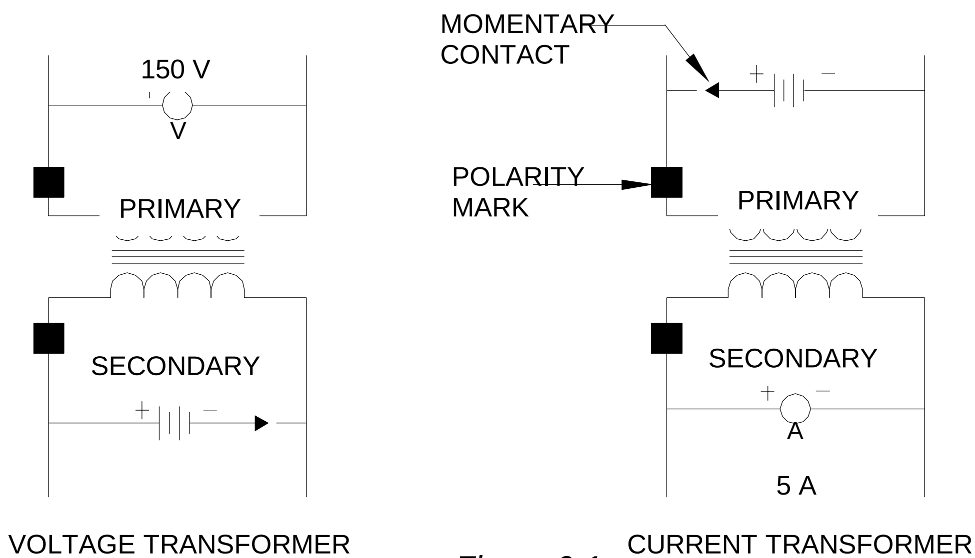


Figure 6-1

Polarity determination circuits

(2) Precautions. Precautions should be taken when making a polarity test on current transformers. Core magnetization can occur due to the direct current. Window or bar type units with low

current ratings (400 ampere and down) are particularly susceptible to this residual magnetism. The longer the direct current is maintained, the larger the effect this will have on the accuracy of the unit. Demagnetizing the current transformer is advisable after using direct current. Connect at least a 50 ohms variable resistance across the secondary terminals and bring the primary current up to full load. Then gradually reduce the variable resistance until it reaches zero without opening the secondary circuit. For best results, gradually reduce the primary circuit voltage to zero before disconnecting the resistance circuit.

f. Application Ratings. An engineer is responsible for ensuring that correct ratings are provided, but technicians should have an understanding of what these ratings mean.

(1) Rating. The rating of an instrument transformer is expressed by two groups of numbers representing the nominal current or voltage which may be applied to its primary winding and the current or voltage which would then be induced in its secondary winding. For example a designation of 400:5 amperes expresses the rating of a current transformer and means that when 400 amperes flow in the primary, 5 amperes will flow in the secondary. Likewise, the designation 480:120 volt expresses the rating of the voltage transformer. This means that it is safe and permissible to apply 480 volts to the primary winding, and that when a voltage of this value is applied to the primary, 120 volts will be induced in the secondary.

(2) Ratio. The ratio of an instrument transformer is the relationship of its primary rating to its secondary rating. For example, the current transformer mentioned previously having a rating of 400:5 amperes will have a ratio of 80:1 and the voltage transformer having a rating of 480:120 volts will have a ratio of 4:1.

(3) Thermal Rating. Instrument transformers have thermal ratings which indicate the maximum values the transformer can carry to meet the permitted temperature rise (typically 55 degrees C or 80 degrees C each in a 30 degrees C ambient for oil or dry-type units respectively).

(a) Current Transformer Thermal Rating Factor. The continuous current rating factor (RF) is the specified factor by which the rated primary current of a current transformer can be multiplied to obtain the maximum primary current that can be carried continuously without exceeding the limiting temperature rise from a 30 degrees C ambient air temperature. In other words, it is a designation of the transformer's overload capability. Standard rating factors are 1.0, 1.33, 1.5, 2.0, 3.0, or 4.0. A rating factor on a current transformer nameplate of 2.0 means that in a 30 degrees C ambient, the current transform will safely carry on a continuous basis two times the nameplate current rating.

(b) Voltage Transformer Thermal Burden Rating. Voltage transformers have a thermal burden rating which designates the maximum volt-ampere burden which may be connected to the voltage transformer's secondary. This burden at a specified ambient temperature will not exceed the voltage transformer's temperature limitations. The thermal burden rating for the applicable ambient temperature is indicated on the transformer nameplate.

