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AGING MANAGEMENT GUIDELINE FOR COMMERCIAL NUCLEAR POWER PLANTS- POWER AND DISTRIBUTION TRANSFORMERS

Prepared by:

Ogden Environmental and Energy Services
1777 Sentry Parkway West
Abington Hall, Suite 300
Blue Bell, PA 19422

Sandia Contract No. 67-0552

Authors:

Gary Toman and Robert Gazdzinski

Under Contract to:

Sandia National Laboratories
Albuquerque, NM 87185
for the
U.S. Department of Energy

Project Managers:

James Nakos and Roger Hill

Abstract

This Aging Management Guideline (AMG) provides recommended methods for effective detection and mitigation of age-related degradation mechanisms in power and distribution transformers important to license renewal in commercial nuclear power plants. The intent of this AMG to assist plant maintenance and operations personnel in maximizing the safe, useful life of these components. It also supports the documentation of effective aging management programs required under the License Renewal Rule 10 CFR Part 54. This AMG is presented in a manner which allows personnel responsible for performance analysis and maintenance to compare their plant-specific aging mechanisms (expected or already experienced) and aging management program activities to the more generic results and recommendations presented herein.

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1. EXECUTIVE SUMMARY

1.1 Purpose and Objectives

Continued operation of nuclear power plants for periods that extend beyond the original 40-year license period may be a desirable option for many U.S. nuclear plant operators. To allow operation of the plant to continue beyond the original licensing period, utilities must show that the aging of components important to license renewal has been managed such that these components will not degrade to the extent that they are incapable of supporting required functions. Therefore, to allow operation during a license renewal period, operators of nuclear power plants must manage the aging of components so that proper function is assured.

The purpose of this Aging Management Guideline (AMG) is to provide guidance for the effective management of aging of power and distribution transformers (subsequently referred to as transformers) used in safety-related and non-safety-related applications in commercial nuclear power plants. An effective aging management program will ensure that these transformers will continue to perform their function or will not prevent the performance of a required function during the current and license renewal terms.

The objective of this AMG is to provide an analysis of the potential aging mechanisms for power and distribution transformers and to provide acceptable guidelines for developing aging management programs for controlling significant aging mechanisms. Use of this guidance will provide nuclear plant operators with a basis for verifying that an effective program for managing age-related degradation of transformers is in place.

1.2 Scope

Power and distribution transformers are used in commercial nuclear plants to connect the main generator to the high-voltage transmission system, and to connect offsite sources of electric power to distribution subsystems for operation of plant auxiliary electrical equipment at medium and low voltages. Equipment covered in this AMG includes transformers that supply power to site loads during plant start-up, shutdown, and post-shutdown periods (commonly referred to as start-up transformers), and transformers that distribute power to medium- and low-voltage site load centers. These categories include both liquid-immersed and dry-type transformers. Main transformers (i.e., those which supply the offsite transmission system with output from the main generator(s)), unit auxiliary transformers, and auto- and grounding transformers were not included in this guideline, as these components do not fall within the definition of "important to license renewal" for the majority of nuclear plants. However, a limited number of plants may be configured such that the main and auxiliary transformers are within the definition because they are considered as off-site feeds; for these plants, the generic guidance and aging management techniques contained herein could be applied to these components as well.

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Transformers important to license renewal are addressed in this AMG. The group of transformers that are important to license renewal includes more equipment than just safety-related transformers. For example, the definition of important to license renewal includes any component or system subject to an operability requirement in the plant's technical specifications. At a minimum for most plants, this would place transformers in the offsite power source paths to the emergency buses within the scope of important to license renewal. The definition of important to license renewal is contained in Section 2.5. The evaluation of the effect of this definition on the scope of a utility's aging management program for transformers is discussed in Section 3.1. Although the types of transformers contained in the grouping "important to license renewal" that are not safety-related are essentially the same as safety-related transformers, they may not have been maintained in the same manner as the safety-related equipment. Therefore, utilities may choose to extend their maintenance practices used on safety-related transformers to the additional transformers covered by the scope of important to license renewal, or to otherwise demonstrate that these practices are not required to effectively manage the aging of the additional equipment. (Note: During review of transformer maintenance practices and procedures from a number of utilities, little difference in treatment between safety-related and non-safety-related transformers was noted.)

The general classifications of transformers that are contained within the grouping of equipment important to license renewal are:

- Transmission Voltage¹ to 13 kVac or 4 kVac
- 13 kVac to 4 kVac²
- 13 kVac or 4 kVac to 480 Vac³

Electrical distribution lines (i.e., the high-voltage transmission lines supplying power transformers, and the cables distributing power throughout the plant) and protective relays/control devices external to the transformer enclosure are not within the scope of this document. The transformer enclosure (tank), windings, insulation system, core, bushings, cooling system, oil preservation and sampling system, tap changers, supporting internal electrical components, and internal protective and monitoring devices are, where installed, all considered to be within scope.

