NUREG/CR-5753
INEL-95/0573

Aging of Safety Class 1E Transformers in Safety Systems of Nuclear Power Plants

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Prepared for
U.S. Nuclear Regulatory Commission

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Manuscript Completed: November 1995
Date Published: February 1996

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Washington, DC 20555-0001
NRC Job Code A6389

ABSTRACT

This report discusses aging effects on safety-related power transformers in nuclear power plants. It also evaluates maintenance, testing, and monitoring practices with respect to their effectiveness in detecting and mitigating the effects of aging. The study follows the U.S. Nuclear Regulatory Commission's (NRC's) Nuclear Plant-Aging Research approach. It investigates the materials used in transformer construction, identifies stressors and aging mechanisms, presents operating and testing experience with aging effects, analyzes transformer failure events reported in various databases, and evaluates maintenance practices. Databases maintained by the nuclear industry were analyzed to evaluate the effects of aging on the operation of nuclear power plants.

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EXECUTIVE SUMMARY

Power transformers of various sizes and types operate in the Class 1E power systems at nuclear facilities throughout the United States. Continued safe and reliable operation of these transformers is critical to the overall safe operation of the nuclear facility. Therefore, it is important to identify the aging mechanisms and their effects that can lead to transformer failure and to implement maintenance and testing practices that can identify and alleviate the effects of these aging mechanisms.

This report describes a study that was sponsored by the U.S. Nuclear Regulatory Commission and performed at the Idaho National Engineering Laboratory to evaluate aging effects on Class 1E power distribution transformers in nuclear power plants. The study identifies materials used in transformer construction, stressors, and aging mechanisms; presents data on Class 1E transformer failure events as reported in various databases; and compares current transformer maintenance and testing procedures.

Transformer data from the NRC Licensee Event Reports (LERs), the Nuclear Plant Reliability Data System (NPRDS), and the Nuclear Power Experience data system were reviewed to determine if evidence of transformer aging effects could be found in the nuclear plant operating experience. A cooperating utility provided manufacturing data, operating experience data, and maintenance information for the study. Maintenance practices and scheduling information were obtained from an operating nuclear station.

Using the information from the above sources, transformer records were examined for 88 plants for the years of 1983 through 1990. During this period, 33 disabling problems and failures were reported on the 723 Class 1E power transformers listed in the NPRDS. Five of the reported incidents resulted in reportable events (LERs). The data for the 88 plants also show that 95% of the Class 1E transformers were under 20 years old, and nearly 75% are less than 15 years old. The low number of problems occurring on the Class lE power transformers give little indication that the aging of transformers is causing significant problems or that there is an increasing number of problems and failures. However, because of the relative young age of the Class 1E transformers it is difficult to determine if this is an accurate picture of the effects of transformer aging at the nuclear plants.

A standard probabilistic risk assessment (PRA) was reviewed to determine the risk significance of Class 1E transformers and the potential for aging to increase the risk significance. The fault trees for the PRA included transformers along with other Class 1E components. Truncation of the cut sets still left the transformers as potentially risk-significant components. Reevaluation with a unity failure probability for the most risk-significant type of transformer shows that aging of the transformer has the potential to significantly increase core damage frequency. Aging is an important factor for the most risk-significant transformers.

An example maintenance program was developed for oil, gas, and air-cooled power transformers using industry and manufacturer's recommendations. The maintenance program for an operating nuclear station was examined and compared with the developed program. The program compared favorably with the example program, with only minor deviations.

It is our conclusion that there is no presently identified transformer aging mechanism that would cause a safety concern. If nuclear plants use currently recognized monitoring and testing methods and follow a rigorous surveillance, testing, maintenance, and replacement program (based on current and future manufacturers and industry guidelines) the effects of transformer aging will not increase the risk to nuclear plant safety. These conclusions are based on our review of (a) the transformer aging mechanisms, (b) the accepted transformer monitoring and testing methods, (c) the manufacturer's and industry transformer maintenance and surveillance guidelines, (d) the current transformer surveillance and maintenance practices at an operating nuclear station, and (e) the transformer plant operating experience for 88 nuclear plants.

However, it is our opinion that owing to the age of the Class 1E power transformers in use at nuclear plants (which are relatively young in comparison to the expected transformer life), the past operating experience may not truly reflect the effects of transformer aging or the current surveillance and maintenance practices in the industry. Review of plant operating data (approximately every 5 years) would be useful in determining if present information remains accurate and in determining if any significant unidentified trends are developing.

Aging of Safety Class 1E Transformers in Safety Systems of Nuclear Power Plants

1. INTRODUCTION

The U.S. Nuclear Regulatory Commission (NRC) initiated the Nuclear Plant-Aging Research Program (NPAR) to obtain a better understanding of how degradation caused by aging of key components could affect nuclear plant safety, if not corrected before loss of functional capability, and how the aging process may change the likelihood of component failures in systems that mitigate transients and accidents. The possibility of aging degradation causing accidents is also a concern.

This report presents an engineering study of power transformers used in safety-related applications. While the 1E power system includes other transformers, such as current, potential, control, and instrumentation transformers, these transformers are not included in this study. Control transformers, which are commonly found in motor control centers, are included in an aging assessment of motor control centers reported in NUREG/CR-5053. Control transformers are similar to current and potential transformers. Therefore, this study focuses on power transformers. The work supports the NPAR goals stated in NUREG-1144, summarized as follows:

- Identify and characterize aging and service-wear effects associated with electrical and mechanical components, interfaces, and systems likely to impair plant safety.
- Identify and recommend methods of inspection, surveillance, and condition monitoring of electrical and mechanical components and systems that will be effective in detecting significant aging effects before loss of safety function, so that timely maintenance and repair or replacement can be implemented.
- Identify and recommend acceptable maintenance practices that can be undertaken to mitigate the effects of aging and to diminish the rate and extent of degradation caused by aging and service wear.

The NPAR Program is being conducted at several national laboratories, including the Idaho National Engineering Laboratory (INEL).

A nuclear plant typically has between 4 and 12 Class 1E power transformers supplying the many safety-related systems and equipment. Reliability of these transformers is essential to ensure continued safe operation of the plant. Even though sufficient redundancy is provided so that failure of only one transformer will not place the plant in an unsafe condition, the failure of one transformer does result in challenges to plant operation (such as reactor scram) and reduces the reliability and redundancy aspects of the 1E power system. This study attempts to resolve two issues: (a) whether aging of transformers is expected to significantly reduce reliability during their installed lifetime, and (b) whether careful monitoring and maintenance would improve or ensure reliability over their service life.

Section 2 describes the power transformers themselves and the components they use; Section 3 describes the materials used; Section 4 reviews transformer failure modes; Section 5 reviews operating experience using various databases and plant specific information; Section 6 addresses transformer aging risk analysis; Section 7 discusses transformer inspection, surveillance, monitoring, and maintenance; Section 8 reviews standards, guides, and design criteria applicable to the Class 1E power transformers; and Section 9 presents conclusions.

This study used two databases to evaluate the effects of aging on transformers in nuclear power plants: the Nuclear Power Experience database (NPE) and the Nuclear Plant Reliability Data System (NPRDS). In addition, Licensee Event

Reports (LERs) were used to identify transformers failures that resulted in events that were reportable to the NRC. During this study, it was determined that the NPRDS was the only information source with nameplate data on Class 1E power transformers. For this reason, the NPRDS was used to identify specific types and ages of transformer that experienced failures. All of the information sources were used to identify failure causes and effects on plant operation. Because this study was on the effects of power transformer aging, the decision was made not to use the transformer data on plants placed in service after January 1, 1989. Subsequent review of NPRDS data shows that only 88 other plants had Class 1E transformer nameplate data included in the database. The information from these plants was used in the study.

2. POWER TRANSFORMERS

Figure 2-1 shows a typical nuclear plant electrical distribution system with the associated power transformers. The maximum voltage for transformers, electrical buses, and electrical equipment within the dashed line is 15 kV. The voltages on the high-voltage winding (primary) of transformers, located outside the dashed line, varies between 15 and 500 kV, depending on the individual plants and the connected commercial power system.

During this study, NPRDS transformer records were reviewed for 88 nuclear plants. NPRDS event records and engineering data show that 19 of the plants list a total for 50 Class 1E high-voltage (>15 kV) transformers. The high-voltage rating for these transformers varied between 19 and 500 kV. The transformers use a liquid insulator/coolant, usually mineral oil. These high-voltage transformers have forced-air and forced-oil supplementary cooling. The 88 plants have 673 Class 1E low-voltage (<15 kV) transformers, with 70 of these using liquid insulation/coolant (mineral oil or noninflammable fluid), 50 using a flourogas insulation/coolant, and 553 using air as the insulation/coolant. A review of the electrical diagrams for several of the 19 plants listed as having 1E high-voltage transformers and conversations with persons with inplant experience indicate that none of these high-voltage transformers are likely to be actually classified as 1E. However, with the exception of some of the auxiliary equipment on the high-voltage transformers, such as load tap changers and forced-oil cooling, descriptions and failure mechanisms are generally applicable to both high- and low-voltage liquid-filled transformers. In addition, failure of these nonsafety-related transformers usually has a significant impact on the operation of the plant, such as reactor scram, actuation of emergency power sources, or loss of redundancy. Therefore, the high-voltage transformers classified as 1E by NPRDS, though probably not actually 1E, will be included in this report.

Although individual plants have different power supply circuitry and corresponding different numbers and location of power transformers, the information on the construction, aging, and maintenance of transformers applies to all transformers used in nuclear plants.

The sections that follow describe the basic elements of the Class 1E power transformers for the 88 nuclear plants used in this study. Transformers have many special design and construction methods for cores, windings, tanks, bushings, load tap changers, and other elements. No attempt has been made to describe these design and construction methods.

2.1 Transformer Construction

Figure 2-2 shows the basic components of power transformers. As the figure shows, the basic transformer components include a silicon-steel core, primary and secondary windings (with connections to the bushings), solid insulation, the winding/core insulator/coolant medium, a transformer tank enclosure, and the primary and secondary bushings. Tables 2-1 through 2-5, located at the end of Section 2 (beginning on page 9), show all of the components normally used for air, nitrogen, and fluorogas, and low- and high-voltage fluid-cooled transformers, respectively.

2.1.1 Core and Windings. Power transformers are constructed using separate copper or aluminum primary and secondary windings on a silicon-steel core. Upon applying an ac voltage to the primary winding, a corresponding varying magnetic flux is created in the core. The magnetic flux in the core, in turn, induces a voltage on the secondary winding. Some transformers have multiple windings allowing power to be transformed to different voltages. The input to output voltages are a direct ratio to the number of turns on each winding. The use of power transformers allows power to be transmitted at high voltages (reducing line losses) and then lowered to usable voltages.

2.1.2 Solid Insulation. To prevent electrical shorting between adjacent turns and between

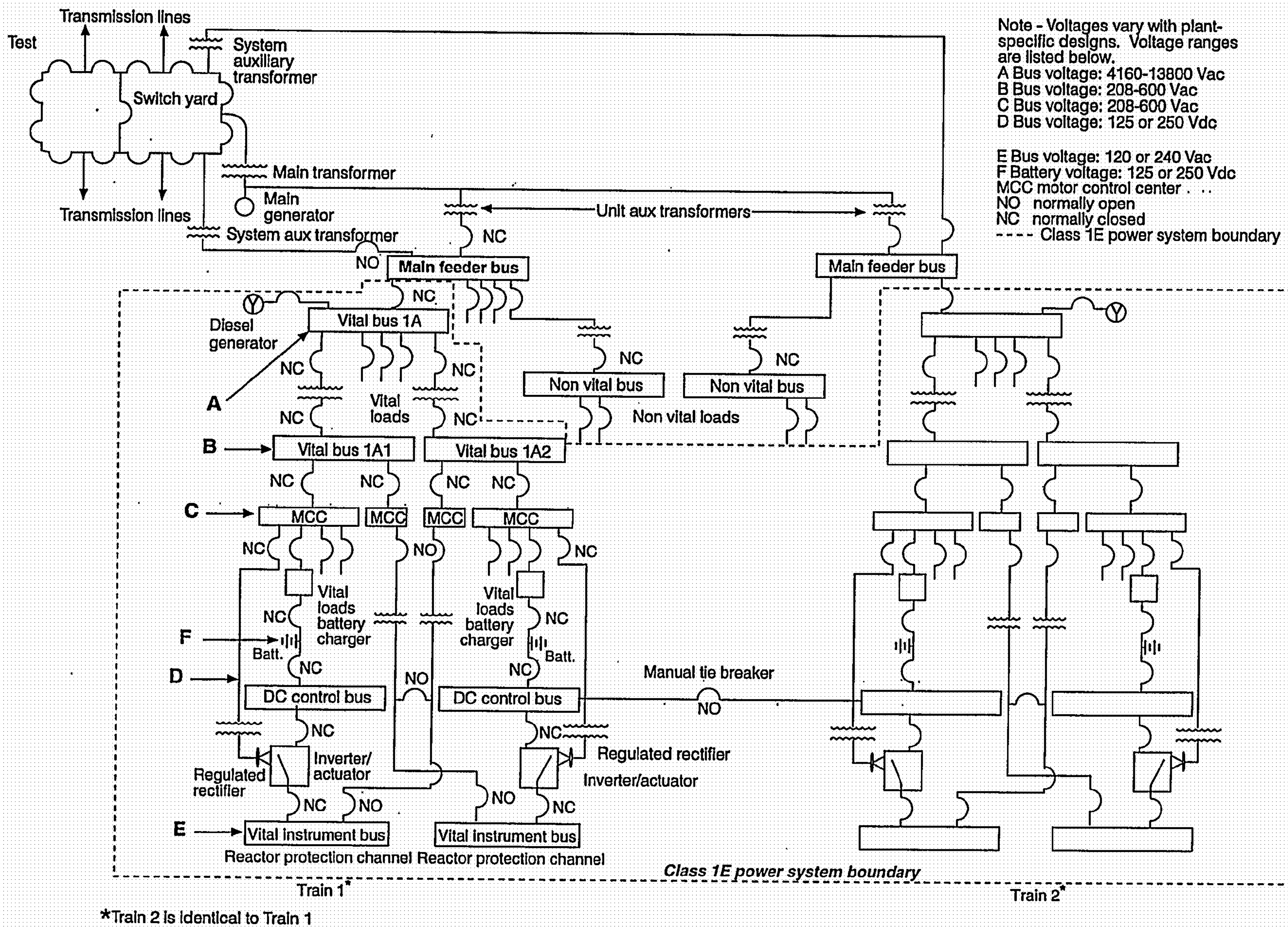


Figure 2-1. Typical nuclear power station electrical diagram.