(4) Insulation Classes. The insulation class indicates the magnitude of voltage which an instrument transformer can safely withstand between its primary and secondary windings and between its primary OR secondary winding and ground (core, case, or tank) without a breakdown in the insulation (see *Paragraph 2.7a*). The insulation class of an instrument transformer should be at least equal to the insulation class of the primary equipment. Under fault conditions instrument transformers can be subjected to line-to-line voltage.

(5) Accuracy and Burden. The accuracy of an instrument transformer is based on the unit not exceeding a maximum industry-standard secondary burden.

(a) Burden. The term "burden" has been adopted to distinguish it from "load". For example, the load rating of a current transformer indicates the load (in current) which may be applied to its primary. The burden rating indicates the amount of resistance (in ohms) and impedance (in millihenries) which may be connected to the secondary of the current transformer. A burden designation of B-0.1 denotes a 0.1 ohm maximum burden; a B-2 denotes a 2 ohm maximum burden. The maximum burden is the load the current transformer can carry without exceeding its industry standard accuracy classifications.

(b) Metering Classification Example. Metering accuracy classification for an instrument transformer includes the standard burden as well as the maximum percent error limits for line power factors between 100 percent and 60 percent lagging. A typical current classification might be 0.3 B0.5 where the 0.3 is the percent allowable error and the B0.5 is the secondary burden in ohms impedance. The accuracy is dependent on the burden.

(c) Relaying Classification Example. Current transformers that are used to operate relays for control and system protection are assigned an accuracy rating which indicates the maximum voltage acceptable at the secondary terminals for a 10 percent ratio error based on the maximum 20 times the rated 5-ampere current times the burden ohms. A "C" classification indicates the value was calibrated (window and bar types with low leakage reactance). A "T" classification indicates the value was tested (wound type with unpredictable leakage reactance). The standard designated voltages are 10, 20, 50, 200, 400, and 800. A C200 unit can tolerate a maximum 200 volts at the secondary terminals with a maximum of 2 ohm burden (B-2) based on 20 x 5 amperes x 2 ohms = 200 volts.

(d) Incorrect Accuracy. Adding relays or meters to an existing installation requires that their added burdens be evaluated as to their effect on the accuracy of their operation.

(6) Grounding. Ground cases and secondary winding of instrument transformer.

f. Instrument Transformer Examples. *Pictures 6-1, 6-2, 6-3*, and *6-4* show examples of instrument transformers and their nameplates

g. Nameplates. Instrument transformers minimum nameplate information is shown on *Table 6-1* and *Table 6-2*.

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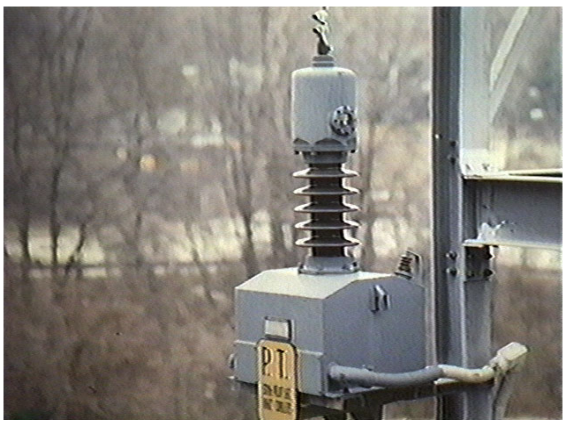
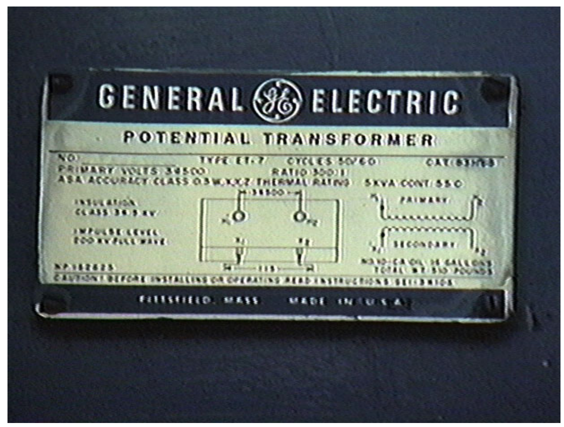
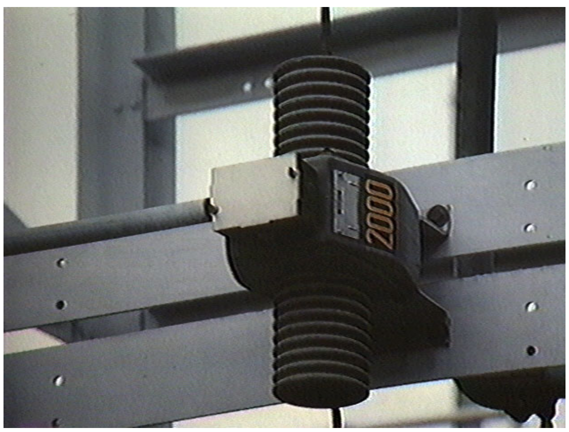


