

TRANSFORMERS

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1.0 SCOPE

This data sheet contains loss prevention recommendations related to the fire protection of **ALL** types of transformers. It also contains loss prevention recommendations related to electrical protection, electrical testing, maintenance, and operation for large and critical distribution, power, and specialty transformers **ONLY**. For loss prevention recommendations related to electrical protection, electrical testing, maintenance, and operation of smaller and less critical transformers, see DS 5-20, *Electrical Testing*.

Specialty transformers include network transformers, rectifier transformers, arc furnace transformers, induction furnace transformers, generator step-up transformers, series reactors, and shunt reactors.

1.1 Changes

April 2014. Minor editorial changes were made.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Electrical Loss Prevention

2.1.1 Electrical Protection

2.1.1.1 Perform an engineering analysis to determine the most appropriate protective scheme for each transformer, taking into account the following factors:

- A. The criticality of the transformer
- B. The lead time required to replace or repair the transformer
- C. The fire exposure presented by the transformer to buildings and equipment
- D. The effect of transformer failure on system integrity and reliability
- E. The service requirements of the transformer (e.g., is the transformer required to operate in a high fault environment or is it exposed to high levels of harmonics, overvoltages, and lightning?)
- F. The condition of the transformer (e.g., is the transformer approaching the end of its useful life, is it operated in a harsh environment, has the transformer been compromised from previous faults?)

See Figure 1A for a typical protective scheme for a two-winding, delta-wye connected transformer up to 10,000 kVA in size using fuses on the primary of the transformers.

See Figure 1B for a typical protective scheme for a two-winding, delta-wye connected transformer up to 10,000 kVA in size using a circuit breaker on the primary of the transformers.

See Figure 1C for a typical protective scheme for a two-winding, delta-wye connected transformer greater than 10,000 kVA in size.

See Figure 1D for a typical protective scheme for transformers greater than 10,000 kVA in size with a secondary selective system.

See Figure 1E for some alternative protective devices that achieve the same level of protection as the schemes shown in Figures 1A, 1B, and 1C.

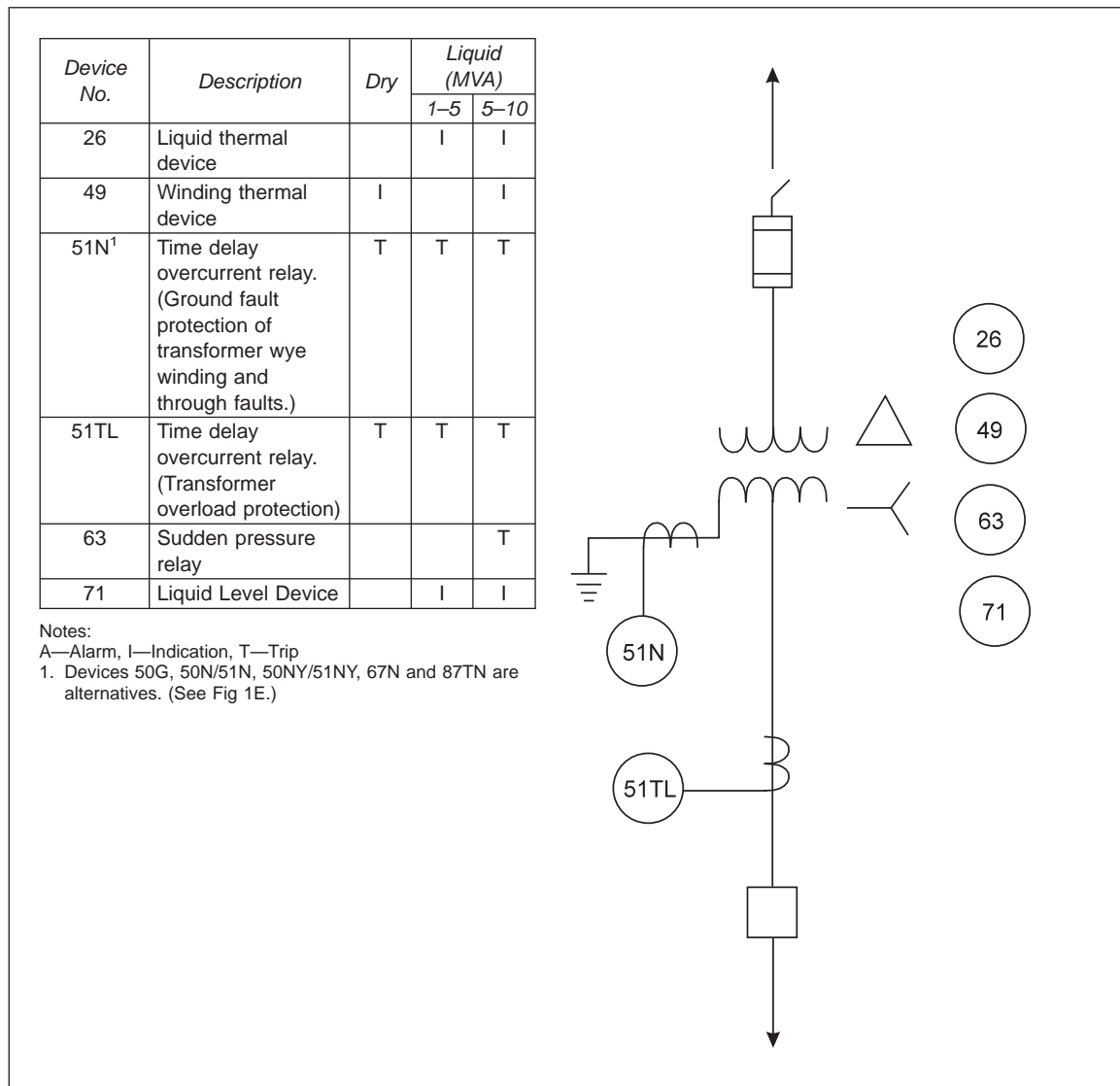


Fig. 1A. Typical protective scheme for a two-winding, delta-wye connected transformer up to 10,000 kVA in size using fuses on the primary of the transformers

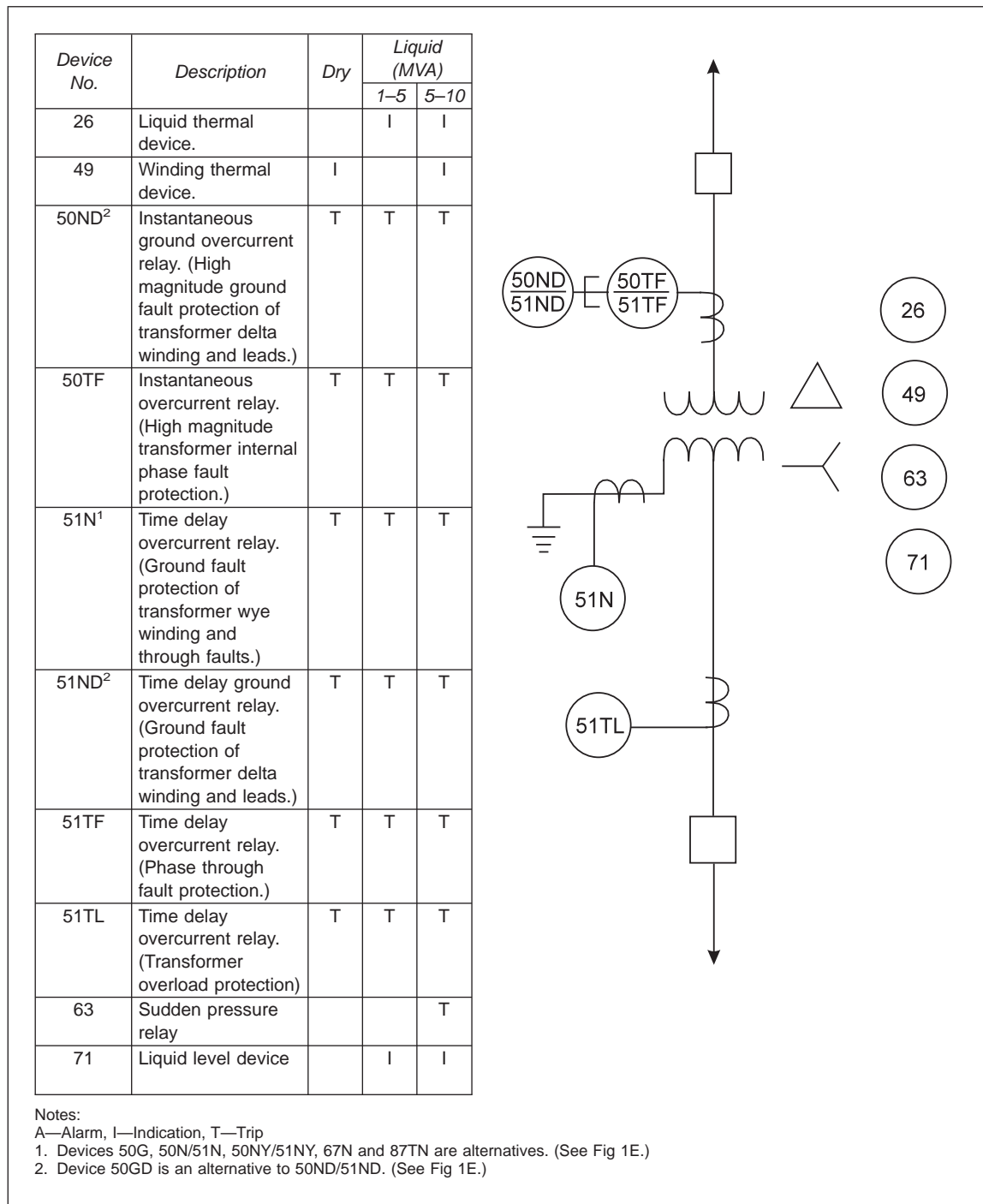


Fig. 1B. Typical protective scheme for a two-winding, delta-wye connected transformer up to 10,000 kVA in size using a circuit breaker on the primary of the transformers

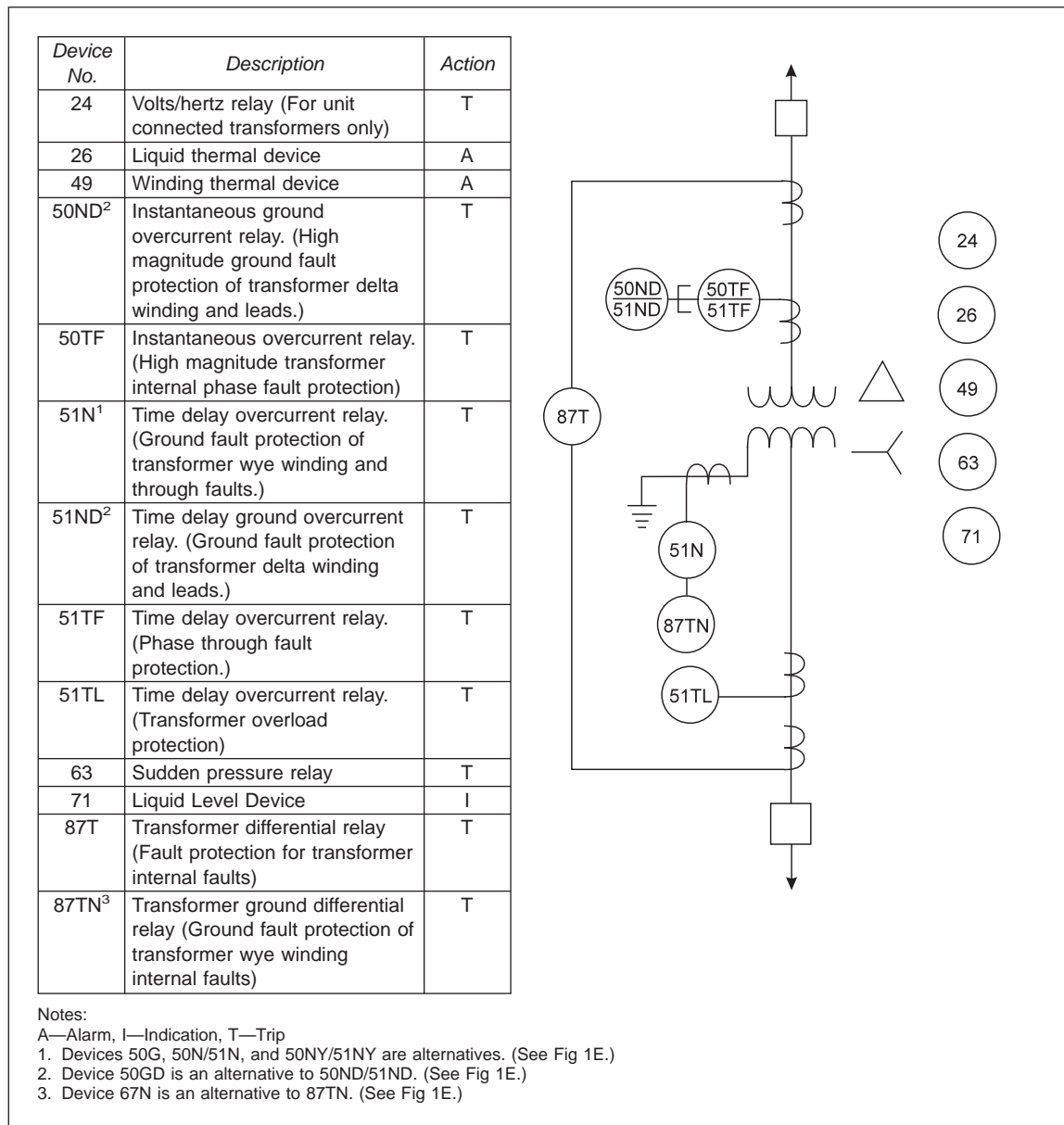


Fig. 1C. Typical protective scheme for a two-winding, delta-wye connected transformer greater than 10,000 kVA in size

