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 the electrical protection, electrical testing, maintenance, and operation of large, critical distribution, power, and specialty transformers ONLY. For loss prevention recommendations related to electrical protection, electrical testing, maintenance, and operation of smaller (5 MVA and below) distribution transformers, see Data Sheet 5-20, *Electrical Testing*. These transformers step down the utility voltage for use in a commercial or industrial property.

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

1.1 Changes

October 2026. Interim revision. Editorial changes were made..

1.2 Hazards

Power and distribution transformers are reliable devices with low failure rates. Adequate electrical protection, electrical testing, maintenance, and proper operation are key factors in reducing the risk of transformer explosions and fires.

FM ’s loss statistics show that it is about 10 times more likely for a transformer to fail without a resulting explosion and fire. However, in some cases an internal fault may result in an overpressure of the transformer sufficient to cause tank rupture. Tank rupture will release substantial quantities of oil, with a resulting oil mist explosion and a long-burning, high heat release, oil pool fire. Fire protection and proper construction features are critical to limiting the extent of damage to adjacent structures and equipment in the event of a transformer fire.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Electrical Loss Prevention

2.1.0 Use dry-type bushings such as resin impregnated paper (RIP) insulated whenever applicable.

2.1.1 Electrical Protection

2.1.1.1 Perform an engineering analysis to determine an adequate electrical 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?)

See Figure 2.1.1.1-1 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 2.1.1.1-2 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 2.1.1.1-3 for a typical protective scheme for a two-winding, delta-wye connected transformer greater than 10,000 kVA in size.

See Figure 2.1.1.1-4 for a typical protective scheme for transformers greater than 10,000 kVA in size with a secondary selective system.

See Figure 2.1.1.1-5 for some alternative protective devices that achieve the same level of protection as the schemes shown in Figures 2.1.1.1-1, 2.1.1.1-2, and 2.1.1.1-3.

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Device No.	*Description*	*Dry*	*Liquid (MVA)*	
			1–5	*5–10*
26	Liquid thermal device		I	I
49	Winding thermal device	I		I
51N[1]	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)	T	T	T
51TL	Time delay overcurrent relay. (Transformer overload protection)	T	T	T
63	Sudden pressure relay			T
71	Liquid Level Device		I	I

Notes:
A—Alarm, I—Indication, T—Trip
1. Devices 50G, 50N/51N, 50NY/51NY, 67N and 87TN are alternatives. (See Fig. 2.1.1.1-5)

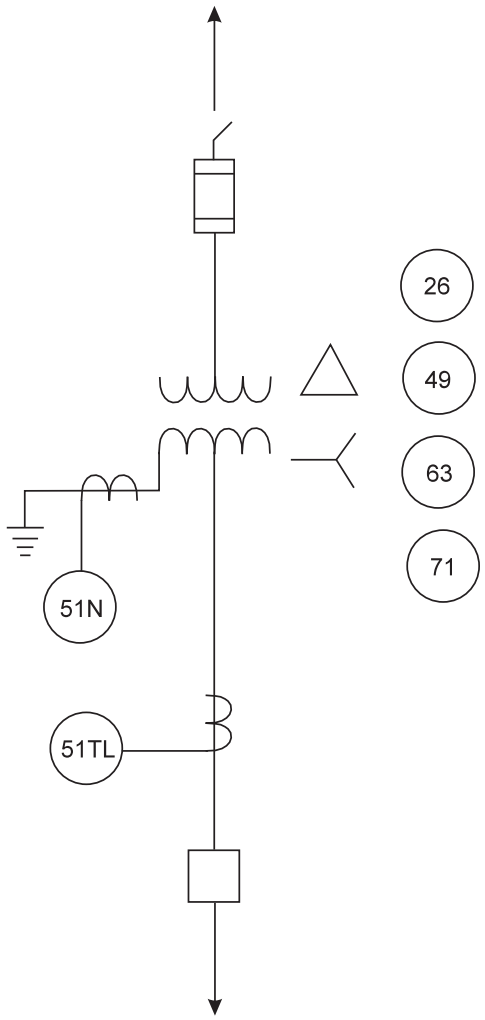
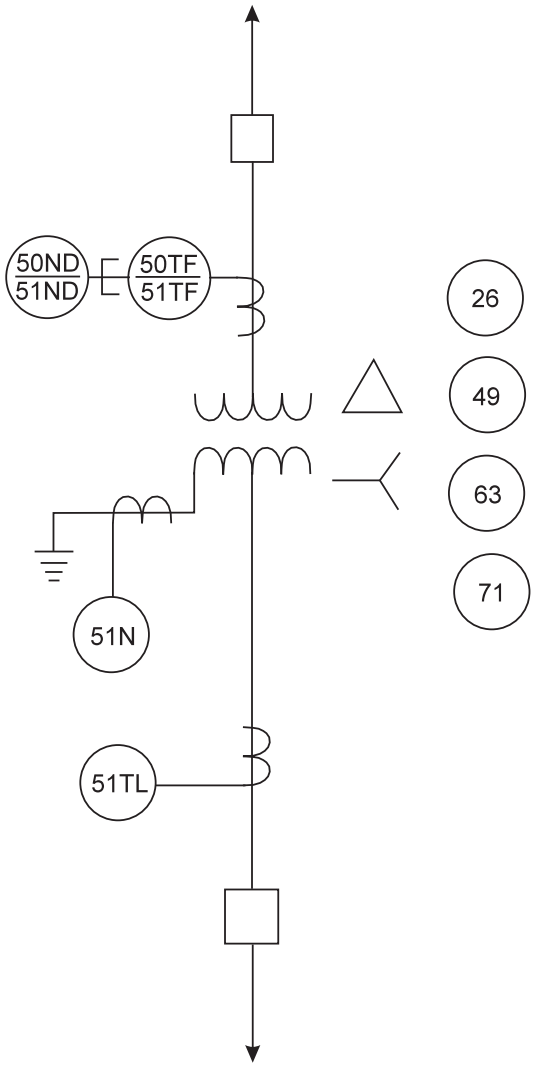


Fig. 2.1.1.1-1.Typical protective scheme for a two-winding, delta-wye connected transformer up to 10,000 kVA in size using fuses on the primary of the transformers

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Device No.	Description	Dry	Liquid (MVA)	
			1–5	5–10
26	Liquid thermal device.		I	I
49	Winding thermal device.	I		I
50ND[2]	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)	T	T	T
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection.)	T	T	T
51N[1]	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)	T	T	T
51ND[2]	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)	T	T	T
51TF	Time delay overcurrent relay. (Phase through fault protection.)	T	T	T
51TL	Time delay overcurrent relay. (Transformer overload protection)	T	T	T
63	Sudden pressure relay			T
71	Liquid level device		I	I

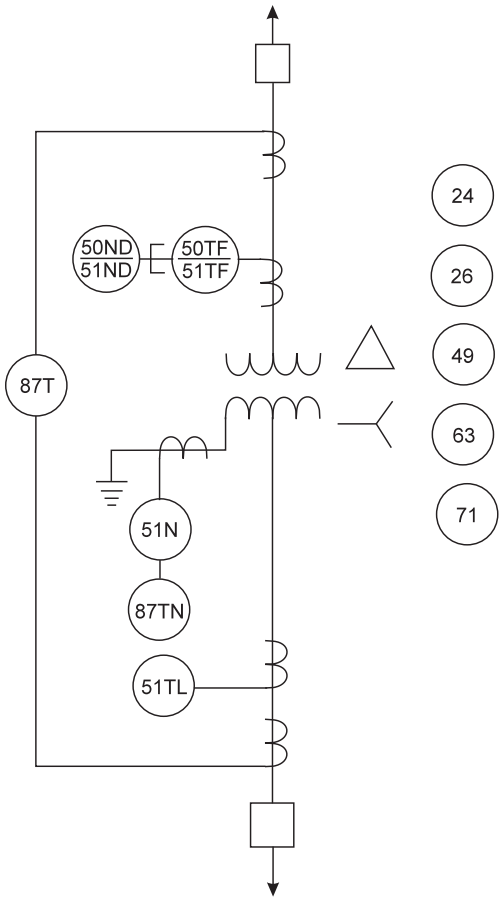


Notes:
A—Alarm, I—Indication, T—Trip
1. Devices 50G, 50N/51N, 50NY/51NY, 67N and 87TN are alternatives. (See Fig. 2.1.1.1-5)
2. Device 50GD is an alternative to 50ND/51ND. (See Fig. 2.1.1.1-5)

Fig. 2-1-1-1-2. 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

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Device No.	*Description*	*Action*
24	Volts/hertz relay (For unit connected transformers only)	T
26	Liquid thermal device	A
49	Winding thermal device	A
50ND[2]	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)	T
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection)	T
51N[1]	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)	T
51ND[2]	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)	T
51TF	Time delay overcurrent relay. (Phase through fault protection.)	T
51TL	Time delay overcurrent relay. (Transformer overload protection)	T
63	Sudden pressure relay	T
71	Liquid Level Device	I
87T	Transformer differential relay (Fault protection for transformer internal faults)	T
87TN[3]	Transformer ground differential relay (Ground fault protection of transformer wye winding internal faults)	T



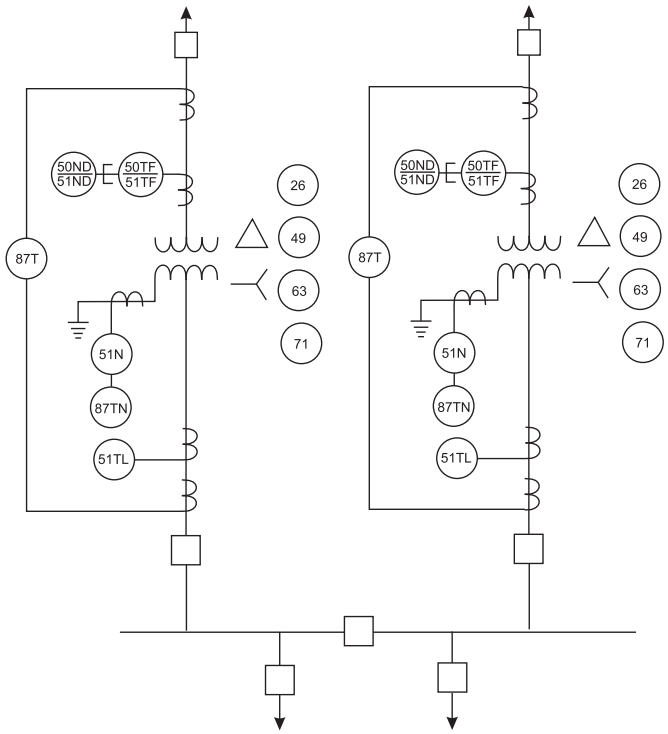
Notes:
A—Alarm, I—Indication, T—Trip
1. Devices 50G, 50N/51N, and 50NY/51NY are alternatives. (See Fig. 2.1.1.1-5.)
2. Device 50GD is an alternative to 50ND/51ND. (See Fig. 2.1.1.1-5.)
3. Device 67N is an alternative to 87TN. (See Fig. 2.1.1.1-5.)