Picture 6-1
Voltage transformer

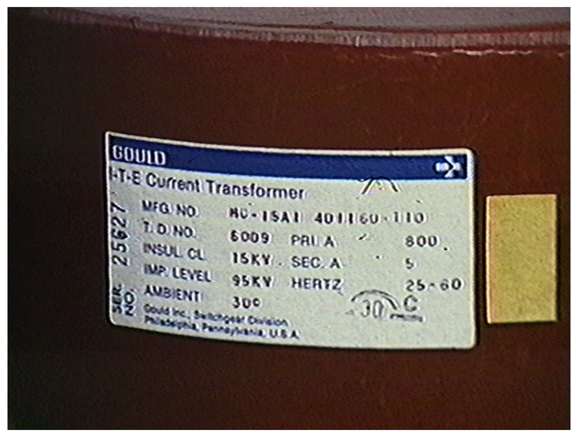


Picture 6-2
Voltage transformer nameplate

 AFH 32-1282V2



Picture 6-3
Current transformer



Picture 6-4
Current transformer nameplate

Table 6-1. Minimum current transformer nameplate data

Manufacturer's name or trademark	Rated frequency (Hz)[2]
Manufacturer's type	Continuous-thermal-current rating factor (RF)[2]
Manufacturer's serial number (SER)	Accuracy rating[2]
Rated primary and secondary current	Relaying accuracy class on transformers intended primarily for relaying applications
Nominal system voltage (NSV) or maximum system voltage (MSV) [1]	Metering accuracy class at specified standard burdens; as a minimum, the burdens at which the transformer is rated 0.3 accuracy class
Basic impulse insulation level (BIL_kV)	

[1]None for bushing current transformers.
[2]Not required for bushing current transformers intended for use inside other apparatus in an ambient other than air.

Table 6-2. Minimum voltage transformer nameplate data

Manufacturer's name or trademark	Basic impulse insulation level (BIL_kV)
Manufacturer's type	Rated frequency (Hz)
Manufacturer's serial number (SER)	Thermal burden rating or ratings at ambient temperature or temperatures, in VA at ___ degrees C
Rated primary voltage (PRI)	
Ratio or ratios	Accuracy rating: maximum standard burden at which the accuracy rating is 0.3 class, as a minimum

6-2. De-Energized Instrument Transformer Tests. Instrument transformers are tested for insulation resistances (see *Paragraph 4.2.b*), polarity (see *Paragraph 6.1.e*), and ratio. High-voltage instrument transformers which are oil-insulated should be checked for oil level and oil analyzed as covered for power/distribution transformers. Follow the manufacturer's instructions. Oil sampling may not be permitted on some manufacturer's units. Burden and saturation tests may also be required for current transformers.

a. Ratio Test. Apply a measured current to a current transformer primary to determine the measured resulting current in the secondary. Provide ammeters in the primary and secondary. The primary reading for a 200/5 rated current transformer with a measured 40-ampere primary reading should result in a measured one-ampere secondary reading or the ratio of 40 to 1. Use voltmeters and apply voltage for voltage transformer ratio checks.

b. Current Transformer Burden Tests. The burden test consists of inserting a known current level (usually 1 to 5 ampere ac) into the load (usually from the shorting terminal block of the current transformer) and measuring the voltage at the point of injection. The impedance (or burden) of the circuit is the ratio of the voltage measured to the current injected.

c. Current Transformer Saturation Tests. A variable voltage source is connected to the secondary of the transformer and raised in steps. Record the current value at each step. When saturation is reached, small voltage changes will cause much larger changes in current. The saturation test is used in conjunction with the burden test to make sure that the current transformer is capable of operating the load (usually protective relays) to which it will be connected. If the burden on the current transformer is too high, it will go into saturation and be unable to maintain its proper ratio. When this happens, protective relays may trip too slowly or not at all due to an insufficient level of current from the current transformer secondary.

6-3. Instrument Transformer EPM Reports. Each installation should prepare local blank EPM report forms to be filled out by the inspecting technicians. (See *Paragraph 1-4*). The following tables indicate the data to be recorded.

a. Basic Instrument Transformer Information To Be Determined Before the Inspection. Provide a suitable record header with blank spaces for insertion of the following data given in *Table 6-3*.