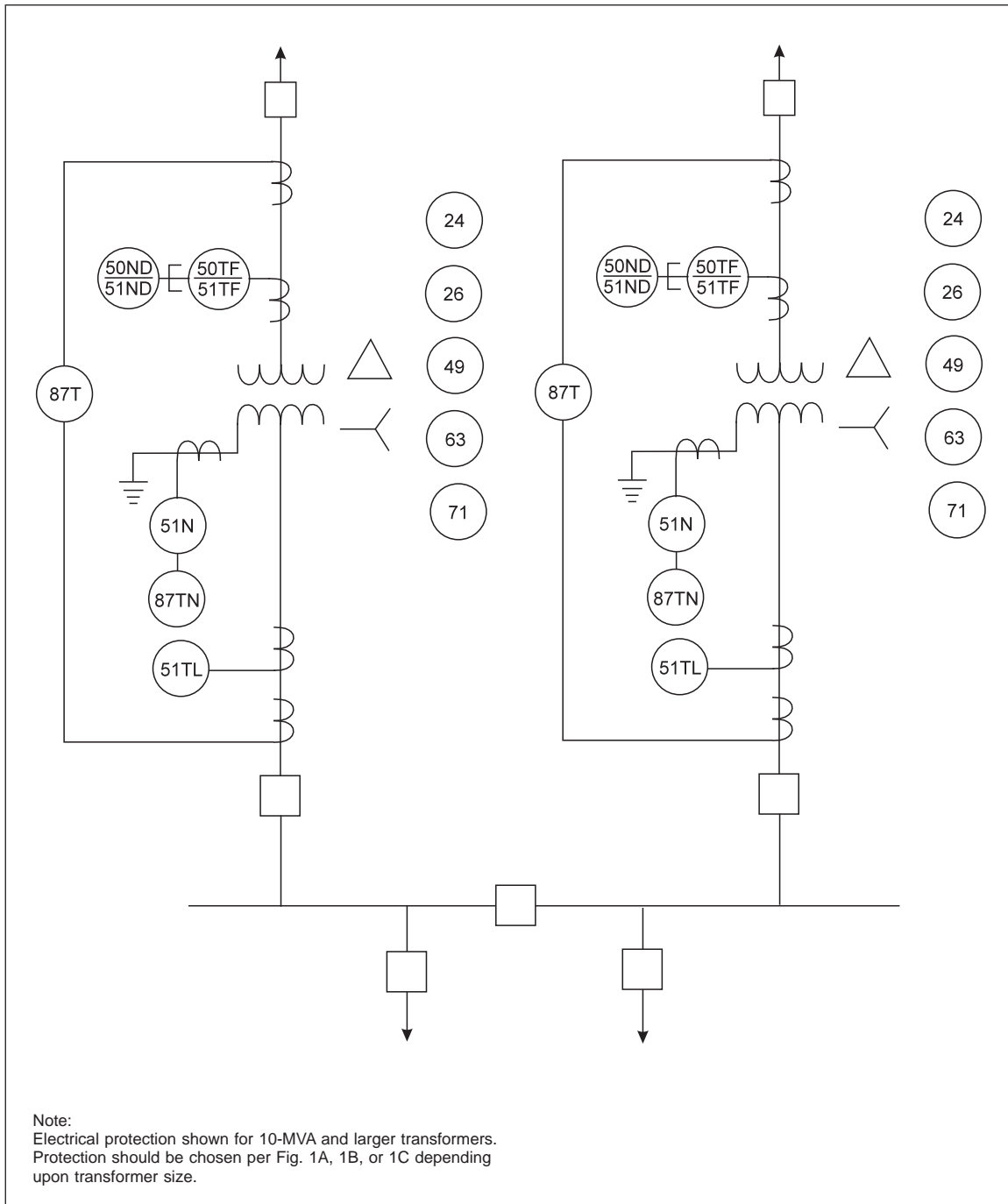


Fig. 1D. Typical protective scheme for transformers greater than 10,000 kVA in size with a secondary selective system

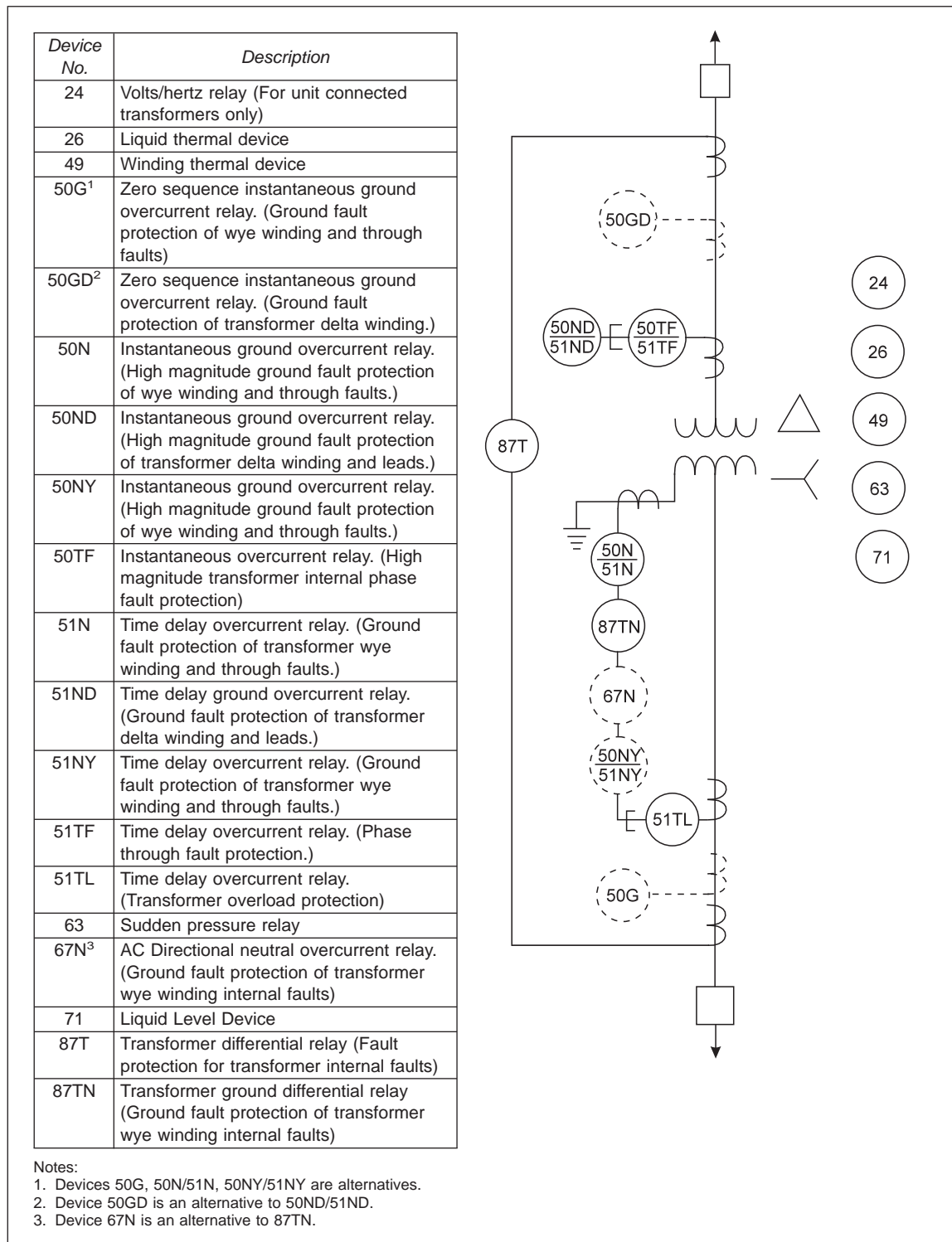


Fig. 1E. Alternative protective devices that achieve the same level of protection as those shown in Figures 1A, 1B, and 1C

2.1.1.2 Provide overvoltage protection for all transformers in accordance with Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems*.

2.1.1.3 Improve the overvoltage protection for transformers that are approaching the end of their useful life. Consult a qualified installation or repair company for upgrade options.

2.1.1.4 Provide differential protection to cover all the windings on multiple winding power transformers, including specialty transformers such as rectifier, induction, and arc furnace transformers. Where the high magnetic fields of specialty transformers prohibit the use of conventional iron core current transformers, use Rogowski Coil current sensors to implement differential protection.

2.1.1.5 Provide overcurrent and ground fault protection for the tertiary winding of three-winding transformers and autotransformers.

2.1.1.6 Do not reenergize transformers after the operation of protective devices until it has been determined that the transformer has not suffered internal damage and any external faults have been removed. At a minimum, perform a dissolved gas analysis test (DGA) to determine if the transformer has suffered internal damage. Additional testing may be needed depending on the results of the DGA test (see Section 2.1.2).

Exercise care when taking a DGA sample immediately following a fault. It may be prudent to wait several hours after the fault since fault gases may not have enough time to migrate through the bulk of the oil. Taking a DGA sample too early can produce misleading results.

2.1.1.7 Provide an arc-monitoring system (e.g., ABB Arc Guard System) or FM Approved equivalent to detect arcing faults in transformer vaults with exposed energized components. Provide this additional protection when the ground fault relay cannot be set low enough to detect ground fault current due to neutral imbalance current flow.

Table 1 contains a list of specialty transformers and the additional protection recommended for them.

Table 1. Recommended Additional Protection for Specialty Transformers

<i>Transformer Type</i>	<i>Special Features</i>	<i>Additional Protection</i>
In-phase regulating transformer	The high impedance exciting winding (or shunt winding) makes it difficult to detect faults in this winding with a high level of sensitivity.	Primary protection should consist of sudden pressure relays in the main tanks as well as the tap changer compartment. Differential protection for the exciting winding is also needed. ¹
Phase-shifting, quadrature booster transformer	In addition to the issues with the high impedance exciting winding mentioned above for in-phase regulating transformers, protection of phase shifting transformers also needs to consider protection requirements for the shunt and series windings.	Primary protection should consist of sudden pressure relays in the main tanks (quadrature booster transformers usually have at least two sets of tanks to house the shunt and series transformers) as well as the tap changer compartment. Differential protection for the exciting, series, and shunt winding is also needed. ²
Load tap changing transformer	The tap winding and preventive auto transformer (if provided) will be part of the protection zone covered by the transformer protection. Therefore, dedicated protection for the tap changer is not needed. However, the tap changer needs to be taken into account when designing the protection for the transformer. For example, the tap position will affect transformer differential protection and needs to be accounted for. The separate tap changer compartment also needs to be protected from overpressure. And, protection should also be considered for the tap changer motor.	Separate Buchholz relays should be provided if the load tap changer compartment is supplied from a separate conservator tank or from a separate compartment of the conservator tank. Sudden pressure relays are also needed for the load tap changer compartment. Overload, short circuit, and ground fault protection should be provided for the load tap changer motor.
Grounding transformer	A grounding transformer that is solidly or low resistance grounded is not able to withstand ground faults for long. When the grounding transformer is located within the differential protection zone of the main transformer, zero sequence current provided by the grounding transformer during external ground faults can cause a false differential protection trip.	Overcurrent relay protection arranged to pick up zero sequence current should be provided to protect the grounding transformer. Differential protection may also be used for this purpose. Sudden pressure relays are needed as a primary defense against internal faults, especially for zig-zag grounding transformers where the internal impedance can limit the current during internal turn-to-turn faults. A zero sequence filter should be included when the grounding transformer is in the protection zone to prevent inadvertent differential protection operation.
Arc furnace transformer	The high magnetic fields, high secondary currents, and a large harmonic content in the secondary current makes it impractical to implement differential protection using conventional iron core current transformers.	Use Rogowski Coil current sensors to implement differential protection.
Rectifier transformer	The same features present in arc furnace transformers, as well as the large physical size of the bushings of the double secondary windings of some rectifier transformers, make it impractical to implement differential protection using conventional iron core current transformers.	Use Rogowski Coil current sensors to implement differential protection.

¹ The CTs for the exciting winding differential protection may need to be installed internally.² The CTs to implement differential protection for these transformers are typically located internally and need to be specified during manufacture.

2.1.2 Testing

2.1.2.1 Benchmark Testing

Benchmark testing (or “fingerprinting”) is a valuable method of providing baseline data about the transformer. This information is used to make asset management decisions, to help with troubleshooting, and make decisions about whether to reenergize a transformer after it has tripped.

2.1.2.1.1 Perform the following benchmark tests on all new transformers:

- Thermography

- Frequency Response Analysis
- Exciting Current
- Leakage Reactance
- Partial Discharge Analysis
- Acoustic Measurement of the On Load Tap Changer
- Acoustic Measurement of the transformer tank
- Power Factor Testing (windings and bushings)
- Capacitance (windings and bushings)
- Furan Analysis
- Moisture in solid insulation
- Corrosive sulfur in oil

2.1.2.1.2 Perform benchmark tests on existing critical in-service transformers if baseline data for these transformers has never been collected.

2.1.2.2 In-Service Testing

2.1.2.2.1 Visually inspect transformers on a regular basis to check for problems such as cracked bushings, fouled radiators, low oil levels, low nitrogen pressure, expired desiccant, leaks, and other abnormal conditions.

2.1.2.2.2 Perform the following on-line tests once a year and more frequently if warranted based on operating history, condition, and criticality:

- Thermography
- Dissolved gas analysis
- Fluid screening

Fluid screening includes the following tests as a minimum:

- Color
- Dielectric breakdown strength
- Moisture
- Power factor
- Interfacial tension
- Neutralization number
- Inhibitor content (only for inhibited oils)

2.1.2.2.3 Perform corrosive sulfur testing of transformers that were built in 2000 or later, or have recently had their oil processed or replaced and the replacement oil has not been tested for corrosive sulfur.

In particular, perform corrosive sulfur testing of transformers that meet the following conditions:

- The transformer fluid is a mineral oil.
- The mineral oil is an uninhibited type.
- The oil preservation system is sealed (not free breathing).
- The transformer has a high sustained load factor.
- The transformer is operating in a hot climate.
- The transformer windings are bare copper.

Transformers that meet these conditions are at the highest risk of failure due to corrosive sulfur contamination.

Perform the IEC 62535 or Doble covered conductor deposition test in addition to the ASTM 1275 Modified Method B test.

When corrosive sulfur is detected, add copper passivators to the transformer oil to a concentration of 100 ppm. Check the concentration of the passivators on an annual basis to determine if additional passivators are needed. Add additional passivators as needed.

The addition of passivators needs to be made known to the laboratory performing dissolved gas analysis, as passivators can affect the stray gassing characteristics of the transformer oil.

2.1.2.2.4 Test the electrical protection system (fuses, circuit breakers, batteries, and relays) in accordance with Data Sheet 5-19, *Switchgear and Circuit Breakers*.