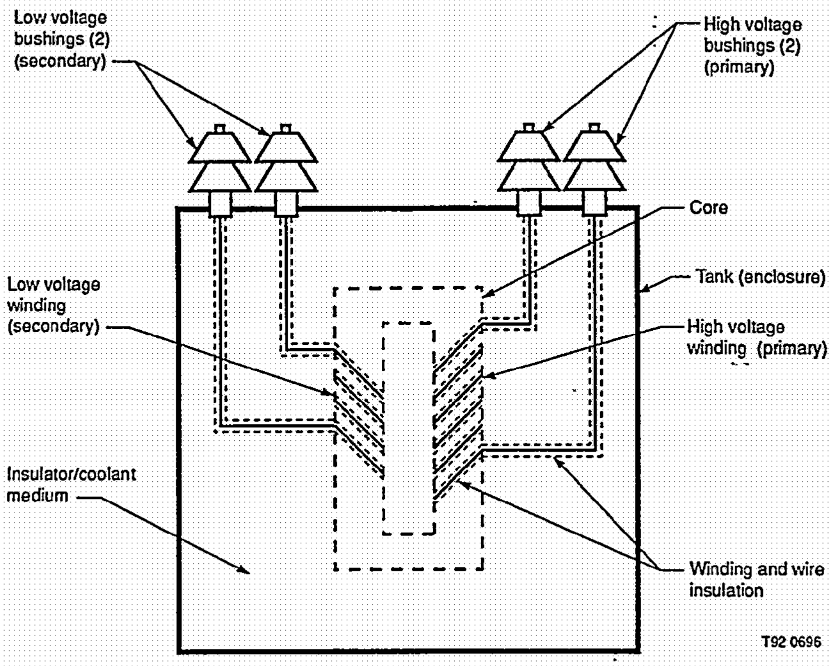


Figure 2-2. Basic components of a power transformer.

separate windings, various methods and materials are used to provide the necessary dielectric strength (insulation) between the winding turns, the high- and low-voltage windings, the magnetic core, and other electrical conductive materials. The insulating methods include applying layer insulation or coil insulation between parts of windings and applying turn insulation between individual or groups of strands forming a single turn. The materials used are described in Section 3 of this report.

2.1.3 Insulating/Cooling Medium. The transformer winding and wire insulation materials have the necessary dielectric strength to prevent electrical shorting between individual winding turns, the windings, the core, and other electrical conductive material. However, entry of contaminating materials to the winding insulation is a threat to the transformer operation. Water is the most frequent contaminant experienced during transformer operation. All contaminants have the potential to reduce the dielectric strength of the winding insulation and can compromise the electrical insulation.

To prevent the entry of contaminating materials, the transformer solid insulation is surrounded by an insulation medium with a dielectric strength as good as, or in some cases better than, the winding insulation. Although different materials and designs are used in transformers, all power transformers use either a gas or liquid insulating medium to surround the solid insulation. These insulating mediums prevent the entry of contaminants. In addition, the insulating medium serves another critical function; it transfers the heat generated by core and winding losses to the atmosphere. Without this heat removal, the life of the solid insulating materials would be significantly reduced. Note also that because the liquids and gases are critical to cooling the transformer core, the terms *type insulated* and *type cooled* are interchangeable.

2.1.3.1 Liquid-Cooled Transformers. The liquid coolants in power transformers are mineral oil or various low-flammability fluids. Mineral oil has a characteristic of high dielectric strength, an ability to recover after high dielectric stress, and an excellent heat transfer capability. Because of its high dielectric strength, mineral oil is used in all transformers with high voltages over 34 kV. In addition, because of its heat transfer capability, mineral oil is the most efficient medium to remove internal heat from power transformers and prevent excessive temperatures that shorten the life of the transformer. However, mineral oil is very flammable. Mineral oil-cooled transformers cannot be located where a transformer fire would be a hazard to other equipment or buildings. Mineral oil-cooled transformers are used for all high-voltage (>15 kV) transformers.

Although transformer oil is a highly refined product, it is not chemically pure. It is a mixture of hydrocarbons with other natural compounds, some of which are detrimental to the oil and others beneficial in retarding the oxidation of the oil. Oil impurities are destructive to dielectric properties. The most troublesome impurities are water, oxygen, and the many combinations of compounds formed by water and hydrogen (acids) at elevated temperatures. Under ideal conditions, only very small amounts of water will dissolve in a true solution with the oil. Small amounts of dissolved water have little affect on the dielectric strength of the oil. However, the presence of acids increases the amount of water that will be dissolved, reducing the dielectric strength of the oil accordingly. The oil-water solution will be subsequently absorbed by the paper and paperboard used in the winding insulation. The result will be a decrease in the dielectric strength of the insulating materials and an accelerated aging of the paper. The problem of air and water in transformer oil can be minimized by eliminating them from, and keeping them out of, the transformer oil. For this reason, all oil-cooled transformers are completely sealed. There are three basic methods used in nuclear plant transformers to perform these functions and permit normal expansion and contraction of the transformer oil without disturbing the integrity of the seal.

- *Leaving an air space above the oil in the sealed tank.* The small amounts of water and oxygen present in the air will be absorbed, leaving a space filled with the nitrogen gas from the air. This method is used for transformers with voltages below 15 kV. Although unconfirmed, it is believed that there are no Class 1E transformers in the 88 plants reviewed that use this method to maintain the integrity of mineral oil-filled transformers.
- *Maintaining a pressurized nitrogen atmosphere above the oil in the sealed tank.* A low nitrogen gas pressure is maintained using nitrogen cylinders, pressure gauges, and pressure regulators.
- *Using a sealed flexible diaphragm on top of the oil inside the sealed tank with an air space above the diaphragm.* A flexible diaphragm completes the seal between the oil in the tank and the air space. The diaphragm is able to accommodate expansion or contraction of the oil and oil leaks.

The other types of fluids used for liquid insulated transformers are Askarel, silicones, high-flash-point hydrocarbons, chlorinated benzenes, or chlorofluorocarbons. Because of environmental concerns, transformers using Askarel are no longer manufactured and are being phased out of service. The low flammability types of insulating fluids have a much lower dielectric constant and can only be used in transformers with a voltage less than 34 kV. These transformers do not transfer heat as well as mineral oil; however, they transfer heat much better than gas-insulated transformers. Transformers using these types of insulating fluids can be used inside of buildings. These transformers use a sealed case with a gas space above the fluid.

2.1.3.2 Gas-Cooled Transformers (Dry). Gas-cooled transformers, commonly known as *dry* type transformers, use air, fluorogas, or nitrogen as the insulating coolant. Air has a low dielectric strength and low heat transfer capability. To make full use of the limited heat transfer capabilities of air, most transformers of this type are usually not sealed and are ventilated to the surrounding atmosphere. To prevent the intrusion of contaminants, including water, the transformers are located in a clean and dry atmosphere. This type of transformer is used in nuclear plant Class 1E power supply systems with a maximum voltage less than 15 kV.

Nitrogen-cooled transformers have dielectric and heat transfer characteristics similar to dry air. Nitrogen insulated transformers require a sealed case, pressure monitoring instruments, and a means to add nitrogen. They may be used in contaminated atmospheres.

Fluorogas-cooled transformers have better dielectric strength and heat-transfer capacity than air or nitrogen. The dielectric strength and the heat-transfer capability increase with density of the fluorogas. For this reason, fluorogas-insulated transformers are used with the internal gas pressure above atmospheric pressure, in some cases with a 3-atm gauge pressure. As with the nitrogen insulated transformers, the fluorogas transformer requires a sealed transformer case, gas pressure monitoring instruments, and a means to add fluorogas. This type of transformer is used in place of air-cooled transformers in contaminated atmospheres where the space is limited and increased load handling capability is required.

2.1.4 Transformer Bushings. A transformer bushing is a structure that provides an insulated passageway through the transformer tank wall for an electrical conductor. The bushing allows external connections to be made to transformer internal electrical parts without violating the tank internal integrity (sealing). The power transformer bushings are designed with insulation capable of handling the dielectric stresses in the transition through the transformer tank to the connection to electric wire or cables. Porcelain is used for the exposed bushing surfaces. Bushings used outside and/or in contaminated atmospheres, are designed with one or more (depending on voltage and atmosphere) skirts to prevent normal moisture or other contamination from making an electrical path across the porcelain. As the voltages are increased, the transformer bushings require an increased dielectric strength. The bushings use insulation materials similar to those used in a transformer, including mineral oil in their internal construction.

2.1.5 Transformer Tank (enclosure). All power transformers have a steel enclosure for the winding and core. This enclosure provides both a physical barrier to the electric parts and a sealed container for the liquids and gases (excluding air) used as an insulator and coolant medium. The enclosures are made using both welded and bolted steel plates. A transformer tank may enclose multiple windings and cores. Normally, a three-phase transformer will have the windings and cores for all three phases in one tank.

2.2 Transformer Cooling Systems

An important part in the operation of the transformer is preventing high core/winding temperatures that would shorten the life of the electrical insulation. Almost all modern transformers have insulation systems designed for operation at 65°C average and 80°C hot spot winding temperature rise over an ambient temperature of 30°C. Older transformers were designed with a 55°C average and 65°C hot spot rise over a 30°C ambient temperature. All power transformers are designed to maintain the transformer temperatures within these limits when the transformer load is within the nameplate rating. There are three methods used to remove the winding/core heat from power transformers: (a) natural convection (self-cooled), (b) forced-air, and (c) forced-oil cooling. A self-cooled transformer may or may not have an external radiator(s); forced-air and forced-oil cooling requires them. Self-cooled is inherent, and forced-air cooling can be applied to all transformers. A forced-oil system uses a pump to move the hot oil above the windings and core to the forced-air cooling radiator. The cooled oil is returned to the bottom of the transformer. All of the 50 high-voltage transformers examined have forced-air and forced-oil cooling. Forced-oil cooling was not used on any lower voltage Class 1E transformers. Each transformer has a self-cooled electrical load rating (kVa). Increasing kVa ratings are allowed for each additional cooling capability included on the transformer. Secondary water cooling is also used on high-power transformers; however, this type of supplementary cooling is not used on any of the transformers for the plants reviewed. Forced-air and forced-oil cooling systems have temperature transducers, control systems, and fan/pump motors to maintain transformer temperatures below set limits. *Note that the failure of any forced cooling system requires the corresponding reduction in transformer loading.*

2.3 Load Tap Changers

A number of the high-voltage (>15 kVA) transformers used in the nuclear plants have load tap changing (LTC) equipment. This equipment enables the transformer to automatically maintain a constant voltage (±2.5%) for plant equipment under variable offsite power conditions. As shown in Figure 2-3, the regulation is performed by increasing or decreasing the active turns in the high-voltage winding. To prevent load interruption, the change is made by shunting one winding load tap to another without opening the winding. Although special methods are used to limit circulating currents through the shunt and connecting contacts, a small amount of arcing is always present during the changing of taps. Because of the contact arcing, the load tap changer contacts and winding connections are always located in a sealed oil-filled compartment that is isolated from the transformer core and windings. An external motor mechanism drives the internal shunting contacts. This mechanism includes the necessary gearing, mechanical coupling, cam-operated stepping switches, and other equipment to step the internal tap contacts. Voltage measuring and tap changer motor controls allow both a variable time delay and voltage operational band to prevent unnecessary wear of the system parts.

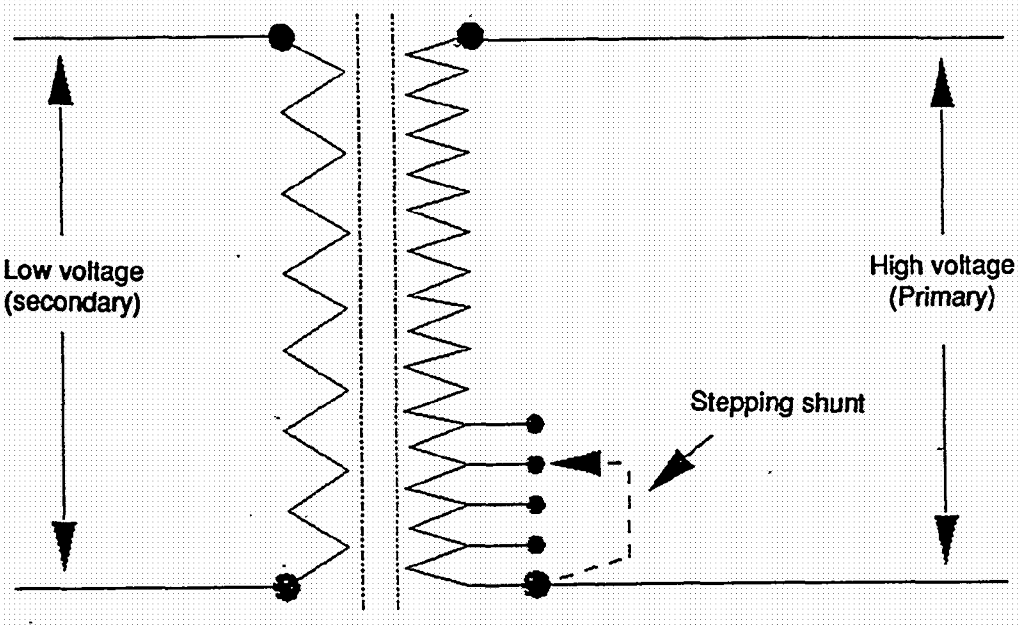


Figure 2-3. Electrical diagram of power transformer load tap changer.

Table 2-1. Components for air-cooled power transformer.

Component	Use	Comments
Windings	High- and low-voltage windings. Tertiary windings.	There may be multiple low-voltage windings.
Silicon-steel core	Contains magnetic flux for voltage induction between core windings.	—
Solid insulation	Electrical insulation between winding turns, windings, and all electrical conductive materials.	—
Tank (enclosure)	Physical protection for electrical parts. May enclose multiple windings and cores.	Unsealed and normally ventilated to atmosphere.
Bushings	Structure to provide for terminations and insulated pathway through transformer tank wall for electrical conductor.	Separate bushings are required for each connection to transformer winding.
Temperature indicator	Indication of interior and ambient temperatures.	May include alarm and contacts. Sensor location depends on design specifications.
Radiator	Forced-air cooling.	Required for forced-air cooling.
Fan(s) and motor(s)	Forced-air cooling.	Required for forced-air cooling.
Temperature transducer (contacts)	Control of forced-air cooling.	May be included with temperature indicator.
Fan motor controller(s)	Controls fan motors for forced-air cooling.	—

Table 2-2. Components for nitrogen- or fluorogas-cooled power transformer.

Component	Use	Comments
Windings	High- and low-voltage windings. Tertiary windings.	There may be multiple low-voltage windings.
Silicon-steel core	Contains magnetic flux for voltage induction between core windings.	—
Solid insulation	Electrical insulation between winding turns, windings, and all electrical conductive materials	—
Tank (sealed enclosure)	Physical protection for electrical parts. May enclose multiple windings and cores.	Sealed from outside atmosphere under nitrogen or fluorogas pressure.
Bushings	Structure to provide for terminations and insulated pathway through transformer tank wall for electrical conductor.	Separate bushings are required for each circuit connection to transformer winding.
Fluorogas insulator coolant cylinder(s)/ regulator/control	Provides fluorogas, controls tank pressure, and provides indication of tank interior pressure.	Fluorogas insulated transformers.
Nitrogen insulator/ coolant cylinder(s)/ regulator/control	Provides nitrogen gas, controls tank pressure, and provides indication of tank interior pressure.	Nitrogen insulated transformers.
Temperature indicator	Indication of interior and ambient temperatures.	May include alarm and contacts. Sensor location depends on design specifications.
Radiator (fins)	Forced-air cooling.	Required for forced-air cooling.
Fan(s) and motor(s)	Forced-air cooling.	Required for forced-air cooling.
Temperature transducer (contacts)	Start-stop forced-air cooling.	Required for forced-air cooling. May be included with temperature indicator.
Fan motor controller(s)	Controls fan motors for forced-air cooling.	Required for forced-air cooling.