Fig. 2.1.1.1-3. Typical protective scheme for a two-winding, delta-wye connected transformer greater than 10,000 kVA in size

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Device No.	*Description*
26	Liquid thermal device.
49	Winding thermal device.
50ND	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection.)
51N	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)
51ND	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)
51TF	Time delay overcurrent relay. (Phase through fault protection.)
51TL	Time delay overcurrent relay. (Transformer overload protection.)
63	Sudden pressure relay.
67N[3]	AC Directional neutral overcurrent relay. (Ground fault protection of transformer wye winding internal faults.)
71	Liquid level device..
87T	Transformer differential relay. (Fault protection for transformer internal faults.)
87TN	Transformer ground differential relay. (Ground fault protection of transformer wye winding internal faults.)

Notes:
1. Device 50G, 50N/51N, 50NY/51NY are alternatives.
2. Device 50GD is an alternative to 50ND/51ND.
3. Device 67N is an alternative to 87TN.

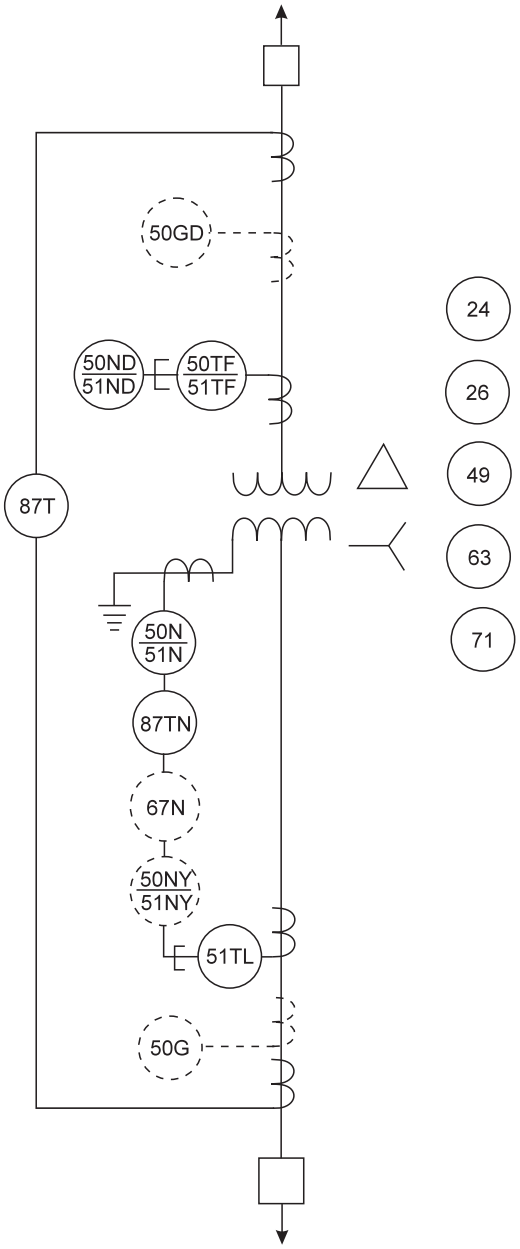


Note:
Electrical protection shown for 10-MVA and larger transformers. Protection should be chosen per Fig. 2.1.1.1-1, Fig. 2.1.1.1-2, or Fig. 2.1.1.1-3 depending upon transformer size.

Fig. 2.1.1.1-4. Typical protective scheme for transformers greater than 10,000 kVA in size with a secondary selective system

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Device No.	*Description*
24	Volts/hertz relay (For unit connected transformers only)
26	Liquid thermal device
49	Winding thermal device
50G[1]	Zero sequence instantaneous ground overcurrent relay. (Ground fault protection of wye winding and through faults)
50GD[2]	Zero sequence instantaneous ground overcurrent relay. (Ground fault protection of transformer delta winding.)
50N	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of wye winding and through faults.)
50ND	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)
50NY	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of wye winding and through faults.)
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection)
51N	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)
51ND	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)
51NY	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)
51TF	Time delay overcurrent relay. (Phase through fault protection.)
51TL	Time delay overcurrent relay. (Transformer overload protection)
63	Sudden pressure relay
67N[3]	AC Directional neutral overcurrent relay. (Ground fault protection of transformer wye winding internal faults)
71	Liquid Level Device
87T	Transformer differential relay (Fault protection for transformer internal faults)
87TN	Transformer ground differential relay (Ground fault protection of transformer wye winding internal faults)



Notes:
1. Devices 50G, 50N/51N, 50NY/51NY are alternatives.
2. Device 50GD is an alternative to 50ND/51ND.
3. Device 67N is an alternative to 87TN.

Fig. 2.1.1.1-5. Alternative protective devices that achieve the same level of protection as those shown in Figures 2.1.1.1-1, 2.1.1.1-2, and 2.1.1.1-3.

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

2.1.1.3 Provide differential protection to cover all the windings on multiple-winding power transformers, including specialty transformers such as rectifier, induction, and arc furnace transformers when applicable. 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.

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

2.1.1.5 Provide an arc-monitoring system 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 2.1.1.5-1 contains a list of specialty transformers and the additional protection recommended for them.

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Table 2.1.1.5-1. Recommended Additional Protection for Specialty Transformers

Transformer Type	*Special Features*	*Additional Protection*
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 differentialprotection 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.

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

2.1.2 Transportation of Transformers

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

2.1.2.2 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.

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

2.1.3 Transformer Operation

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

2.1.3.2 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.

2.1.3.3 Immediately after commissioning, and periodically for several days after commissioning, inspect the transformer thoroughly for indications of overheating, oil leaks, abnormal vibration, abnormal noise, and malfunction. Verify proper operation and calibration of each monitoring and protective device. Perform benchmark tests as recommended in Section 2.1.4.1.

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

2.1.3.4 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, or a cooling system upgrade if frequent overloading of the transformer is expected.

2.1.3.5 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, investigate the operation of the protective device and perform a dissolved gas analysis (DGA) test 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).

2.1.3.5.1 Exercise care when taking a DGA sample immediately following a fault. It may be prudent to wait several hours after the fault, because fault gases may not have had enough time to migrate through the bulk of the oil. Taking a DGA sample too early can produce misleading results. In addition, industry best practice is to take a second oil sample for DGA testing about 24-48 hours after the event; because gases formed from faults deep in the core take time to disperse through the oil. This 24-48 hour waiting time will ensure that the gases appear in the second sample. The result of this sample combined with that of the first sample will provide a more complete picture of the gases in the oil.

2.1.3.5.2 Record the event and any subsequent tests results.

2.1.3.6 Do not perform online insulating fluid processing, such as degassing or regenerating, on a routine basis or without a proper evaluation of the need for and consequences of processing the insulating fluid.

2.1.3.6.1 Take the following precautions when insulating fluid is 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 DGA, oil screening test 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 dry air be circulated into the transformer at a specified flow rate.

F. Replace all fluid-immersed tank gaskets when insulating fluid is replaced, regardless of the type of oil.

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G. When ester-based fluid is used to replace mineral oil in power transformers with voltage class of 69 kV or higher, consult with the transformer's OEM for a design review for fitness of use.

2.1.4 Transformer Maintenance

Establish and implement a transformer inspection, testing, and maintenance program. See Data Sheet 9-0, *Asset Integrity*, for guidance on developing an asset integrity program.

2.1.4.1 Benchmark Testing

Benchmark testing (or "fingerprinting") is a valuable method of providing baseline data about a 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.

2.1.4.1.1 Perform the following benchmark tests on all new or rebuilt transformers:

- Sweep Frequency Response Analysis (SFRA)
- Exciting Current
- Leakage Reactance
- 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
- Dielectric Frequency Resonance (DFR)
- Corrosive sulfur in oil

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

2.1.4.2 Routine Inspection, Testing and Maintenance

The recommended frequencies for inspection, testing, and maintenance are a general guide. These frequencies should be increased or decreased depending on factors such as the criticality of the unit, operating history, operating condition, availability of online monitoring, and age and/or remaining life.

2.1.4.2.1 For transformers with oil-impregnated paper (OIP) insulated condenser bushings, perform power factor and capacitance testing one year after commissioning.

2.1.4.2.2 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. For indoor transformers, check that equipment is operating in a clean, cool, dry, and tight condition with no abnormal noises, smells, vibration, or heat. Also ensure housekeeping is satisfactory, with no dust, debris, temporary storage, or exposed combustible materials.

2.1.4.2.3 Perform the following online tests once a year, and more frequently if warranted based on operating history, condition, and/or criticality for main tank and LTC oil compartment:

A. Thermography

B. Dissolved gas analysis

C. Fluid screening

1. For mineral oil, include the following tests at a minimum:

- Color
- Dielectric breakdown strength
- Moisture
- Power factor

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- Interfacial tension
- Neutralization number
- Inhibitor content (only for inhibited oils)

2. For natural ester oil, include the following tests at a minimum:

- Color
- Dielectric breakdown strength
- Moisture
- Power factor
- Fire point
- Viscosity

2.1.4.2.4 Perform corrosive sulfur testing of transformers that were built or have had their oil processed or replaced in 2000 or later, and if the 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.

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

2.1.4.2.4.2 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. Note: 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.