2.1.2.2.5 In addition to the recommended standard fluid tests, perform the following tests on the transformer fluid every three years:

- PCB
- Furan analysis

2.1.2.2.6 Perform the off-line tests listed in Table 2 every three years.

Table 2. Routine Off-line Tests

Component	Test
Windings	Insulation resistance
	Winding resistance
	Polarization index
	Turns ratio
	Power factor/capacitance
Bushings	Power factor/capacitance
Core	Core insulation resistance
On load tap changer	Turns ratio
	Contact resistance
	Insulation resistance
	DGA
	Fluid screen test
	Motor current measurement
	Acoustic signature analysis

2.1.2.2.7 Perform the additional tests listed in Table 3 if regular on-line tests indicate a problem with the transformer.

These additional tests are also useful in making a decision about whether to reenergize the transformer after it has tripped due to the operation of protection relays.

Table 3. Focused Off-Line Tests

Test	Failure Mode	Transformer Condition
Partial discharge	<ul style="list-style-type: none"> Partial discharge activity involving the transformer core, winding or bushings 	On-line
Electromagnetic interference	<ul style="list-style-type: none"> Partial discharge activity involving the transformer core, winding, bushings and connections 	On-line
Acoustic measurement	<ul style="list-style-type: none"> Partial discharge activity involving the transformer core, winding or tap changer 	On-line
Exciting current	<ul style="list-style-type: none"> Shorted core laminations Poor core joints Short circuited or open circuited windings Poor electrical connections Tap changer problems Core and winding movement 	Off-line
Frequency response analysis	<ul style="list-style-type: none"> Radial buckling or axial deformation of windings Core and winding movement Clamping failure Shorted turns 	Off-line
Leakage inductance measurement	<ul style="list-style-type: none"> Core and winding movement Winding distortion or damage 	Off-line
Capacitance/power factor (winding)	<ul style="list-style-type: none"> Moisture, carbon and other internal contamination of the winding insulation 	Off-line
Winding resistance	<ul style="list-style-type: none"> Shorted turns Poor connections Open circuited windings Poor tap changer connections 	Off-line
Core insulation	<ul style="list-style-type: none"> Unintentional core grounds Deteriorated core ground insulation 	Off-line
Turns ratio	<ul style="list-style-type: none"> Shorted turns Open circuited windings Tap changer problems 	Off-line
Capacitance/power factor (bushing)	<ul style="list-style-type: none"> Moisture, carbon and other internal contamination of bushing Shorted condenser layers in capacitive type bushings Faulty bushing test taps 	Off-line
Winding resistance	<ul style="list-style-type: none"> Shorted turns Open circuited turns Loose or high resistance connections in the tap changer Loose or high resistance connections on the bushings 	Off-line
Insulation resistance	<ul style="list-style-type: none"> Core grounds Contaminated or deteriorated winding insulation. Shorted turns Open circuited turns 	Off-line

2.1.3 Transportation of Transformers

2.1.3.1 Install multiple impact recorders on transformers whenever transformers need to be moved.

2.1.3.2 Perform a frequency response analysis measurement of the transformer before it is moved. Repeat this measurement after the transformer has arrived at its destination to determine if any winding or core movement occurred.

Note that FRA measurements will be affected by whether there is fluid in the transformer and whether bushings are installed. Perform the measurements with the transformer in the same state so the results can be compared.

2.1.4 Condition Monitoring

2.1.4.1 Provide on-line condition monitoring for the following types of transformers:

A. High-value or critical transformers where loss of the unit will have a significant business impact

- B. Transformers with known problems such as a history of gassing, high moisture levels, winding movement, and design defects
- C. Transformers that are operated under onerous conditions such as in a high surge environment, constant or frequent overload operation, and high harmonic distortion
- D. Critical arc furnace transformers and rectifier transformers
- E. Transformers where the maintenance and testing intervals have to be significantly extended due to reasons such as the inability to remove the transformer from service, location in remote areas, and lack of resources
- F. Transformers that are on a condition-based maintenance program

2.1.4.2 Provide on-line condition monitoring systems that will monitor the following parameters (several separate pieces of equipment may be needed to achieve the required level of condition monitoring):

- Moisture-in-oil (with appropriate algorithms to translate this to a moisture-in-paper measurement)
- Temperature
- Dissolved gases
- Bushing power factor
- Partial discharge activity
- Tap changer motor current

2.1.4.2.1 In addition to online condition monitoring systems, conduct routine on-line condition monitoring using the following equipment:

- Thermography cameras
- Acoustic sensors
- Corona cameras

The online condition monitoring should be performed on an annual basis and adjusted based on Appendix D.

2.1.4.3 Where transformers are frequently operated in overload condition (for contingency or emergency purposes) use transformer monitoring and control systems that give real-time thermal ratings of the transformer by measuring load, tap position, winding temperature, oil temperature, ambient temperature and moisture. These systems will adjust transformer cooling in an intelligent manner to optimize the life of the transformer and can also warn of dangerous conditions (such as when there is a high level of moisture in the paper insulation) and will prevent the transformer from being overloaded in this condition.

2.1.4.4 Select on-line condition monitoring systems with the following features and capabilities:

- The ability to either transmit data continuously to a manned location (SCADA), or the ability to allow remote retrieval of the data.
- The ability to generate alarms when unusual conditions are detected.
- The ability to analyze monitored parameters and generate a summary of the condition of the transformer.
- The ability for the user to set caution and alarm levels.
- The ability to store and trend monitored parameters.
- Field calibration and self diagnostic capabilities.
- A measurement accuracy of $\pm 5\%$ for DGA gases and moisture-in-oil.
- A sampling rate of at least once every 4 hours, with an hourly sampling rate being the preferred option.
- Robustness and immunity to electromagnetic fields.
- Security to prevent unauthorized changes to alarm conditions and limits.

2.1.5 Operation

2.1.5.1 Install, operate and maintain transformers in accordance with the manufacturers' recommendations.

2.1.5.2 Follow the manufacturer's instructions for filling new transformers with oil. Check all oil to ensure it meets the specifications for new oil. In particular, make sure the moisture content, PCB content and corrosive sulfur content are within limits.

2.1.5.3 Immediately after commissioning, and periodically for several days after commissioning, inspect the transformer thoroughly for indications of overheating, oil leaks, abnormal vibration, abnormal noise, or malfunction. Proper operation and calibration of each monitoring and protective device should be verified. Perform benchmark tests as recommended in Section 2.1.2.1.

As a minimum, perform dissolved-gas-in-oil analysis within 18 to 24 hours after energization, one month later, and six months later to determine if the transformer has any infant mortality problems.

2.1.5.4 Do not overload the transformer. If short-term overloading is required for emergency purposes, perform studies to determine the economic, loss of life, and bubbling risks associated with overloading. Consider the use of a dynamic transformer monitoring and control system as described in Section 2.1.4.3 if frequent overloading of the transformer is expected.

2.1.5.5 Do not perform on-line insulating fluid processing on a routine basis or without a proper evaluation of the need and consequences of processing the insulating fluid.

2.1.5.6 Take the following precautions when insulating fluid has to be processed or replaced:

- A. Perform DGA and furan analysis before the insulating fluid is processed or replaced to preserve data about the transformer's condition. Repeat DGA analysis immediately after the fluid has been processed or replaced. Perform both DGA and furan analysis about six months after the fluid has been processed or replaced.
- B. Take proper precautions when handling insulating fluid with high levels of combustible gas as this may present an explosion risk.
- C. Check replacement mineral oil for corrosive sulfur and PCB contamination.
- D. Ensure the equipment used to process the insulating fluid has been thoroughly cleaned to prevent PCB cross-contamination.
- E. Follow the manufacturer's instructions regarding insulating fluid processing or replacement to prevent moisture contamination of the transformer's solid insulation. For example, if the transformer has to be opened, most manufacturers limit this time to no more than 2 hours and recommend that dry air be circulated into the transformer at a specified flow rate.
- F. Replace tank gaskets when insulating fluid is replaced.

2.1.5.7 For transformers with a bladder in the conservator tank, check the bladder for leaks once every two years. This is done by swabbing the inside of the bladder to check for oil, and also checking the oil screen and DGA results for indications of bladder leaks. Replace leaking bladders as soon as possible.

The bladder in a conservator tank generally has a 10-year life. A leaking bladder will allow oxygen and moisture to enter the transformer, which accelerates its aging process. Proper maintenance of the bladder is a critical part of a transformer life management program.

2.2 Fire Protection for Indoor Transformers

2.2.1 Construction and Location

2.2.1.1 If transformers cannot be located outdoors in accordance with Section 2.3, provide a detached dedicated building or room with location and construction safeguards as described in Figure 2a and Table 4.

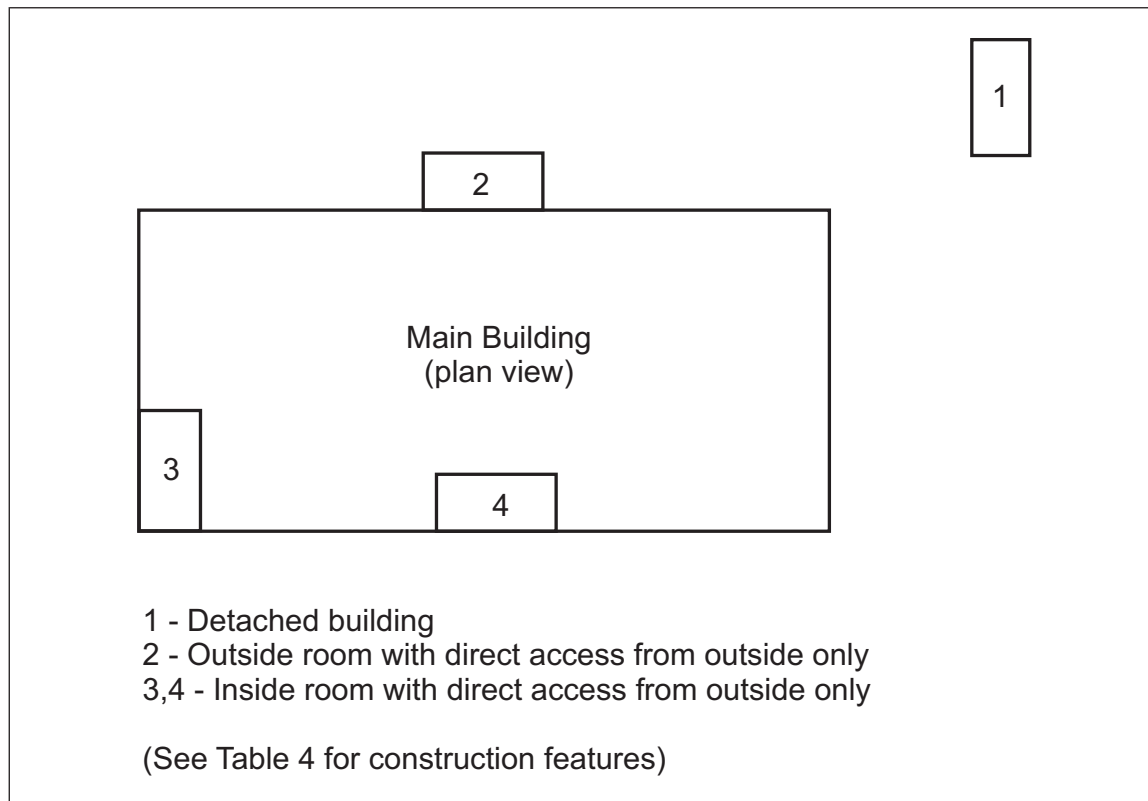


Fig. 2a. Locations for transformer buildings and rooms

Table 4. Recommended Construction for Transformer Buildings and Rooms

Transformer Type	Fluid Type	Fluid Volume in Largest Transformer	Room or Building Fire Rating	Fire Protection for Transformer Liquids
Dry or gas insulated ^a	Not applicable		Noncombustible	None ^b
FM Approved or equivalent ^c	FM Approved liquids	Any ^d	Noncombustible	None ^b
Non-Approved Transformer	FM Approved liquids	Any ^d	One-hour fire-rated	None ^b
			Noncombustible	Per Section 2.2.3 ^e
	Non- Approved liquids	Less than 100 gal (380 L) ^d	One-hour fire-rated	None ^b
		More than 100 gal (380 L) ^d	Three-hour fire-rated with subdivisions if multiple transformers ^f	None ^b
			Three-hour fire-rated with multiple transformers and no subdivision	Per Section 2.2.3 ^e
			One-hour fire-rated with single transformer	

^a With no oil-filled bushings, oil-filled tap changers or other oil-filled accessories that could increase the fire hazard.

^b See also Section 2.2.3.4 for protection of combustibles other than transformer liquids.

^c Section 3.3 describes FM Approved and equivalent transformers.

^d Provide liquid spill containment in accordance with Section 2.2.1.5

^e Automatic sprinklers, foam-water sprinklers or water mist. Also provide emergency drainage for sprinkler discharge per Section 2.2.1.6

^f Subdivide room or building with three-hour fire-rated construction for each transformer if multiple transformers are present.

2.2.1.2 Arrange transformer rooms for direct access only from outdoors.

2.2.1.3 Provide construction for transformer rooms and detached buildings as follows:

- A. Dry, gas-insulated and FM Approved or equivalent transformers: non-combustible construction.
 - B. Non-Approved transformers with FM Approved transformer fluids:
 - 1. One-hour fire-rated construction if no fire protection is provided, or
 - 2. Noncombustible construction if fire protection (automatic sprinklers, FM Approved foam-water sprinklers, or FM Approved water mist) is also provided per Section 2.2.3.
 - C. Transformers with no more than 100 gal (380 L) of Non-Approved fluids: one-hour fire-rated construction.
 - D. Transformers with greater than 100 gal (380 L) of non-Approved fluids: three-hour fire-rated construction. If multiple transformers are present, also provide one of the following:
 - 1. Three-hour fire-rated subdivisions for each transformer, or
 - 2. Automatic sprinklers, FM Approved foam-water or FM Approved water mist protection per Section 2.2.3.
- 2.2.1.4 Where three-hour fire-rated construction is recommended for transformer rooms with non-Approved fluids in Section 2.2.1.3 (D), also protect exposed structural steel with a 3-hour fire-proofing rated for hydrocarbon fires.
- 2.2.1.5 Provide liquid spill containment in transformer rooms containing FM Approved and non-Approved transformer liquids as follows:
- A. Use blank liquid-tight walls sealed to the floor.
 - B. If interior openings must be made in these walls, locate above the level of minimum curb height specified in item C below.
 - C. Design curb height or pit depth for largest design spill (based on contents of one transformer) plus 2 in. (50 mm), but no less than 4 in. (100 mm) total height.
 - D. Provide individual containment for the contents of each transformer containing non-Approved liquid to prevent spills from flowing to other transformers or important equipment in the room.
- 2.2.1.6 Where sprinklers are provided for transformer fluid protection in accordance with Sections 2.2.1.3 (B) and (D), also provide an emergency drainage system to direct the transformer fluid and sprinkler discharge out of the building to an impoundment area. Design the emergency drainage and containment in accordance with DS 7-83, *Drainage for Ignitable Liquids*.
- 2.2.1.7 Where foam-water sprinklers are provided for transformer liquid protection in accordance with Sections 2.2.1.3 (B) and (D), design containment pits or curbing to hold the transformer liquid contents and at least 30 minutes discharge from the foam-water sprinklers.
- 2.2.1.8 Locate transformers a minimum of 3 ft (0.9 m) from walls, or more as needed for maintenance access and ventilation requirements.
- 2.2.1.9 If transformer rooms contain liquid-filled transformers, arrange openings to be normally closed, with FM Approved fire doors and/or fire shutters having the same fire rating as the rest of the room.
- 2.2.1.10 Where conductors penetrate fire-rated construction in transformer rooms and detached buildings, use FM Approved fire stops with fire resistance equivalent to 1 hour or to the rating of the construction, whichever is greater.