Table 2-3. Components for low voltage (<15 kV) fluid cooled power transformer.

Component	Use	Comments
Windings	High- and low-voltage windings. Tertiary windings.	There may be multiple low voltage windings.
Silicon-steel core	Voltage induction between core windings.	—
Solid insulation	Electrical insulation between winding turns, windings, and all electrical conductive materials.	—
Tank (sealed enclosure)	Physical protection for electrical parts. May enclose multiple windings and cores. Contains coolant fins.	Tank seals internal components from outside atmosphere. Uses a gas blanket to prevent the entry of air, water, and other contaminants.
Bushings	Structure to provide for terminations and insulated pathway through transformer tank wall for electrical conductor.	Separate bushings are required for each circuit connection to transformer winding.
Insulator/coolant (mineral oil)	Provides dielectric insulation support, protection from contaminants, and a medium to remove winding/core heat. Used where fire does not present hazard to other equipment or buildings.	Mineral oil has a high dielectric strength, the ability to recover after dielectric stress, and is an excellent heat transfer medium. Oil is flammable and is not used where a fire would present a hazard to equipment or facilities.
Insulator/coolant (nonflammable fluids)	Provides dielectric insulation support, protection from contaminants, and a medium to remove winding/core heat.	The nonflammable fluids used are silicons, high-flash-point hydrocarbons, chlorinated benzenes, or chlorofluorocarbons. Askarel is being phased out. Silicons are used on modern transformers. These fluids have lower dielectric strength than mineral oil.
Nitrogen blanket	Optional—Provides nitrogen gas blanket over the transformer fluid. The blanket acts to prevent the entry of contaminants and allow for the expansion/contraction of fluids.	The equipment used for the system include gas cylinders, gas regulator, a pressure control, and a gas pressure indicator.

Table 2-3. (continued).

Component	Use	Comments
Temperature indicators	Indicate bulk or hot spot temperature of windings.	May include alarm contacts.
Radiator (fins)	Forced-air cooling.	Required for forced-air cooling.
Air fan(s) and motor(s)	Forced-air cooling.	Required for forced-air cooling.
Temperature transducer (contacts)	Start-stop forced-air cooling.	Required for forced-air cooling. May be included with temperature indicator.
Fan motor controller(s)	Controls fan motors for forced-air cooling.	Required for forced-air cooling.
Liquid level gauge	Indicates liquid level.	May include alarm/control contacts.
Pressure relief valve	Automatic relief and reseal after high pressure in tank.	May include alarm/control contacts.
Top liquid temperature gauge	Indicates oil temperature at high point of oil.	May include alarm/control contacts.

Table 2-4. Components for high voltage (>15 kV) mineral oil-cooled power transformer.

Component	Use	Comments
Windings	High- and low-voltage windings. Tertiary windings.	There may be multiple low-voltage windings and windings for taps.
Silicon-steel core	Contains magnetic flux for voltage induction between core windings.	—
Solid insulation	Electrical insulation between winding turns, windings, and all electrical conductive materials. Contains mineral oil. Provides core support.	—
Tank (sealed enclosure)	Physical protection for electrical parts. The tank may enclose multiple windings and cores. Contains mineral oil. Provides core support.	Tank seals internal components from outside atmosphere. Uses a gas blanket to prevent the entry of air, water, and other contaminants.

Table 2-4. (continued).

Component	Use	Comments
Bushings	Structure provides for terminations and insulated pathway through transformer tank wall for electrical conductor.	The bushings are mineral oil-filled with a level gauge. Separate bushings are required for each circuit connection to a transformer winding.
Insulator/coolant (mineral oil)	Provides dielectric insulation support to winding insulation and acts as a medium to remove winding/core heat.	Mineral oil has a high dielectric strength, the ability to recover after dielectric stress, and is an excellent heat transfer medium.
Filter press, drain, and sampling valves	Theses valves are required to allow the sampling and testing of the oil, the addition of oil, and filtering of contaminated oil.	—
Flexible diaphragm	Flexible synthetic-rubber diaphragm is sometimes used over the mineral oil to prevent the entry of air/water/contaminants and allows the expansion and contraction of the oil without damaging the tank; maintains positive pressure.	—
Radiator (fins)	Required for forced-air and forced-oil cooling.	Required for forced-air and forced-liquid cooling.
Air fan(s), motor(s), temperature transducers, and controls	Required for forced-air and forced-liquid cooling.	Required for forced-air and forced-liquid cooling
Air fan(s), motor(s), temperature transducers, and controls	Required for forced-oil cooling.	Required for forced-air cooling. Transducer input may be from oil temperature gauge contacts.
Liquid level gauge	Indication of liquid level.	May include alarm/control contacts.
Pressure/vacuum relief valves	Automatic relief and reseal after tank high/vacuum pressure.	May include alarm/control contacts.
Top liquid temperature indicator	Indication of oil temperature at high point of oil.	May include alarm/control contacts.
Winding temperature indicator	Indication of average winding or hot spot winding temperature.	May include alarm/control contacts.
Rapid pressure rise relay	Provides alarm/trip in the event of transformer failure.	—
Load tap changer	Regulates output voltage to plant with varying off-site voltages.	High maintenance item.

Table 2-5. Components of power transformer cooling systems.

Component	Required by coolant system: Self-cooled (AA)	Forced-air-cooled (FA)	Forced-oil cooled (FO)[a]
Gas heat exchanger(s)—air, nitrogen, or fluorogas-cooled transformers	No	Yes	No
Liquid heat exchanger(s)—oil or nonflammable liquid cooled transformers	No	Yes	Yes
Temperature transducers	Optional	Yes	Yes
Control system(s)	No	Yes	Yes
Fan(s) and motor(s)	No	Yes	Design dependent[b]
Pump(s) and motor(s)	No	No	Yes
Temperature indicator(s)	Yes	Yes	Yes

a. Forced-oil cooling is only used on high-voltage transformers (>15 kV).

b. Normally yes for transformers rated ≥15 kV.

3. SIGNIFICANCE OF AGING

Aging of Class 1E transformers has the potential to degrade their ability to meet design requirements. General Design Criteria 17 of 10 CFR 50, speaks in general terms of requirements placed on transformers. The 1E power system, including transformers, must have sufficient capacity and capability to ensure adequate protection of the reactor core, reactor coolant pressure boundary, and the containment integrity. In addition, sufficient independence, redundancy, and testability must be provided to perform their safety functions assuming a single failure. Aging has the potential to affect the capability to provide rated capacity and to reduce the effectiveness of redundancy through aging degradation that is common to redundant transformers. General Design Criteria 17 also requires the consideration of environmental conditions that are a result of accidents. However, Class 1E transformers are located in buildings and rooms that have controlled environments that are independent of postulated accidents and, therefore, are not affected by this requirement.

Aging is a natural phenomenon and is highly related to the environmental conditions the transformer encounters. Transformer aging would be minimal if the transformer were not operating. However, environmental conditions inherent with transformer operation cause components to degrade with time in service. Aging of transformer insulation causes deterioration that can reduce the period a transformer is capable of producing the needed capacity. In addition, as transformers approach their end of life, deteriorated insulation becomes more susceptible to failures caused by electrical transients such as those caused by lightning and switching. Some aging mechanisms are reversible, and quality can be regained, such as moisture or impurities in the insulation oil that can be removed, while others are irreversible, such as deterioration of the cellulosic paper used as insulating material. With an appropriate transformer surveillance and maintenance program, the rate of aging can be minimized. Thus, the full design life of the transformer can be achieved.

3.1 Major Transformer Components

A transformer is composed of a magnetic core, electrical windings and terminations, an enclosure, and insulation and coolant. Table 3-1 gives a brief description of these major components.

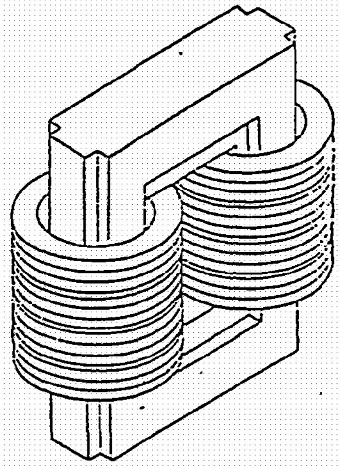
The magnetic circuit of a transformer comprises mainly a core of laminations. There are two basic core lamination design types: the core-form type is typically used in power transformers up to 50 MVA, and the shell-form type is typically used for transformers with ratings greater than 50 MVA. Figure 3-1 shows the two design types.

The cores used in modern transformers are improved versions of the fundamental designs developed early in the twentieth century. Most transformer cores are constructed of thin sheets (approximately 0.3-mm thick) of grain-oriented, 3% silicon steel. Steel is used because it carries and confines the magnetic field better than air or other low cost materials. The industry is experimentally using an amorphous steel developed by Allied-Signal, Inc. The amorphous steel, called Metglass, has greatly reduced core losses over conventional silicon steels.

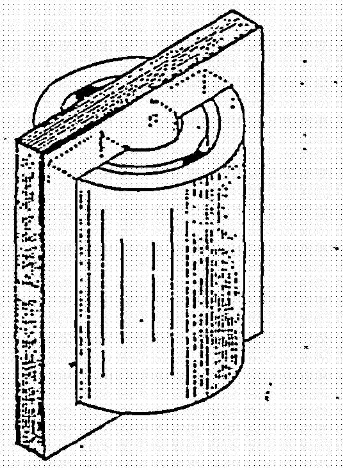
Early transformers used thick laminations of soft iron. Excessive hysteresis and eddy current losses produced heat in the cores. This excessive core heat caused transformer failures. Modern transformer cores are constructed of thin steel sheets with their grain oriented to give less resistance to magnetic flux and to reduce eddy currents. In addition, flux densities are design-limited to minimize hysteresis losses. Modern design methods for transformer cores and windings have improved projected transformer life. Transformer cores are very reliable if the transformers are operated within the temperature limits specified by the manufacturers and the cores are properly supported to reduce vibration and mechanical damage.

Table 3-1. Components of power transformers and materials of construction.

Component	Materials	Comments
Core	Silicon steel	Laminated sheets.
Windings	Cooper or aluminum	Each turn may be made up of groups of strands.
Solid insulation	Cellulose, kraft paper, phenolics, fiberglass, and varnishes–shellac, enamel, or various resins	Used to provide wire, turn, and layer insulation for the windings. Paper wrapping is also used on the leads coming from the windings.
	Fibrous–resin-paper laminates, pressboard and various kinds of paper (nylon or wood based)	Used to bond and protect (mechanical and moisture) fibrous insulating material.
Liquid–insulating/ cooling medium	*High-flammability* Mineral oil	High dielectric strength and excellent heat transfer capability. No high voltage (>15 kV) restrictions.
	Low-flammability Askarel, silicones, high-flash-point hydrocarbons, chlorinated benzenes, or chlorofluorocarbons	Good dielectric strength and heat transfer capabilities. High voltage limit is $\leq$15 kV. Askarel is being phased out. Silicones are used on all modern low-flammability fluid transformers.
Gas–insulating/ cooling medium	Air	Relatively low dielectric strength and heat transfer capabilities.
	Nitrogen/fluorogas	Relatively low dielectric strength and heat transfer capabilities. Requires pressure regulation system to maintain pressure in sealed tank.
Bushings	Porcelain, kraft paper, metal foil, mineral oil and copper or aluminum conductor	High-voltage bushings use kraft paper, metal foil, and oil inside a porcelain outer surface. Lower voltage bushings use kraft paper with a conductor inside a porcelain outer surface.
Tank	Carbon steel	Heavy gauge steel, painted to prevent corrosion.
Connections	Copper, aluminum, solder, brazing	—



An arrangement of winding used with core-form transformers.



An arrangement of winding used with shell-form transformers.

Figure 3-1. Comparison of windings used for core- and shell-form transformers.

Transformer windings have two major components: conductors and insulation. The conductors commonly used in power transformers are copper or aluminum. Each material has specific advantages. For instance, copper has greater mechanical strength and greater electrical conductivity than aluminum. Aluminum, however, costs less and is lighter than copper. The many turns in a winding must be insulated from each other and from neighboring windings. Winding conductors use Kraft paper,[a] Nomex, cellulose, or another similar insulating medium. Windings include spaces, or channels, to allow flow of the insulating coolant (such as air, oil, or gas). This cooling establishes the life of the insulation. Degraded cooling accelerates the aging of the insulating materials.

Heavy gauge structural steel is typically used to make transformer enclosures. The enclosures can be vented or sealed, indoor or outdoor, pad-mounted or pole-mounted, or dry-type or liquid-filled. The enclosure contains the insulating medium and coolant, and it protects the transformer from external environments.

The majority of transformers used in Class 1E applications are open-wound, dry-type transformers. Dry-type transformers use air as the sole source of coolant. The insulation is provided by a combination of air or nitrogen and solid insulating materials. Most dry-type transformers use a Class H, 220°C insulation system. Thus, the maximum allowable hot spot winding temperature is 220°C.

Liquid-filled transformers are also used in Class 1E applications. A specific liquid is used as a heat transfer medium. The liquid removes heat from the transformer core and windings. The enclosure surface and radiators dissipate the heat to the ambient environment. Oil pumps, forced air fans, and external radiators increase the cooling capacity of the liquid-filled transformer. The cooling fluid is in contact with the transformer windings. Therefore, the fluid must be an acceptable insulator. Historically, liquid-filled transformers have a high reliability because of the high dielectric strength of the coolant, the insulating structure, the sealed enclosure construction, and a proven design. Many different insulating liquids are currently used in liquid-filled transformers,

a. Mention of specific products or manufacturers in this document implies neither endorsement, preference, nor disapproval by the U.S. Government, any of its agencies, or Lockheed Martin Idaho, of the use of a specific product for any purpose.

including mineral oils, silicone fluids, synthetic hydrocarbons, high molecular weight hydrocarbons, trichlorotrifluoroethane, and chlorinated benzene.

Gas-cooled (vapor-cooled) transformers have characteristics that are similar to liquid-filled transformers. A gas-cooled transformer has its core and windings immersed in a refrigerant such as Freon (R-113). The refrigerant vaporizes at the core or winding interface with the refrigerant. The vaporization removes the heat from the core or winding. The vaporized coolant rises to a condensing unit above the transformer. It cools and condenses to a liquid state before returning to the transformer tank by gravity.

3.2 Construction Materials

Materials used in dry-type, liquid-filled, and gas-cooled transformers are, in general, the same, except that the cooling medium differs. Every material has its own aging mechanisms. The aging mechanisms are accelerated by contaminants or excessive heat. As the dielectric strength of the insulation decreases, a point is reached where flashover (winding to winding, winding to ground, or primary winding to secondary winding) occurs. The flashover results in contamination (discharge tracking) of the insulation. This permanently reduces the insulation's dielectric strength. These effects accelerate aging and increase the likelihood of further flashovers.