Table 6-3. Instrument transformer general data

General	Current
Designation	Rated primary and secondary currents
Date of inspection	Nominal or maximum voltage
Location	Continuous RF
Serial no.	Accuracy rating
Year installed	
Last inspection date	**Voltage**
Manufacturer	Rated primary voltage
Instruction manual	Ratio(s)
Dry or fluid-filled type	Thermal burden rating
Rated frequency	Accuracy rating
Basic impulse insulation level	

b. Basic Inspection Items To Be Checked. Provide an inspection listing with column headings covering items to be checked off for each listed number given in *Table 5-2.*

c. Inspection Items To Be Covered. List inspection items to be covered. *Table 6-4* indicates transformer readings and appropriate evaluation paragraphs for passing criteria. *Table 6-5* indicates transformer components and appropriate inspection actions.

Table 6-4. Instrument transformer readings

Gauge reading or test value	Evaluation reference paragraph
1. Ambient temperature	--
2. Winding insulation resistance	4.2b
3. Ratio	6.2b
4. Burden	6.2b
5. Saturation	6.2c
6. Liquid level	6.2d
7. Oil sampling	6.2[1]
8. Pressure condition	If applicable[1]

[1]See manufacturer's instructions.

Table 6-5. Instrument transformer components

Component Inspection	Component Inspection
1. Case	2. Electrical connections
a. Paint condition	a. Tightness
b. Liquid leaks	b. Hot spots[1]
c. Gasketing or other sealing	3. Voltage transformers
d. Supports	a. Fuses
e. Outdoor contamination	b. Operation transformer withdrawal mechanism (tip out) and grounding.

[1]For infrared checking see Paragraph 4.1b.

d. Corrective Action. Describe corrective actions taken. Deficiencies requiring action beyond the technicians at the site should be indicated as "see note X." "Note X" should explain reasons. Such a note might indicate that an oil leak needs to be repaired requiring a shut down of the transformer and appropriate welding materials.

e. Miscellaneous. Instrument transformers which have been out of service for a long period of time should be dried before being put into service.

CHAPTER 7. BUSHINGS

7-1. Performance. A bushing is an insulating structure which provides a through conductor or a passageway for such a conductor. A bushing mounts on a barrier (conducting or otherwise). The bushing insulates the conductor from the barrier and its through conductor carries current from one side of the barrier to the other side. A bushing's primary function is to provide an insulated entrance for an energized conductor into an apparatus tank. Externally their watersheds reduce potential flashover from moisture or contamination because bushings are water-tight, oil-tight, and gas-tight to prevent contamination from entering apparatus. *Figure 7-1* shows bushing details.

a. Construction. Bushings vary widely in construction. Requirements of industry standards on their performance characteristics, dimensions, test procedures, and loading allow manufacturers a certain amount of diversity in utilizing insulation to meet the requirements on oil-filled transformers or circuit breakers. They can be classified by design.

(1) Noncondenser Types. Noncondenser (two-terminal) types do not have a tap for measuring power factor. A grounded specimen (hot or cold collar) test for power factor as covered in AFMAN 32-1280(I) must be used. The test measures the power factor between the terminal cap and the grounded bushing flange. Units generally have solid cores or layers of solid and liquid insulation, solid insulating material such as porcelain with or without oil filling, or are gas filled between the conductor and weathershed.

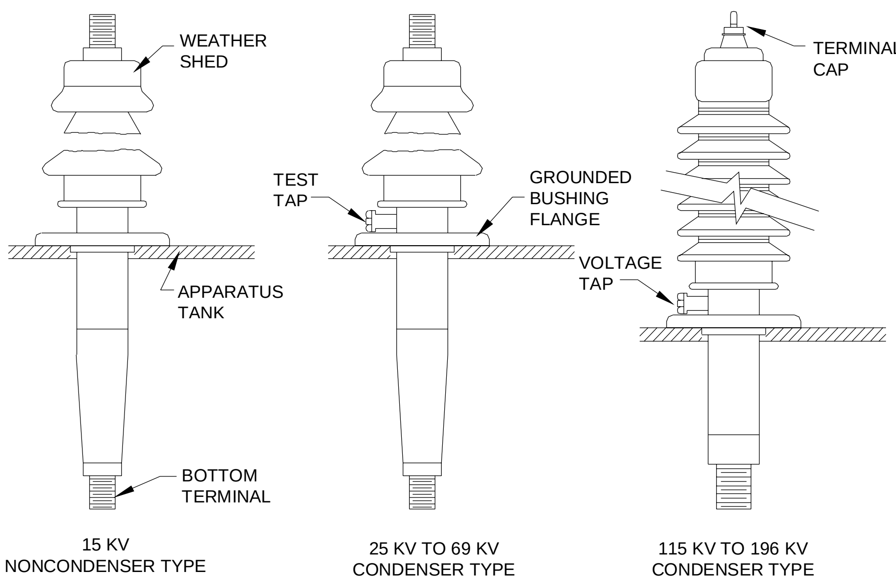


Figure 7-1
Medium- and high-voltage bushings

 AFH 32-1282V2

(2) Condenser Types. Condenser (three-terminal) types have either a bushing voltage (capacitance) tap (all bushings rated 450 kV BIL or greater) or a bushing test (power factor) tap (all bushings rated below 450 kV). The 450 kV BIL is an intermediate rating between 115 kV and 69 kV insulation classes. These taps allow for measurement of partial discharge, power factor, and capacitance values. An ungrounded specimen test for power factor as covered in AFMAN 32-1280(I) is used for measuring power factor between the terminal cap and the ungrounded bushing voltage or test tap. Measurement of power factor between the ungrounded bushing voltage or test tap and the grounded bushing flange is done with the grounded specimen test.