2.2.2 Occupancy

- 2.2.2.1 Use dry-type or gas-insulated transformers if suitable for the application.
- 2.2.2.2 Design new equipment to limit the loading of combustible materials, including transformer fluids, plastics, and insulation on grouped electrical cables.
- 2.2.2.3 Where a liquid-filled transformer is to be located indoors, provide one of the following if an appropriate transformer or fluid is available for the application:
 - A. An FM Approved transformer or equivalent. (See Section 3.3 for a description of FM Approved and equivalent transformers).
 - B. An FM Approved transformer fluid.

2.2.2.4 Visually inspect transformer rooms on a daily recorded basis:

- A. Check that equipment is operating in a clean, cool, dry, and tight condition with no abnormal noises, smells, vibration, or heat.
- B. Ensure housekeeping is satisfactory, with no dust, debris, temporary storage, or exposed combustible materials.
- C. If storage is necessary, use closed metal cabinets.
- D. Ensure emergency access routes are clear and the exterior is free of vegetation.
- E. Establish a reporting and tracking procedure to ensure any deficiencies identified by the visual inspections are corrected in an expedited fashion.

2.2.2.5 Where the surrounding occupancy could be exposed to nonthermal damage due to an indoor transformer fire, provide one of the following:

- A. Locate the transformers in rooms with suitable construction so the surrounding occupancy will not be exposed or
- B. Equip the transformer room with a mechanical ventilation system designed to vent smoke to outdoors. Provide power for the ventilation system from an emergency source that will not be deenergized as part of the pre-fire plan.

2.2.2.6 Install FM Approved ionization-type smoke detection in transformer rooms, with alarms to sound at a constantly attended location regardless of any automatic sprinkler protection or heat detection that may also be provided. The presence or absence of smoke detectors does not change the need for sprinklers. Arrange smoke detection spacing in accordance with Data Sheet 5-48, *Automatic Fire Detection*.

2.2.2.7 In locations where dusty or corrosive atmospheres are or may be present, locate air-cooled transformers in a pressurized room. Also filter the cooling air and remove corrosive contaminants. Also filter the cooling air and remove corrosive contaminants.

2.2.3 Protection

Provide automatic fire protection for transformer buildings and rooms in accordance with the following recommendations.

2.2.3.1 Where sprinkler protection is recommended for transformer fluids per Table 4, provide the following design:

- A. FM Approved transformer fluids: provide sprinkler protection over the entire room with a density of 0.20 gpm/ft² (8 mm/min).
- B. Transformers using non-Approved fluids: provide sprinkler protection in accordance with Data Sheet 7-32 (Table 3).
- C. Where sprinkler protection is provided, design containment and drainage in accordance with DS 7-32, *Ignitable Liquid Operations*.

2.2.3.2 An FM Approved foam-water sprinkler system with the following features is acceptable as an alternative to sprinkler protection for transformer liquids where recommended in Table 4.

- A. Designed per DS 7-32 and DS 4-12, *Foam-water Sprinkler Systems*.
- B. Containment for transformer liquid contents plus at least 30 minutes of discharge from the foam-water sprinklers.

2.2.3.3 An FM Approved automatic water mist protection system with the following features is an acceptable alternative to automatic sprinkler protection for transformer liquids, where recommended in Section 2.2.1.3 (B) and (D):

- A. The system is FM Approved for machinery spaces. Ensure the size of door openings into the room do not exceed the limitations of the Approval listing.
- B. The area of openings in the walls does not exceed the FM Approval listing.
- C. The system is designed and installed in accordance with Data Sheet 4-2, *Water Mist Systems*.

2.2.3.4 Provide sprinkler protection for transformer rooms and buildings where combustible grouped electrical cables are present, per DS 5-31, *Cables and Bus Bars*.

2.2.4 Human Factor

2.2.4.1 Develop a pre-fire plan for transformer fire and electrical emergency response:

- A. Prepare a documented procedure to promptly isolate the transformer equipment in order to expedite firefighting activities.
- B. Train and authorize electrical personnel on each shift who will respond promptly to isolate the transformer for access by fire responders.

2.2.4.2 Conduct transformer fire drills and review and update the pre-fire plan at least annually.

2.3 Fire Protection for Outdoor Transformers

Apply the following recommendations to protect important buildings and equipment from exposure to fire involving outdoor transformers.

2.3.1 Location and Construction

The separation distances and construction features recommended in this section are intended to be implemented together with spill containment. The recommended distances for liquid-filled transformers may not protect surrounding property from damage due to overpressure and rupture of transformer casings or bushings.

2.3.1.1 Exposure Protection for Main Buildings

2.3.1.1.1 Provide any one of the following five alternatives to protect exterior walls of main buildings against exposure to outdoor transformer fires:

- A. Providing minimum separation distances according to the construction type and transformer fluid in accordance with Figure 2b and Table 5.
- B. Provide a 2-hour fire barrier of concrete block or reinforced concrete with separation distance and horizontal and vertical dimensions (X, Y, and Z respectively) as shown in Figure 2c and Table 6.
- C. Provide at least 5 ft (1.5 m) separation with a 3-hour fire rated barrier with the same horizontal and vertical extent as dimensions Y and Z in Table 6.
- D. Provide at least 5 ft (1.5 m) separation from fire-rated or noncombustible construction, plus water spray protection on the transformer in accordance with Section 2.3.2.
- E. Provide at least 5 ft (1.5m) separation from the inside edge of containment barrier and install water spray protection on the exposed building wall, over the vertical and horizontal extent (coverage area) as dimensions Y and Z in Table 6. Design water spray in accordance with Section 2.3.2.

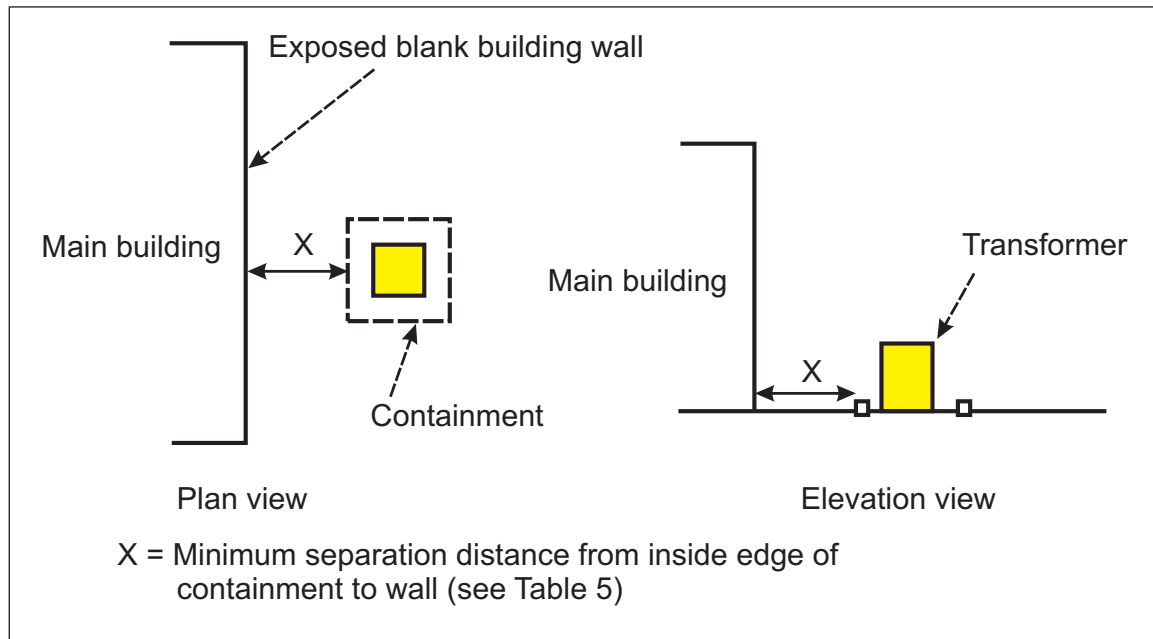


Fig. 2b. Minimum horizontal separation distance between outdoor liquid-insulated transformers and exposed walls of main buildings

Table 5. Separation for Exposure Protection of Main Building Walls (also refer to Figure 2b)

Fluid or Transformer Type	Fluid Volume, gal (m ³)	Minimum Horizontal Distance from Containment to Exposed Building Wall (Dimension X in Figure 2b)		
		2-hour fire-rated wall, ft (m)	Non-combustible wall, ¹ ft (m)	Combustible Wall, ¹ ft (m)
FM Approved transformer or equivalent	per Approval listing	3 (0.9)		
FM Approved Liquid in non-Approved transformer	≤10,000 (38)	5 (1.5)		25 (7.6)
	>10,000 (38)	15 (4.6)		50 (15.2)
Non-Approved transformer liquid	<500 (1.9)	5 (1.5)	15 (4.6)	25 (7.6)
	≤5,000 (1.9-19)	15 (4.6)	25 (7.6)	50 (15.2)
	>5,000 (19)	25 (7.6)	50 (15.2)	100 (30.5)

¹ For definitions of combustible and noncombustible construction materials, see Appendix A of DS 1-1, *Firesafe Building Construction and Materials*.

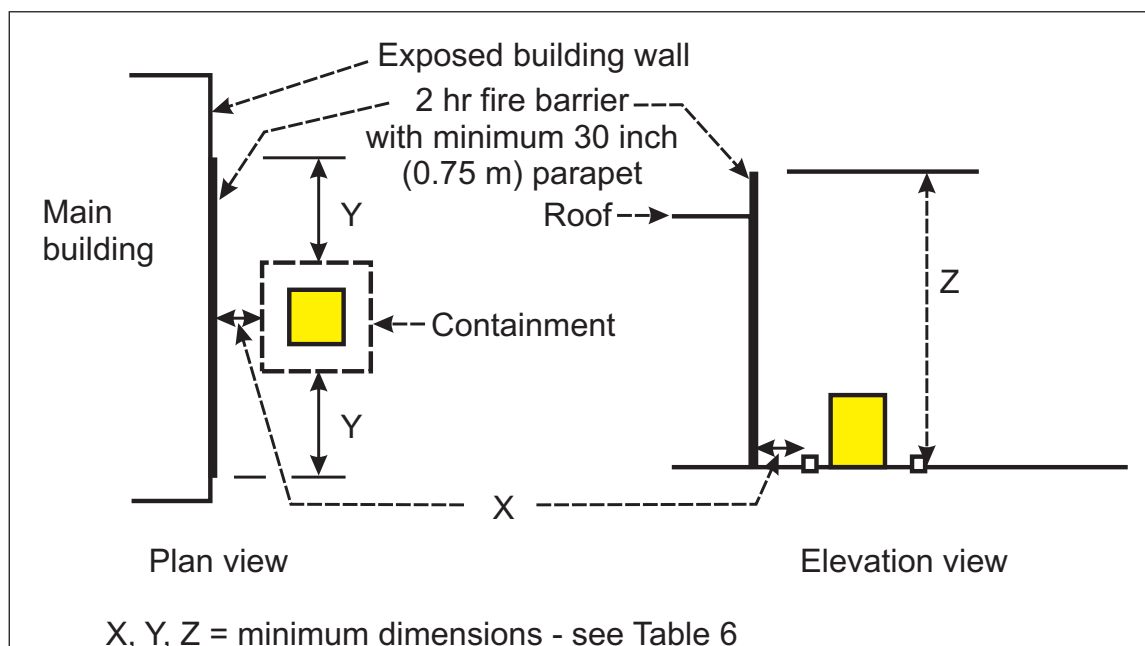


Fig. 2c. Use of 2-hour fire barriers and separation distances for protection of exposed main building walls

Table 6. Separation and Extent of 2-hour Fire Barriers for Protection of Main Building Walls (for dimensions refer to Figure 2c)

Fluid Type	Fluid Volume gal (m ³)	Separation and Extent of 2-hour Fire Barrier		
		Dimension ^{1,2} (See Fig. 2c)	Noncombustible Wall ³ ft (m)	Combustible Wall ³ ft (m)
FM Approved transformer fluid	≤10000 (38)	X	5 (1.5)	(1.5)
		Y	5 (1.5)	25 (7.6)
		Z	25 (7.6)	25 (7.6)
	>10000 (38)	x	15 (4.6)	15 (4.6)
		Y	15 (4.6)	50 (15.2)
		Z	50 (15.2)	50 (15.2)
Non-Approved transformer fluid	<500(1.9)	X	5 (1.5)	5 (1.5)
		Y	15 (4.6)	25 (7.6)
		Z	25 (7.6)	25 (7.6)
	≤5000(19)	X	15 (4.6)	15 (4.6)
		Y	25 (7.6)	50 (15.2)
		Z	50 (15.2)	50 (15.2)
	>5000 (19)	X	25 (7.6)	25 (7.6)
		Y	50 (15.2)	100 (30.5)
		Z	100 (30.5)	100 (30.5)

¹The X distances refer to minimum separation between the closest inside edge of the spill containment barrier area and the 2 hour fire barrier. These are the same as Table 5 for 2-hour fire-rated walls. Dimension Y is the horizontal extent of the barrier starting from the respective edge of containment.