Typical transformers are constructed of high permeability silicon steel cores. Structural steel forms the tank (enclosure) and structural supports. Windings are formed by copper or aluminum conductors. Liquid coolants can include mineral oils, silicone fluids, synthetic hydrocarbons, high molecular weight hydrocarbons, trichlorotrifluoroethane, and chlorinated benzene. Insulation can be cellulosic (paper or pressboard), Kraft paper or Nomex, phenolics, plastics, porcelain, wood, epoxy, fiberglass, rubber, cork, thermoplastics, and varnishes. Other miscellaneous materials include paints and solder. The above materials do not include auxiliary equipment such as cooling fans, radiators, and oil pumps.

Each material listed above has its own aging mechanism, as identified in Table 3-2.

3.3 Transformer Loading

An issue separate from reduced transformer capacity induced by aging is increased transformer loads resulting from plant modifications. Modifications to the plant design over years of operation add electrical loads to the electrical distribution system and transformers. These additional loads cut into the design reserve capacity of the transformers. Thus, late in the design life of a transformer, a transformer may be loaded beyond the original station design requirements. The transformer may be loaded beyond its continuous rated capacity under accident conditions as a result. The additional loads will accelerate the naturally occurring aging of the transformer. This is because transformer-generated heat is directly proportional to the transformer load. The heat generated can be further increased by the physical condition of the transformer. The amount of heat retained in the transformer is related to the physical condition of its cooling system.

3.4 Transformer Capacity Considerations

As stated, transformers are specified and designed with minimum design capacity and capability. The transformers are relied on to operate under postulated accident and environmental conditions while minimizing the likelihood of simultaneous failures. Thus, with the additional loads imposed by responding to an accident, a transformer is designed to have sufficient design reserve capacity to continue operation. This design reserve capacity exists beyond additional growth loads caused by plant modifications and loss of transformer capacity caused by transformer aging. Additionally, the loads imposed may be peaked by such items as swing loads and loads such as battery chargers operating at their maximum output.

Catastrophic failure or end of transformer life, it is hoped, will not occur during an accident or accident recovery. System redundancy alleviates the concern. However, the same aging mechanisms are at work on both redundant transformers.

Table 3-2. Component stressors and failure mechanisms.

Component	Stressor	Failure mechanism	Result	Comments
Windings	Overvoltages.	Partial discharge.	Breakdown of turn-to-turn insulation.	Long term damage to the insulation is the most likely occurrence.
	High continuous current (overloads).	Solid insulation hot spot temperatures.	Aging of solid insulation increases with increased heat.	See "Solid Insulation."
	Lightning and switching surges.	Core movement.	Insulation deformation.	
	Vibration.		Turn-to-turn short.	
Core	Vibration.	Delamination.	Increase in core heat/hot spots.	See "Solid Insulation."
		Core telescoping and lateral shifts.	Core movement deforms solid insulation. Decomposition of insulation by core vibration.	
Solid insulation	Heat above design limits.	(1) Loss of mechanical strength—increases brittleness. (2) Eventual reduction in dielectric strength.	Heat speeds up the chemical action that eventually destroys the insulation.	Hot spot or average winding temperatures above the rated temperature increases the aging rate of the solid insulation. The effects of the overheating solid insulation are accumulative, that is, nonreversible.
	Moisture.	Reduced dielectric strength of solid insulation.	Electrical shorts between turns, winding, and/or ground. Disable transformer.	Moisture held in combined form releases under increasing temperatures producing same consequences as free moisture.
	Contaminants.	Same as "Moisture."	Same as "Moisture."	Contaminants usually have inferior dielectric strength.
	Core movement.	Insulation compaction.	Decomposition of insulation.	Reduces ability to withstand lightning and switching-induced surge voltages and 60 H_z over voltages and transient.
		Mechanical damage.	Electrical failure.	
Bushings	Heat and moisture on inside of bushing.	See "Solid Insulation" for failure mechanisms, results and comments.	Cracking, embrittlement.	
	Contamination on outside of bushing.	Reduced electrical distance though air to ground.	Short to tank (ground).	Can be easily cleaned and prevented.
Connections	Oxidation and vibration.	High electrical resistance, arcing, and high heat.	Open circuits and protective relay tripping.	Visual and infrared inspection used to detect.

Table 3-2. (continued).

Component	Stressor	Failure mechanism	Result	Comments
Mineral oil (Insulating/ cooling mediums)	Entrained air or water.	Sludge formed.	Reduced heat transfer capability.	Requires derating transformer or sludge removal. Buildup causes shrinkage of cellulose insulation.
		Acids formed.	Absorbed by fibrous insulations attacks metallic and other components.	Most acids formed are weakly acidic, however, over time, material aging is accelerated if acids not removed.
		Solid insulation absorbs water.	Absorbs increasing amounts of moisture in solution.	See "solid insulation–moisture."
			Reduces electrical breakdown strength.	Decomposition products include H_2, CH_4, C_2H_2, C_3H_3, H_3, and other types of hydrocarbons.

4. TRANSFORMER AGING MECHANISMS

Historically, transformers have been reliable components in electrical power systems. However, various stressors and aging mechanisms can cause transformer failures, and many of these can lead to sudden failure under electrical stress. For this reason, transformers tend to appear as a two-state device; it operates or it fails. Through an understanding of transformer aging mechanisms, material conditions can be tested and trended so timely replacement or repair can be performed prior to catastrophic failure. In addition, maintenance actions can be taken to minimize the rate of aging and ensure maximum transformer lifetime.

Transformer failures are classified as one of four types: magnetic circuit, winding, insulation, or structural failures. These do not include failures of auxiliary equipment such as cooling fans. Some overlap of these classifications may occur, such as the structural failure of an insulating bushing. Another example of overlapping classification is a flashover between adjacent winding turns that causes degradation of the dielectric strength of the insulating structure.

The metals in the structure, magnetic circuit, and windings are, in general, not subject to aging as are nonmetallic components. Thus, the life of the transformer depends mostly on the life of the insulation. Transformer failures follow a typical bathtub curve. Manufacturing defects (such as poor design, faulty materials, burred conductors, and workmanship) show up early in the life of a transformer. Then a period of relatively trouble free operation occurs. Late in the life of a transformer, aging mechanisms could potentially translate into transformer failures. The objective of General Design Criteria 17 is to have transformers operate in the second, bottom portion of the bathtub curve. That is, transformer life will either extend beyond the station life or the transformer will be replaced before failure would occur if responding to an accident condition.

Temperature is an aging mechanism that decreases the mechanical strength and increases the brittleness of the fibrous insulation. This aging mechanism accelerates with increased operating or hot spot temperatures. Heat accelerates the chemical reactions that liberate oxygen from the fibrous atomic structure. This mechanism makes a transformer more likely to fail as it increases in age. This occurs even though the dielectric strength of the insulation material may not be seriously decreased. The deterioration of the fibrous insulation is not reversible. Monitoring transformer temperatures to verify continued operation within design temperature limits helps to ensure the design transformer life. Imbedded temperature sensors and infrared heat scans can be used.

Moisture in an insulating medium (oil, air, or gas) is another aging mechanism. Heat accelerates this mechanism. The primary concern with moisture is that the paper and pressboard insulation readily absorbs the moisture. This decreases the dielectric strength, accelerating the aging of the insulator structure. Appreciable quantities of water in insulating oil decreases the dielectric strength of the oil. This may lead to failure at operating voltages. Moisture permanently damages the insulation. Subsequent drying of the insulation only reduces the rate of deterioration. The lower the water content in the insulation, the greater the possibility of meeting the design life of the transformer. Complete removal of moisture from a cellulose insulation is not possible without damaging the cellulose.

The dielectric strength of the oil and cellulose insulation systems are drastically weakened when there are free gas intrusions (bubbles). In an oil-filled transformer, gas bubbles in the oil can result in partial discharges and reduced cooling effectiveness. Wet fibers can distort the electrical field and cause local stress that can also result in partial discharges. Partial discharges can also be caused by small conducting particles or contaminants in the insulating coolant. These discharges result in burning and charring of the insulating materials. Gaseous combustion products are released by these discharges also.

All these aging accelerators can be monitored by periodic sampling and analysis or by on-line analysis of the cooling (liquid or gas) fluid and insulation testing. The design life of the transformer can be preserved by maintaining the purity of the cooling fluid and the insulating properties of the insulation. The historical trend and the current condition of the insulation and any cooling fluid can be used for identification of maintenance measures needed to preserve or extend the life of a transformer. Physical inspections of all transformer types can provide similar and supportive end information. The interpretation of the condition of the insulation depends primarily on comparison of current insulation testing with previous test results.

Oil-filled transformers have the separate aging mechanism of sludge formation. Sludge is one of many oil decay products. Sludges formed into solid insulation cause insulation shrinkage. Insulation shrinkage results in winding motion under shock or impulse loading. Sludge deposits result in higher transformer operating temperature. Derating the transformer to account for sludge deposits helps ensure the design life of the transformer.

Another aging concern is solar magnetic disturbances. Solar flares have a characteristic effect on earth. Solar magnetic disturbances cause geomagnetic-induced currents in the miles-long transmission circuits. These currents are harmonics of the base (60-Hz) power frequency. The harmonics cause a half-cycle saturation of the transformer. There is a direct relation between geomagnetic-induced currents and half-cycle transformer saturation. The saturation causes increased heating and greatly increased generation of combustible gases within the transformer. There are known instances of transformer failures attributed to active solar storm activity.

Systems to monitor the effects of geomagnetic-induced current flows are being developed by industry. These will supplement any other transformer monitoring program. Having ample reserve transformer capacity will help the transformer weather the storm.

Lightning- and switching-induced impulse voltages have similar effects on a transformer. However, the stress loads caused by lightning and switching transients are somewhat limited by their short duration and by installed surge protective device characteristics.

The ambient temperature directly affects the equilibrium temperature of an operating transformer. Electrical and mechanical properties of insulating materials are related to their temperature. Softening of polymeric insulators increases as the temperature rises. Other temperature-related changes such as, melting, crystallization, embrittlement, deformation, and creep occur in insulating materials. Some of these changes are not reversible. Dielectric loss also exhibits a temperature-dependent change. Increased dielectric loss could lead to local thermal runaway. On the other hand, maintaining transformer temperatures under design limits ensures that the useful life of the transformer is not compromised. If the temperature is maintained low enough, the useful life of the transformer may extend beyond the design life.

The magnetic forces within a transformer exert mechanical forces on the windings and the magnetic materials. These repulsive and attractive forces combine with thermal expansion and contraction forces. These forces may distort insulating structures, especially if the structure is already weakened by temperature-induced deformations. Stationary windings can move as much as three inches under short-circuit conditions. A short circuit generates considerable magnetic force. Steady 60-Hz alternating current also causes magnetic forces to operate on the windings. The continual alternating force causes a vibration that, over time, will compact the mechanical insulation structure that holds the windings in place. Thus, both vibration- and surge-induced core movements damage the insulating structure of the transformer. A loose transformer structure means unrestrained windings for impulse- and fault-induced stress. These conditions when further stressed, cause further transformer aging.

Systematic programs that monitor physical conditions, insulation properties, sound levels, coolant properties and purity, geomagnetic-induced transients, and transformer temperatures help to ensure the design life of the transformer. A program of testing and monitoring, along with preventive and corrective maintenance, is the key to achieving the desired transformer life.

Confidence that a transformer has always operated within its design envelope gives assurance that a transformer will operate to or beyond its design life.

5. REVIEW OF OPERATING EXPERIENCE

This review was completed using information obtained from the Nuclear Regulatory Commission's Licensee Event Reports (LERs), the Institute for Nuclear Power Operations' Nuclear Plant Reliability Data System (NPRDS), the Nuclear Power Experience database (NPE), and information obtained from a cooperating utility. The data and information were analyzed to determine the types of Safety Class 1E transformers used, their ages, and their problems and failures associated with aging. The information was also analyzed to determine if any transformer problem/failure trends have developed as the transformers became older.

The use of information from the NPRDS database, the NPE database, or the LER records has limitations. Licensee reporting requirements are such that a complete record cannot be obtained from any one of the sources. Because each database requires different information, in varying degrees of detail, a partial piece of information might be misleading, and might be recorded in one database and not in another. The NPE and LER databases only report problems and failures resulting in recordable events (LERs). They do not include any transformer specifications or nonevent transformer failures for either Safety Class 1E or non-1E transformers. The NPRDS, however, includes information on transformer specifications and failures (event and nonevent) for each reporting plant.

The use of the NPRDS transformer specification and inservice data also had some limitations. Only 91 operating plants have Class 1E power transformer nameplate data and failure information in the NPRDS. In addition, a comparison of failures (LERs) reported in the LER, NPE, and NPRDS show that the NPRDS records were sometimes incomplete. To obtain a better view of the problems and trends caused by transformer aging, the NPRDS transformer information on plants licensed since January 1, 1989, was not used in this study, resulting in the use of NPRDS data from 88 plants for this study.

Some plants included information in the NPRDS for large numbers of special transformers. One nuclear power station included information for 120 transformers in the NPRDS. Included in the data was information on special low-power transformers, such as current and potential, control, voltage regulating (electronic controlled), and adjustable voltage transformers. Because this study is on power transformers, all NPRDS information was reviewed, and data on nonpower transformers were not included in the study.

The majority of reported transformer problems and failures in the NPRDS, NPE, and the LER are not directly related to power transformer aging. These include problems and failures caused by human error, design and operation deficiencies, and acts of nature. The database also lists as transformer-related, problems for other power equipment. For example, problems on electrical buses, breakers, lightning arresters, relays, and other equipment were frequently included in the transformer category. To ensure that all problems and failures included in this study were actually on power transformers, an examination was made on each problem and failure that was reported in the databases.

To separate problems that were directly associated with the transformer proper and the aging of the transformer, guidelines were established for the engineering evaluation of the database information. The guidelines used are listed as follows:

- The transformer envelope included connections, insulators (bushings), current transformers, and potential transformers on the transformer proper.
- The transformer envelope also included all cooling equipment (controls, control transformers, and fans).
- Database reported transformer problems and failures not associated with the transformer envelope and/or not related to the aging of power transformers were not to be used in this study.

During the study, a detailed engineering review was completed on 269 NPRDS problem reports, 1167 NPRDS transformer information records, 400 NPE entries, and 70 LER reports. All reports, records, and entries that were not related to the effects of power transformer aging were discarded. For comparison, the NPRDS-reported operating experience for non-1E power transformers is also included in this report.

Note that as discussed in Section 2, transformers listed in NPDRS as 1E and having voltage ratings above 15 kV are likely not actually 1E transformers. However, NPRDS data are being used, and the NPRDS classifications will be used in this section of the report.