(a) Capacitance Grading. Condenser bushings are capacitance graded in which metallic or nonmetallic conducting layers are arranged within the insulating material for the purpose of controlling the distribution of the electric field of the bushing both axially and radially. These layers are essentially a series of horizontally concentric capacitors between the center conductor and the ground sleeve. The conducting layer is brought out to a tap terminal which is normally grounded by connection of its grounding tap screw to the grounded bushing flange. With the grounding connection removed the ungrounded specimen test may be used.

(b) Condenser Layers. Units generally are of oil-impregnated paper insulation or resin-bonded paper insulation with interspersed conducting (condenser layers) or continuously wound with interleaved lined paper layers.

b. Treatment. Bushings are comparatively inexpensive compared to the cost of the power apparatus for which they provide electrical connections. They are important because their failure can result in the total destruction of the transformer. Check them regularly and repair or replace as applicable to the type and degree of deterioration. Many manufacturers recommend replacement citing that special equipment/tools are only available at their factory. Refer to AFMAN 32-1280(I) where data on porcelain, metal parts, cement, gasket, conductor lead, line connection, and other inspection and repair items are more fully covered. Check the oil level if applicable.

c. Nameplates. Nameplates for outdoor power apparatus bushings which have impulse levels of 110 kV (15 kV class) and above for use as components of oil-filled transformers must provide the minimum nameplate information to meet requirements of IEEE C57.1900 *(IEEE General Requirements and test Procedures for Outdoor Power Apparatus Bushings*). *Table 7-1* indicates bushings not covered by IEEE C57.1900. *Figures 7-1, 7-2, 7-3*, and *7-4* show examples of bushings and enclosed terminations. *Table 7-2* indicates the nameplate data for outdoor power apparatus bushings.

Table 7-1. Items not covered by IEEE C57.1900

High-voltage-cable terminations (potheads)
Bushings for instrument transformers, test transformers, distribution class circuit breakers and transformers, automatic circuit reclosers, line sectionalizers, and for oil-less or oil-poor apparatus
Bushings in which the internal insulation is provided by a gas or applied with gaseous insulation (other than air at atmospheric pressure) external to the bushing.

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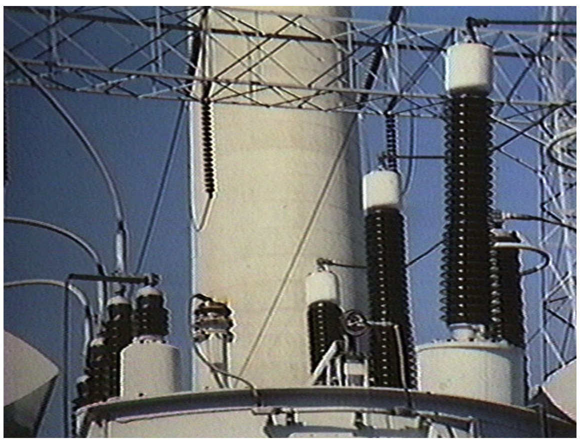
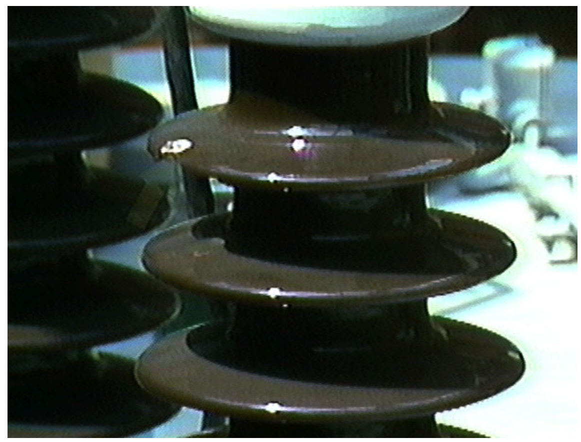
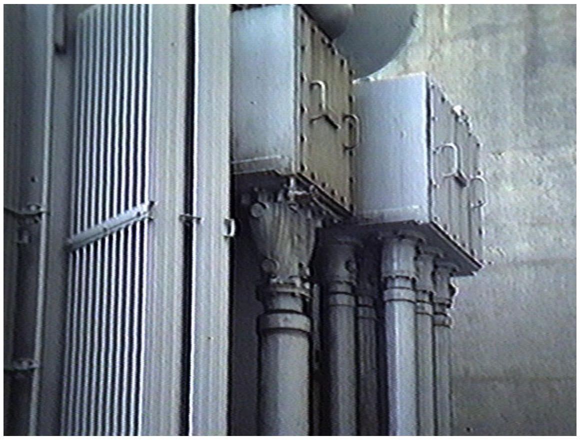