² Barrier vertical extent is dimension Z in the Table or the building height plus 30 in. (0.75 m) parapet, whichever is less.

³ For definitions of combustible and noncombustible construction materials, see Appendix A of DS 1-1, *Firesafe Building Construction and Materials*.

2.3.1.1.2 Where exposure protection is provided per alternatives C, D or E of 2.3.1.1.1, determine the extent of roof area exposed to excessive radiant heating, if any, using Figure 2d and Table 7.

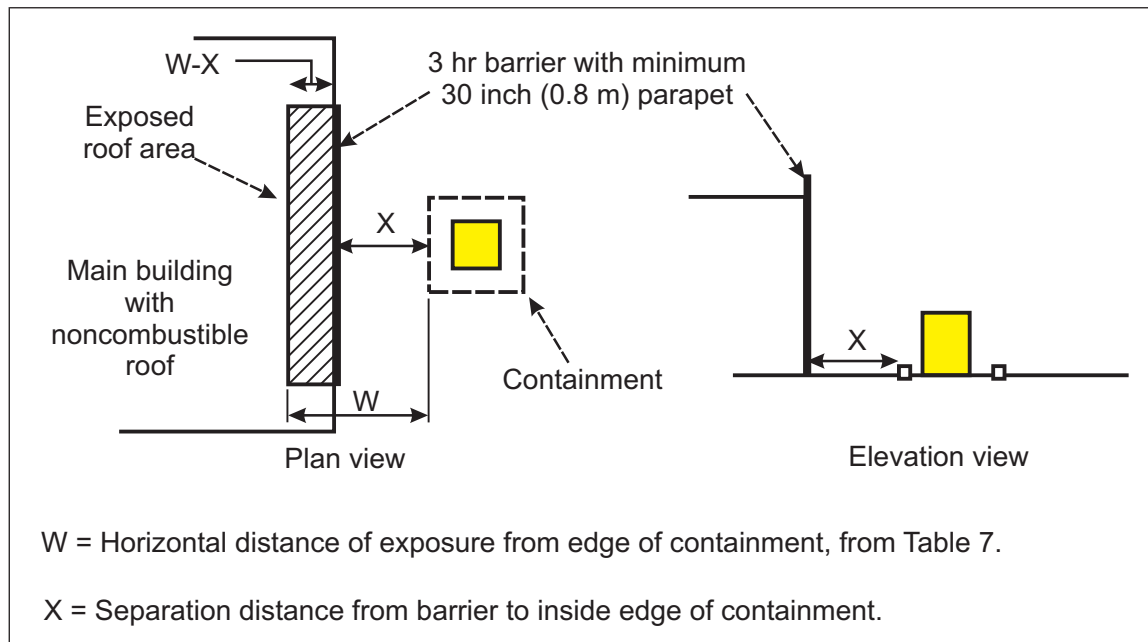


Fig. 2d. Determination of exposed roof area

Table 7. Transformer Fire Exposure to Noncombustible Building Roof Where Separation from Wall is Based on a 3-hour Fire Barrier or Water Spray Protection

Liquid Type	Maximum Liquid Volume gal (m ³)	Building Height, ft (m)	W (see Fig. 2d) ft (m)
Non-Approved transformer fluid	<1000 (3.8)	Any	Not exposed
	Any	≥50 (15)	Not exposed
	1000-5000 (3.8-19)	≥25 (7.5)	Not exposed
		<25 (7.5)	15 (4.5)
	>5000 (19)	<50 (15)	25 (7.5)

2.3.1.1.3 Provide a Class A rating for external fire resistance over at least the section of the roof, if any, that is determined to be exposed per 2.3.1.1.2 and Table 7. (See DS 1-22, *Maximum Foreseeable Loss*, for description of Class A roof installations).

2.3.1.2 Exposure Protection from Roof-Mounted Transformers

Avoid locating transformers on roofs of main buildings. Where rooftop location is unavoidable, provide all of the following safeguards.

A. Use one of the following types of transformers:

1. Dry-type transformer
2. FM Approved transformer or equivalent
3. Transformer filled with FM Approved transformer fluid

B. Provide spill containment for all liquid-insulated transformers in accordance with Section 2.3.1.4.

C. If roof-top transformers use non-Approved fluids, do the following:

1. Locate the transformer away from walls of adjoining buildings with higher roofs in accordance with Section 2.3.1.1, and
2. Provide a Class A roof covering for at least the horizontal distance from the transformer specified for noncombustible construction in Table 5. (See DS 1-22, *Maximum Foreseeable Loss*, for description of Class A roof installations.)

2.3.1.3 Exposure Protection for Outdoor Transformers and Other Equipment

To protect transformers and other important equipment against exposure fire from adjacent transformers, provide separation, a fire barrier, or a water spray system in accordance with any one of the following three alternatives:

2.3.1.3.1 Provide separation distances for exposed transformers and other critical equipment in accordance with Table 8. Distances in Table 8 are referred to the closest edge of containment.

Table 8. Minimum Separation Distances Between Adjacent Transformers

Liquid Type	FM Approved Transformer or Equivalent?	Liquid Volume gal(m ³)	Distance ft(m)
FM Approved Transformer Fluid	Yes	N/A	3 (0.9)
	No	≤10000 (38)	5 (1.5)
		>10000 (38)	25 (7.6)
Non-Approved Transformer Fluid	N/A	<500 (1.9)	5 (1.5)
		500 - ≤5000 (19)	25 (7.6)
		>5000 (19)	50 (15.2)

2.3.1.3.2 Where the separation distances in Table 8 cannot be met, provide 2-hour fire-rated barriers between transformers as shown in Figure 2e and as follows:

- A. Extend the barriers 1 ft (0.3 m) vertically and 2 ft (0.6 m) horizontally beyond transformer components that could be pressurized as the result of an electrical fault, including bushings, pressure-relief vents, radiators, and tap changer enclosures.
- B. Use concrete block or reinforced concrete construction adequate for two-hour fire-resistance for the fire barriers.
- C. Fire barriers constructed of materials other than concrete may be used if:
 1. All components are capable of withstanding a two-hour hydrocarbon fire exposure test from either side with no flame penetration to the unexposed side.
 2. Barriers are capable of withstanding not less than 25% of full design wind loads at maximum fired-exposed material temperatures, using design wind speeds (3-second gust) per DS 1-28, *Design Wind Loads*, or similar, acting concurrently with the worst-case fire exposure.

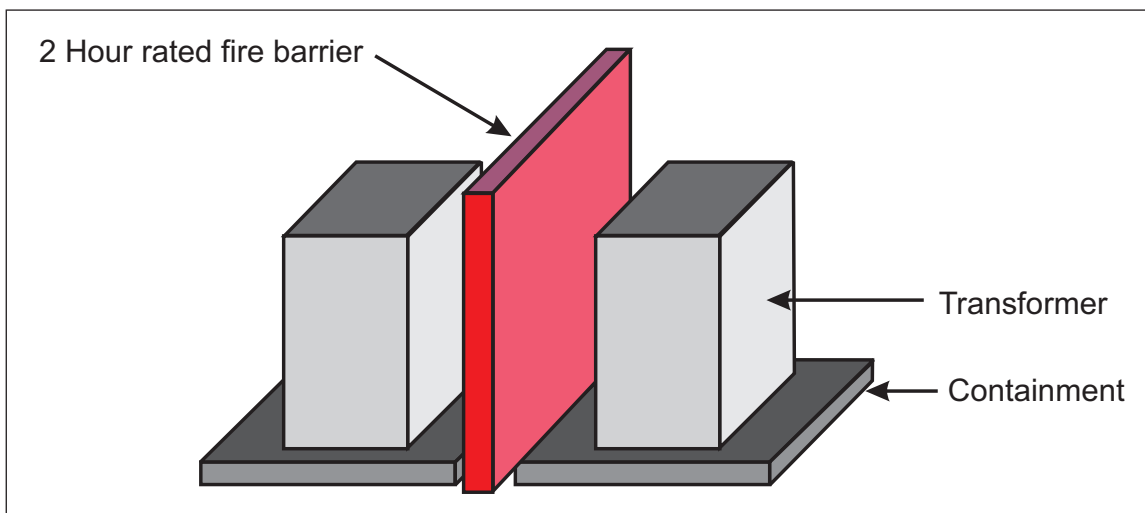


Fig. 2e. Fire barriers for multiple outdoor transformers

2.3.1.3.3 For installations where the separation distances between transformers in Table 8 are not met and barriers are not provided, install water spray protection on each transformer in accordance with Section 2.3.2.

2.3.1.4 Spill Containment and Emergency Drainage

Spill containment requirements for environmental protection and related regulations are outside the scope of this data sheet.

2.3.1.4.1 Provide outdoor liquid-filled transformers with spill containment when accidental release of the transformer fluid could expose a main building or adjacent equipment or storage.

2.3.1.4.2 Design the spill containment system in accordance with Chapter 7 of IEEE STD 980-1994 (*Guide for Containment and Control of Oil Spills in Substations*, 1995) or equivalent standard.

2.3.1.4.3 Where water spray protection is provided for a transformer, install additional containment or direct the discharged water to an impoundment with a capacity of at least a 60-minute discharge of fire hoses plus the design flow of the water spray system. Size the drainage and containment assuming adjacent water spray systems on both sides of an exposing transformer will operate simultaneously with the original activating system. Design drainage in accordance with DS 7-83, *Drainage Systems for Flammable Liquids*.

2.3.1.4.4 Provide a system for removal of rainwater from the containment area.

2.3.1.4.5 Extend the containment perimeter at least 5 ft (1.5 m) beyond fluid-containing components, including any external coolers, for transformers with up to 1,000 gal (3.8 m³); and 8 ft (2.4 m) for transformers with more than 1,000 gal (3.8 m³).

2.3.1.4.6 Provide containment systems for roof-mounted liquid-filled transformers as follows:

- A. For transformers with 500 gal (1.9 m³) or less of insulating liquid, the containment system may be a welded steel pan or curbed and sealed concrete pad with capacity large enough to handle the liquid in the largest transformer.
- B. For mineral oil-insulated transformers with more than 500 gal (1.9 m³), provide a rock-filled containment design with drainage to a suitable impoundment area.
- C. Open containment is acceptable for FM Approved transformer liquids.

2.3.2 Active Protection for Outdoor Transformers

2.3.2.1 If automatic water spray exposure sprinkler protection is provided for outdoor transformers (i.e., when the space separation distances in 2.3.1 above cannot be met and fire barriers are not provided), design as follows:

- A. Provide a discharge density of 0.30 gal/min ft² (12 mm/min) over transformer surfaces, except areas under the transformer, with equipment designed in accordance with Data Sheet 4-1N, *Water Spray Fixed Systems* and DS 2-0, *Installation of Sprinkler Systems*.
- B. Also provide water spray with a density of 0.30 gal/min ft² (12 mm/min) for the diked area around the transformer.
- C. Locate components of the water spray system, such as piping, spray nozzles, etc., a minimum of 18 in. (45 cm) from the transformer.
- D. Do not pass piping over the top of the transformer or tank relief vents.
- E. Orient water spray nozzles to avoid water discharge onto bushings.
- F. For multiple transformer installations, design the water spray system based on simultaneous operation of the water spray systems for the adjacent transformers and diked areas.

2.3.2.2 If automatic water spray is provided on the building wall for exposure protection (per Section 2.3.1.1.1[E]), design protection as follows:

- A. Provide a density of 0.20 gpm/ft² (8 mm/min) over the coverage area.
- B. Determine coverage (demand) area per Section 2.3.1.1.1(E).
- C. Design for direct impingement application, or provide rundown application with maximum distance between levels of 10 ft (3 m).
- D. Use FM Approved water spray nozzles and other equipment.

E. Spacing between adjacent nozzles on each level per the manufacturer's design tables.

F. Axial distance between nozzles and wall per the manufacturer's design tables.

G. Water spray equipment designed in accordance with Data Sheet 4-1N, *Water Spray Fixed Systems* and installed per DS 2-0, *Installation of Sprinkler Systems*.

2.3.2.3 Where transformers present an exposure to buildings or equipment, provide a hose stream water supply using nozzles FM Approved for application on oil-filled electrical equipment in accordance with the Approval listing. Design for the following duration and flow rates:

A. Adequate for 1 hour hose stream demand of 250 gpm (950 L/min) for transformers holding FM Approved liquids or up to 1000 gal (3.8 m³) of mineral oil.

B. Adequate for 2 hour hose stream demand of 500 gpm (1900 L/min) hose stream for greater than 1000 gal (3.8 m³) of mineral oil in an individual transformer.

2.3.3 Occupancy

Adhere to the recommendations in Section 2.2.2.

2.3.4 Human Factor

Adhere to the recommendations in Section 2.2.4.

2.4 Fire Protection for Transformer Production Test Areas

2.4.1 Provide containment and emergency drainage for transformer production test areas sized for the type of fluid and largest transformer fluid volumes to be tested, in accordance with recommendations for indoor transformer rooms (Sections 2.2.1.5 - 7).

2.4.2 Where non-Approved transformer fluids are present in the tested transformers, provide sprinkler or foam-water protection at the roof level or locally in accordance with Figures 2f and 2g, using 286°F (141°C) temperature ratings with K11.2 or larger orifice and with design densities per Table 9.