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

- PCB
- Furan analysis

2.1.4.2.6 Perform the routine offline (de-energized) tests listed in Table 2.1.4.2.6-1 every three years.

Table 2.1.4.2.6-1. Routine Offline (De-Energized) Tests

Components	*Test*
Windings	Insulation resistance
	Winding resistance
	Polarization index
	Turns ratio
	Power factor/capacitance
Bushings	Power factor/capacitance[1]
Core	Core insulation resistance[2]
On-load tap changer[3]	Turns ratio
	Contact resistance
	Insulation resistance
	Motor current measurement

Note 1. For non-condenser bushings where there is no test tap, perform hot collar test.
Note 2. Transformers generally have intentional core ground connection mounted under a manhole at the top of transformer or through the tank wall via a small low voltage bushing. It allows the ground to be easily disconnected and allows a measurement of the resistance between core and ground. However, there are some designs like shell form in which the core ground is inaccessible that makes the core ground insulation resistance measurement impossible.
Note 3. The electrical testing such as turn ratio, contact resistance for on-load tap changer is performed by repeating relevant winding electrical testing when the tap is moved at different tap positions.

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2.1.4.2.6.1 For OIP transformer bushings over 15 years old, rated at 230kV and above, the electrical testing interval should be three years maximum. Increase the testing frequency to annual base when the power factor values increase more than 70% from the base value.

2.1.4.2.7 Perform routine maintenance servicing for on-load tap changers per OEM guidance.

2.1.4.2.7.1 For an arc furnace transformer, perform primary switch maintenance in accordance with OEM recommendations.

Similar to tap changes, the maintenance frequency of a primary switch in an arc furnace application is often driven by cycles or number of switches, rather than on a time-based schedule.

2.1.4.2.8 Perform the additional tests listed in Table 2.1.4.2.8-1 if routine tests indicate a problem with the transformer to evaluate and investigation the fitness for continued use.

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

Table 2.1.4.2.8-1. Focused Off-Line Tests

Test	*Failure Mode*	*Testing Remarks*
Partial discharge	• Partial discharge activity involving the transformer core, winding or bushings	In-service
Electromagnetic interference	• Partial discharge activity or arcing involving the transformer core, winding, bushings or connections	In-service
Acoustic measurement	• Partial discharge activity involving the transformer core, winding or tap changer	In-service
Exciting current	• Shorted core laminations • Poor core joints • Short circuited or open circuited windings • Poor electrical connections • Tap changer problems • Core and winding movement	Outage needed
Frequency response analysis	• Radial buckling or axial deformation of windings • Core and winding movement • Clamping failures • Shorted turns	Outage needed
Leakage inductance testing	• Core and Winding movement • Winding distortion or damage	Outage needed
Capacitance/power factor (winding)	• Moisture, carbon and other internal contamination of the winding insulation	Outage needed
Winding resistance	• Shorted turns • Poor connections • Open circuited windings • Poor tap changer connections	Outage needed
Core insulation	• Unintentional core grounds • Deteriorated core ground insulation	Outage needed
Turns ratio	• Shorted turns • Open circuited windings • Tap changer problems	Outage needed
Capacitance/power factor (bushings)	• Moisture, carbon and other internal contamination • Shorted condenser layers in capacitive type bushings • Faulty bushing test taps	Outage needed
Insulation resistance	• Contaminated or deteriorated winding insulation	Outage needed

2.1.4.3 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.

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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.

2.1.4.4 Test the electrical protection system (fuses, circuit breakers, batteries, surge arrestor, and electrical and mechanical relays such as sudden pressure relay) in accordance with Data Sheet 5-19, *Switchgear and Circuit Breakers*.

2.1.4.5 Replace the OIP condenser bushing when the verified power factor value increases more than two times the baseline value, capacitance increases to 10% or more over the baseline value, or when significant oil leaks are present.

2.1.4.6 Develop a transformer lifecycle plan and replacement strategy. At a minimum, the plan should include the following components:

A. Transformer design data, year of manufacture, and operational history

B. OEM design operating conditions and design service life

C. Outline of parameters which would trigger a condition assessment and remaining life assessment (RLA) per Section 2.1.4.7 below. Such parameters/conditions might include age, hours of operation, fleet experience or history of operational incidents, and preventative ITM results.

Review and update the plan annually or when appropriate (following upset conditions, adverse maintenance results or management of change).

2.1.4.7 Perform transformer paper insulation remaining useful life assessment when one of the following conditions are detected:

A. CO_2/CO ratio is greater than 10, and CO_2 concentration is greater than 10,000 ppm.

B. DP levels (as indicated by furan analysis) are 400 or lower.

C. Transformer operating history indicates there has been accelerated deterioration of the paper insulation, such as overloading or high moisture level.

2.1.5 Online Condition Monitoring

2.1.5.1 Provide continuous online condition monitoring for the following types of transformers:

A. High-value or critical transformers, the loss of which will have a significant business impact. Examples include:

- Power generation step-up transformers (e.g. generator step-up transformers, collector step-up transformers, etc.)
- HVDC converter station transformers
- Greater than 50MW power transformers
- Electric arc furnace transformers
- Rectifier transformers

B. Transformers for which the maintenance and electrical testing intervals must be significantly extended due to reasons such as the inability to remove the transformer from service, location in remote areas, or lack of resources. Examples include:

- Power transformers in remote hydro power stations
- Solar/wind far transformers
- Rectifier transformers (recti-formers) where the rectifier and transformer are built into the same enclosure, preventing effective electrical testing.

2.1.5.2 Provide online condition monitoring systems to monitor the following parameters (several separate pieces of equipment may be needed to achieve the required level of condition monitoring):

A. Moisture-in-oil (with appropriate algorithms to translate this to a moisture-in-paper measurement)

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B. Temperature

C. Dissolved gases:

- Multi-gas monitoring for critical transformers
- FM Approved, single gas monitoring system as an economical alternative for less critical transformers such as inverter-based transformers in solar farm/battery energy storage system and wind turbine transformers

D. FM Approved power factor or leakage current for condenser bushings rated at 69kV and above

E. FM Approved partial discharge activity monitoring for bushings rated at 69kV and above

F. On-load tap changer motor current, where applicable

2.1.4.2.1 In addition to online condition monitoring systems, conduct periodic in-service testing using the following equipment:

- Acoustic sensors to monitor partial discharge activity
- Corona cameras

2.1.5.3 Select online condition monitoring systems with the following features and capabilities:

A. The ability to either transmit data continuously to a manned location (SCADA), or the ability to allow remote retrieval of the data

B. The ability to generate alarms (to a staffed location) when unusual conditions are detected.

C. The ability to analyze monitored parameters, generate a summary of the condition of the transformer, and produce recommendations for basic action

D. The ability for the user to set caution and alarm levels

E. The ability to store and trend monitored parameters

F. Field calibration and self-diagnostic capabilities

G. A measurement of accuracy of +/-5% for multi-gas DGA monitoring systems and moisture in the oil. For standalone H_2 continuous on-line condition monitoring, provide a measurement accuracy of +/-20% or 25 ppm, whichever is the greater

H. A measurement accuracy of +/-1% for bushing leakage current monitoring and be able to accept leakage current up to 300 mA

I. A sampling rate of at least once every 4 hours

J. Robustness and immunity to electromagnetic fields interference and radio frequency interference.

K. Security to prevent unauthorized changes to alarm conditions and limits

L. Environmental appropriateness for local site conditions

2.1.5.3.1 Online condition monitoring systems are not a substitute for electrical testing. Online condition monitoring systems can be used to adjust the interval between electrical testing but should not be used to justify a lack of testing. FM views online condition monitoring systems as broadband, early warning systems that trigger more focused electrical tests, including offline testing to confirm problems detected by the online condition monitoring system. An effective online condition monitoring system requires at least the following human elements:

A. Pre-defined action plans for various alert setting levels that are agreed by stakeholders.

B. Tracking of actions for response to alerts, including who responds to alerts, when, and with what comments.

C. Clear ownership of the online condition monitoring systems with sufficient knowledge and experience level. The data should be integrated with all available periodic offline testing and in-service testing information, and operation history for condition assessment.

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2.1.6 Contingency Planning

2.1.6.1 Equipment Contingency Planning

2.1.6.1.1 When a transformer breakdown would result in an unplanned outage to site processes and systems considered key to the continuity of operations, develop and maintain a documented, viable transformer equipment contingency plan per Data Sheet 9-0, *Asset Integrity*. See Appendix C of that data sheet for guidance on the process of developing and maintaining a viable equipment contingency plan. Also refer to sparing, rental, and redundant equipment mitigation strategy guidance in that data sheet.

2.1.6.1.2 In addition, include the following elements in the contingency planning process specific to transformers:

- OEM design information for the transformer
- The process and procedures needed for removal, dismantling, transportation, availability, installation, testing and re-energizing the transformers to restore operations.
- A review of any service contracts with OEM and/or vendors to identify duration of delivery of transformers and impacted components, including availability of rental units.
- OEM and/or third-party vendor review to determine transformer repair capabilities (including rewinding and availability/lead time of replacement components) or transformer replacement.
- Evaluation of the electrical system design to consider alternative options for reducing the production interruption exposure from a transformer breakdown, including restoration of power from alternate circuits in the electrical system.

2.1.7 Sparing

Sparing can be a mitigation strategy to reduce the downtime caused by a transformer breakdown depending on the type, compatibility, availability, fitness for the intended service, and viability of the sparing. For general sparing guidance, see Data Sheet 9-0, *Asset Integrity*.

2.1.8 Equipment Breakdown Spares

Equipment breakdown spares for transformers are spares intended to be used in the event of an unplanned outage of a transformer to reduce downtime and restore operations.

2.1.8.1 Provide the following equipment breakdown spares for arc furnace transformers:

- Arc furnace transformer
- Associated Josyln switches
- Secondary bus bar and delta closure. In cases where the secondary bus connections differ between the in-service AFT and the spare AFT, provide the necessary adaptors/bus work to align with the existing in-service cabling.

To be a viable arc furnace transformer equipment breakdown spare, the transformer must be owned/dedicated, of proper size (MVA, volts, and amps) to support full production, electrically and physically compatible, and in a known serviceable and reliable condition. A spare that is from a different mill or application, for example, would not be considered viable. To maintain viability of the spare, ensure the recommendations in 2.1.8.3 Storage and Maintenance of Spare Transformers are met.