5.1 Types, Applications, and Descriptions of Safety Class 1E Power Transformers

Transformers currently in Safety Class 1E installations in Nuclear Power Plants consist largely of three types: liquid-filled, dry-type, and gas-cooled. Each type has specific applications for which they are commonly used. A typical nuclear power station electrical diagram is shown in Figure 2-1. The Safety Class 1E transformers covered by this component aging study are shown within the dashed line area.

As shown in Table 5-1, the NPRDS records of the 88 plants show a total of 723 Safety Class 1E power transformers, 76.5% of these are air-cooled (dry-type), 16.6% are oil-filled, and 6.9% are gas cooled.

Table 5-2 shows the high-voltage rating for NPRDS-listed Safety Class 1E power transformers. As shown in the table, the majority of Safety Class 1E transformers have a high-voltage rating between 601 and 15,000 volts. The highest Safety Class 1E transformer voltage rating included in the NPRDS data is 500 kV for two transformers at one nuclear station.

5.2 Transformer Age

The ranges of age for the Safety Class 1E power transformers are shown in Table 5-3. The NPRDS data for the 88 plants indicate that over 95% of the transformers are less than 20-years old, and about 75% are under 15-years old.

5.3 Transformer Problems, Failures, and Replacements

The NPRDS data show that 56 power transformers have been put in service since the plants

Table 5-1. Type cooling for NPRDS-listed Class 1E power transformers.

Type cooling	Number	Percentage of transformer
Oil	120	(16.6%)
Air	553	(76.5%)
Gas	50	(6.9%)
Total	723	(100%)

Table 5-2. Voltage ratings of NPRDS-listed power transformers.

High-voltage rating of transformers	Percentage of transformers
0 to 601 volts	36.1
601 to 15,000 volts	57
Over 15,000 volts	6.9

Table 5-3. Age of NPRDS-listed safety Class 1E power transformers.

Age	Number	Percentage
0 to 5 years	119	16.5
5 to 10 years	218	30.1
10 to 15 years	199	27.5
15 to 20 years	154	21.3
Over 20 years	33	4.6
Total	723	100.0

have been licensed, with 33 of these occurring since 1983. Twenty-six of these were oil-filled, and the remainder were dry type. The data do not show the reasons for the installation or whether they were replacements for existing transformers. The installations of these transformers happened between 4 to 18 years after plant licensing. The installations do not correspond to identified problems, failures, or LERs.

Table 5-4 shows both the NPRDS-recorded Safety Class 1E and all classes of plant transformer aging-related problems and failures during the period from January 1983 through April 1991. During this period, a total of 143 problems/failures occurred on all classes of transformers at the 88 plants. Of these problems, 33 were attributed to Safety Class 1E transformers. Only 38 of the 143 recorded problems/failures resulted in reportable events (LERs). Of the 33 recorded Safety Class 1E problems/failures, five caused reportable events (LERs).

The NPRDS data show that detection of failures during routine observation, preventive maintenance, and surveillance tests appear to have prevented reportable events. For example, either an "Internal Failure" or a "Bushing (Insulator)" failure result in the total failure of a transformer. However, only 50% of these types of failures resulted in LERs. Only three events (LERs) resulted from the ten problems with "Load Tap Changers" and "Connections." Other events were prevented by problem detection during routine observations, incidental observations, inservice inspections, and surveillance tests. The problems with "Oil, Nitrogen, and Gas Leakage" did not result in any events during the period reviewed. However, undetected leakage can result in transformer failure, as reported in NRC 1E Information Notice Number 82-53, Main Transformer Failures at the North Anna Nuclear Power Station, December 22, 1982. (See Section 5.5 of this report.)

Table 5-5 shows the causes of transformer problems and failures for both NPRDS-listed Class 1E and all safety classes (Class 1E and nonclass 1E) versus the type cooling for the period between January 1, 1983, and April 30, 1991. As can be observed, 64% of the problems and failures occurred on oil-cooled transformers for both 1E and non-1E transformers. Sixty-four percent of Class 1E transformer problems and failures occurred on a population of 16.6% of the total transformers in service (see Table 5-1). This was attributed to use of oil-cooled transformers at high voltages and greater loads, with the resulting increased stresses on insulation. In addition, problems with load tap changers were the cause of 5 of the 21 reported problems and failures for NPRDS-listed

Table 5-4. Reported safety-related transformer problems.

Problems and failures	All safety classes transformers: Total	All safety classes transformers: LERs	Safety Class 1E transformers: Total	Safety Class 1E transformers: LERs
Internal failure	49	23	6	1
Bushing (insulator)	11	7	3	1
Cooling system	44	3	7	0
Transformer connections	9	1	5	1
Load tap changers	11	4	5	2
Oil, nitrogen, gas leakage	19	0	7	0
Total	143	38	33	5

Table 5-5. Transformer problems by cooling type (1983 through May 1991).

	All safety classes			Safety Class 1E	
Problems and failures	Oil	Air	Gas	Oil	Air
Internal failure	25	25	—	2	4
Bushing (insulator)	10	1	—	2	1
Cooling system	31	13	—	4	3
Transformer connections	1	8	—	1	4
Load tap changers	11	—	—	5	—
Oil, nitrogen, gas leak	14	—	5	7	—
Total	92 (64%)	46 (32%)	5 (4%)	21 (64%)	12 (36%)

Class 1E transformers. Load tap changers are only used to regulate output voltages for oil-cooled, high-power, and high-voltage transformers.

5.4 Trends

The transformer problems/failures for all NPRDS-listed transformers and Safety Class 1E transformers, from 1983 through 1990, are shown in Figure 5-1. The experience of all classes of transformers shows a peak period of problems and failures starting in 1985 with 19 occurrences, rising to 27 during 1987, receding to 19 during 1988, and followed by 16 each during 1989 and 1990. The Safety Class 1E transformer experience is very similar, with a peak of 8 problems and failures occurring in 1987. During 1987, cooling equipment problems were the major factor for the failures in all classes of transformers, while connections proved to be the major problem experienced by Safety Class 1E transformers.

5.5 NRC IE Information Notices

Since 1982, there have been two Inspection and Enforcement Notices providing information on significant transformer problems. A summary of each notice follows:

- *IE Information Notice 82-53, Main Transformer Failures at the North Anna Nuclear Power Station.*

This notice described a series of seven main transformer failures on the 330-MVA, 500-kV primary winding main power transformers. The problems experienced are also common to all oil type transformers, including cooling system and bushing failures. Although all of the factors leading to the failures are contributors to, and indicators of, the aging of the transformer, none of the described failures were directly attributed to transformer aging.

- *IE Information Notice 83-37, Transformer Failure Resulting from Degraded Internal Connection Cables.*

This notice described an event caused by a degraded internal transformer connection on a Safety Class 1E 4160/480 volt dry-type transformer at Brunswick 2 on April 26, 1983. The failure was attributed to long-term, heat-induced degradation initially caused by a poor connection. Later inspection of similar safety-related transformers at Brunswick 2 identified eight of 48 connections with cable-to-lug degradation. Detailed transformer inspections, necessary to detect these failure mechanisms prior to complete failure, were not included in the licensee preventive maintenance program. Similar connection problems and failures have been detailed in the NPRDS, LER, and NPE data bases, with 8 occurrences in 1987

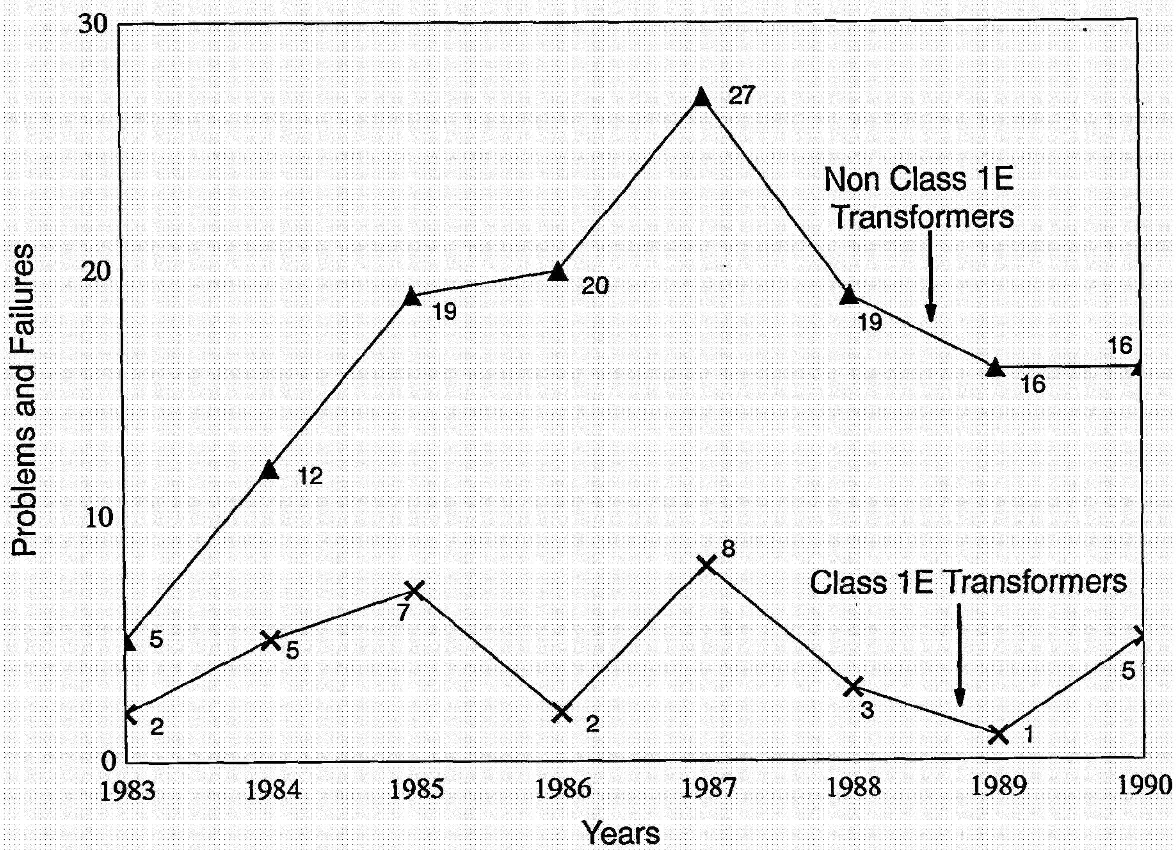


Figure 5-1. Class 1E and nonclass 1E power transformer problems and failures listed by year.

(3 for Class 1E transformers). However, none of these have occurred since 1987.

5.6 Summary

A review of the information provided by the NPRDS database, the NPE database, and LERs yields the following information:

- The NPRDS records of the 88 plants show a total of 723 Safety Class 1E power transformers; with 76.5% of these using air (dry-type), 16.6% oil, and 6.9% using an inert gas as the insulation and cooling medium. Over 57% of the transformers have a high-voltage rating of 600 volts to 15 kV, and only 6.9% have a rating over 15 kV.

- This review shows that about 95% of the transformers are under 20 years of age, and about 75% are less than 15 years old. The young age of the transformers makes it difficult, if not impossible, to determine the effects of transformer aging using plant operating experience.

- From January 1983 through April 1991, only 5 LERs were caused by problems or failures of Safety Class 1E transformers (Table 5-4). Only 33 failures were reported on 723 Class 1E power transformers. Based on the number of plants operating in a given year, this is an average failure rate of 0.822×10^{-6} failures per hour per transformer. Categories of transformer problems and failures include internal failure, bushing (insulator), cooling system, transformer connections, load tap changers, and oil, nitrogen, or gas leakage. About 64% of the problems occurred on oil-insulated transformers. (During this same period, 38 LERs were caused by problems or failures on non-1E power transformers at the plants. There were 143 total problems or failures on these transformers. About 64% of the problems occurred on oil-insulated transformers.)

- It was not possible to determine the reasons for the installation of 56 transformers after the plants start up (34 of these occurring since 1983). If this information were available, a better understanding of the transformer experience, the detection of failures, and the licensee's surveillance/maintenance programs might have been obtained. In any case, if they were replacements for existing failed units, the problems were detected in time to prevent licensing events (LERs).

- There is no present evidence, based on the NPRDS, NPE, and LER data that there are significant problems with the aging of transformers. This is based on the NPRDS, NPE, and LER data, which show that only 56 replacements, 33 problems/failures and 5 LERs occurred from 1983 through 1990 on the 723 Safety Class 1E transformers for the 88 plants studied.

6. TRANSFORMER RISK ANALYSIS

A standard PRA was used to determine which components were risk significant. The PRA for the Surry Nuclear Power Station (Bertucio 1990) was used. The Surry PRA was chosen because it is well documented in NRC-supported literature and is familiar to many in the PRA community. Additionally, the authors had previously loaded the PRA and verified it to quantify correctly on the Integrated Reliability and Risk Assessment System (IRRAS) software. The quantified risk was expressed in terms of core damage frequency. The fault trees for the Surry PRA included breakers, transformers, bus work, inverters, rectifiers and batteries. Only the relays and isolation devices were not included explicitly in the PRA.

Quantification of a PRA generally involves truncation of those cut sets that do not contribute significantly to the final core damage frequency. This was the case for the Surry PRA. All cut sets with a probability of less than 1.0E-09 before recovery were truncated. The truncation resulted in the complete removal of the battery, inverter, and rectifier components from the final set of cut sets. This left only the breakers, transformers, and bus work as potentially risk-significant components.

It is possible to further screen components based on the increase in risk caused by assuming that the failure probability of a particular component is unity. If such an assumption does not result in a significant increase in risk, then the aging of the component is not risk significant. Unity failure probability for a key 1E transformer yields a risk increase of 1.0E-04. Comparing this increase to the total core damage frequency of 3.0E-05 indicates that the increase in failure probability of transformers could contribute significantly to plant risk.

The Surry PRA used a transformer failure rate of 1.7E-06. The average failure rate observed in this study was 0.822E-06. At the time of this study, there does not appear to be an increase in the transformer failure rate with the age of the transformers. If the transformer failure rate is kept at the presently observed level, by using a maintenance and surveillance program, an increase in the risk of core damage because of the aging of transformers is not expected.

7. TRANSFORMER INSPECTION, SURVEILLANCE, MONITORING, AND MAINTENANCE

7.1 Guidance for Maintenance, Surveillance, Monitoring, and Inspection

Inspection and testing of certain items on the Safety Class 1E transformers at regular intervals extends the life of the transformer. Recommended maintenance and inspection practices for Safety Class 1E transformers vary according to transformer type (dry, oil-filled, or gas-filled), size (kVA), and voltage ratings. The objective of the inspections is to verify that there are no abnormalities with regard to noise, leakage, level, and temperature of the dielectric, and operation of the cooling system. The following maintenance, inspection, and testing procedures follow the recommended procedures of transformer manufacturers and those sources closely involved with the power distribution transformer industry, including S. D. Myers, Inc., and the *J&P Transformer Book* by Franklin and Franklin (see Bibliography). Some of the recommended procedures cannot be performed during reactor operation; therefore, schedules coinciding with refueling outages are appropriate.

7.1.1 Oil-Filled Transformers. Maintenance intervals for Safety Class 1E oil-filled transformers are summarized in Table 7-1. Where a interval is listed as annual, this can be understood as during a refueling outage.