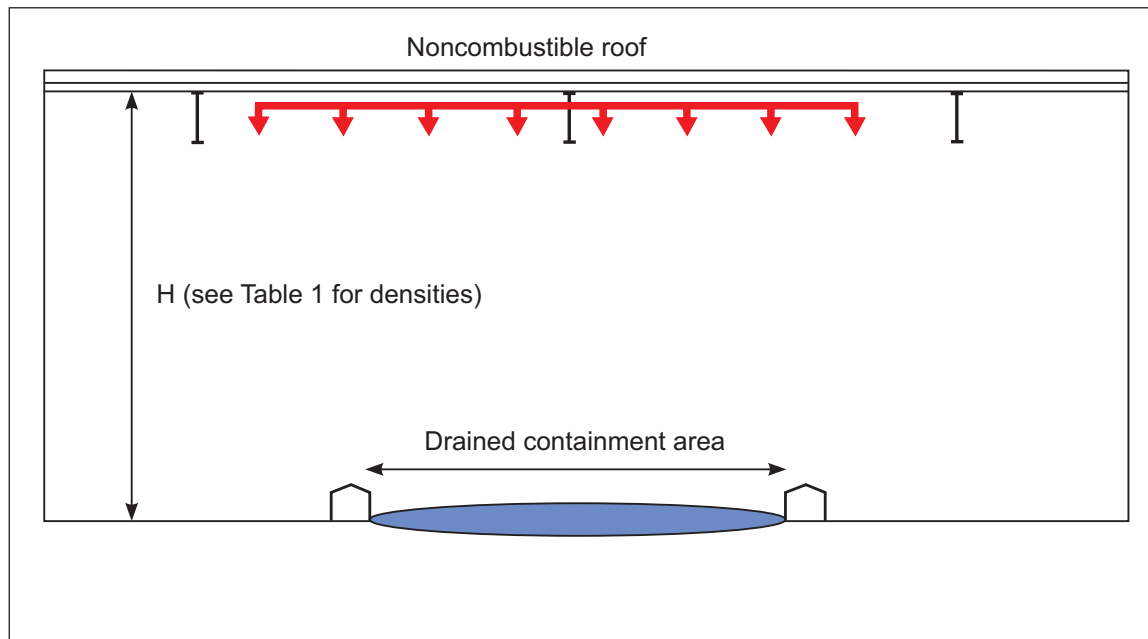


Fig. 2f. Roof level sprinkler option

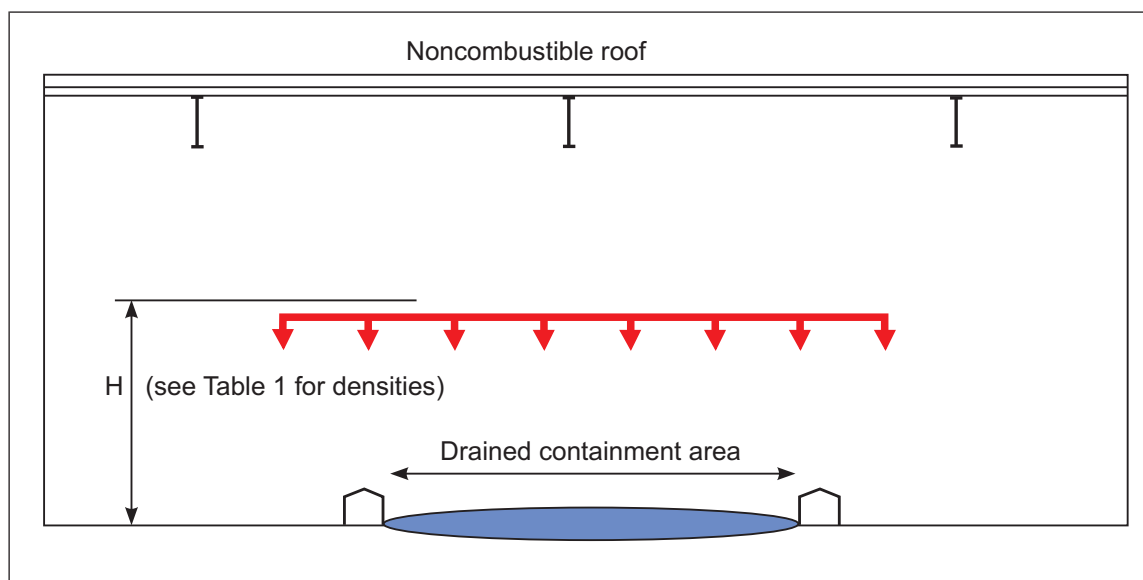


Fig. 2g. Local sprinkler option

Table 9. Sprinkler Densities for Roof Level and Local Protection Options for Transformer Production Test Areas (see Figures 2f and 2g)

Height (H) of Sprinklers Above Pool, ft (m)	Water Density ¹ gpm/ft ² (mm/min)
H ≤ 15 (4.6)	0.30 (12)
15 (4.6) < H ≤ 30 (9.0)	0.40 (16)
30 (9.0) < H ≤ 45 (13.8)	0.80 (32)
45 (13.8) < H ≤ 60 (18.5)	1.60 (64)

¹ Design foam-water systems in accordance with DS 7-32 and DS 4-12.

2.4.3 Design roof level sprinklers for a demand area of 5,000 ft² (465 m²).

2.4.4 Design local sprinklers for a demand area of 5000 ft² (465 m²) or the limits of the containment, whichever is less.

2.4.5 Provide a water supply adequate for at least 2 hours, with hose stream demands as follows:

- A. Adequate for 1 hour hose stream demand of 250 gpm (950 L/min) for transformers holding FM Approved liquids or up to 1000 gal (3.8 m³) of mineral oil.
- B. Adequate for 2 hour hose stream demand of 500 gpm (1900 L/min) hose stream for greater than 1000 gallons (3.8 m³) of mineral oil in an individual transformer.
- C. A standpipe with 1.5 in. (40 mm) hose connections such that all areas can be reached with at least one hose stream.

2.5 Transformers Insulated with Liquids Containing Polychlorinated Biphenyls (PCBs)

2.5.1 Replace PCB-filled and PCB-contaminated transformers containing more than 50 ppm of PCBs. Alternatively, flush and fill the transformers with PCB-free fluid. Use a competent and certified company to perform this work.

2.5.2 Every three years, test transformers that have been flushed and refilled with a replacement liquid to verify that PCB concentrations are below 50 ppm.

2.5.3 Adhere to the following recommendations pending replacement of PCB-filled and PCB-contaminated transformers.

2.5.3.1 Develop a written emergency response plan to handle a PCB spill. Include the following information:

- Availability of an emergency replacement power supply
- Telephone numbers for critical facility staff, emergency response personnel, PCB handling and disposal companies, and, for clients, the local FM Global office
- Telephone numbers of the appropriate authorities responsible for handling PCB contamination (in the United States this includes the National Spill Response Center and the nearest EPA Office)

2.5.3.1.1 Perform monthly visual inspections of transformers, including stored transformers, to check for leaks. Repair any leaks immediately.

2.5.3.1.2 Seal floor drains exposed to a PCB spill, with the exception of drains leading to an oil-containment system for fire protection purposes.

2.5.3.2 Do the following for PCB-filled or PCB-contaminated transformers located in open facility areas:

A. Provide a curbed area around each transformer or bank of transformers sufficient to contain liquid from the largest transformer.

B. Isolate PCB-contaminated transformers from hazardous processes or areas of combustible storage by means of one of the following:

1. A one-hour fire-rated barrier
2. A minimum 15 ft (5 m) separation distance free of combustibles

2.5.3.3 Do the following for PCB-filled or PCB-contaminated transformers located within rooms:

- A. Seal wall penetrations.
- B. Exhaust air directly to the outside.
- C. Keep the room free of combustibles.

2.5.4 Take the following precautions when replacing PCB-filled or PCB-contaminated transformers:

- A. Develop a plan before moving PCB-filled equipment or containers to minimize exposure to plant areas and to prepare for a PCB spill.
- B. Provide spill containment equipment such as plastic sheeting, oil-absorbent materials, and empty drums.
- C. Drain PCB-contaminated liquid from transformers containing more than 100 gal (0.38 m³) before moving.
- D. Pack drums containing PCB within a larger outer drum with absorbent material between the two drums.
- E. Remove drums containing PCBs from main facility areas and dispose of as soon as possible.
- F. If PCB-filled drums are stored on-site, locate the drums in detached, low-value buildings. Take the following precautions for on-site PCB storage:
 1. Store the drums in rooms of noncombustible construction with noncombustible occupancy.
 2. Provide a minimum 6 in. (15.2 cm) high curb around the drum storage sufficient to contain either twice the volume of the largest container or 25% of the volume of the PCB containers in the room, whichever is larger.
 3. Ensure there are no drains within the curbed area.
 4. Use an impervious material for the floor and curbing.

2.5.5 Use a competent, certified company to perform all PCB-related work.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Transformer Testing

The test limits discussed in this section are only general guidelines and should not be relied on to make important decisions. Better interpretation of test results can be obtained by comparing results from past tests, comparing test results with name plate information or with results from a family of similar equipment and observing trends.

Improved interpretation can also be obtained by looking at results from other relevant tests; for example, oil screen results should be checked if power factor measurements on a transformer are unexpectedly high.

Complementary tests should be performed to confirm a diagnosis. For example, frequency response analysis can be used to confirm if large changes in the capacitance measurement of a transformer is indicative of winding movement.

Do not rely on any single test to make an important decision.

3.1.1 Thermography

Thermography is performed with a thermographic camera with the transformer on-line. It can be used very effectively to detect the following problems:

- Low fluid level in transformer or bushing
- Blocked oil flow in radiators
- Shut radiator banks
- Eddy current heating of the tank
- Overheating tap changer contacts
- Loose connections at bushing terminals
- Moisture contamination of surge arrestors

A general criteria for evaluating thermographic scans is provided in Table 10.

Table 10. General Criteria for Evaluating Thermographic Scans

<i>Temperature Above Reference</i>	<i>Action</i>
0°C to 10°C	Continue to monitor on regular basis.
10°C to 20°C	Repair at next convenient opportunity.
20°C to 40°C	Repair immediately.
>40°C	Failure imminent; shut down equipment for repair.

3.1.2 Fluid Screen Testing

Fluid screen testing is performed to determine if the transformer insulating fluid is suitable for continued service. The tests listed in Table 11 are typically included in a mineral oil screen test. Their parameters and acceptance limits are also included. These limits are based on IEEE C57.106 and refer to service-aged insulating oil. Different limits apply to new oil.

Table 11. Tests Typically Included in a Mineral Oil Screen Test

Test	Acceptance Limits Based on Voltage Class						
	Less than 69 kV		69kV to 230 kV		More than 230 kV		
Dielectric Strength ASTM D1816-97 1 mm gap 2 mm gap	23 kV min 40 kV min		28 kV min 47 kV min		30 kV min 50 kV min		
Power Factor ASTM D924-99e1 25C 100C	0.5% max 5.0% max		0.5% max 5.0% max		0.5% max 5.0% max		
Interfacial Tension ASTM D971-99a mN/m	25 min		30 min		32 min		
Neutralization Number ASTM D974-02 Mg KOH/g	0.2 max		0.15 max		0.10 max		
Water Content	50C	27 mg/kg	15% sat	12 mg/kg	8% sat	10 mg/kg	5%sat
	60C	35 mg/kg	15% sat	20 mg/kg	8% sat	12 mg/kg	5% sat
	70C	55 mg/kg	15% sat	30 mg/kg	8% sat	15 mg/kg	5% sat
Oxidation Inhibitor Content ASTM D2668-96 Type II oil	0.09% min		0.09% min		0.09% min		

The interfacial tension and neutralization number (acidity) are usually used as criteria for determining when the oil needs to be processed or replaced. At certain interfacial tension and acidity levels, the oil is prone to forming sludge that can coat the windings and lead to decreased cooling efficiency. In addition to increasing the oil-sludging tendency, acid is also a catalyst for cellulose aging and can accelerate the deterioration of the paper insulation.

The tests described in the following sections may also be performed on the oil to determine if incipient faults or deterioration are present in the transformer.

3.1.2.1 Furan Analysis

Furanic compounds are generated when paper insulation in the transformer degrades. These compounds are concentrated in the paper, but will partition to the oil. Sampling the oil and testing for furanic compounds provides a convenient and nonintrusive means of determining the extent of degradation of the transformer's paper insulation.

There are some important factors that need to be considered:

A. Type of paper insulation. Transformers with thermally up-rated (KTU) paper will generate much less furan compounds. For this reason, furan analysis on transformers with KTU paper relies on the measurement of the total furan concentration rather than just the 2FAL (2-furfural) concentration. Transformers used in North America are almost all manufactured with KTU paper, while transformers in the rest of the world use non-thermally up-rated (NTU) paper.

B. Filtering or replacement of transformer fluid. Filtering of transformer fluid or replacement of the fluid will remove the furan compounds from the oil. However the furan compounds will repartition back into the oil from the paper and will reach equilibrium within six months. FM Global recommends the fluid be tested for furans before filtering or replacement and then again six months later to ensure valuable data is not lost.

3.1.2.2 Particles in Oil

The measurement of metallic as well as non-metallic particles in oil allows problems such as oil pump wear, pump bearing deterioration, electrical arcing, and contamination to be detected.

3.1.3 Dissolved Gas Analysis

Dissolved gas analysis is performed to determine if there are incipient faults in the transformer windings, core, and tap changer. By analyzing the concentration, ratios, and generation rates of key dissolved gases in the transformer oil, the type of fault, as well as its severity, can be determined. The key gases that are included in a typical DGA report and the most likely faults that generate these gases are listed in Table 12 (see Table 13 for names of gases represented by the chemical formulas).

Table 12. Gases Included in a Typical DGA Report

Key Gas	Secondary Key Gas	Likely Cause
CO ₂ /CO	H ₄ , C ₂ H ₄	Conductor overheating involving cellulose
C ₂ H ₄	CH ₄ , H ₂ , and C ₂ H ₆	Oil overheating
H ₂	CH ₄ , C ₂ H ₆ , and C ₂ H ₄	Partial discharge
C ₂ H ₂	H ₂ , CH ₄ , and C ₂ H ₄	Arcing

Table 13. Gases Represented by Chemical Formulas

Chemical Formula	Name
H ₂	Hydrogen
CH ₄	Methane
C ₂ H ₂	Acetylene
C ₂ H ₄	Ethylene
C ₂ H ₆	Ethane
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
O ₂	Oxygen
N ₂	Nitrogen

Other key gases sometimes included in DGA results are propane and propylene.

There are many factors that will affect the DGA results for a transformer. The interpretation of DGA results is a highly specialized field requiring an understanding of both oil and paper chemistry as well as transformer design, construction, and operation.

Factors such as the oil preservation system (sealed, nitrogen blanketed, or free breathing) will influence the dissolved gas analysis results. Sealed transformers keep most of the fault gases within the oil. Free breathing transformers allow some fault gases to escape to atmosphere, while the dissolved gases in nitrogen blanketed transformers will partition between the oil and the gas blanket depending on the individual gas partial pressures. These transformers will all show different DGA patterns for the same fault.

Having the tap changer in a separate compartment or within the main tank will also have an effect on the DGA pattern. Tap changers generate gases at different rates depending on factors such as the diverter switch type, number of tap changer operations, and the tap changer design. Faults with the tap changer will also generate gases. These gases can mix with the oil in the main tank and may either mask faults in the main tank or lead to a wrong conclusion that there is a fault in the main tank.