Picture 7-1
Power transformer bushings

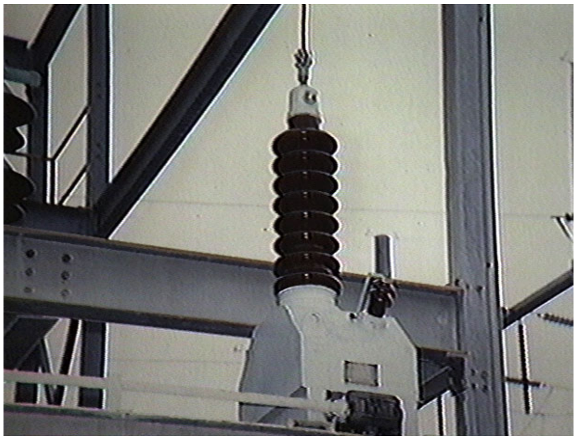


Picture 7-2
Correctable bushing chip

AFH 32-1282V2



Picture 7-3
Terminal enclosures



Picture 7-4
Voltage transformer bushing

Table 7-2. Minimum outdoor power apparatus bushing nameplate data[1]

Manufacturer's name, identification number, type, year of manufacture, and serial number.
Rated maximum line-to-ground voltage
Rated continuous current[2]
Rated full-wave lightning impulse withstand voltage (BIL)
Capacitance, C_1 and C_2, on all bushings equipped with voltage taps, and C_1 on all bushings equipped with test taps.[3]
Power factor measured from conductor to tap, where applicable, at 10 kV or above and referred to 20 degrees C, by the ungrounded specimen test method.
Length of bushing below mounting surface

[1]The following information shall appear on all bushing nameplates, except on small 110-kV BIL bushings which shall be marked in a conspicuous place with the manufacturer's specific identification.

[2]Where bushings have a dual continuous current rating, the nameplate shall indicate the rating for (1) oil circuit breaker application, (2) power transformer application.

[3]The main capacitance, C_1, of a bushing is the capacitance between the high-voltage conductor and the voltage tap or the test tap. The tap capacitance, C_2, of a capacitance-graded bushing is the capacitance between the voltage tap and mounting flange (ground). The capacitance, C, of a bushing without a voltage or test tap is the capacitance between the high-voltage conductor and the mounting flange (ground).

7-2. De-Energized Bushing Tests. Bushings should be tested for power factor. In the absence of facilities to test power factor, insulation resistance tests may prove useful.

a. Power Factor Tests. The power factor of the main capacitance C_1 and, where applicable, the tap capacitance C_2 of capacitors should be measured. Short-circuited capacitor sections can be detected by an increase in capacitance. The presence of moisture or other contaminants can usually be detected by an increase in power factor. Temperature corrections should be made during the measurements. When performing tests on the C_2 capacitance, care should be taken not to exceed the test voltage of the tap. It should be noted that the power factors of the C_1 and C_2 capacitances may be considerably different from each other and it is not uncommon for the C_2 capacitance to be ten times greater than that of the C_1 capacitance. Note that moisture or surface contamination should be removed before performing power factor measurements.

(1) Hot Collar Testing. The hot collar test can be used to assess the condition of a specific small section of the bushing insulation to locate cracks in porcelain, degradation of insulation inside the upper section of the bushing, low compound or liquid level, and voids in the compound.

(2) Power Factor Limits. Power factor limits are published by the manufacturers and many bushings have the factory power factors stamped on the nameplate. Field measurements should be compared with the nameplate values. Bushings that exhibit a continued increase in power factor over a period of several years should be investigated further and possibly removed from service. In practice, if the power factor of capacitance-graded bushings exceeds 1 percent, further specialized help should be sought.

b. Insulation Resistance Tests. Bushings cannot be checked while connected to transformer windings. See *Paragraph 4-2* and AFJMAN 32-1280(I).

7-3. Bushing EPM Reports. Each installation should prepare local blank EPM report forms to be filled out by the inspecting technicians. (See *Paragraph 1-4*). The following tables indicate the data to be recorded.

a. Basic Bushing Information To Be Determined Before the Inspection. Provide a suitable record header with blank spaces for insertion of the following data given in *Table 7-3*.