Having a spare transformer that is not electrically compatible with the existing installation can negatively impact furnace operations. This includes furnace emissions, depending on the operating permit requirements. This needs to be considered in the ECP process.

See Section 3.4.1 for additional arc furnace transformer information.

2.1.8.2. Provide the following equipment breakdown spares for power generation step-up transformers rated 100 MVA and above:

- One spare bushing for condenser bushings rated at 66kV and above

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To be a viable spare, each bushing should be owned/dedicated, of proper size (voltage, current), physically compatible, and in known serviceable and reliable condition to support prompt replacement of an in-service bushing with a critical deficiency, thereby preventing a failure in service.

2.1.8.3 Storage and Maintenance of Equipment Breakdown Spare Transformers

2.1.8.3.1 Store transformers in accordance with manufacturer's instructions and protect against physical damage, moisture, dirt, and other contaminants, including process hazards, to maintain viability.

2.1.8.3.2 Store transformers in a location not subject to fire, natural hazards, or other equipment exposures including molten release. Provide sufficient space and sufficient lightning to walk around for inspection to observe any adverse condition such as oil leaks, etc.

2.1.8.3.2.1 Store spare arc furnace transformers indoors.

2.1.8.3.3 Store liquid-immersed transformers with oil filled if the storage time will be longer than 6 months. Operate the fans and pumps in accordance with manufacturer's instructions where applicable.

2.1.8.3.4 Connect the control cabinet heaters to a power supply and keep them energized to prevent condensation.

2.1.8.3.5 For transformers lacking a conservator tank, or when the conservator tank has been disconnected for short term storage, ensure the spare is stored with a nitrogen blanket above the oil level to minimize moisture ingress. Check the gas pressure on weekly basis to ensure the positive pressure is maintained.

2.1.8.3.6 When a bushing is stored as an accessary, store it indoor in its shipping crate with its upper part elevated from horizontal.

2.1.8.3.7 Perform oil quality analysis on liquid-filled equipment breakdown spare transformers on an annual basis.

2.1.8.3.8 Visually inspect equipment breakdown spare transformers at the same frequency as the in-service transformers to check for problems such as low oil levels, water saturated desiccant, leaks, and other abnormal conditions.

2.2 Fire Protection for Indoor Transformers

2.2.1 Construction and Location

2.2.1.1 If transformers are to be located indoors, provide a detached dedicated building or room with location and construction safeguards as described in Figure 2.2.1.1-1 and Table 2.2.1.1-1. If transformers are to be located within cut-off rooms for exposure protection, ensure the cooling characteristics of the transformer are not compromised.

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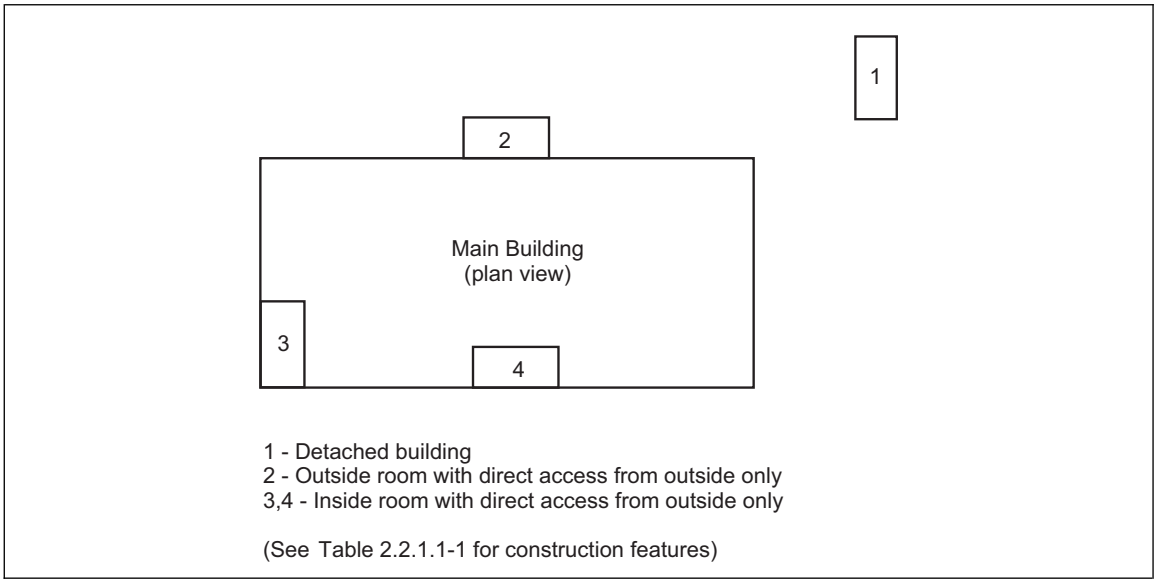


Fig. 2.2.1.1-1. Locations for transformer buildings and rooms

Table 2.2.1.1-1. Recommended Construction for Transformer Buildings and Rooms

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

[a] Transformers in Location 1 may also be treated as outdoor transformers in accordance with Section 2.3.
[b] With no oil-filled bushings, oil-filled tap changers, or other oil-filled accessories that could increase the fire hazard.
[c] See also Section 2.2.3.4 for protection of combustibles other than transformer liquids.
[d] Section 3.3 describes FM Approved transformers.
[e] Provide liquid spill containment in accordance with Section 2.2.1.4.
[f] Automatic sprinklers, foam-water sprinklers, or water mist. Also provide emergency drainage for sprinkler discharge per Section 2.2.1.5.
[g] 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 to allow for direct access from outdoors.

2.2.1.3 Where three-hour fire-rated construction is recommended for transformer rooms with non-FM Approved fluids in Table 2.2.1.1-1, also protect exposed structural steel in accordance with Data Sheet 7-32, *Ignitable Liquid Operations*.

2.2.1.4 Provide containment and emergency drainage in accordance with Data Sheet 7-83, *Drainage and Containment Systems for Ignitable Liquids*. Where multiple oil-filled transformers are installed, provide individual containment for the contents of each transformer to prevent spills from flowing to other transformers or important equipment in the room.

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2.2.1.5 Where a special protection system (e.g., foam-water sprinklers, compressed air foam, water mist) is provided for transformer protection in accordance with Section 2.2.3, design containment to hold the transformer liquid contents plus special protection system discharge for at least 20 minutes. Regardless of the calculated curb height, provide no less than 3 in (7.6 cm) of containment.

2.2.1.6 Locate transformers a minimum of 3 ft (0.9 m) from walls, or more as needed for maintenance access and ventilation requirements.

2.2.1.7 If transformer rooms contain liquid-filled transformers, arrange openings to be normally closed and provide FM Approved fire doors and/or fire shutters that have the same fire rating as the rest of the room.

2.2.1.8 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 Limit the loading of combustible materials, including transformer fluids, plastics, and insulation on grouped electrical cables.

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

A. Locate the transformers in rooms with suitable construction so the surrounding occupancy will not be exposed.

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.

2.2.2.4 Install FM Approved smoke detection in transformer rooms, with alarms arranged 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*.

2.2.2.5 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.

2.2.3 Protection

2.2.3.1 Where sprinkler protection is recommended for transformer fluids per Table 2.2.1.1-1, provide one of the following designs:

A. For FM Approved transformer fluids, provide sprinkler protection with a design of 0.2 gpm/ft^2 (8 mm/min) over the entire room.

B. For transformers using non-FM Approved fluids, provide sprinkler protection in accordance with Data Sheet 7-32, *Ignitable Liquid Operations*. Also design containment and drainage in accordance with Data Sheet 7-32.

2.2.3.2 An FM Approved foam-water sprinkler system, or a water mist system is acceptable as an alternative to sprinkler protection for transformer liquids where recommended in Table 2.2.1.1-1.

A. Design the system per Data Sheet 7-32, *Ignitable Liquid Operations*, as well as Data Sheets 4-2, *Water Mist Systems*, or 4-12, *Foam Extinguishing Systems*, as applicable.

B. Design the duration of system water flow for a minimum of 60 minutes.

C. Design the foam concentrate supply to provide flow for a minimum of 30 minutes.

D. Provide an FM Approved water mist system for machinery spaces. Ensure the size of door openings into the room does not exceed the limitations of the Approval listing.

2.2.3.3 An FM Approved compressed air foam (CAF) system is acceptable to supplement a sprinkler/design system or as an alternative to emergency drainage for transformer liquids. Design the system per Data Sheet 7-32, *Ignitable Liquid Operations*.

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2.2.3.4 Provide sprinkler protection for transformer rooms and buildings where combustible grouped electrical cables are present, per Data Sheet 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.

2.2.5 Fire Protection for Transformer Production Test Areas

2.2.5.1 Provide containment and emergency drainage for transformer production test areas. Size them in accordance with recommendations for indoor transformers (see Section 2.2.1) for the type of fluid and largest transformer fluid volumes to be tested.

2.2.5.2 Where non-FM Approved transformer fluids are present in the tested transformers, provide fire protection in accordance with Data Sheet 7-32, *Ignitable Liquid Operations*.

2.3 Fire Protection for 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. Alone, 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 alternatives to protect exterior walls of main buildings against exposure to outdoor transformer fires:

A. Minimum separation distances based on the construction type and transformer fluid in accordance with Figure 2.3.1.1.1-1 and Table 2.3.1.1.1-1.

B. 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 2.3.1.1.1-2 and Table 2.3.1.1.1-2.

C. 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 2.3.1.1.1-2.

D. 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. At least 5 ft (1.5 m) separation from the inside edge of the containment barrier, and water spray protection installed on the exposed building wall, over the same vertical and horizontal extent (coverage area) as dimensions Y and Z in Table 2.3.1.1.1-2. Design water spray in accordance with Section 2.3.2.