¹ Transmission voltages for nuclear plants are typically 500 kVac, 345 kVac, or 230 kVac, although other voltages may be used. Medium voltages are typically 13.8 kVac or 4.16 kVac although other voltages may be used as well. A few plants transform transmission voltage directly to low voltage (i.e., 480 Vac); these applications are included in this category also.

² Some plant distribution systems transform medium voltages (such as 13 kVac) directly to 480 Vac, and hence do not use this type of equipment.

³ The 13-kVac, 4-kVac, and 480-Vac designations are used throughout the remainder of this document although some plants use systems with slightly different nominal voltages.

1.3 Conclusions of This Study

This study evaluated the stressors acting on transformer components, industry data on aging and failure of transformer components, and maintenance activities performed on transformers. The potential aging mechanisms resulting from environmental and operating stressors on transformers were identified, evaluated, and correlated with actual plant experience to determine if the potential aging mechanisms were actually being experienced. Then, the maintenance procedures used by nuclear plant operators were evaluated to determine if the potential and experienced aging mechanisms are being identified and managed. Where an aging mechanism was properly managed, the procedures were deemed to be "effective." Where an aging mechanism was not fully managed or not considered, additional plant-specific activities to manage the aging mechanism were identified.

1.3.1 Potentially Significant Component/Aging Mechanism Combinations Managed by Effective Programs

Evaluation of the components of the transformers, the stressors acting upon the components, and the operational history data indicates that nearly all transformer components have potentially significant aging mechanisms that can affect their function. Evaluation of the failure history coupled with review of existing plant maintenance procedures shows that these aging mechanisms can be managed in the current and license renewal periods. Table 1-1 provides a summary of the components and aging mechanisms, coupled with the maintenance and surveillance technique that manages the aging mechanism. It should be noted that not all components and their aging mechanisms listed in Table 1-1 are applicable to every transformer; each transformer must be evaluated individually to determine which components are installed. Those mechanisms and components applicable to only one type of transformer (either liquid or dry) are so noted. A full tabulation of components, aging mechanisms, maintenance techniques, and periodicities is provided in Table 5-1. Section 5 (Section 5.2 and others) provides additional information on inspection frequencies. Appendix A provides definitions of the terminology used throughout the report.

Table 5-1 provides additional detail for the transformer components listed above. All of the potentially significant aging mechanisms were amenable to aging management through currently available maintenance and surveillance techniques.

1.3.2 Non-significant Component/Aging Mechanism Combinations

Table 1-2 provides a summary of the non-significant aging mechanisms.

Table 1-1. Component and Aging Mechanism Summary

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Metal Enclosure (Tank) and Cover(s)	Material degradation	Visual inspection; cleaning; painting
	Deterioration of seals & gaskets	Visual inspection; replacement as necessary
	Metal fatigue	Visual inspection; leak testing (liquid or sealed dry-type only); weld or patch repair as necessary
	Loss of fastening components	Visual inspection; replacement of lost components
Primary and Secondary Windings	Degradation of organic supports and spacers	Visual inspection*; insulation resistance testing; power factor testing; gas and oil evaluation (liquid only)
	Formation of localized high temperature areas (hot spots)	Monitoring of temperature indications; sampling and analysis of transformer insulating fluid (liquid only); purification/replacement of insulating fluid as required; cleaning of windings and insulation (dry-type); infrared (IR) inspection
	Loosening of winding mounting system	Visual inspection*; measurement of critical winding/core tolerances
	Winding (conductor) failure	Visual inspection for overheating or breaks in insulation/conductor*; resistance and continuity testing
Magnetic Core	Loosening of core mounting system	Visual inspection; core-to-ground test; measurement of critical core/winding dimensions*
	Core material embrittlement	Visual inspection*
Insulation System (liquid-immersed)	Dielectric breakdown of insulating fluid	Sampling and analysis for dielectric strength, power factor, and water/impurity content; gas and oil evaluation
	Particulate and/or moisture contamination	Visual inspection; dielectric strength testing; analysis for water content
	High acidity	Sampling and laboratory analysis (pH, neutralization number)
	Oxidation and sludge formation	Visual inspection of insulating fluid; laboratory analysis; maintenance of seals and air-tight integrity of tank and oil preservation system components
(Dry-Type)	Thermal deterioration of organic materials	Insulation resistance testing
(Liquid and Dry)	Thermal deterioration of solid organic insulating materials	Load and temperature control; gas and oil evaluation; analysis of insulating fluid for decomposition byproducts; visual inspection* for discoloration, cracking; insulation resistance testing
Bushings	Degradation of organic materials	Power factor and capacitance testing