It is important to ensure that oil sampling practices follow ASTM D3613 or equivalent standards. This is especially true if oil sampling is done by the transformer owner or a third party rather than a transformer oil testing laboratory. Improper oil sampling practices will render oil screen testing and dissolved gas analysis completely useless and, even worse, it can give misleading results that cause a bad decision to be made. For example, when taking oil samples for dissolved gas analysis, an oil sampling syringe should be used so dissolved gases are not lost to atmosphere. The syringe should also be protected from sunlight and extreme temperatures that can also cause the concentration of dissolved gases to change. Taking an oil sample for DGA from the same bottle that has been used to collect oil for oil screen tests will result in a DGA result that has higher concentrations of oxygen and nitrogen. The concentration of hydrogen and some of the other lighter gases will also be lower as these gases are lost when the oil sample is exposed to atmosphere.

A proper flushing of the oil valve on the transformer is needed to ensure a good oil sample is collected. The body of the oil valve frequently collects debris, rust, and free water, which will result in misleading oil screen test results.

3.1.4 Exciting Current

Purpose: To detect shorted core laminations, poor core joints, short circuited or open circuited windings, poor electrical connections, tap changer problems, core and winding movement.

The exciting current test is performed by applying the same AC voltage to the high side windings. The voltage is applied to one winding at a time with all other windings open circuited. The exciting current (comprising the core magnetizing current, resistive loss current and capacitive charging current) drawn by the winding is measured. This test should be performed before any DC tests have been performed. DC testing leaves a residual magnetism of the core that will influence the exciting current.

It is good practice to repeat each exciting current measurement with the tap changer in neutral, raised one position and lowered one position, as well as at full raise and full lower positions. If the exciting current test is being used to diagnose problems with the tap changer, the test should be performed for all tap position. Doble Engineering has identified 12 different tap changer exciting current patterns.

The exciting current test is evaluated by looking at the pattern of the exciting current.

For three phase, star connected, core form transformers, the exciting current pattern is two high similar currents corresponding to the two windings on the outer core limbs and a low current corresponding to the middle winding.

For three phase, delta connected, core form transformers the exciting current pattern is two high but dissimilar currents corresponding to the two windings on the outer core limbs and a low current corresponding to the middle winding.

It is important to note that exciting current patterns can vary depending on transformer construction.

It is possible to use the difference between the two higher currents to detect problems. As a general rule, if the exciting current is greater than 50 mA, there should not be more than 5% difference between the magnitudes of the two higher currents. If the exciting current is less than 50 mA, there should not be more than 10% difference between the magnitudes of the two higher currents.

3.1.5 Turns Ratio for On-Load Tap Changers

Purpose: To detect shorted turns, open circuited windings, and tap changer problems.

The turns-ratio test is performed using a special test set. A known low voltage is applied to the primary winding and the induced voltage is measured on the secondary winding. In a three winding transformer, the induced voltage on the tertiary winding is also measured. The test is performed one phase at a time.

The measured turns-ratio should be within 0.5% of the nameplate value. Deviations between the measured and nameplate value can indicate shorted turns, open circuits, incorrect winding connections and tap changer problems. Usually further testing or visual internal inspection of the transformer or tap changer is needed to locate a fault identified by turns-ratio testing.

It is good practice to perform turns-ratio tests on each of the tap changer positions and compare these against the nameplate values to detect problems with the tap changer.

3.1.6 Leakage Inductance

Purpose: To detect core and winding movement, as well as winding distortion.

Leakage inductance (also referred to as "leakage reactance" or "short circuit impedance") is calculated by measuring the current drawn when a voltage is applied to the primary winding with the secondary winding shorted. This current is due to the transformer leakage flux and is used to calculate the transformer's leakage inductance. This calculated value can be compared to the transformer nameplate. Difference between the nameplate leakage inductance and the calculated leakage inductance indicates winding deformation or winding movement.

The leakage inductance test is often performed using the power factor test set with the addition of another module.

3.1.7 Power Factor and Capacitance

Purpose: Power factor and capacitance measurement is used to determine the condition of the capacitive insulation between the windings, and between the windings and the core and tank. It can detect contamination of the winding insulation by moisture, carbon, and other material.

This test can also be applied to the bushings to determine the condition of condenser-type bushings. It can also detect contamination as well as deterioration of the capacitive layers in the bushing.

The test is performed by applying AC voltage to one set of windings with the test set in various modes. The current and watts from the other winding, as well as flowing to ground, are measured. The three different test set modes are:

- GST-ground: where all currents are measured,
- GST-guard: where only currents flowing to ground are measured, and
- UST: where currents that flow to ground are not measured.

During the test, all the terminals, including the neutrals, are connected together to remove any inductance effects, and the neutral is ungrounded. The tap changer is set in a position off neutral. Test voltage is applied to one set of windings with the test set in the three different modes. The test is then repeated by applying the test voltage to the other set of windings. This helps reveal errors in the testing procedure since the results obtained should be similar.

The power factor is calculated from the watts and current measurements. The power factor is equivalent to the dissipation factor, tan delta, or dielectric loss angle for the ranges of power factor that are of interest.

The test set also measures the capacitance for each test mode. Depending on the test mode, different capacitances are measured. These capacitances are:

- CH: capacitance of the insulation between the high voltage winding and the grounded tank and core including the HV bushings,
- CL: capacitance between the low voltage windings and the grounded tank and core including the LV bushings, and
- CHL: capacitance between the high and low voltage windings.

Changes in capacitance usually indicate changes in the geometry of the windings relative to each other or to the tank and core. Since the capacitance also includes components such as the tap changer, bushings, insulating fluid pressboard barriers, and structural elements, changes in the capacitance could also be influenced by changes in these components (e.g., insulating fluid contamination, bushing and tap changer faults).

Power factor test results must always be corrected for temperature. General rules for interpreting power factor results are listed in Table 14. The power factor limits for transformers are listed in Table 15, changes in the current between tests that can also be used for interpretation are listed in Table 16, and power factor limits for dry-type transformers are listed in Table 17.

Table 14. General Rules for Interpreting Power Factor Results

Power factor	Interpretation
<0.5%	Good
Between 0.5% and 0.7%	Deteriorated
Between 0.5% and 1.0 % with an increasing trend	Investigate
>1.0%	Bad

Table 15. Power Factor Limits for Transformers

Size	New	Service Aged
<500 kVA	1.0%	2.0%
>500 kVA	0.5%	1.0%

Table 16. Interpretation of the Changes in Current Between Tests

Change in Current	Interpretation
<3%	Good
3-5%	Deteriorated
5-10%	Investigate
>10%	Bad

Table 17. Power Factor Limits for Dry-Type Transformers

Power Factor	Non-Cast Resin	Cast Resin
CHL	2.0%	1.0%
CH	3.0%	3.0%
CL	4.0%	2.0%

It is important to note that, as with all general guidelines for test results, better interpretation can be obtained from trends and comparing test results to similar transformers or nameplate data. Other relevant test information should also be consulted and complementary tests performed to confirm a diagnosis.

The power factor test set can also be used to determine the condition of the transformer bushings. Condenser or capacitive bushings will have either a potential test tap or a power factor test tap to allow power factor and capacitance testing to be performed.

The GST-ground mode is used to measure the overall power factor and capacitance of the bushing. In this test mode all the terminals of the winding under test are short circuited and the other windings are grounded. The high voltage lead is attached to the center conductor of the bushing and the bushing flange ground is connected to ground terminal of the test set. All currents flowing through the main capacitive insulation of the bushing, the upper porcelain, the lower porcelain, the sight glass, and the liquid or compound filler in the bushing are being measured.

The UST test mode is used to measure the power factor and capacitance of the bushing's main insulation (C1) only. The high voltage lead is attached to the center conductor of the bushing, the low voltage lead is connected to the test tap, and the bushing flange ground is connected to ground terminal of the test set and is guarded. Only currents flowing through the main capacitive insulation of the bushing are being measured.

The GST-guard mode is used to measure the power factor and capacitance of the test tap (C2). In this test the high voltage lead is connected to the test tap (it is important to make sure the applied test voltage is appropriated for the test tap so as not to damage the test tap insulation), the low voltage lead is connected to the center conductor of the bushing and guard, and the bushing flange ground is connected to the ground terminal. Only currents flowing through the test tap insulation, the ground flange, and the immediate area of the porcelain around the test tap, are measured

- **Overall and C1 Power Factor:** Should closely match nameplate and in general be below 0.5%.
- **C2 Power Factor:** Should closely match nameplate and in general be less than 1.0%.
- **Capacitance:** Should match nameplate with changes of more than 10% being cause for concern.

Non-condenser-type bushings (e.g., solid porcelain bushings, epoxy bushings, compound filled, oil-filled and gas-filled bushings) do not have a test tap. It is not possible to measure the power factor and capacitance for these bushings. A hot collar test can be performed on these bushings to measure the watts loss and current. Increase of the watts loss is an indication of contamination of the outer surface of the bushing (typical Watts loss is between 0.02 and 0.04 Watts, with a Watts loss greater than 0.1 Watts being a cause for concern). Decrease of the current is an indication of internal voids, low oil or compound levels (typical currents of 40 to 120 mA).

3.1.8 Frequency Response Analysis

Purpose: This test detects movement of the windings, core, and leads.

This test measures the frequency response of the transformer to either a variable frequency sinusoidal voltage input (frequency response method) or to an impulse voltage input (impulse response method). In both cases, the voltage is very low and the test is nondestructive.

The test protocol is as follows:

For each winding, inject the signal at one end of the winding and measure the response at the other end of the same winding. For star connected windings, inject the signal at one end of the winding and measure the response at the neutral.

Inject the signal into the high voltage winding and measure the response at the low voltage winding for each phase.

For windings with tap changers, perform the test with the tap changer in 2 positions: the neutral position and the position that puts the entire winding in the circuit.

The response (or transfer function) is displayed as a Bode Plot (amplitude vs. frequency) from power frequency to 2 MHz.

The shape of the frequency response is analyzed. In particular, the resonances of the frequency response curve provide information about the mechanical disposition of the transformer windings, leads, and core. This test is sensitive to very small changes in transformer winding, lead, and core geometry and can pick up problems such as axial winding collapse, hoop buckling, movement of windings relative to each other, and shorted turns.

To gain the most value from frequency response analysis, it is useful to have a previous frequency response plot to compare the readings to. However, the skill of knowledgeable experts as well as the experience in frequency response analysis has advanced to the stage where it is possible to obtain good information from a standalone test by comparing this against a database of expected results.

This test does require a knowledgeable person to interpret the results. Some companies are developing expert systems to perform this analysis as well as general rules for reading the results. This will enable less knowledgeable persons to provide a preliminary diagnosis. This is particularly valuable if FRA testing is used to determine if a transformer should be reenergized after seeing a fault.

3.1.9 Insulation Resistance

Purpose: This test is performed by applying a DC voltage and measuring the leakage current to determine if the transformer insulation is dry and clean. The test can also pick up any unintentional grounds.

A mega-ohmmeter (Megger®) is typically used. The test is performed by shorting all the windings and making sure the tank and core are grounded. The resistance to ground is then measured from the primary windings to the secondary windings, and then from the secondary windings to the primary windings, as well as from each winding to ground. In a three winding transformer, the tertiary winding is also measured.

The resistance is a function of temperature (winding temperature, oil temperature, and ambient temperature). The resistance is also a function of the physical size of the transformer and its construction. Therefore, in order to evaluate insulation resistance readings, the measured 60-second resistance value should be corrected to 20°C and compared to a minimum resistance value derived from the following formula:

$$R_{\text{minimum}} = \frac{0.8 \times E}{\sqrt{\text{kVA}}}$$

Where:

E is the voltage rating of the winding under test.

kVA is the rating of the transformer.

0.8 is a factor used for oil filled transformers at 20°C. A factor of 16 should be used when windings are untanked.

Because of the temperature dependence of resistance measurement, dielectric absorption ratios are used to evaluate insulation cleanliness and dryness. The dielectric absorption ratio is the ratio of the 60-second insulation reading to the fifteen second insulation reading. A dielectric absorption ratio in the range of 1.3 to 3 indicates a clean and dry transformer.

Another insulation ratio used is the polarization index, which is a ratio of the 10-minute insulation reading to the 60-second insulation reading. A polarization index less than 1 indicates a wet or contaminated insulation. A polarization index greater than 2 indicates dry and clean insulation.

It is important to discharge the windings after an insulation resistance test because any residual charge will interfere with other electrical tests and generate bad results. There is also a potential for insulation resistance testing to magnetize the core and this can also result in bad test results. For these reasons it is good practice to make insulation resistance testing the last test performed on the transformer.

3.1.10 Winding Resistance

Purpose: This detects shorted turns, poor connections, open circuited windings and problems with the tap changer connections.

Winding resistance is measured using a low resistance ohmmeter (Ductor®). The test is performed by measuring the phase to neutral winding resistance in a wye connected winding and the phase to phase winding resistance in a delta connected winding. The phase to phase winding resistance should be resolved to individual phase winding resistances.

Because winding resistance is temperature dependent, the following precautions must be taken:

1. The current used to perform the measurement should not exceed 10% of the rated winding current.
2. The transformer top and bottom oil temperature differential should be no more than 5°C.
3. The winding temperature should be close to the average oil temperature. (Leaving a transformer deenergized for at least 3 hours is normally enough to meet the temperature requirements.)

The measured winding resistance should be corrected to the same temperature at which the nameplate winding resistance has been provided, and then corrected in accordance to the following formula:

$$R_{\text{corrected}} = \frac{R_{\text{measured}} \times (CF + CT)}{CF + \text{winding temperature}}$$

Where

CF = 234.5 for copper windings and 225 for aluminium windings.

CT = 75 for 55°C rise transformers and 85 for 65°C rise transformers.

Winding temperature is given in C.

There should not be more than 2% difference between the corrected measured value and the nameplate value. Differences more than 2% indicate short circuits, tap changer contact problems, or turn to turn shorts.

3.1.11 Core Insulation Resistance

The transformer core is typically insulated from ground with only one deliberate core ground. Multiple core grounds lead to circulating currents in the core laminations and overheating of the core.

The core ground may be brought through the tank wall via a low voltage bushing or accessed by opening a man hole.

Core insulation resistance testing performed on accessible core grounds can provide indication of multiple core grounds. The test is performed using a standard DC insulation resistance tester at no more than 1 kV.