Table 2.3.1.1.1-1. Separation for Exposure Protection of Main Building Walls (also refer to Figure 2.3.1.1.1-1)

Fluid or Transformer Type	*Fluid Volume, gal (m^3)*	*Minimum Horizontal Distance from Containment to Exposed Building Wall (Dimension X in Figure 2.3.1.1.1-1)*		
		2-hour fire-rated wall, ft (m)	Non-combustible wall,[1] ft (m)	Combustible Wall, ft (m)
FM Approved transformer	Per Approval Listing	3 (0.9)		

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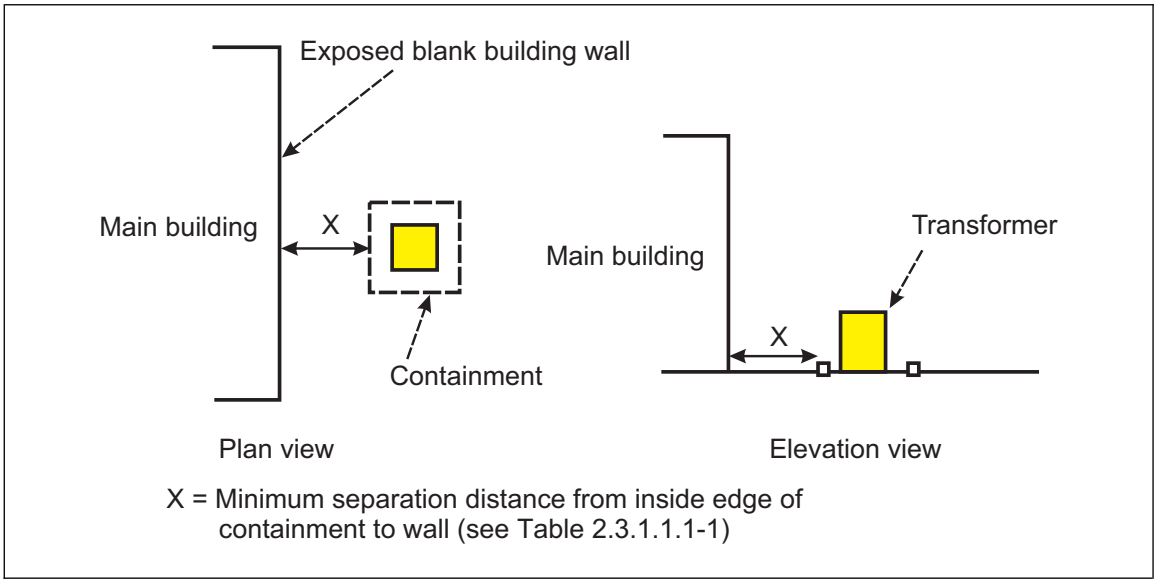


Fig. 2.3.1.1.1-1. Minimum horizontal separation distance between outdoor liquid-insulated transformers and exposed walls of main buildings

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 (19)	15 (4.6)	25 (7.6)	50 (15.2)
	>5,000 (19)	25 (7.6)	50 (15.2)	100 (30.5)

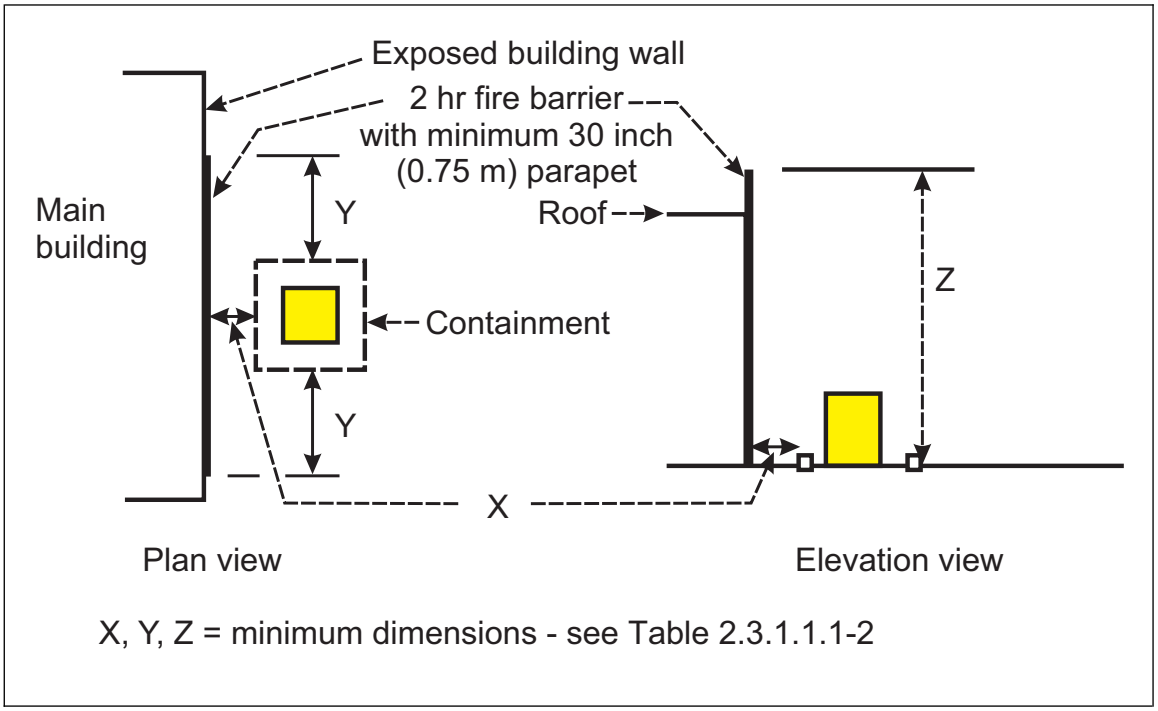


Fig. 2.3.1.1.1-2. Use of 2-hour fire barriers and separation distances for protection of exposed main building walls

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Table 2.3.1.1.1-2. Separation and Extent of 2-hour Fire Barriers for Protection of Main Building Walls (for dimensions refer to Figure 2.3.1.1.1-2)

Fluid Type	*Fluid Volume gal (m^3)*	*Separation and Extent of 2-hour Fire Barrier*		
		Dimension[1,2] (See Fig. 2.3.1.1.1-2)	Noncombustible Wall ft (m)	Combustible Wall ft (m)
FM Approved transformer fluid	≤10000 (38)	X	5 (1.5)	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)

Note 1. The 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 2.3.1.1.1-1 for 2-hour fire-rated walls. Dimension Y is the horizontal extent of the barrier starting from the respective edge of containment.
Note 2. Barrier vertical extent is dimension Z in the Table or the building height plus 30 in. (0.75 m) parapet, whichever is less.

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 2.3.1.1.2-1 and Table 2.3.1.1.2-1.

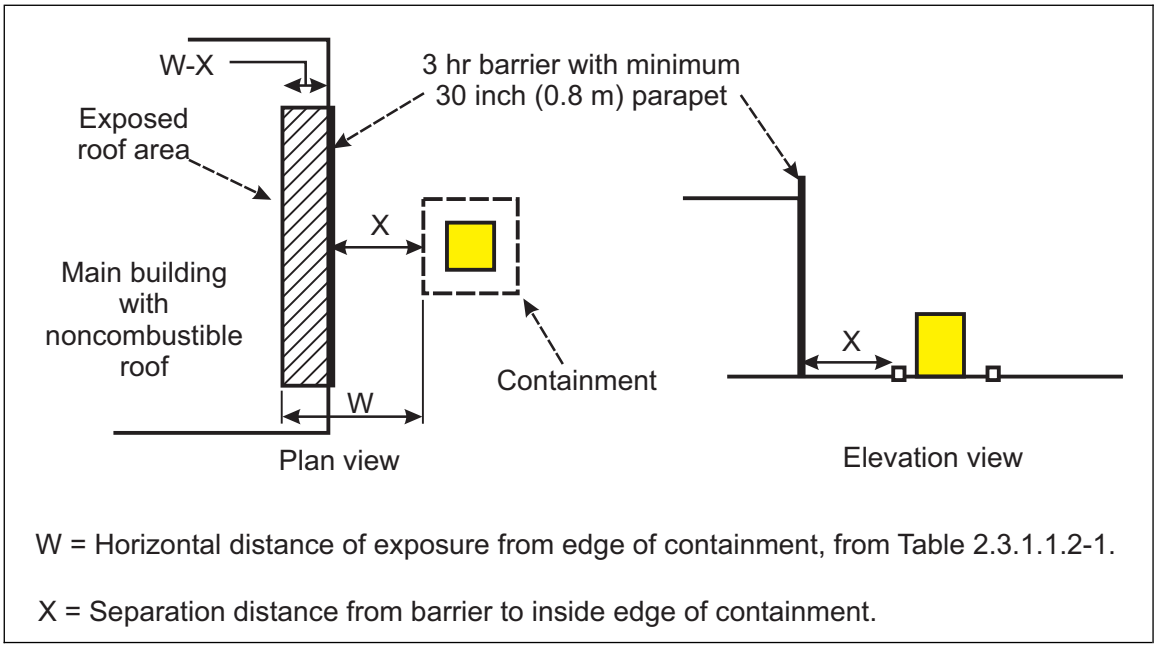


Fig. 2.3.1.1.2-1. Determination of exposed roof area

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Table 2.3.1.1.2-1. 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. 2.3.1.1.2-1) 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 2.3.1.1.2-1. (See Data Sheet 1-42, *MFL Limiting Factors*, for description of Class A roof installations).

2.3.1.2 Exposure Protection from Roof-Mounted Transformers

2.3.1.2.1 If roof-top transformers use non-FM Approved fluids, locate the transformer away from walls of adjoining buildings with higher roofs in accordance with Section 2.3.1.1.

2.3.1.2.2 If roof-top transformers use non-FM Approved fluids, provide a Class A roof covering for at least the horizontal distance from the transformer specified for noncombustible construction in Table 2.3.1.1.1-1. (See Data Sheet 1-42, *MFL Limiting Factors*, 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 2.3.1.3.1-1. Distances in Table 2.3.1.3.1-1 refer to the closest edge of containment.

Table 2.3.1.3.1-1. Minimum Separation Distances Between Adjacent Transformers

Liquid Type	*FM Approved Transformer?*	*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)
		≤5000 (19)	25 (7.6)
		>5000 (19)	50 (15.2)

2.3.1.3.2 Where the separation distances in Table 2.3.1.3.1-1 cannot be met, provide 2-hour fire-rated barriers between transformers as shown in Figure 2.3.1.3.2-1 and as follows:

A. Extend 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 of concrete block or reinforced concrete construction is preferred.