Table 1-1. Component and Aging Mechanism Summary (continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Bushings (continued)	Contamination or deterioration of porcelain exterior surfaces	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning or replacement as necessary
	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required
	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain
Cooling System	Wear/fatigue of the pump and fan motor bearings, shaft, and impeller	Visual inspection and verification of normal fan or pump operation (no vibration, abnormal noise, overheating, etc.); periodic lubrication; bearing or component replacement as required
	Degradation of motor winding and lead insulation	Winding insulation resistance testing; replacement of motor and/or leads as required
	Electrical component degradation	Visual inspection and cleaning; functionality testing; replacement as necessary
	Fouling of heat transfer surfaces	Visual inspection and cleaning
Fluid Preservation and Sampling System (liquid only)	Deterioration of organic and inorganic materials	Visual inspection for cracking, rust, corrosion, or other deterioration; cleaning; painting and preservation; functionality testing; replacement as required
	Wear of mechanical components	Inspection for looseness or loss of adjustment; measurement and adjustment of component tolerances; lubrication; replacement as required
	Loss of component adjustment	Verification of proper pressure regulating valve operation; cleaning and adjustment as required
Tap Changers (Load Tap Changer; liquid only)	Wear of mechanical components	Verification of component tolerances and adjustment
	Deterioration or failure of electrical components	Visual inspection and cleaning; electrical and functionality testing; replacement as necessary
	Degradation of organic insulating materials	Visual inspection* of components for cracking or other loss of mechanical properties; insulation resistance testing
	Loss of adjustment of braking systems	Visual inspection of linings for wear; verification of proper braking system adjustment and torque; replacement of brake linings when required
	Wear of main contact surfaces	Visual inspection* of moving and stationary contact surfaces for wear or contamination; cleaning, reconditioning, or replacement as necessary.

Table 1-1. Component and Aging Mechanism Summary (continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Tap Changers (Load Tap Changer; liquid only) (continued)	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level
Fault Pressure Relay (liquid only)	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation
Bushing Current Transformers	Degradation of organic insulating materials	Insulation inspection; electrical testing
Pressure Relief Devices (liquid and sealed dry-type only)	Degradation of seals	Functionality testing ^{**} ; visual inspection for seal degradation
Temperature Indicators	Failure of hot spot heating coil element	Periodic verification of temperature sensor functionality and accuracy

* Generally only accomplished during invasive maintenance procedures requiring disassembly, draining, and/or untanking. Inspection of this type would be an uncommon practice performed only after failure or when a significant problem was indicated by other symptoms or tests.

** Generally performed only when device removed/replaced or under other similar conditions.

Table 1-2. Summary of the Non-significant Aging Mechanisms

Component	Aging Mechanism	Maintenance and Surveillance Techniques
Fault Pressure Relay (liquid only)	Wear of mechanical components	Periodic functional testing of relay *
	Electric switch failure	Periodic functional testing of relay *
No-Load Tap Changers	Contact surface and mechanism wear	Visual inspection; functional testing
Resistance Temperature Detectors	Corrosion	Periodic calibration
	Mechanical shock	Periodic calibration
Thermocouples	Thermal degradation	None
Pressure Relief Devices (liquid and sealed dry-type only)	Spring relaxation	Periodic functional testing of relief*
Flow Indicator (liquid only)	Wear of internal components	Visual inspection for operation
Control Compartment Space Heater	Failure of heating element	Visual inspection; verification of operation

* Generally performed only when device removed/replaced or under other similar conditions.

1.3.3 Potentially Significant Component/Aging Mechanism Combinations Requiring Plant-Specific Management

Section 5 of this report evaluates the maintenance procedures for power and distribution transformers and concludes that transformers maintained in accordance with the guidance contained in Sections 5.2 and 5.3 will be subject to an effective maintenance program as required for license renewal, subject to the following limitations:

- **Dielectric Breakdown of Insulating Fluid.** Failure data for large liquid-immersed transformers indicate that failures are primarily detected during operation and that they frequently resulted in preclusion of the transformer's required function(s). Many of the more damaging failures (such as explosions and fires) occurred as a result of dielectric breakdown of the insulating fluid. This breakdown can be precipitated by various conditions, such as moisture contamination and abnormal gas formation in the fluid, and may be detected by various types of laboratory and/or in-situ analysis. Hence, periodic fluid analysis and gas monitoring appear to be the most effective means of identifying incipient failure in large liquid-immersed transformers.
- **Bushing Flashover.** Bushing flashover has occurred on several occasions; this mode of failure can result in substantial damage to the affected bushings (and transformer) as well as affecting the transformer's required function(s). Contamination and subsequent flashover is primarily caused by airborne dust and/or salt spray accumulation on exterior bushing surfaces acting in combination with rain or high humidity. This problem can be avoided through periodic removal of the dust/salt deposits or through the use of special bushing coatings.
- **Deterioration of Solid Insulation.** Degradation of solid transformer insulation (i.e., organic materials such as wood, paper, or resins) results primarily from exposure to heat generated within the transformer/windings (applicable to both liquid and dry units), and exposure to the insulating fluid in which the material is immersed (liquid only). Although generally a very slow process, deterioration of the solid insulation proceeds essentially unimpeded during the life of the unit. This deterioration may be monitored through periodic visual inspection (when accessible) or insulating fluid analysis (liquid only).

Accordingly, operators with liquid or dry-type transformers installed at their nuclear plants should consider implementing the following actions (as applicable):

1. Review and evaluate the adequacy of existing maintenance, analysis, and testing programs with relation to the manufacturer's recommendations and other industry guidance; specific care should be taken to ensure that comprehensive insulating fluid analysis and bushing cleaning are conducted with sufficient frequency so as to limit the probability of catastrophic transformer failure. If existing testing and maintenance procedures are not adequate, upgrade the programs as necessary.

2. When failures of the main insulation system occur for transformers or their components, conduct a root-cause evaluation. Implement those corrective actions necessary to mitigate the effects of the identified causes.

In addition, plant-specific review of the maintenance program is recommended if:

- The transformer experiences abnormal electrical loading conditions (such as loading for a significant period beyond rated condition, significantly unbalanced voltages, or fault conditions). Then, procedures should require the transformer to be evaluated as soon as practical after the abnormal occurrence to ensure that no damage that could potentially affect the required operation of the transformer has occurred.
- The transformer is exposed to ambient temperatures in excess of 40°C [104°F] (or 30°C [86°F] average temperature for any 24-hour interval) for extended periods (unless specifically designed for operation at elevated temperature). Then, the periodicity of maintenance and surveillance should be reviewed to verify that the insulation system and other organic components such as solid insulation and gaskets have not been adversely affected by the elevated operating temperature.
- The transformer is subject to environments containing high levels of dust, dirt, or other airborne contaminants such as salt or chemical vapor. Then, the procedures for maintenance of the transformer should be reviewed to verify that (1) any filters (dry-type units only) protecting the transformer from dust or particulates are inspected and cleaned at sufficient intervals, (2) heat transfer surfaces (such as radiator cooling fins) are periodically inspected and cleaned to preclude fouling, (3) periodic inspection of the primary/secondary windings for signs of contamination and/or degradation and any required cleaning is conducted (dry-type), and (4) inspection and cleaning (or application of protective coatings) of the bushing surfaces is conducted at sufficient intervals to preclude instances of surface tracking and possible flashover.

More detail on these issues is contained in Section 6.

1.4 References

None.

2. INTRODUCTION

2.1 Background

The DOE-sponsored Plant Lifetime Improvement (PLIM) Program, in cooperation with the Electric Power Research Institute (EPRI) Life Cycle Management (LCM) Program, is establishing and demonstrating a predictable license renewal process for existing Light Water Reactors (LWRs) in the United States. An important element of this program was the development of Nuclear Management and Resources Council (NUMARC) License Renewal Industry Reports (IRs), which cover critical classes of equipment such as reactor pressure vessels, reactor coolant pressure boundary piping, containment structures, and cables. To support continued demonstration of PLIM and LCM concepts, there is a need for further industry development of guidelines that describe and evaluate acceptable aging management approaches for several groupings of equipment not evaluated in the IRs. This AMG evaluates power and distribution transformers determined to be important to license renewal.[2.1]

Continued operation of nuclear power plants for periods that extend beyond the original 40-year license period may be desirable for many U.S. nuclear plant operators. To allow operation of the plant during a license renewal period, utilities must show that the aging of components important to license renewal which are subject to age-related degradation unique to license renewal has been managed such that these components will not degrade to the extent that they are incapable of supporting required functions. Therefore, to control the aging of components important to license renewal during the license renewal period, operators of nuclear power plants must identify and perform activities necessary to manage the aging of components so that proper function is assured.