Periodic Cleaning and Inspections. Inspection of porcelain bushings at regular intervals helps ensure they are kept free from dust, dirt, acid fumes, salt deposits, and other contaminants. The accumulations of contaminants on the external surface may result in flashover.

Although surge arresters do not require testing, inspection for dirt or dust contamination reduces the likelihood of external flashover.

Keeping the heat radiating surfaces of the transformers and the screened openings in the breathers and/or pressure-vacuum bleeder clean helps reduce internal pressures and operating temperatures. Painting transformers prevents corrosion of the metal parts.

Verifying that connections to the terminals are tight avoids abnormal junction heating.

Liquid Level. Low transformer oil levels invite transformer failure. A liquid level gage with remote alarm contacts on oil-filled transformers can help prevent low fluid levels. A monthly inspection and calibration of the liquid level gage, along with testing of the low-level alarm circuit, is important for the proper operation of that instrumentation.

Cooling Fans. The regular inspection of forced-air cooling equipment verifies it is in satisfactory operating condition. Motor bearings, if permanently lubricated and sealed at the factory, need no attention. Otherwise, monitoring motor bearings for wear and periodic oiling, if called for, helps ensure reliable fan operation. Oiling is needed if the bearings are not sealed. Painting fan blades can cause an imbalance that may lead to the destruction of the blade. Checking excessive noise from the pumps and fans can detect possible anomalies.

Control Circuits and Equipment. Regular inspection of the following items for control circuits helps ensure transformer operability:

- Control-circuit voltage
- Collections of dirt and gum
- Evidence of excess heating of parts (discoloration, odor, etc.)
- Freedom of moving parts
- Corrosion of metal parts
- Excess wear on contacts
- Loose connections

Table 7-1. Maintenance intervals for oil-filled transformers.

Maintenance item	Frequency	Comments
	Visual Inspections	
Tap changers	Annually[a]	Clean and inspect functionality
Bushings	Monthly	Clean and inspect
Radiators	Monthly	Clean and inspect
Cooling intakes	On demand	Clean and inspect
Oil filters	Weekly	Clean
Inspect for leaks	Weekly	Visual inspection
Cooling fans	Daily	Inspect for damage and noise
Pumps	Daily	Inspect for damage and noise
Connections	Monthly	Inspect and tighten
Control circuits	Quarterly	Inspect and test
Transformer housing	Quarterly	Paint if needed
Vacuum interrupter	Annually[a]	Inspect for wear
Auto gas control	Quarterly	Inspect and maintain
Surge arresters	Quarterly	Clean and inspect
	Instrumentation and Control	
Temperature gages	Monthly	Functional test
	Annually[a]	Calibrate
Pressure gages	Monthly	Functional test
	Annually[a]	Calibrate
Level gages	Monthly	Functional test
	Annually[a]	Calibrate
Alarm circuits	Annually[a]	Check functionality
On-line gas analyzer	Monthly	Check functionality
Load tap changers	Monthly	Check functionality
Relays	Monthly	Clean and test
	Testing	
Oil-dielectric	Annually[a]	—
Oil-acidity	Annually[a]	—
Oil-moisture	Annually[a]	—
Oil-color	Annually[a]	—
Oil-sludge	Annually[a]	—
Combustible gas analysis	On-line monitor	—
Gas chromatography	Every 3 months or when warranted	—
Acoustic emissions	When conditions warrant	—
Infrared scan	Annually[a] and when damage is suspected	—

Table 7-1. (continued).

Maintenance item	Frequency	Comments
	Doble Power Factor Tests	
Windings	Annually[a]	—
Bushings	Annually[a]	—
Liquid	Annually[a]	—
	Electrical Insulation Tests	
Excitation current	Annually[a] and when damage is suspected	—
Turns ratio test	Annually[a] and when damage is suspected	—
Winding resistance	Annually[a] and when damage is suspected	—
Ground resistance	Annually[a]	—

a. *Annually* means 18 months or during each scheduled reactor refueling outage.

- Proper contact pressure
- Excessive arcing in opening circuits
- Evidence of water in controls
- Excess slam on pickup
- Worn or broken mechanical parts.

Combustible Gas Analysis. Sampling Safety Class 1E liquid-filled transformers greater than 500 kVA for combustible gases at regular intervals is an effective way to detect insulation degradation. Either a portable gas analyzer or an online combustible gas analyzer can be used. Of the two methods, the online gas analyzer is the most desirable. It provides alarm capabilities of an internal fault in the transformer when a preset level of combustible gases is exceeded. The online gas analyzer has an excellent record for reliability in predicting incipient failures in both old and new transformers. Gas chromatography (laboratory gas analysis), following any indication of an incipient fault by the online gas analyzer, confirms a preliminary diagnosis.

The types of gases (H_2, CH_4, C_2H_2, C_2H_4, C_2H_6, CO, and CO_2) present in a sample and their relative amounts enable the nature of the fault to be determined (thermal or electrical). The type of material producing the gas can also be determined. A log of combustible gas readings, if kept, will show an increasing trend. With an increasing trend, the time between tests can be shortened. If the combustible gas content exceeds a preset limit (>1% by volume), a laboratory dissolved-gas-in-oil analysis helps to develop a plan of action.

Acoustic Emission Measurement. When used in conjunction with a gas-in-oil analysis, acoustic emission (AE) measurements of corona (partial discharges) provide an accurate prediction of incipient failures. Acoustic emission measurements can detect imminent faults. An online gas detector has delays of hours and even days while the gases propagate through the oil to the analyzer. Present AE technology offers the advantage of being able to determine the location of partial discharges and/or arcing within a transformer to a high degree of accuracy.

AE measurements are made externally, on the transformer housing, or with a waveguide, which is placed in the oil next to each high-voltage winding. With new installations, wave guides can be installed during transformer fabrication. The drawback with acoustic emissions detection is that it takes a trained operator to both take and interpret the data. AE does not replace a gas analysis, but it is a method of confirming the results of a gas analysis and is a means to help pinpoint fault locations within the transformer.

Sampling and Testing Insulating Oil. Transformer oil not only serves as the cooling medium, it plays a major role as part of the electrical insulation system. It can reflect the cleanliness, dryness, and to some extent, the degree of aging of the transformer. The following information covers the sampling and testing of transformer oil and the significance of the test results.

Sampling—The accuracy of the test results can be seriously affected by an improper sampling procedure. Procedures outlined in American Society for Testing and Materials (ASTM) Method D923, if followed, help obtain consistent results. ASTM Method D923 addresses recording the top oil temperature at the time of sampling. Particular attention is given to the cleaning and drying of testing containers. Taking samples when the insulating oil is at least as warm as the ambient air avoids moisture condensation. Samples taken on a clear dry day, avoids the possibility of water or dust contamination. The sample must be protected from contact with light, air, and moisture. It is very important that the sample not be exposed to the ultraviolet rays of the sunlight, which will accelerate aging. Ideally, the sample will be drawn quickly, kept in a dark sealed container, and tested as quickly as possible.

The following tests determine the condition of the transformer oil:

- Dielectric strength test
- Acidity (neutralization)
- Water or moisture content
- Color
- Sludge (interfacial tension).

Dielectric Strength Test—Maintaining a high dielectric strength of the insulating oil ensures transformer operability. Oil samples taken from transformers in the field, tested according to ASTM Method D1816 helps achieve this goal. A low breakdown voltage is an indication that impurities such as moisture, conductive dust, lint, or carbonized particles have entered the oil. Compact and efficient dielectric test equipment is available for use in the field. The test set applies an ac voltage at a controlled rate to two electrodes immersed in the dielectric fluid. Ideally, the oil tests 26 kV or higher with a 0.040-in. (1-mm) spacing between electrodes. Oil testing lower than 25 kV is either filtered to bring it back to 26 kV or replaced.

Although the dielectric test can indicate the presence of some impurities in the oil, it cannot detect the presence of dissolved water below 80% saturation, acids, or sludges.

Acidity Test—The acidity test is the best single test for indicating oil oxidation. ASTM Method D974 is a laboratory means measuring acidity from oil oxidation in transformers. Acids are detrimental to the insulation system and can induce rusting of metal parts when moisture is present. An increase in the neutralization number is an index to the rate of deterioration of the oil. Under normal conditions, the oil acidity is below 0.2 mg KOH. There are field tests available to measure acidity (ASTM Method D1534); however, they are not as sensitive as the laboratory method and therefore are not recommended.

Water and Moisture Content—Water content is critical in that an increase can indicate a leaking condition and ultimate reduction in dielectric strength. Free water may be detected in the sample by visual examination, in the form of droplets or as a cloud dispersed throughout the oil. Because water in solution cannot be detected visually, the Karl Fischer Reagent method (ASTM Method D1533) is recommended as a means of determining water content in the oil, in parts per million.

Instrumentation suitable for water-in-oil analysis is available for use in the field. Recording results from this analysis periodically aids in detecting anomalities. Although a gradual increase in water content over the life of the transformer is to be expected, any abrupt increase needs investigation to ascertain if serious conditions, such as leaks, may exist.

Color Test—The next in a series of oil sample tests is the color test. A gradual darkening of the oil in service can be expected. The test, meaningless by itself, is significant when there is a distinct change. The color test can be useful for diagnostic purposes, along with acidity and other tests to indicate the degree of contamination or deterioration of the oil.

There are two ASTM methods available for performing the color test: (a) a laboratory method (see ASTM Method D1500), and (b) a field test kit (see ASTM Method D1524).

Sludge Test—The test used to determine the degree of sludging in the insulation system is called the interfacial tension test (IFT).

The test procedure is described in ASTM Method D971. IFT test results are related to the degree of the oils oxidation and are an indicator of the degree of oil deterioration and contamination of the oil by the solid materials immersed in it.

Electrical Insulation Tests. The following tests are used to evaluate the condition of the transformer insulation. When the results from the insulation tests are coordinated with data from the oil tests, the general working condition of the transformer can be determined.

Insulation Power Factor Tests—The insulation power factor (IPF) tests are divided into the following three categories:

1. Winding IPF
2. Bushing Power Factor
3. Liquid IPF.

The purpose of the insulation power factor tests is to provide an indication of the integrity of the insulation system. Power factor is a measure of the power loss through the insulation system to ground, caused by leakage current. The IPF can be measured by applying a voltage across a capacitive network, in this case the transformer insulation, and measuring the amperes and watts loss and using these data to calculate a power factor. For field application, a de-energized series of tests that measure insulation power factor (Doble tests) are used.

All insulating systems will have some minor leakage paths that permit a small current to flow. A transformer is deemed suspect if the insulation power factor exceeds 2%. The causes of high power factor can be determined through additional testing. The bushings and liquid insulation can be tested to determine if they contribute to the high reading.

The recommended procedure for testing bushings is the ungrounded specimen test (UST) method. The equipment manufacturer recommends a maximum permissible test voltage not to be exceeded during testing.

The liquid IPF is determined by taking an oil sample from the transformer and testing for a power factor using the UST Method. New oil should have a power factor of $\leq 0.05\%$ at 20°C. When the power factor exceeds 0.5%, further tests (insulation resistance or moisture content tests) can determine the cause, or whether moisture is present.

Excitation Current—Excitation current measurements are made to detect shorted turns and heavy core damage. The excitation current tests are performed using the UST method and the same test equipment used for the power factor tests. The test results can be compared to factory and previous field test data to determine abnormal readings. High precision in excitation current measurements is not a requirement, because fault conditions found as a result of the test have excitation current values greater than 10% over normal.

Transformer Turns Ratio (TTR) Test—The transformer turns ratio test can be performed in the field to detect short-circuited turns, incorrect tap settings, mislabeled terminals, and tap changer failures. A TTR test can indicate that a fault exists, but does not determine its exact location. The test is normally performed annually, any time a transformer has been repaired or modified in the field, or if a fault has occurred dropping the transformer offline.

The TTR test uses the transformer turns ratio test set. The test equipment has an internal alternator to supply test voltage and is reliable and simple to use in the field.

Winding Resistance Measurements— Winding resistance measurements will reveal a change in dc winding resistance when there are short-circuited turns, poor joints, or bad connections. Prior factory and/or field test readings are required so that a comparison of data can be made.

Measurements made with a Wheatstone or Kelvin double bridge yield the most accurate results. It is essential that the temperature of the windings be accurately measured top to bottom, as all test readings must be converted to a common temperature to give meaningful results. The dc circulating current applied to the system needs to settle down before measurements are taken.

Ground Resistance Measurements— Ground resistance measurements are conducted to determine the integrity of the grounding connections and the copper ground conductors. High resistance readings can indicate a poor condition of the ground grid or ground electrode or that the soil may have to be conditioned with water or chemicals. A good ground system will protect both personnel and equipment. The resistance measured to ground should not exceed 5 ohms.

Load Records. Records of load and voltage on the transformer, when checked regularly, verifies that the transformer is operating within its prescribed limits and is being used efficiently.

Temperature Measurements—The operating temperature of the transformer has limits defined in American National Standards Institute (ANSI) Standard C57.12.00. Temperatures above those recommended limits will result in accelerated deterioration of the oil and aging of the cellulose insulation. Local overheating is a primary indicator of incipient faults within a transformer.

Top-liquid and bottom-liquid temperature are not suitable for indicating operating conditions within the transformer. Hot-spot temperature readings give a more accurate indication of load conditions within the transformer windings. Two winding temperature indicating instruments are suitable for existing transformers. One local temperature gage with a high limit set point mounted at the transformer at eye level aids local operators. A second temperature indicator with an audible high-temperature alarm and room operators located at a manned remote location aids control.

Operating temperatures, along with coincident records of ambient temperature, load, and voltage, when carefully recorded as often as practical, aid in evaluating the operating history of the transformer. Changes in operating temperatures are often the only means by which the operator can detect an abnormal condition within the transformer.

Infrared Detectors—Portable infrared detectors can be used periodically to aid in the detection of incipient faults on both old and new transformers. Periodic thermal imaging is performed with an operating guide that defines temperature as a function of image color. Although the infrared detector will not pinpoint a fault location, it can aid in determining whether or not a piece of equipment has overheated.

Polarization Recovery Voltage Test. A method of detecting moisture and aging degradation products in the paper insulation, as well as the oil, has been developed and marketed for use in Europe and in the United States. The technique applies a voltage between a transformer winding and the transformer tank for a period of time, applies a short to the winding, removes the short, and then records the recovery voltage as a function of time. This process is repeated by varying the period of time that the voltage and short are applied. An analysis of the results provides an indication of the moisture content and the presence of aging degradation products. The presence of either of these products indicates a degradation of the total insulation system. The technique appears to be very sensitive to the presence of moisture and aging degradation products. Oil analysis provides a good measurement of moisture content in the oil, but since moisture is more readily absorbed in the paper than in the oil this technique may be particularly useful for indicating the presence of moisture in the paper insulation.