Table 7-3. Bushing general data

Designation	Basic impulse insulation level
Date of inspection	Maximum line-to-ground voltage
Location	Rated continuous current
Serial no. and type	Capacitance C1______ C2______ (if applicable)
Year of manufacture	Power factor
Last inspection date	Length of bushing below mounting surface
Manufacturer	Tap type (if applicable)
Instruction manual	

b. Inspection Items To Be Covered. List inspection items to be covered. *Table 7-4* indicates bushing readings and appropriate evaluation paragraphs for passing criteria. *Table 7-5* indicates bushing components and appropriate inspection actions.

Table 7-4. Bushing readings

Gauge reading or test value	Evaluation reference paragraph
1. Ambient temperature	--
2. Power factor	7.2a
3. Capacitance values	7.2a
4. Liquid level	7.1b
5. Insulation resistance	7.2b

Table 7-5. Bushing components

1.	Excessive contamination.	8.	Bushing conductor lead.
2.	Cracked or broken porcelain.	9.	Line/bus hot spot connections[1]
3.	Broken or deteriorated gaskets and seals.	10.	Migration of compound.
4.	Fractured metal parts.	11.	Internal carbon deposits.
5.	Cementing deterioration.	12.	Arcing gap.
6.	Excessive operating temperature.	13.	Oil gage.
7.	Loose or missing parts, such as a power factor test tap cover.	14.	Oil level.

[1]For infrared check see *Paragraph 4.1b*.

d. Corrective Action. Describe corrective actions taken. Deficiencies requiring action beyond the technicians at the site should be indicated as “see note X.” “Note X” should explain reasons. Such a note might indicate that a high pressure water stream is needed to remove excessive contamination.

e. Miscellaneous. Never operate bushings with the voltage tap exposed or without the grounding cap in place on the test tap shown on the condenser type bushings of *Figure 7-1*.

CHAPTER 8. SURGE ARRESTERS

8-1. Performance. A surge arrester is one of the most important devices in an electrical distribution system. Surge arresters limit surge voltages on equipment by discharging or bypassing high-frequency lightning or switching surge currents to ground. It performs as a reverse circuit breaker. Surge arrester circuits are normally open, only closing to discharge the system disturbance surge then reopening again. Under normal conditions the surge arrester acts as an insulator. Upon a surge the arrester functions as a low resistance conductor for the microseconds it takes for discharge. This action prevents dangerous voltages from developing and destroying the power apparatus for which the surge arrester provides protection. A surge arrester, correctly applied, will be capable of providing its protective function for repeated overvoltages from lightning and switching. See *Figure 8-1*. Despite its importance, the surge arrester is probably the most poorly maintained power circuit protective device. This lack of inspection, in part, can be attributed to developments that have made surge arresters very reliable and almost trouble-free.

a. Construction. Surge arresters may be constructed as a gapped silicon-carbide or either a gapped or gapless metal oxide. They are classified in a descending order of available protective level and energy-discharging capability as station, intermediate, distribution, and secondary types. Metal-oxide surge arresters (MOSA's) should be considered for replacement when silicon-carbide types fail. The protective characteristic of MOSA's are not true equivalents of silicon-carbide units but have superior protective characteristics, so engineering judgment is required in ordering a replacement.

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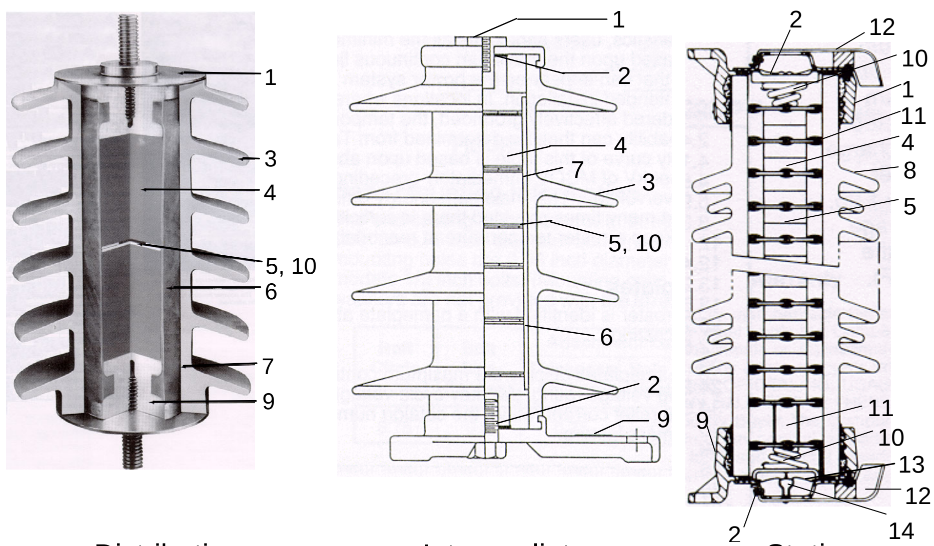