With respect to aging during the license renewal period, aging is a regulatory concern when (1) its effects are different in character or magnitude after the term of the current operating license, or (2) its effects were not explicitly identified and evaluated by the licensee for the period of extended operation and the evaluation found acceptable by the U.S. Nuclear Regulatory Commission (NRC), or (3) when it occurs only during the period of extended operation.[2.1]* These concepts indicate that the age-related degradation of concern during license renewal is degradation that is unique to the license renewal period. However, the aging and control of aging during the current operating license period must be identified and differentiated from age-related degradation that occurs during the license renewal period. The effects of age-related degradation that would occur during the current operating license must be shown to be under control upon entering the license renewal period, and the effects of any additional age-related degradation unique to the license renewal period must be shown to be effectively managed. Because age-related degradation unique to the license renewal period cannot always be differentiated from that encountered during the current license period, this AMG evaluates all relevant age-related degradation mechanisms.

* Numbers in brackets are references, which appear at the end of each section.

For components to retain function during the license renewal period, activities such as preventive maintenance and refurbishment may be necessary during the current license period even though some of these activities may not have been necessary to guarantee function during the current license period. These activities would be necessary to assure that there is no loss of required functions, no unacceptable reduction in safety margins, and that higher rates of challenge to plant safety systems do not occur during the license renewal period.

2.2 Purpose and Objectives

The purpose of this AMG is to provide guidance for the effective management of aging of power and distribution transformers used in safety-related and non-safety-related applications in nuclear power plants. An effective aging management program will ensure that each transformer component will continue to perform its function or will not prevent performance of a required function during the license renewal term.

The objective of this AMG is to provide an analysis of the potential degradation modes for power and distribution transformers and to provide acceptable guidelines for developing effective aging management programs for controlling significant degradation mechanisms.

This AMG is intended for use by nuclear plant personnel performing transformer aging evaluations to provide additional information and guidance in the formulation of their aging management programs. This AMG also provides additional value to nuclear plant operators as follows:

1. The AMG is a well-researched technical document that can be used by maintenance and system engineering personnel for the identification, characterization, and management of age-related degradation in power and distribution transformers. It can also be applied to a variety of the proposed approaches for the Integrated Plant Assessment (IPA). For example, the AMG can be used to resolve aging issues and devise effective programs for the management of aging occurring during both the current and license renewal periods. Failure data presented in the guideline may also be used to help justify that current maintenance practices are effective at mitigating equipment functional failures.
2. The development of this AMG required an extensive literature search. Therefore, nuclear plant personnel can use the guideline as an exhaustive reference document for relevant information about transformers. Some of the references used include:
 - Independent Research Reports
 - EPRI/Nuclear Maintenance Applications Center (NMAC) Reports and Maintenance Guides
 - NRC Bulletins, Information Notices, Circulars, Generic Letters and Reports
 - Code of Federal Regulations (CFR)

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- Vendor Manuals
 - Institute of Electrical and Electronics Engineers (IEEE) and American National Standards Institute (ANSI) Standards
 - Other Technical Papers
3. This AMG consolidates historical maintenance and industry operating information into one source. The plant maintenance/system engineer will find this useful for both the identification of age-related degradation (including root causes) and the verification of appropriate corrective action. Issues discussed in this AMG include:
- Equipment design and configuration differences relevant to aging considerations
 - Equipment obsolescence as it affects aging management
 - Service environments
 - Operating and maintenance history from the Institute for Nuclear Power Operations (INPO) Nuclear Plant Reliability Data System (NPRDS) and NRC Licensee Event Report (LER) databases
 - Additional operating and maintenance history from responses to plant surveys
4. The phenomena of component aging are described in detail. This will be useful for transformer maintenance interval and reliability evaluations. The following topics are discussed:
- Stressors acting on transformer components
 - Aging mechanism identification
 - Significance of aging mechanisms using "if-then" criteria
 - Age-related degradation of transformer components
 - Potential failure modes
5. This AMG is an effective tool for transformer aging management and personnel training. That is, it:
- Heightens awareness concerning the need for aging management and compliance with Maintenance Rule requirements
 - Establishes a correlation between the scope and frequency of maintenance practices and transformer performance and rate of degradation

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- Provides information that can be used in the construction of meaningful life-cycle management charts and to improve the reliability of cost/benefit determinations
- Discusses both conventional and non-conventional maintenance techniques, and considers how these practices can be utilized to effectively manage equipment aging
- Characterizes manifestations of equipment aging for use in training personnel responsible for maintenance and inspection activities
- Establishes concepts, principles, and methods for evaluating transformers not in the scope of this guideline.