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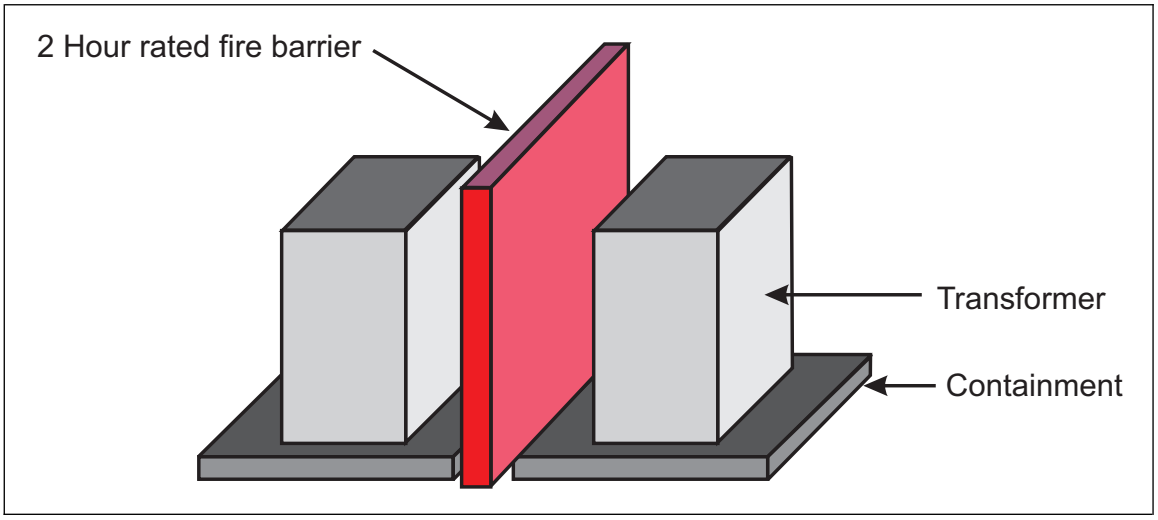


Fig. 2.3.1.3.2-1. Fire barriers for multiple outdoor transformers

2.3.1.3.3 For installations where the separation distances between transformers in Table 2.3.1.3.1-1 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 if accidental release of the transformer fluid could expose a main building or adjacent equipment or storage to fire damage.

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

2.3.1.4.3 Where water spray protection is provided for a transformer, provide containment with a capacity of at least a 60-minute discharge of fire hoses (500 gpm) plus the 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. Provide drainage in accordance with Data Sheet 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 m^3); and 8 ft (2.4 m) for transformers with more than 1,000 gal (3.8 m^3).

2.3.2 Active Protection for Outdoor Transformers

2.3.2.1 If automatic water spray exposure sprinkler protection is provided for outdoor transformers, design the system as follows:

A. Provide a discharge density of 0.3 gpm/ft^2 (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 Data Sheet 2-0, *Installation of Sprinkler Systems*.

B. Refer to Figures 2.3.2.1-1 and 2.3.2.1-2 for typical nozzle layouts.

C. Locate components of the water spray system (piping, spray nozzles, etc.) a minimum of 18 in. (45 cm) from the transformer.

D. Do not locate piping over the top of the transformer or tank relief vents.

E. Do not let nozzles spray onto bushings.

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F. For multiple transformer installations, design the water spray system and water supply based on simultaneous operation of the water spray systems for the transformer of fire origin and adjacent transformers on each side.

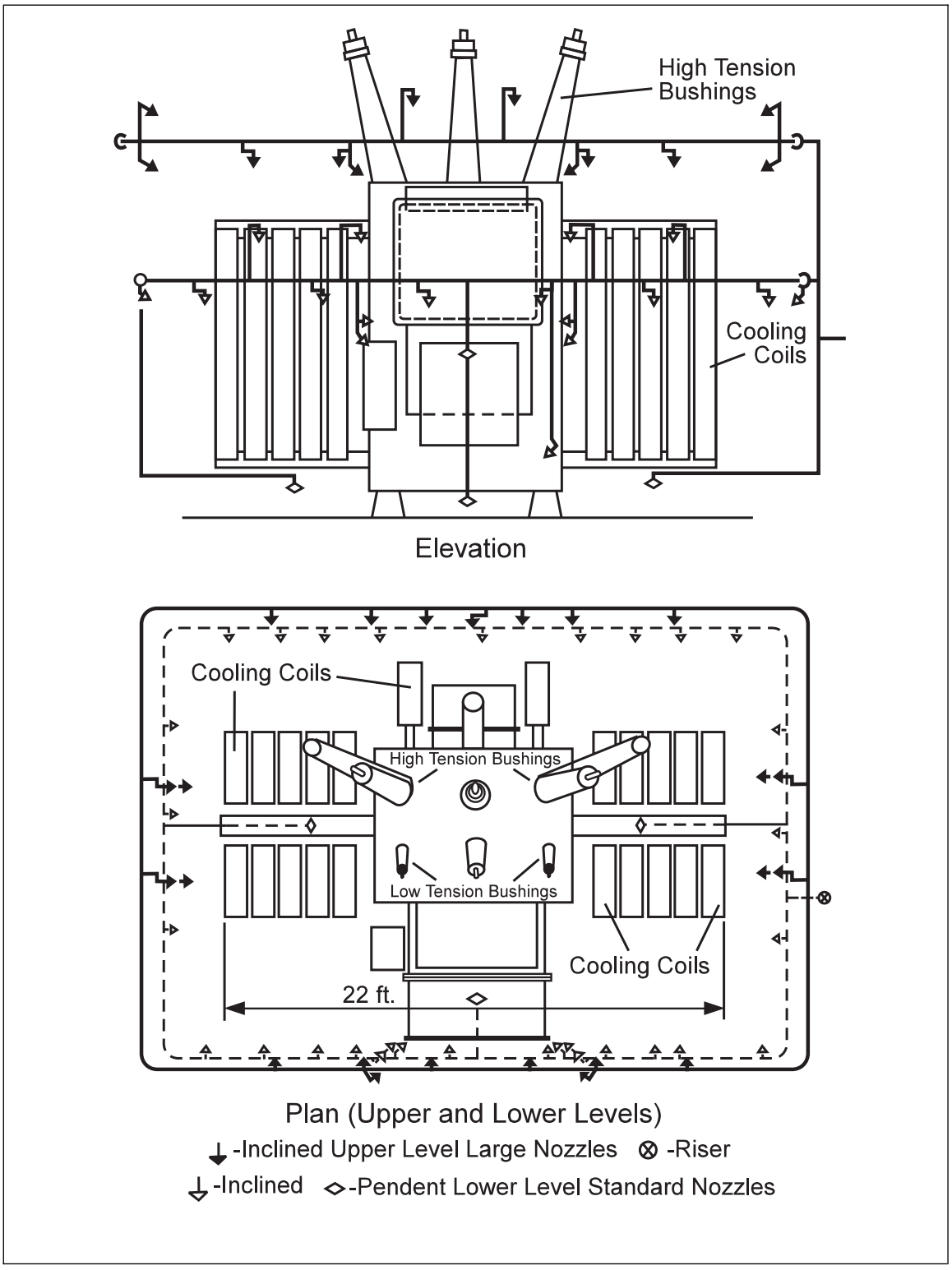


Fig. 2.3.2.1-1. Nozzle and piping arrangement for transformer using nozzles of ordinary capacity. Upper-level nozzle piping shown by solid line, lower level by dashed line. Both levels are the same distance from the transformer.

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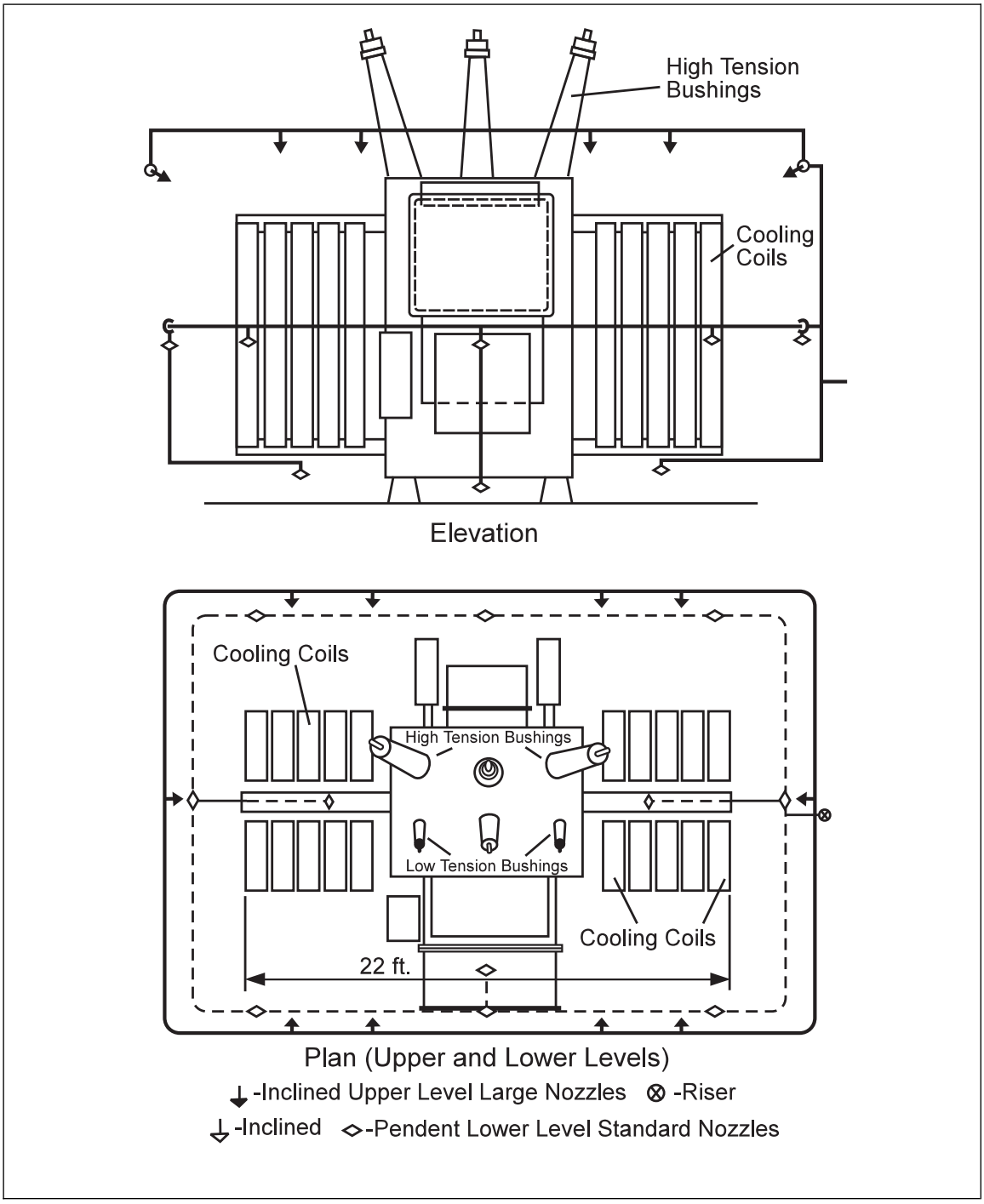


Fig. 2.3.2.1-2. Nozzle and piping arrangement for transformer using large-capacity nozzles. Upper-level nozzle piping shown by solid line, lower level by dashed line. Both levels are the same distance from the transformer.