Fluoroptic Sensors—Online hot spot measurements using fluoroptic sensors wound into the transformer windings can accurately measure winding temperature. The fluoroptic device uses a phosphor sensor at the end of an optical fiber to measure temperature. The temperature of the sensor is determined by measuring the rate of decay of the fluorescence of the phosphor after it has been excited by a pulse of blue-violet light sent down the fiber from a Xenon flash lamp within the instrument. Once the rate of decay of the fluorescence has been measured, sensor temperature can be determined by comparison with an empirical calibration curve. The probes and fibers are made of durable material that can withstand shock and vibration within the transformer and many years of continuous exposure to hot transformer oil. Because the fluoroptic sensors are installed within the transformer windings, they should only be considered for new installations where the sensors can be installed at the factory. The relative high cost of the fluoroptic system must be weighed against the cost and critical nature of the transformer to determine whether or not the system is cost effective.

Pressure Relief Devices and Sensors. An excessive increase in tank pressure is an indication that an internal fault condition exists. Mechanical pressure relief devices, fault-pressure relays with alarm contacts, and digital or analog pressure gages (with a means of recording tank pressures) ensure that pressures have remained within normal limits.

Pressure Relief Devices. Pressure relief diaphragms are usually mounted on the end of a pipe connected to the transformer case above the liquid. They are designed to rupture at 10 to 15 psi. Mechanical-relief devices are usually mounted on the top of the tank. The pressure relief device typically include alarm contacts to indicate operation of the device.

Fault-Pressure Relay—The fault-pressure relay is designed to de-energize the transformer and/or initiate an alarm in the event of sudden pressure rise. The relay is not susceptible to trip because of vibration, mechanical shock, or pressure variations due to transformer temperature changes. The relay is mounted on a valve on the tank wall, near the base of the transformer.

If a periodic test program is followed, it will help ensure that fault pressure relays are available for their role of protecting the transformer and initiating an alarm. Electrically tripping the relays during any scheduled outage of equipment and at yearly intervals will ensure that they are in good condition, and that all the circuits are complete so that breakers and alarms can be tripped.

Relay contacts can be cleaned during testing with a flexible brushing tool to ensure reliable operation. Knives, files, or abrasive paper or cloth should not be used to clean relay contacts.

Load Tap Changers (LTCs). Load tap changers are typically inspected and tested for proper operation annually; the following six procedures are normal:

1. Check the condition and dielectric strength of the oil in the tap selector compartment and replace if necessary. Proper minimum oil level should be maintained.

2. Check the self-adjusting oil seal for wear or leaks.

3. Check operation of the protective system.

4. Verify that the gear-teeth paint marks are properly aligned.

5. Keep the mechanism gears and control cams lightly greased.

6. Clean relay contact surfaces.

Vacuum Interrupter. The arcing contacts within the interrupter will gradually wear over a period of time as a result of interrupting current during each tap change. Inspection of the wear indicators and the entire switch mechanism, annually or after 25,000 operations, whichever occurs first, helps ensure reliable operation. Worn interrupters should be replaced based on manufacturer's recommendations.

Automatic Gas Controls. Some medium power Safety Class 1E transformers may be equipped with automatic gas-control equipment. The purpose of gas-control equipment is to maintain an atmosphere of dry nitrogen under pressure between the top oil surface and the transformer cover. This isolates the oil from the outside air and prevents oxygen, moisture, and other contaminants from being absorbed in the oil. The nitrogen is supplied from a gas cylinder and enters the transformer through a gas regulator. High- and low-pressure alarms, along with the transformer gas space pressure gage, are normally part of these controls.

Excessive loss of gas can be the result of a high oil level, abnormal loading, a defective regulator, or leaks. A log of transformer pressure, oil temperature, and gas cylinder pressure, if kept, can aid in determining the cause of gas consumption. Regulator operation is tested, and a leak test performed on the nitrogen system on a regular basis to ensure reliable operation.

Transient Recorders. One primary cause of transformer failure is power line disturbance. The purpose of the transient recorder is to keep a record of the power line anomalies that tend to accelerate transformer aging. By knowing the frequency of occurrence and the magnitude of the transients, testing can be initiated to detect possible damage to the transformers before failure of the unit occurs.

7.1.2 Dry-Type Transformers. Maintenance, testing, and instrumentation procedures for the dry-type transformers are similar to the oil-filled units with the exception of the oil testing common to the oil-insulated transformers. Procedures and requirements for electrical insulation testing and dielectric testing of the windings (Doble Tests) are similar to the oil-filled units (discussed previously). The following sections discuss maintenance, inspection, and surveillance practices common to dry-type transformers. Maintenance intervals for dry-type transformers are summarized in Table 7-2.

Periodic Cleaning and Inspections. With the transformer de-energized, the front and rear access panels are removed. Inspections are made for dirt, especially on insulating surfaces or for those that will restrict air flow, for loose connections, for the condition of tap changers or terminal boards, and for the general overall condition of the transformer. Tracking or carbonization are signs of overheating and voltage creeping over insulating surfaces. Any anomalies are identified and corrected where possible.

Painted surfaces are checked for signs of rust, corrosion, or deterioration. Any deteriorated surfaces need to be cleaned, prepared, and repainted with the type of paint recommended by the transformer manufacturer.

Fans and motors are inspected for wear or damage and receive periodic service. The fan control system is checked to ensure that air delivery is made to the transformer coils.

Excessive dirt on the windings or insulators is removed to permit free air circulation and to protect against insulation breakdown. Cleanliness of the top and bottom ends of winding assemblies, as well as ventilating ducts, ensures ventilation. Tap changers, terminal boards, bushings, and other insulating surfaces can be brushed or wiped with a dry cloth. Pressurized air should not be used for cleaning because it may blow abrasive debris into the windings and damage the winding insulation.

Insulation Resistance and Dielectric Tests. Prior to initial energization of the transformer, and following any shutdown exceeding 24 hours, an insulation resistance test will determine if moisture is present in the insulation.

Table 7-2. Maintenance intervals for dry-type transformers.

Maintenance item	Frequency	Comments
	Visual Inspections	
Internal surfaces	Quarterly	Clean and inspect
Tap changers	Quarterly	Clean and inspect
Terminal boards	Quarterly	Clean and inspect
Transformer housing	Quarterly	Paint if needed
Connections	Monthly	Inspect and tighten
Cooling fans	Daily	Inspect for damage and noise
Windings	Annually[a]	Clean and inspect
	Instrumentation	
Temperature sensors	Monthly	Functional test
	Annually[a]	Calibrate
Alarm circuits	Monthly	Check functionality
Relays	Monthly	Clean and test
	Testing	
Insulation resistance	Annually[a] and/or when damage is suspected	—
Dielectric	Following insulation resistance test	—
Infrared scan	Annually[a] and/or when damage is suspected	—

a. *Annual* means 18 months or during each scheduled reactor refueling outage.

Recording megger readings along with test temperature is part of the insulation resistance. Using factory test data and tables, corrected field test megger values can be obtained. Drying is often specified if the field test megger values are less than one-half of factory test readings. Transformer drying using one of the following three methods restores the insulation resistance.

1. External heat

2. Internal heat

3. External and internal heat.

The transformer manufacturer will recommend proper drying procedures and temperature limitations.

Insulation resistance measurements are taken for each winding to ground, with all windings grounded except the one being tested.

Once the transformer has successfully passed the insulation resistance test, the dielectric test is run immediately to prevent the possibility of transformer failure due to moisture. The dielectric test supplements the insulation resistance test by determining the suitability of the transformer to operate at rated voltage. The dielectric test can be performed in the field using a variable high potential test set.

Field test voltages are usually set at 65% of factory test voltage, and care is taken to avoid exceeding 75% of factory test voltage. After successful testing of the high- and low-voltage windings with no failures or breakdowns, all control circuits, lightning arresters, and primary and secondary connections can be reconnected. The sooner the transformer is energized, moisture intrusion is less likely.

Temperature Measurements. Thermal sensors installed in each winding monitors the hot spot temperature. Resistance temperature detectors (RTDs) work very well for this type of application because they are inexpensive, rugged, reliable, and easily installed in transformers. An RTD is adaptable for use as the control element for load shutdown on high temperature and/or providing a signal for a remote visual display of the transformer temperature. As a rule of thumb, the hottest spot temperature is two-thirds up the coil stack and one-third the way into the high voltage winding.

An infrared scan of the transformer on a periodic basis aids to detect hot spots and potential overheating of the transformer. A permanent record of each thermal image provides the thermal history of the transformer. Unusually high temperature deviations from previous tests can be an indication of incipient faults.

A fiber optic temperature system similar to the system discussed previously with oil-filled transformers can also be implemented in the dry-type transformer windings during fabrication. Although these probes are quite accurate and capable of withstanding stress in their working environment, they are also very expensive and would only be cost effective if installed in very high-cost, critical transformers.

Acoustic Emissions Detection. Measurement of acoustic emissions (partial discharge) in dry-type transformers is still under development. Although some progress has been made toward developing a system, there is presently nothing commercially available that can be recommended for partial discharge detection in dry-type transformers.

7.1.3 Gas-Cooled Transformers. Gas-cooled transformers are identical in construction to dry-type transformers with the exception that the gas-cooled units are completely sealed for protection against the environment and operate in their own atmosphere of nonflammable dielectric gas. The insulation and dielectric tests performed on dry-type units are also suitable for the gas-cooled transformers. Maintenance and test intervals for gas-cooled transformers are summarized in Table 7-3.

Periodic Cleaning and Inspections. Because the gas-cooled transformers are sealed, no cleaning of the interior of the transformer is recommended.

The key elements of gas-cooled transformer maintenance are the pressure indicator and relief device, the top gas temperature indicator, the vacuum pressure switch, and the pressure line valves and fittings. Each of these elements have inspection, cleaning, or calibration recommendations by the transformer manufacturer. The vacuum pressure gage is of particular importance because the loss or increase in pressure can indicate an internal failure of the transformer. Cleaning and calibrating this vacuum pressure gage on a regular basis helps ensure proper operation.

Pressure Checks. A loss of pressure within the transformer can indicate a leak within the gas coolant system or the transformer enclosure itself. A loss of gas can result in overheating and eventual failure of the unit if the system is not recharged with gas. When recharging the gas cooling system, care is taken not to exceed the manufacturer's recommended pressure levels for the particular transformer in question. If loss of coolant is a recurring problem, the transformer can be taken out of service and inspected for leaks. A rise is gas pressure can indicate a fault condition or possible winding failure within the transformer.

Instrumentation. Typical gas-cooled transformers have gas pressure and top gas temperature indicators (with local and remote alarms for high/low pressure and high temperature) to ensure reliable operation. Hot spot RTD temperature detectors similar to those for the dry-type transformers are also used to detect hot spots and provide a thermal history of the transformer.

Painted surfaces are checked for signs of rust, corrosion, or deterioration. Any deteriorated surfaces need to be cleaned, prepared, and repainted with the type of paint recommended by the transformer manufacturer.

Table 7-3. Maintenance intervals for gas-cooled transformers.

Maintenance item	Frequency	Comments
	Inspections	
Terminal boards	Quarterly	Clean and inspect
Transformer housing	Quarterly	Clean and inspect
Valves and fittings	Weekly	Check for leaks
External connections	Monthly	Inspect and tighten
Pressure checks	Daily	Check for high/low
	Instrumentation and Control	
Temperature sensors	Monthly	Functional test
	Annually[a]	Calibrate
Alarm circuits	Monthly	Check functionality
Relays	Monthly	Clean and test
Pressure gauges	Monthly	Functional test
	Annually[a]	Calibrate
	Sampling and Testing	
Insulation resistance	Following installation and when damage is suspected	—
Dielectric	Following insulation resistance	—
Infrared scan	Annually[a] and/or when damage is suspected	—

a. *Annual* means 18 months or during each scheduled reactor refueling outage.

7.2 Current Maintenance Practices for Safety Class 1E Transformers

Table 7-4 summarizes a typical maintenance schedule for the Safety Class 1E oil-filled transformers at a nuclear power station.

7.3 Comparison of Typical and Current Maintenance Practices

The maintenance practices implemented at a typical nuclear station are similar to those identified in this study, with the following exceptions:

- Gas Analysis—Performing a gas chromatograph every three months is good practice. An online incipient fault monitor, if installed on the Safety Class 1E liquid filled units, especially the transformers 5 MVA and larger, can be useful for transformer maintenance programs. The gas chromatograph can then be used to confirm a preliminary diagnosis by the online monitor.

- Acoustic Emission Testing—Although not part of a periodic testing program, acoustic emission tests can be considered when the results from a gas chromatograph or other tests indicate the possibility of partial discharge within the oil-filled transformers. Acoustic emission tests can help verify that a problem exists and help identify the location of the partial discharge.

- Electrical Insulation Tests—The full extent of the electrical insulation tests was not clear from the information provided by personnel at the nuclear station. While they did conduct doble power factor tests periodically, turns ratio test, excitation current measurements, and winding resistance measurements were not included in their report.

7.4 Functional Indicators of Transformer Degradation

Table 7-5 summarizes the known modes of transformer age-induced failure, as discussed in Section 3, and the methods (testing, monitoring, etc.) used to detect each failure mode. The table is itemized as to transformer type (liquid, gas, and air).

Table 7-4. Maintenance practices for oil-filled transformers at a typical nuclear power station.

Maintenance item	Frequency	Comments
	Inspections	
Oil filters	Weekly	Clean
Transformer exterior	Every refueling	Clean
Control cabinet	Every 3 months	Clean
Connections	Every refueling	Re-torque
Leak inspection	Every 3 months	Inspect
Cooling fans	Annually	Clean and inspect
Protective relays	Every refueling	Clean and inspect
Cooling intakes	On demand	Clean
Sudden pressure relays	Every refueling	Clean and inspect
	Instrumentation and Control	
Thermographic monitoring	Annually	Infrared scan
Temperature gauges	Every refueling	Calibrate
Level gauges	Every refueling	Calibrate
Pressure gauges	Every refueling	Calibrate
	Sampling and Testing	
Gas sample	Every 6 months	Laboratory analysis
Oil sample	Every 6 months	Laboratory analysis
Doble power factor tests	Every refueling	—
Megger core ground	Every refueling	—

Table 7-5. Functional indicators of transformer degradation.

	Functional indicator		
Failure mode	Dry-type	Liquid	Gas
Windings	Doble test Temperature Winding resistance	Doble test Temperature Winding resistance	Doble test Temperature Winding resistance
Enclosure	Visual inspection	Visual inspection	Visual inspection
Coolant/insulant	Insulation resistance	Insulation resistance	Insulation resistance
Coolant/insulant	Insulation resistance Doble test	Insulation resistance Doble test	Insulation resistance Doble test
Core	Exitation current Gas chromatograph	Exitation current	Exitation current

8. REVIEW OF STANDARDS, GUIDES, AND DESIGN CRITERIA RELATED TO TRANSFORMER AGING

General Design Criteria (GDC) 2, 4, 5, 17, 18 and 50, "General Design Criteria of Nuclear Power Plants," of 10 CFR 50 apply to the Class 1E power system. These GDC are listed in Table 8-1. One sees from reviewing these GDC that aging is not included as a natural phenomena in GDC-2. In addition, a list of industry standards applicable to Class 1E power transformers is presented in Table 8-2.