2.3 Scope

Power and distribution transformers are used in nuclear plants to connect the main generator to the high-voltage transmission system, and to connect offsite sources of electric power to distribution subsystems for operation of plant auxiliary electrical equipment at medium and low voltages.[2.2] Equipment covered in this AMG includes transformers that supply power to the site loads during plant startup, shutdown, and post-shutdown periods (commonly referred to as start-up transformers) and transformers that distribute power to medium- and low-voltage site load centers. These categories include both liquid-immersed and dry-type transformers. Transformers important to license renewal are addressed by this AMG. Although the types of transformers contained in the grouping "important to license renewal" that are not safety-related are essentially the same as safety-related transformers, they may not have been maintained in the same manner as the safety-related equipment. Therefore, utilities may choose to extend their maintenance practices used on safety-related transformers to the additional transformers covered by the scope of important to license renewal, or to otherwise demonstrate that these practices are not required to effectively manage the aging of the additional equipment.

The general classifications of transformers that are contained within the grouping of equipment important to license renewal are:

- Transmission Voltage* to 13 kVac or 4 kVac
- 13 kVac to 4 kVac**

* Transmission voltages for nuclear plants are typically 500 kVac, 345 kVac, or 230 kVac, although other voltages may be used. Medium voltages are typically 13.8 kVac or 4.16 kVac, although other voltages may be used as well. A few plants transform transmission voltage directly to low voltage (i.e., 480 Vac); these applications are included in this category also.

** Some plant distribution systems transform medium voltages (such as 13 kVac) directly to 480 Vac, and hence do not use this type of equipment.

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- 13 kVac or 4 kVac to 480 Vac*

Electrical distribution lines (i.e., the high-voltage transmission lines supplying power transformers, and the cables distributing power throughout the plant) and protective relays/control devices external to the transformer enclosure are not within the scope of this document. The transformer enclosure (tank), windings, insulation system, core, bushings, cooling system, oil preservation and sampling system, tap changers, supporting internal electrical components, and internal protective and monitoring devices are, where installed, all considered to be within scope.

Liquid-immersed and dry-type transformers from the following manufacturers are addressed in this guideline:

- General Electric
- Westinghouse
- McGraw-Edison
- ITE/Brown Boveri
- Federal Pacific
- Moloney

Section 3 lists and describes the components evaluated and the component boundaries and discusses manufacturers' design differences. It also includes a discussion of the design requirements that apply to power and distribution transformers, including applicable Codes, Standards, and Regulations. Lastly, Section 3 includes a detailed study of the operating history of the components evaluated from NPRDS data, LER data, and other sources.

Section 4 discusses stressors acting on the subcomponents. Stressors acting over time produce aging mechanisms that ultimately can cause component degradation. The results of aging studies are used to describe aging mechanisms known to cause degradation. An aging mechanism is potentially significant when, if allowed to continue without detection or mitigation measures, it may cause the component to lose its ability to perform its required function. Aging mechanisms for the subcomponents are identified and evaluated. Operational demands, environmental conditions, failure data, and industry operations and maintenance history are considered, and the significance of the aging mechanism determined.

Section 5 discusses effective aging management techniques for aging mechanisms determined to be potentially significant in Section 4. Common maintenance, inspection, testing, and surveillance techniques or programs are described. A brief discussion of less common activities and techniques is also included. The effectiveness of these techniques or programs to

* The 13-kVac, 4-kVac, and 480-Vac designations are used throughout the remainder of this document although some plants use systems with slightly different nominal voltages.

manage the significant aging mechanisms is described. Variations in plant aging management programs or techniques are considered. Requirements for an effective technique or program are presented in the form of "if/then" criteria wherever possible.

Section 6 discusses management options to deal with action items identified in Section 5. Refurbishment criteria are also discussed.

2.4 Generic License Renewal Requirements

10 CFR 54.21 [2.3] describes the requirements for the content of technical information in the license renewal application.* Section 54.21 states that a supplement to the Final Safety Analysis Report (FSAR) must be prepared that contains an IPA that must:

1. identify and list all systems, structures, and components (SSCs) important to license renewal
2. identify those structures and components (SCs) that contribute to the performance of a required function or could, if they fail, prevent an SSC important to license renewal from performing its required function.
3. for the identified SCs, determine those that could have age-related degradation that is unique to license renewal.

To identify the age-related degradation** that is unique to license renewal (in item (a)(3) of Section 54.21), the definition of age-related degradation unique to license renewal must be applied. Age-related degradation unique to the license renewal period [2.1] is degradation:

1. that occurs during the term of the current operating license, but whose effects are different in character or magnitude after the term of the current operating license (the period of extended operation); or
2. whose effects were not explicitly identified and evaluated by the licensee for the period of extended operation and the evaluation found acceptable by the NRC; or
3. that occurs only during the period of extended operation.