New transformers have core ground resistances greater than 1000 Mohm. Service aged transformers have core ground resistances greater than 100 Mohm. Core ground resistances less than 10 Mohm should be investigated.

DGA results can be used to check if core overheating is occurring. The presence of hot metal gases (ethane, ethylene and methane) is an indicator that core overheating may be occurring. CO and CO₂ may also be present if the core overheating involves pressboard or paper insulation.

3.1.12 Electromagnetic Interference Measurement

Purpose: This test detects problems with the windings, core, and bushings that generate electrical noise.

Electromagnetic interference measurement detects radio frequency noise using radio frequency antennae or high frequency current transformers. It is possible to apply triangulation or other methods to localize the source of radio frequency noise generated by the transformer. This test is relatively new and is often used as a complement to partial discharge measurements.

3.1.13 Partial Discharge Measurement

Purpose: This test detects problems with the windings, core and bushings that generate electrical noise.

Partial discharge measurement may be performed using a variety of acoustic, electrical and radio frequency sensors. This test is relatively new but it is becoming more common as a factory acceptance test as well as a benchmarking test. It is also being performed more frequently as a condition monitoring or diagnostic test. Methods to triangulate the partial discharge activity have been developed that provide additional information as to the source and therefore the seriousness of the problem.

3.1.14 Power Factor Tip-Up

Purpose: This test detects contamination and other defects in the winding insulation.

This is the same test as conventional power factor testing; however, multiple measurements are taken as the test voltage is increased in steps.

Increasing power factor with increasing voltage is evidence of ionic contamination (i.e., conductive contaminants like rust, salts, and copper particles) or carbonization of the oil and/or winding. Polar contaminants such as moisture will not cause the power factor to increase with voltage.

The power factor tip up test, when applied to dry-type transformers, is useful in detecting ionic contamination and voids in the insulation. These will cause the power factor to increase with increasing voltage.

3.1.15 Dielectric Frequency Response

Purpose: This test is used to measure the amount of moisture in the solid insulation.

The validity of this test remains controversial.

Dielectric frequency response is an extension of the power factor test. While the power factor test is performed at a single frequency (power frequency), the dielectric frequency response test measures the power factor of the transformer across a frequency range from 0.001 Hz to 1.0 kHz. This allows the determination of the cause of a poor power factor reading.

This test in particular allows engineers to distinguish between moisture in cellulose insulation, chemical contamination of cellulose insulation, and contamination of the oil or moisture in the oil as possible causes of a poor power factor reading. Knowing the cause of a poor power factor reading allows the problem to be treated more effectively.

The dielectric frequency response test is also able to provide an estimate of the moisture concentration in the cellulose insulation. This is useful in determining the aging rate and remaining life of the transformer as well as its susceptibility to bubbling.

3.2 Condition Monitoring

There are many commercial condition monitoring products available, and this market is constantly evolving, with new products continually being offered to the transformer owner.

3.3 FM Approved and Equivalent Transformers

FM Approval is intended for liquid-filled transformers rated at 5 to 10,000 kVA. If a transformer is FM Approved per Approval Standard 3990, fire frequency is considered reduced sufficiently that fire protection is not necessary. The FM Approval program considers the transformer as a system that includes evaluation of the fire properties of the liquid, the ability of the tank and transformer components to withstand the pressure generated by a low-level electrical fault, and the ability of electrical protection to clear a fault before tank rupture. The conditions of FM Approval are as follows:

Tank design strength to prevent tank rupture under low energy fault conditions.

A pressure relief device to relieve pressure if a low current fault occurs until the fault can be cleared by electrical protection described in Item 3 below.

Electrical protection to clear sustained low current faults. This protection could be in the form of a ground fault relay and sudden pressure relay, or other devices of equivalent reliability.

Electrical protection to clear high current faults. This protection is based on the kVA rating of the transformer and is intended to electrically isolate the transformer rapidly enough to prevent pressure increase to greater than half the tank burst pressure.

FM Approved transformer fluids have a fire point of 572°F (300°C) or more.

For FM Approved network transformers, secondary side electrical protection is needed in addition to the above. This protection could be in the form of ground fault detection or other technology of demonstrated equivalence. This device should trip the high-side disconnect devices of the transformer experiencing the fault and other paralleled transformers in the network.

An equivalent transformer is one that includes all the protection features described above.

3.4 Transformer Aging

The following discussion is based on rules of thumb and should only be used as a guide to qualitatively determine how different factors affect loss of transformer life. Knowledgeable experts should be used to accurately determine the remaining life of transformers.

Transformer age is determined by the tensile strength of its paper insulation. The tensile strength will decrease as the paper insulation degrades. When the paper insulation loses most of its tensile strength, it is no longer able to withstand the normal electrical stresses associated with everyday operation of the transformer. Insulation failure will occur.

In addition to normal operating electrical stress, the paper insulation also has to withstand mechanical and electrical stresses due to abnormal conditions such as overvoltages, electrical faults, and mechanical vibration. These stresses are typically higher than the normal operating stress.

The degradation of paper insulation in transformers depends on three mechanisms:

1. Pyrolysis (heat)
2. Hydrolysis (water)
3. Oxidation (air)

These degradation mechanisms are interrelated. Heat will cause paper to degrade. Degradation of paper will generate moisture. Moisture will contribute to the degradation of paper. The assessment of transformer life is a complex problem.

The following rules of thumb exist for the three degradation mechanisms:

- Every 6°C increase in temperature above the rated hot spot temperature will result in a halving of transformer life.
- Every doubling of the moisture content in the paper insulation above 0.5% by wt will result in a halving of transformer life.
- Transformers operating in a high oxygen environment will age in the order of 2.5 times faster than transformers operating in a low oxygen environment.

Because aging of transformers depends on these three factors, the nameplate age alone cannot be relied upon to determine when a transformer needs to be replaced.

For example, a free breathing transformer with dry insulation (0.5% by wt) operating at its rated hot spot temperature will last about four years, while a sealed transformer with dry insulation, also operating at its rated hot spot temperature, will last about 18 years. If the moisture in the sealed transformer is doubled to 1.0% by wt, the transformer will fail in 9 years. If the operating temperature of the sealed transformer is increased to 6°C above its rated hot spot temperature, its life is further reduced to 4.5 years.

Degradation of paper causes the long cellulose chains to break. Shorter cellulose chains provide less tensile strength. The length of cellulose chains in paper is measured in degrees of polymerization (DP). New transformers have paper insulation with a DP of 800. The IEEE has set the transformer end-of-life criterion at a DP of 200, which represents a loss of 50% tensile strength.

FM Global recommends the use of oil screen tests, DGA, and furan analysis as screening tools to determine when transformers are approaching their end of life. Oil screen tests will identify transformers with high

moisture in paper concentrations. The ratios and concentrations of CO and CO₂ in DGA analysis will identify transformers where thermal degradation of the paper is a serious concern. And, furan analysis will provide an approximation of the DP of the paper insulation.

4.0 REFERENCES

4.1 FM Global

Data Sheet 4-1N, *Fixed Water Spray Systems for Fire Protection*
 Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems*
 Data Sheet 5-19, *Switchgear and Circuit Breakers*
 Data Sheet 5-48, *Automatic Fire Detection*

4.2 Other

ANSI/IEEE Std. 493, *Design of Reliable Industrial and Commercial Power Systems*
 ANSI/IEEE Std. C57.91, *Guide for Loading Mineral Oil-Immersed Transformers*
 ANSI/IEEE Std. C57.92, *Guide for Loading Oil-Immersed Power Transformers*
 ANSI/IEEE C57.109, *Transformer Through-Fault Current Duration*
 ANSI/IEEE C37.100, *Thermal Evaluation of Oil-Immersed Distribution Transformers*
 International Council on Large Electric Systems (CIGRE). *Life Management Techniques for Power Transformers*. WG A2.18. 2003

APPENDIX A GLOSSARY OF TERMS

Equivalent transformer: A transformer equivalent to an FM Approved transformer. An example is a UL transformer listed per Section 450-23 and provided with electrical protection to clear a sustained low-current fault.

FM Approved: References to "FM Approved" in this data sheet means the product or service has satisfied the criteria for Approval by FM Approvals. Refer to the *Approval Guide* for a complete listing of products and services that are FM Approved.

FM Approved transformer: A less flammable liquid filled transformer rated at 5 to 10,000 kVA. The transformer includes electrical protection to clear high current as well as sustained low current faults. A pressure relief device and tank discharge strength prevent tank rupture under a low-level electrical fault.

Higher secondary voltages: Secondary voltages equal to or greater than 480 volts, including 480/277 volt systems.

In or near commercial buildings: within the interior of, on the roof of, attached to the exterior wall of, in the parking area serving, or within 30 meters of a non-industrial non-substation building. Commercial buildings are typically accessible to both members of the general public and employees, and include: 1) Public assembly properties, 2) educational properties, 3) institutional properties, 4) residential properties, 5) stores, 6) office buildings, and 7) transportation centers (e.g., airport terminal buildings, subway stations, bus stations, or train stations).

Less flammable liquid insulated transformer: A transformer insulated with an FM Approved less flammable liquid with a fire point of not less than 572°F (300°C). The transformer is not FM Approved.

Lower secondary voltage: Transformers with secondary voltages below 480 volts.

Navigable waterway: Navigable waterway is defined by 40 CFR Part 112 as:

- A. All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters subject to the ebb and flow of the tide.
- B. All interstate waters, including interstate wetlands, mudflats, and sandflats.
- C. All other waters such as intrastate lakes, rivers, streams (including intermittent streams), wetlands, mudflats, sandflats, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation, or destruction of which could affect interstate or foreign commerce including any waters that

could be used for recreational purposes, or from which fish or shellfish could be taken and sold in interstate or foreign commerce; or that are used or could be used for industrial purposes by industries in interstate commerce.

Network transformer: These transformers are located in vaults in buildings or adjacent to buildings. The vaults contain two or more power transformers. These transformers are supplied from different transmission or distribution lines and are paralleled on their low voltage side through circuit interrupting devices called "network protectors". Typically high voltage current interrupting devices have not been used in the network vault. The low-voltage bus of a network vault may be electrically tied to a number of other vaults to form a network secondary distribution system, called a low-voltage network grid.

Primary winding: The winding into which energy normally flows. The primary winding can be energized from the secondary winding under abnormal conditions.

Radial transformer: A transformer that can only be energized from the primary winding.

Secondary winding: The winding from which energy flows during normal operation.

APPENDIX B DOCUMENT REVISION HISTORY

April 2014. Minor editorial changes were made.

July 2013. Minor editorial changes were made.

July 2012. Major changes include the following:

- The electrical testing, electrical protection, maintenance and operation sections of this data sheet have been substantially revised.
- This data sheet no longer refers to DS 5-20 for electrical testing recommendations.
- Recommendations related to specialty transformers have been added to this data sheet.
- Fire protection recommendations have been re-organized for better clarity.
- Total flooding gaseous systems are no longer recommended as alternatives to sprinklers for protection of indoor transformers.
- Sprinkler protection criteria for indoor test areas have been revised.
- Emergency drainage is recommended for indoor transformers where sprinkler protection is provided.

May 2010. Minor editorial changes were done for this revision.

January 2007. The reference goal of the recommendation 2.3.1.1.2.2.2 was classified.

May 2006. New definitions were added to Appendix A, Glossary of Terms.

May 2005. Editorial changes were done to the recommendation 2.3.1.2.1.1.

January 2005. The following changes were done for this revision:

1. Section 2.2 Indoor Transformers, recommendations 2.2.1.2.2 & 2.2.1.3.2.2. A protection alternate to CO-2 of an FM Approved gaseous agent protection system or a water mist system FM Approved for machinery spaces is recommended. Also, where automatic sprinkler protection is used, the density has been increased to 0.3 gpm/ft² (15 mm/min) from 0.2 gpm/ft² (10 mm/min).
2. Section 2.3 Outdoor Transformer, recommendation 2.3.1.2.3 for open pit containment system. Where automatic sprinkler protection is used, the sprinkler density has been increased to 0.3 gpm/ft² (15 mm/min) from 0.15 gpm/ft² (6 mm/min). Where a flame arrestor is used to increase the amount of time before burning oil enters the pit Size No 5 rather than Size No 2 ASTM D448 Standard Classification for Sizes of Aggregate for Road and Bridge Construction should be used. Size No 5 is closer to the 1.5 in (3.8 cm) washed and uniformly sized rock tested at the FM Global Research Campus.
3. Section 3.1.1, Approved and Equivalent Transformer. A transformer equivalent to an FM Approved transformer is defined as a transformer with a UL listing per NEC Section 450-23 with electrical protection to clear sustained low current faults. The reference to NEC 450-23 was left out of the previous edition. Transformers complying with NEC 450-23 include four of the five safeguards requested for an FM Approved transformer. Low current fault protection is the remaining safeguard.

May 2003. The following changes were done for this revision:

1. Tables 2a and 2b Separation Distances. The change allows medium sized transformers containing FM Approved less flammable fluids to be located as close to buildings and to other transformers as small transformers were in the previous standard. This provided there is adequate space for inspection and maintenance. Medium sized transformers may contain up to 10,000 gal (37.9 m³) of fluid.
2. Section 2.3.1.2 Containment. The change increases the quantity of FM Approved less flammable fluid in a transformer before a containment system is recommended. It increases the size of the transformer to 1320 gal (5 m³) for transformers containing all FM Approved less flammable fluids. It further increases the size to 2640 gal (10 m³) if the fluid is certified as biodegradable and if a release does not expose navigable waterways. A definition is included for navigable waterways. The fluid would have to be certified as biodegradable by the responsible governmental authority.
3. Minor editorial changes were made to Section 2.3.1.2.1.4.

January 2001. The recommendation for the smoke detection for electrical rooms was revised to provide consistency within 5-series data sheets.

September 2000. This revision of the document was reorganized to provide a consistent format.

The following major changes have been made:

- a) Addition of emergency power supply recommendation for mechanical ventilation (Section 2.2.1.1.3).
- b) Change requirement for smoke detection to fire detection (Section 2.2.1.1.4).
- c) Add recommendation for location of rooms containing network transformers to outside wall where possible (Section 2.2.1.2).
- d) Addition of fire protection recommendations for multiple indoor oil insulated transformers (Section 2.2.1.3.2).
- e) Open pits without protection acceptable containment for FM Approved less flammable fluid insulated transformer (Section 2.3.1.2.1.2 and 2.3.1.3.1).

December 1998. Editorial changes were made.

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