1. Line end connection and cap
2. Gasket
3. Alloy ethylene-propylene diene monomer silicone rubber housing
4. Metal oxide varister
5. Contact disc
6. Epoxy-fiberglass wrap
7. Silicone interface
8. Porcelain housing
9. Ground end connection and cap
10. Spring
11. Spacer assembly
12. Gas deflector assembly
13. Pressure relief diaphragm
14. Puncturing prongs

Distribution 13.8 kV | Intermediate 46 kV | Station 110 kV

Figure 8-1
Surge arrester construction

b. Treatment. Correctly applied modern surge arresters have relatively few failures. Experience has shown that most failures are caused by damaged, defective, or contaminated units. Acceptance and routine maintenance testing in the field can minimize this type of failure. It is recommended that units found to be defective be replaced rather than repaired. Surge arresters are almost always applied with one terminal connected to an electrically energized source and one terminal to ground. No work should be done, or contact made with surge arresters, when connected to the energized source.

c. Identification data. The following minimum information to be firmly attached to or made an integral part of each arrester is given in *Table 8-1*.

Table 8-1. Minimum surge arrester identification data

Arrester classification
Manufactures name or trademark
Manufacturer's type and identification number
Duty-cycle voltage rating of the arrester
Maximum continuous operating voltage (MCOV) rating of a MOSA or voltage rating of other types
Setting of the external series gap, if used
The year of manufacture[1]
For intermediate and station arresters, the pressure-relief rating in amperes

[1]Applies to all MOSA type arresters but only to distribution class arresters for other types.

8-2. De-Energized Surge Arrester Tests. Test results on arresters are affected to varying degrees by surface leakage. These losses can usually be minimized by wiping the porcelain with a clean, dry cloth. If it is necessary to use cleaning agents and waxes they must be in accordance with the manufacturer's directions.

a. Power Factor Tests. Each type and class of surge arrester has a specific power factor when new. Periodic testing of a unit will show little deviation from the original (when new) power factor, so long as it remains in good operating condition. A major deviation from the original value indicates that the arrester has been mechanically damaged or contains moisture. A single arrester can be tested only by the routine ungrounded specimen test. The high-voltage power factor test lead connects to the top of the arrester and the low-voltage power factor lead connects to the bottom of the arrester which is grounded. Before testing, make sure the associated bus is de-energized and the arrester connection to the bus is removed.

b. Insulation Resistance Tests. A megger test for insulation resistance can be made to provide additional information on the condition of an arrester. Such a test may indicate shorted valve elements in valve-type arresters. See *Paragraph 4-2* and AFMAN 32-1280(I).

8-3. Surge Arrester EPM Reports. Each installation should prepare local blank EPM report forms to be filled out by the inspecting technicians. (See *Paragraph 1-4*). the following tables indicate the data to be recorded.

a. Basic Surge Arrester Information To Be Determined Before the Inspection. Provide a suitable record header with blank spaces for insertion of the following data given in *Table 8-2.*

Table 8-2. Surge arrester general data

Designation	Manufacturer
Date of inspection Location	Instruction manual
Serial no.	Setting of external series gap[1]
Year installed	Maximum continuous operating voltage[1]
Year of manufacture[1]	Voltage rating[1]
Last inspection date	Pressure-relief rating[1]

[1]If applicable

b. Basic Inspection Items To Be Checked. Provide an inspection listing with column headings covering items to be checked off for each listed number given in *Table 5-2*.

c. Inspection Items To Be Covered. List inspection items to be covered. *Table 8-3* indicates surge arrester readings and appropriate evaluation paragraphs for passing criteria. *Table 8-4* indicates surge arrester components and appropriate inspection actions.

Table 8-3. Surge arrester readings

Gauge reading or test value	Evaluation reference paragraph
1. Ambient temperature	--
2. Power factor	8.2a
3. Insulation resistance	8.2b

Table 8-4. Surge arrester components

1.	Excessive contamination.	6.	Excessive operating temperature.
2.	Cracked or broken porcelain.	7.	Line lead connection.
3.	Broken or deteriorated gaskets and seals.	8.	Ground lead connection.
4.	Fractured metal parts.	9.	Evidence of flashover.
5.	Cementing deterioration.	10.	External caps clean and set correctly.

d. Corrective Action. Describe corrective actions taken. Deficiencies requiring action beyond the technicians at the site should be indicated as “see note X.” “Note X” should explain reasons. Such a note might indicate that it appears that the surge arrester is located so as to be subject to abnormal vibrations.

JOHN W. HANDY, Lt General, USAF
DCS/Installations & Logistics

Notes

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