The criteria for determining SSCs important to license renewal, the criteria for evaluating whether an SC is necessary for the performance of a required function, and the technical criteria used to determine whether an SC is subject to age-related degradation unique to license renewal must be defined.

* The NRC is in the process of a rule change regarding 10 CFR 54 at the time of this writing.

** See Appendix A for definitions of the aging terminology used in this report.

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For each of the SCs having age-related degradation that is unique to license renewal, the age-related degradation must be addressed by an effective program or shown not to need to be addressed by an effective program. An effective program is a documented program to manage age-related degradation that ensures that an SSC important to license renewal will continue to perform its required function or will not prevent the performance of a required function.

The effective program must:

1. identify and mitigate age-related degradation unique to license renewal
2. contain acceptance criteria against which the need for corrective action can be evaluated and assure timely corrective action when the acceptance criteria are not met
3. be implemented by the facility operating procedures and reviewed by the onsite review committee.

10 CFR 54.21 continues with a discussion of changes to the current licensing basis and plant modifications, which are outside the scope of this report.

Additionally, this AMG supports the determination that existing aging management practices are satisfactory for fulfilling license renewal requirements and meeting review conditions stated in the draft version of NUREG-1299, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants." [2.4] Components included in the classification of "important to license renewal" are identified, and stressors, aging mechanisms, and failure modes for these components are defined. Furthermore, this AMG states the type of existing practices that are acceptable for the management of aging as well as areas requiring further plant-specific evaluation. Exemptions and requests for relief (pursuant to 10 CFR 50.12 and 10 CFR 50.55a, respectively) were not considered under this guideline because these areas are plant-specific in nature and therefore must be considered on a plant-by-plant basis.

This report will evaluate power and distribution transformers with respect to the requirements of 10 CFR 54.21, and will provide a discussion of the types of transformers important to license renewal and the age-related degradation affecting components and subcomponents of the transformers. Sections 2.5 and 2.6 below detail the analysis leading to the determination of transformers important to license renewal and the determination of aging mechanisms to be evaluated.

2.5 Method Used to Define the Scope of Components Important to License Renewal

To determine the transformer components covered by license renewal requirements, the definition of SSCs important to license renewal [2.1] must be evaluated. The current definition of SSCs important to license renewal includes:

1. Safety-related SSCs, which are those relied upon to remain functional during and following design basis events to ensure:

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- (i) The integrity of the reactor coolant pressure boundary;
 - (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or
 - (iii) The capability to prevent the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR 100 guidelines.
2. All non-safety-related SSCs whose failure could directly prevent satisfactory accomplishment of any of the required functions identified in paragraphs (1) (i), (ii), or (iii) of this definition.
 3. All SSCs relied on in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).
 4. All SSCs subject to operability requirements contained in the facility's Technical Specifications' Limiting Conditions for Operation.

The evaluation of this definition with respect to transformers and the components determined to be important to license renewal is given in Section 3.1.

2.6 Method Used to Define Aging Mechanisms Assessed in This Study

To define the aging mechanisms assessed in this study, a two-part evaluation was performed. First, the effects of stressors, such as temperature, humidity, voltage, non-seismic vibration, and radiation, on equipment operation were determined. The aging mechanisms associated with those stressors that cause degradation were then determined. This evaluation is contained in Section 4.1.

Second, industry-wide operating experience was examined, particularly that reported in NRC LERs; Information Notices, Bulletins, Generic Letters, and Circulars; INPO Significant Event Reports (SERs); and the NPRDS. A review of the NRC and INPO documentation was conducted to identify age-related failures. The aging mechanisms associated with reported age-related failures were then determined. Events described in the NPRDS data and LERs were analyzed for age-related deterioration and failures to identify the numbers of particular types of failures. The aging mechanisms associated with these failures were then determined. This review of industry-wide operating experience is contained in Section 3.6.

Additional important information was gained through examination of other industry studies on transformer/electrical equipment aging. The results presented in these sources were used to supplement the conclusions drawn from the evaluation of stressors and operating experience described above and to assist in the identification of additional aging mechanisms.

This multi-source analysis (i.e., using data from INPO and NRC documentation in conjunction with information gathered from other industry sources) provides a descriptive

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characterization of equipment aging by using actual plant and industry data to substantiate and refine those aging mechanisms postulated to occur as the result of stressors.