Table 8-1. Acceptance criteria and guidelines for electric power transformers.

Criteria	Title	Applicability[a]	Remarks
1. General Design Criteria (GDC) of 10 CFR Part 50			
GDC 2	Design Bases for Protection Against Natural Phenomena	A	Does not include aging in natural phenomena
GDC 4	Environmental and Missile Design Bases	A	—
GDC 5	Sharing of Structures, Systems, and Components	A	—
GDC 17	Electric Power Systems	A	—
GDC 18	Inspection and Testing of Electrical Power Systems	A	—
GDC 50	Containment Design Bases	A	—
2. Regulatory Guides (RGs)			
RG 1.29	Seismic Design Classification	G	—
RG 1.32	Use of IEEE Standard 308, "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations"	G	See IEEE 308 Address dust and temperature control
RG 1.75	Physical Independence of Electric Systems	G	See IEEE 384
RG 1.118	Periodic Testing of Electric Power and Protection Systems	G	See IEEE 338 Lightning and ground tests
3. Branch Technical Positions BTP PSB-1	Adequacy of Station Electric Distribution System Voltages	G	—

a. "A" designates acceptance criteria, and "G" designates guidelines.

Table 8-2. Industry standards applicable to Class 1E power transformers.

System component function	Standard number	Title	Addresses these items relative to aging: Aging degradation	Maintenance	Operational records	Inspection surveillance monitoring	Comments
General Industry Standards							
Class 1E equipment	IEEE 323-1983	Qualifying Class 1E Equipment for Nuclear Power Generating Stations	Yes	Applied to testing only	EQ only	Testing only	—
Class 1E equipment	IEEE 336-1980	Installation, Inspection, and Testing Requirements for Class 1E Instrumentation and Electric Equipment at Nuclear Power Generating Stations	No	No	No	No	—
Safety systems testing	IEEE 338-1977	Criteria for the Periodic Testing of Nuclear Power Generating Station Safety Systems	No	No	Tests only	Yes	—
Seismic qualification	IEEE 344-1980	Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations	EQ seismic	No	No	No	—
Reliability analysis	IEEE 352-1975	General Principle of Reliability Analysis of Nuclear Power Generating Station Protection Systems	Basic methods of identifying degradation	No	No	Installation	—
Risk analysis	IEEE 577-1976	Reliability, Analysis in the Design and Operation of Safety Systems for Nuclear Power Generating Stations	No	No	No	Yes	—
Design	IEEE 379-1977	Standard Application for the Single-Failure Criterion to Nuclear Power Generating Station Class 1E Systems	No	No	No	No	—
Design	IEEE 384-1981	Standard Criteria for Independence of Class 1E Equipment and Circuits	No	No	No	No	—

Table 8-2. (continued).

			Addresses these items relative to aging				
System component function	Standard number	Title	Aging degradation	Maintenance	Operational records	Inspection surveillance monitoring	Comments
Documentation	IEEE 494-1974	Standard Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Stations	No	No	No	No	—
Safety system criteria	IEEE 603-1977	Standard Criteria for Safety Systems for Nuclear Power Generating Stations	No	No	No	No	Aging not included in Sections 4 and 5
Safety system qualification	IEEE 627-1980	Design Qualification of Safety Systems Equipment Used in Nuclear Power Generating Stations	Generically	No	EQ only	EQ only	—
Quality assurance	ANSI/ASME NQA-1-1983 NQA-2-1986	Standard Recommended Practices for Quality Assurance Program Requirements Applicable to All Phases of Nuclear Power Plant Design, Construction, and Operation	No	No	Yes	Yes	—
Replacement parts	934-1987	Standard Requirements for Replacements Parts for Class 1E equipment in Nuclear Power Generating Stations	No	No	No	Yes	—
Statistical analysis	930-1987	Guide for Statistical Analysis of Voltage Endurance Data for Electrical Insulation	Yes	No	No	No	—
<u>Standards for 1E Power Systems</u>							
Design criteria	308-1980	Criteria for Class 1E power Systems for Nuclear Power Generation Stations	No	No	No	Yes	—
Testing programs	415-1986	Preoperational Testing Programs for Class 1E power Systems for Nuclear Power Generating Stations	No	No	Preoperation test procedures	Preoperation testing only	—

Table 8-2. (continued).

			Addresses these items relative to aging				
System component function	Standard number	Title	Aging degradation	Maintenance	Operational records	Inspection surveillance monitoring	Comments
Protection of 1E power	741-1986	Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations	Degraded voltage	No	Test and records only	Degraded voltage	—
<u>1E Power Component Standards</u>							
All electrical equipment	943-1986	IEEE Guide for Aging Mechanisms and Diagnostic Procedures in Evaluating Electrical Insulation Systems	Yes	No	No	Only as applied to diagnostic techniques	—
Askarel	ANSI/ASTM D2129-79	Test for Color of Chlorinated Aromatic Hydrocarbons (Askarel)	Yes	No	No	Yes	—
	ANSI/ASTM D1936-64R1980	Test for Thermal Stability of Chlorinated Aromatic Hydrocarbons (Askarels)	Yes	No	No	Yes	—
	IEEE 76-1974	Transformer Askarel in Equipment	No	Yes	No	No	—
Bushings	ANSI/IEEE 757-1983	Loading Power Apparatus Bushings	No	Yes	No	No	—
	ANSI/IEEE 24-1976	Outdoor Apparatus Bushings, Requirements, and Tests	No	Tests	No	No	—
	ANSI/IEEE 24-1984	Outdoor Apparatus Bushings, Performance	No	No	No	Yes	—
Insulating materials, systems, and electric insulations	ANSI/IEEE C57.106-1977	Acceptance and Maintenance of Insulating Oil in Equipment	No	Yes	No	No	—

Table 8-2. (continued).

System component function	Standard number	Title	Aging degradation	Maintenance	Operational records	Inspection surveillance monitoring	Comments
			Addresses these items relative to aging				
	IEEE 266-1969 R1981	Evaluation of Insulation Systems for Electronic Power Transformers	No	Yes	No	No	—
	IEEE 62-1978	Field Testing Power Apparatus Insulation	No	Yes	No	No	—
	HVI-1978	High-voltage Insulators	No	Yes	No	No	—
	ANSI/EIA RS364-21A-1983	Insulation Resistance Test	Test	Yes	No	No	—
	UL 1446	Systems of Insulating Materials—General	No	No	No	Yes	—
Insulators	ANSI C29.1-1982	Electrical Power Insulators	No	Yes	No	Yes	—
Power apparatus	IEEE 62-1978	Field Testing Power Apparatus Insulation	No	Yes	No	No	—
Testing equipment and testing	IEEE 498-1980	Calibration and Control of Measuring and Test Equipment Used in the Construction and Maintenance of Nuclear Power Generating Stations	No	Yes	No	No	—
	IEEE C57.12.14	Dielectric Test Requirements for Power Transformers for Operation at System Voltages from 115kV to 230kV	No	Yes	No	No	—
	ANSI/IEEE C57.98-1968	Transformer Impulse Tests	No	Yes	No	No	—

Table 8-2. (continued).

System component function	Standard number	Title	Addresses these items relative to aging: Aging degradation	Maintenance	Operational records	Inspection surveillance monitoring	Comments
Transformers	ANSI/IEEE C57.106-1977	Acceptance and Maintenance of Insulating Oil in Equipment	No	Yes	No	No	—
	ANSI/IEEE C57.104-1978	Detection and Determination of Generated Gases in Oil-immersed Transformers and Their Relation to Serviceability of the Equipment	Yes	Yes	No	No	—
	IEEE C57.12.14	Dielectric Test Requirements for Power Transformers for Operation at System Voltages from 115 kV to 230 kV	No	Yes	No	No	—
	NEMA TR98-1978	Guide for Loading Oil-immersed Power Transformers With 65C Average Winding Rise	No	Yes	No	No	—
	ANSI/IEEE C57.94-1982	Installation, Application, Operation, and Maintenance of Dry-type General Purpose Distribution Transformers	No	Yes	No	No	—
	ANSI C57.12.27-1982	Liquid-filled Transformers Used in Unit Installations Including Unit Substations	No	Yes	No	No	—
	ANSI/IEEE C57.12.90-1980	Liquid-immersed Distribution, Power, and Regulating Transformers and Guide for Short-circuit Testing of Distribution and Power Transformers	No	Yes	No	No	—
	ANSI C57.12.30-1977	Load-tap Changing Transformers	No	Yes	No	No	—
	ANSI/IEEE C57.92-1981	Loading Mineral Oil-immersed Power Transformers	No	Yes	No	No	—

Table 8-2. (continued).

System component function	Standard number	Title	Aging degradation	Maintenance	Operational records	Inspection surveillance monitoring	Comments
			Addresses these items relative to aging				
	IEEE 756	Loading Mineral Oil-immersed Power Transformers	No	Yes	No	No	—
	ANSI/IEEE C57.12.11-1980	Oil-immersed Transformers	No	Yes	No	No	—
	ANSI C57.12. 22-1980	High-voltage Bushings	No	Yes	No	No	—
	ANSI C57.12. 52-1981	Pad-mounted Compartmental-type Self-cooled Three-phase Distribution Trans-Formers With Separable Insulated High-Voltage Connectors	No	Yes	No	No	—
	ANSI C57.12. 26-1975	Sealed Dry-type Power Transformers	No	Yes	No	No	—
	ANSI/IEEE C57.100-1974	Test Procedure for Thermal Evaluation of Oil-immersed Distribution Transformers	No	Yes	No	No	—
	ANSI/IEEE C57.12.80-1978	Terminology for Power and Distribution Transformers	No	Yes	No	No	—

9. CONCLUSIONS

The results presented in this section are the product of the Phase I study for understanding and managing aging of transformers. Transformers perform their primary function without the use of moving parts but do depend on auxiliary equipment such as fans, motors, pumps, and load tap changers. Transformers have the critically important function of providing power to equipment that is necessary for accident prevention, accident management, and accident mitigation. The following conclusions have been developed and supported by failure data from several databases and from plant-specific records. They provide the basis for future research and work to mitigate aging degradation and improve the reliability of transformers.

Degradation or deterioration of electrical insulation is the most significant failure mode for transformers. Failures of the windings (turn to turn, winding to winding, or winding to ground faults) and failures in the bushings that provide the interface between the transformer and the transmission lines are primarily caused by a failure of the insulation system. Insulation failures are caused by excessive temperature, excessive voltages, moisture, and contamination. Contamination is most often in the form of moisture, acids, and foreign material from the outside environment or from the aging of internal components. Vibration also causes insulation failures by contributing to the breaking down of solid insulation material.

Transformers currently installed in Class 1E applications consist of three types: liquid-filled, dry-type, and gas-cooled. Dry-type (air cooled) account for about 76.5% of the transformers, while 16.6% are liquid-filled, and 6.9% are gas-cooled. Liquid-filled are primarily used in high-voltage, high-power applications such as those that supply power to the 4160-Vac bus. Dry-type are typically used in lower-voltage, lower-power applications such as those found in the distribution system within the various buildings. Gas-cooled transformers are found in applications where more power is needed than would normally be supplied by a dry-type but where the use of oil is not appropriate, such as inside applications where the concern for transformer fires prevents the use of oil.

Failure data from the NPRDS, LERs, and NPE databases were reviewed. The failure rate of transformers does not indicate an increased failure rate with age of transformer. However, over 95% of the transformers are less than 20-years old and 75% are under 15-years old. Because transformers are normally considered to be a long life item (40 years or greater), a significant trend with age would not be expected at this time. Reported categories of transformer problems include internal failure, bushing (insulator), cooling system, transformer connections, load tap changers, and oil, nitrogen or gas leakage. The total number of transformer failures is not large. From January 1983 through May 1991, NPRDS data for 88 plants with 723 safety-grade Class 1E transformers reported only 33 problems and failures. The incidence of transformer failures does not appear to be increasing with the age of the transformer. Therefore, we conclude that presently identified aging mechanisms are not expected to cause safety problems.

A review of the Surry PRA revealed that transformers, along with circuit breakers and buses, are the risk-significant components in the Class 1E power system. If the transformer failure rate is kept at the presently observed level, an increase in the risk of core damage frequency is not expected.

A continual program of inspection, surveillance, monitoring, and maintenance will help ensure transformer reliability. Such a program will detect and reduce stressors that shorten transformer life, prevent stressors before they cause degradation, and detect degradation in the early stages so that preventive and corrective action can be taken prior to transformer failure to reduce the rate of aging. An effective program of inspection, surveillance, monitoring, and maintenance consists of periodic cleaning and inspections; testing of dielectric strength; and testing of oil in liquid-filled transformers; testing to verify that electrical characteristics such as winding resistance, insulation resistance, turns ratio, excitation current, and resistance to ground are maintained. Regular measurement of temperature is an important element of a transformer monitoring program. There are numerous codes and standards that are applicable to transformers. These codes and standards provide guidance for design, the performance of several tests, and maintenance of all types of transformers.

Because transformers installed in nuclear facilities are relatively young, a periodic review of operating experience of transformers would be useful to monitor their continued performance. A period of five years would be appropriate for the review. The review would determine if the present information remains accurate, and determine whether significant trends, not previously identified, are developing.

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NRC FORM 335 (2-89) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

1. REPORT NUMBER (Assigned by NRC. Add Vol., Supp., Rev., and Addendum Numbers, if any.)

NUREG/CR-5753
INEL-95/0573

2. TITLE AND SUBTITLE

Aging of Safety Class 1E Transformers in Safety Systems of Nuclear Power Plants

3. DATE REPORT PUBLISHED

MONTH	YEAR
February	1996

4. FIN OR GRANT NUMBER

A6389

5. AUTHOR(S)

E. W. Roberts
J. L. Edson
A. C. Udy

6. TYPE OF REPORT

7. PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION – NAME AND ADDRESS (If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)

Idaho National Engineering Laboratory
Lockheed Idaho Technologies Company
P.O. Box 1625
Idaho Falls, Idaho 83415

9. SPONSORING ORGANIZATION – NAME AND ADDRESS (If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)

Division of Engineering Technology
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555 - 0001

10. SUPPLEMENTARY NOTES

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11. ABSTRACT (200 words or less)

This report discusses aging effects on safety-related power transformers in nuclear power plants. It also evaluates maintenance, testing, and monitoring practices, with respect to their effectiveness in detecting and mitigating the effects of aging. The study follows the U.S. Nuclear Regulatory Commission's (NRC) Nuclear Plant-Aging Research approach. It investigates the materials used in transformer construction, identifies stressors and aging mechanisms, presents operating and testing experience with aging effects, analyzes transformer failure events reported in various databases, and evaluates maintenance practices. Databases that were analyzed included the NRC's Licensee Event Report (LER) system and the Institute for Nuclear Power Operations' Nuclear Plant Reliability Data System (NPRDS).

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)

Transformers
Aging
Stressors
Class 1E

13. AVAILABILITY STATEMENT

Unlimited

14. SECURITY CLASSIFICATION

(This Page)
Unclassified

(This Report)
Unclassified

15. NUMBER OF PAGES

16. PRICE

Printed on recycled paper

Federal Recycling Program