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 0.2 gpm/ft^2 (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 a maximum distance of 10 ft (3 m) between levels.

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

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

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

2.3.2.3 Where transformers present an exposure to buildings or equipment, provide a hose stream allowance 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 m^3) 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 m^3) 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 Transformers Insulated with Liquids Containing Polychlorinated Biphenyls (PCBs)

2.4.1 Replace transformers with insulating liquid containing trace amounts up to 50 ppm PCBs in locations susceptible to nonthermal damage (hospitals, offices, residential, pharmaceutical manufacturing, food manufacturing and processing, etc.).

2.4.2 Replace PCB-filled and PCB-contaminated transformers containing more than 50 ppm in industrial and commercial facilities that are not susceptible to nonthermal damage (e.g., machine shops and heavy manufacturing). Alternatively, flush and fill the transformers with PCB-free fluid. Use a competent and certified company to perform this work.

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

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

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

A. Availability of an emergency replacement power supply

B. Telephone numbers for critical facility staff, emergency response personnel, PCB handling and disposal companies, and, for clients, the local FM office

C. 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)

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

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

2.4.3.4 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

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2.4.3.5 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

2.4.4 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 m^3) 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 them 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 onsite 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.

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

2.5 Equipment Alerts

2.5.1 General

2.5.1.1 Original equipment manufacturers and alternative service providers issue technical bulletins or alerts when design or operating problems occur that differ from expectations. Establish a bulletin/alert management process to track, prioritize, and implement the bulletins/alerts utilizing a management of change process to address any impacts on programs, procedures and generator integrity and reliability. Urgency and implementation are designated by the timing and compliance codes within the bulletin/alert.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Transformer Testing Diagnostics

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.

The reference temperature is ideally taken as the rated temperature for each component as provided by the manufacturer. However, this is not always readily available. It is also acceptable to use the temperature of neighboring equipment or neighboring points on the transformer as a reference. For example, when

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evaluating the bushings, a good reference temperature would be the coolest bushing. And, when evaluating the radiator banks, a good reference point would be the temperature of the top of the transformer tank.

3.1.1 Thermography

Thermography is performed with a thermographic camera with the transformer online. 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

General criteria for evaluating thermographic scans is provided in Table 3.1.1-1.

Table 3.1.1-1. General Criteria for Evaluating Thermographic Scans

Temperature Above Reference	*Action*
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 3.1.2-1 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.

For natural ester oil, see Table 3.1.2-2 for parameters and acceptance limits that are based on IEEE C57.147.

Table 3.2.1-1. 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	50°C	27 mg/kg	15% sat	12 mg/kg	8% sat	10 mg/kg	5%sat
	60°C	35 mg/kg	15% sat	20 mg/kg	8% sat	12 mg/kg	5% sat
	70°C	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	

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Table 3.2.1-2. Tests Typically Included in an In-Service Natural Ester Oil Screen Test

Test and ASTM method	*IEEE Value for Voltage Class*		
	≤69kV	69 kV to 230 kV	More than 230 kV
Dielectric strength, kV ASTM D1816 1 mm gap 2 mm gap	23 40	28 47	30 50
Dissipation factor, ASTM D924,%, maximum 25°C 100°C	Per OEM guidance	Per OEM guidance	Per OEM guidance
Water content, ASTM D1533, mg/kg, maximum	450	350	200
Fire point (ASTM D92)	300	300	300
Viscosity (ASTM D445)	≥10%	≥10%	≥10%

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 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 3.1.3-1 (see Table 3.1.3-2 for names of gases represented by the chemical formulas).

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Table 3.1.3-1. Gases Included in a Typical DGA Report

Key Gas	*Secondary Key Gas*	*Likely Cause*
CO_2/CO	H_4, C_2H_4	Conductor overheating involving cellulose
C_2H_4	CH_4, H_2, and C_2H_6	Oil overheating
H_2	CH_4, C_2H_6, and C_2H_4	Partial discharge
C_2H_2	H_2, CH_4, and C_2H_4	Arcing

Table 3.1.3-2. Gases Represented by Chemical Formulas

Chemical Formula	*Name*
H_2	Hydrogen
CH_4	Methane
C_2H_2	Acetylene
C_2H_4	Ethylene
C_2H6	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.

Table 3.1.3-3 lists the 90th percentile value of dissolved gas concentration values for a mineral oil filled transformer as a reference. They are statistic values based on IEEE C57.104: IEEE guide for the interpretation of gases generated in oil-immersed transformers. Users may decide to use different dissolved gas concentrations for a transformer based on experience with other similar transformers.

Table 3.1.3-4 provides reference guidance for gas generation rate when there is no industrial reference or manufacturer guidance available. When any gas has the generation rate above those indicated in Table 3.1.3-4, further investigation is needed to assess the root cause and corrective action based on the assessment results.

For silicon oil filled transformers, refer Table 3.1.3-5. Table 3.1.3-6 is used for ester oil filled transformers.

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Table 3.1.3-3. 90th Percentile Gas Concentration Values for Transformers Filled with Mineral Oil

	Gas Concentration in Oil in µL/L (ppm)							
	O_2/N_2 Ratio ≤ 0.2				O_2/N_2 Ratio > 0.2			
	Transformer Age in Years				Transformer Age in Years			
Gas	Unknown	1-9	10-30	>30	Unknown	1-9	10-30	>30
Hydrogen(H_2)	80	75		100	40	40		
Methane(CH_4)	90	45	90	110	20	20		
Ethane(C_2H_6)	90	30	90	150	15	15		
Ethylene(C_{2H_4})	50	20	50	90	15	25	60	
Acetylene(C_2H_2)	1				2			
Carbon Monoxide(CO)	900				500			
Carbon dioxide (CO_2)	9000	5000	10000		5000	3500	5500	

Table 3.1.3-4. 95th Percentile Values of Gas Generation Rate for Transformers Filled with Mineral Oil

	Gas Generation Rate µL/L/year (ppm/year)			
	O_2/N_2 Ratio ≤ 0.2		O_2/N_2 Ratio > 0.2	
	Period between first and last point of the series			
Gas	4-9 Months	10–24 Months	4–9 Months	10–24 Months
Hydrogen(H_2)	50	20	25	10
Methane(CH_4)	15	10	4	3
Ethane(C_2H_6)	15	9	3	2
Ethylene(C_2H_4)	10	7	7	5
Acetylene(C_2H_2)	Any increasing rate		Any increasing rate	
Carbon Monoxide(CO)	200	100	100	80
Carbon Dioxide(CO_2)	1750	1000	1000	800

Table 3.1.3-5. Typical Gas Values and Generation Rate for Transformers Filled with Silicon Oil with no previous history

Status	*H_2 (Hydrogen)*	*CH_4 (Methane)*	*C_2H_2 (Acetylene)*	*C_2H_4 (Ethylene)*	*C_2H_6 (Ethane)*	*CO (Carbon Monoxide)*	*CO_2 (Carbon Dioxide)*	*TDCG (Total dissolved combustible gas)*
Typical value (ppm)	<200	<100	<1	<30	<30	<3000	<30,000	<3360
Generation rate G1 limit[1] (ppm per month)	<20	<10	<1	<3	<3	<300	<1500	na
Generation rate G2 limit[2] (ppm per month)	<100	<50	<1	<15	<15	<1,500	<15,000	na

Note 1. G1 limit means: if one or more gases generation rates exceed G1 limits, the unit needs to be paid attention.
Note 2. G2 limit means: if one or more gases generation rate exceed G2 limits, the unit is considered in critical condition.

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Table 3.1.3-6. Typical Dissolved Gas Concentration Value for Transformers with Ester Oil with no previous sample history

Ester Fluid Type	*H_2 (Hydrogen)*	*CH_4 (Methane)*	*C_2H_6 (Ethane)*	*C_2H_4 (Ethylene)*	*C_2H_2 (Acetylene)*	*CO (Carbon Monoxide)*	*CO_2 (Carbon Dioxide)*
Soybean-based, (ppm)	<115	20	<235	20	<2	<170	na
High-oleic sunflower-based (ppm)	<35	<25	<60	<20	<1	<500	na
Synthetic (ppm)	<65	<105	<125	<150	<15	<1400	na

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.

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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 interested.

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 another or to the tank and core. Since the capacitance also includes components such as the tap changer, bushings,

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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 3.1.7-1. The power factor limits for transformers are listed in Table 3.1.7-2, changes in the current between tests that can also be used for interpretation are listed in Table 3.1.7-3, and power factor limits for dry-type transformers are listed in Table 3.1.7-4.

Table 3.1.7-1. 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 3.1.7-2. Power Factor Limits for Transformers

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

Table 3.1.7-3. Interpretation of the Changes in Current Between Tests

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

Table 3.1.7-4. 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

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to the center conductor of the bushing and guarded, 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: In general, if the value doubles original nameplate value or more, the bushing is questionable and needs to be replaced or refurbished.
- 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. Otherwise, the bushing is questionable, and needs to be replaced or refurbished.

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 another, 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 R) 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

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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 20C and compared to a minimum resistance value derived from the following formula:

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

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 R). 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:

A. The current used to perform the measurement should not exceed 10% of the rated winding current.

B. The transformer top and bottom oil temperature differential should be no more than 5°C.

C. 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:

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

Where
CF = 234.5 for copper windings and 225 for aluminum 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.

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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 manhole.

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 CO_2 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.

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.

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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 Online Condition Monitoring

The main advantage of continuous online monitoring comparing with routine testing is to allow for early detection in case of faults, monitor a transformer condition at emergency or the progress of deficiency conditions, and enables users to assess the hazards remotely. Therefore, online monitoring should be viewed as “warning” tools. Same level of attention and follow up action should be provided when online monitoring data indicate a potential problem evolving on the transformers as with results coming from routine laboratory or off-line testing.

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

3.2.1 Gas-in-Oil Monitor System

Gas-in-oil online monitor system have been available for many years starting with hydrogen sensors. It is one of the best detectors of abnormalities in power transformers. Today, multiple-gas monitors are available that can detect all the important fault gasses individually. The following are main categories of the monitoring system per gas monitored:

A. Single gas or composite gas monitors: these sensors detect hydrogen primarily. These monitoring systems give a single readout in respond to abnormal operation of transformers and provide warning signal once the pre-set threshold value is exceeded. It is a relatively economical system.

B. Multi-gas monitors: these systems can monitor up to eight or nine dissolved gasses individually. There are three main technologies used: gas-chromatography system, infrared based or photoacoustic spectroscopy. These systems provide a lot more information about the condition of transformers. They significantly increase the usefulness of the monitoring system for real time diagnostics on transformers.

Installation of dissolved gas monitors on existing transformers requires connection oil valves that are pre-existing.

3.2.2 Moisture in Oil Monitoring System

The commonly used moisture-in-oil sensors are based on thin-film capacitive element technology. The capacitance measured changes proportionally to the change in the relative saturation (relative humidity) of the moisture in the oil as those sensors respond to the change in relative humidity in the air. The instruments can provide indication of relative saturation of moisture in oil or converted PPM performed using a built-in formula.

3.2.3 Condenser Bushing Insulation Monitoring System

There are different ways to monitor bushing insulation:

A. Sum current monitoring system: The principle of the sum current method is based on the fact the initial sum of the leakage current from the testing tap of the three bushing should be theoretically zero when three bushings are identical. Any change in the sum current from the initial sum value would indicate a deterioration of the insulation of one or more of bushings.

B. Relative power factor monitoring systems: They measure the power factor in a similar principle as the off-line power factor measurement. The main difference is the measurement circuit of an online systems uses the voltage of another phase as the reference.

3.2.4 Partial Discharge Monitoring

Partial discharge activity monitoring systems are either electrical or acoustic based in general. They are only applicable for transformers with a highest voltage rating above 4 kV. Either method has its own their own advantages and disadvantages and can be complimentary rather than exclusive

Electrical method uses sensors are installed on bushing testing tap to measure electrical signal from PD activities. In such case, bushings act like capacitors and so electrical PD signal is induced through capacitance

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coupling. Alternatively, using split-core radio frequency current transformer (RFCT) or Rogowski around neutral connection, main tank ground, HV cable at the cable box or on the neutral strap of such cable, or ultrahigh frequency valve antenna.

3.2.4.1 Acoustic Monitoring

These monitoring systems are to detect acoustic wave in the range between 20kHz and 1 MHz propagated from partial discharge sources within the transformer tank. They can identify and locate PD sources with multiple sensors temporarily installed on transformer tanks externally.

3.2.5 Load Tap Changer Motor Current Monitoring

The use of online tap changers monitors has been successful to determine when mechanical problem with the mechanism are occurring. Motor current is to determine if any abnormal binding is occurring. This binding is usually indicative of a serious problem or impending failure of the tap change mechanism. However, the user must exercise caution when using this the method as the monitoring device must have the necessary measurement speed to correctly capture the motor current signature.

3.3 FM Approved Transformers

FM Approval is intended for liquid-filled transformers are either naturally cooled or utilizing forcibly circulated cooling medium. The standard limits Approval for the naturally cooled transformers rated from 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:

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

B. 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 C below.

C. 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.

D. 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.

E. Use of FM Approved transformer fluids.

F. 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.

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 four mechanisms:

- Pyrolysis (heat)

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- Hydrolysis (water)
- Oxidation (air)
- cidity

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 four degradation mechanisms:

A. Every 7°C increase in temperature above the rated hot spot temperature will double paper insulation aging rate.

B. Every doubling of the moisture content in the paper insulation above 0.5% by weight will double paper insulation aging rate.

C. 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 four factors, the nameplate age alone cannot be solely relied upon to determine when a transformer needs to be replaced.

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 recommends the use of oil screen tests, DGA, and furan analysis as screening tools to indicate 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 CO_2 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.

3.4.1 Arc Furnace Transformers

The arc furnace transformer is designed for operation with short circuit arcing on the load side for periods of 1 hour out of every 1.5 to 2 hours. Arc furnace transformer designs can have a shorter life span than power distribution transformers as a result due to the service aging caused by the operating environment. An equipment breakdown spare arc furnace transformer is essential. They are available in sizes ranging from 200 kVA to over 100 MVA. The transformer windings are normally oil-immersed and water-cooled, although some have natural or forced oil circulation. Most modern units employ external heat exchangers for cooling the oil.

4.0 REFERENCES

4.1 FM

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*
Data Sheet 9-0, *Asset Integrity*

FM Approval Standard 6520, *Dissolved Gas Analysis Monitoring Systems in Liquid Immersed Transformers*

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*

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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

Arc furnace transformer (AFT): A specialized transformer used in the metals production industry to power an electric arc furnace (EAF). In the steel industry, an AFT is used for making both carbon and specialty steel. The transformer produces electric arcs between electrodes that provide the energy to melt the steel.

Distribution transformer: A transformer for transferring electrical energy from a primary distribution circuit to a secondary distribution circuit or consumer's service circuit. These transformers can range in size up to 10MVA with primary voltage at 69kV and below.

FM Approved: Products and services that have satisfied the criteria for Approval by FM Approvals. Refer to the *Approval Guide*, an online resource of FM Approvals, for a complete listing of products and services that are FM Approved.

FM Approved transformer: A transformer filled with an FM Approved fluid, either naturally cooled or utilizing forcibly circulated cooling medium. The standard limits Approval for the naturally cooled transformers rated from 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.

FM Approved transformer fluid: A transformer insulating fluid that exhibits a reduced fire hazard, proven through testing by FM Approvals. The transformer is not necessarily FM Approved.

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).

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.

PCB-contaminated transformers: Transformers that contain PCBs at concentrations of ≥ 50 ppm and < 500 ppm in the contaminating fluid.

PCB filled transformers: Transformers that contain ≥ 500 ppm PCBs.

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Power transformer: A transformer that transfers electrical energy in any part of the circuit between the generator and the primary distribution circuits.

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.

Rectifier transformer: A transformer that provides power to a rectifier for converting alternating current (AC) to direct current (DC). The term “rectiformer” is used in the aluminum smelting industry.

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

APPENDIX B DOCUMENT REVISION HISTORY

The purpose of this appendix is to capture the changes that were made to this document each time it was published. Please note that section numbers refer specifically to those in the version published on the date shown (i.e., the section numbers are not always the same from version to version).

October 2026. Interim revision. Editorial changes were made.

October 2025. Interim revision. Editorial changes were made to improve clarity.

April 2025. Interim revision. Significant changes include the following:

A. Added new recommendation of dry-type condenser bushings for new installations in Section 2.1.0.

B. Added new recommendation for replacement strategy of critical transformers in Section 2.1.4.

C. Added new recommendation of spare condenser bushing as part of equipment breakdown spare for transformers rated 100 MVA and above in Section 2.1.8.

D. Clarified the guidance for on-line condition monitoring recommendations, including FM Approved monitoring systems, in Section 2.1.5.

October 2024. Interim revision. Minor editorial changes were made.

July 2024. Interim revision. Minor editorial changes were made.

July 2023. Interim revision. Minor editorial changes were made.

July 2022. Interim Revision. Added guidance for the use of FM Approved dissolved hydrogen on-line monitoring system. Minor editorial changes were also made.

January 2022. Interim revision. Minor editorial changes were made.

July 2021. Interim revision. The following significant changes were made:

A. Clarified Section 1.0, Scope.

B. Clarified equipment contingency planning guidance.

C. Added guidance for arc furnace transformer spare viability.

April 2021. Minor editorial changes were made (Sections 2.1.3 and 2.1.4).

October 2020. Minor editorial changes were made.

July 2020. Interim revision. The following changes were made:

A. Updated contingency planning and sparing guidance.

B. Added arc furnace transformer sparing guidance.

C. Updated DGA information in Table 13 and Table 14.

October 2019. Interim revision. Minor editorial changes were made.

July 2019. This document has been completely revised. Major changes include the following:

A. Updated differential protection recommendations for special transformers.

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B. Improved the clarity and consistency of guidance on transformer online condition monitoring sensor recommendations, and their integration into an overall condition-based maintenance approach.

C. Improved contingency plan guidance.

D. Added new CAF guidance for protection of indoor transformers.

E. Revised content related to silicone insulating fluids.

F. Revised guidance for PCB-contaminated transformers.

G. Aligned B&M guidance with an asset integrity approach with some emphasis on recommendations on deficiency management.

October 2017. Interim revision. Editorial changes were made.

April 2016. Interim revision. Clarifications were made in Sections 2.2.1 and 2.3.1, *Construction and Location*.

January 2016. Interim revision. 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/ft^2 (15 mm/min) from 0.2 gpm/ft^2 (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/ft^2 (15 mm/min) from 0.15 gpm/ft^2 (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 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:

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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 m^3) 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 m^3) for transformers containing all FM Approved less flammable fluids. It further increases the size to 2640 gal (10 m^3) 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.

APPENDIX C BIBLIORGRAPHY

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