After a list of all possible aging mechanisms was developed, the significance of each aging mechanism was determined. Those aging mechanisms that were confirmed by operating or overhaul experience, had a high probability of occurrence, or would result in a loss of functionality having a large impact on equipment operation were designated as significant aging mechanisms. Those aging mechanisms designated as significant are discussed in Section 4.2.1. The remaining aging mechanisms were then reviewed to determine if:

1. They were fully controlled by current preventive maintenance programs, and
2. Sufficient time had passed for the effects of the aging mechanism to be identified.

Items not prevented by current preventive maintenance programs but that had not had time to for the effects to become detectable (by standard detection means) were deemed to be significant. Those remaining aging mechanisms that had sufficient time to be recognizable but had not occurred were designated non-significant and are discussed in Section 4.2.2. The aging mechanisms that are not addressed by current maintenance programs are discussed in Section 5.4.2. Effective management options for these aging mechanisms are identified in Section 6.1.

It should be noted that aging mechanisms and their associated degradations were not categorized either as occurring in the current license period or as being unique to license renewal. Aging as a whole is covered in this document. There is no generically applicable methodology that has been agreed upon for identifying those age-related degradation mechanisms that are unique to license renewal. Therefore, the approach herein identifies those techniques that manage aging mechanisms to preclude adverse effects during the current and license renewal periods.

2.7 References

- 2.1 Title 10, U.S. Code of Federal Regulations, 10 CFR Part 54.3, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants - Definitions," Federal Register, Vol. 56, No. 240, December 13, 1991, pp. 64976-64977.
- 2.2 Power Plant Electrical Reference Series, Volume 2, "Power Transformers," prepared by A. W. Goldman and C. G. Pebler for the Electric Power Research Institute, 1987.
- 2.3 Title 10, U.S. Code of Federal Regulations, 10 CFR Part 54.21, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants - Contents of Application - Technical Information," Federal Register, Vol. 56, No. 240, December 13, 1991, p. 64978.
- 2.4 NUREG-1299, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," USNRC, Draft Report for Comment, November 1990.

3. EQUIPMENT EVALUATED

3.1 Results of Methodology Used to Select Components Important to License Renewal

For each plant entering license renewal, an assessment must be performed to identify power and distribution transformers that are important to license renewal. Figure 3-1 shows a simplified nuclear power plant electrical system. Per paragraph 1 of the definition of systems and components important to license renewal provided in the introduction (Section 2.5), all transformers deemed safety-related are important to license renewal. Paragraph 2 of the definition generally would not bring additional transformers into the scope of important to license renewal, whereas Paragraph 3 may, by virtue of the addition of transformers to meet station blackout requirements.

Paragraph 4 of the definition does add components to the list of SSCs important to license renewal. Section 3.8.1.1 of most Technical Specifications [3.1, 3.2, 3.3, 3.4, 3.5, 3.6, 3.7, 3.8, 3.9] has the following Limiting Condition for Operation (LCO):

"As a minimum, the following A.C. electrical power sources shall be OPERABLE:

- a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and"

This LCO causes the electrical distribution equipment between the offsite transmission network and the onsite Class 1E (safety-related) distribution system to be included within the scope of SSCs important to license renewal. Figure 3-1 shows a simplified arrangement of a plant electrical system with traditional safety-related versus non-safety-related boundaries indicated. Figure 3-2 indicates the scope of electrical equipment important to license renewal, with the start-up transformers (and any other transformers interposed between the start-up transformers and the safety-related loads) included in the scope.

In some plants, voltage transformation from transmission voltage to 4-kVac will be accomplished via a single transformer. In other plants, additional step-down transformers may be placed between the start-up transformers and the safety-related load centers. In a few plants, transmission voltage is directly transformed to low-voltage (i.e., 480-Vac), however these applications are not common. [3.10, 3.11] It should be noted that inclusion of these transformers (regardless of the configuration used) in the scope of license renewal will add further equipment to the scope of important to license renewal. Supporting components and systems for these transformers (such as control systems, protective relaying, and power cabling) would also come within the scope of important to license renewal. (Note: These systems are not within the scope of this document.) Current maintenance and surveillance practices applied to these non-safety-related transformers may differ somewhat from that of their safety-related counterparts; however, most plants maintain both safety- and non-safety-related transformers using identical practices. In the event that such differences do exist, plants implementing a license renewal program should evaluate these differences to affirm that aging degradation is appropriately managed for those non-safety-related components that are important to license renewal.

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Figure 3-1. Simplified Nuclear Power Plant Electrical System.

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Figure 3-2. Scope of Electrical Equipment Important to License Renewal.

The remainder of the LCOs in Standard Technical Specification Section 3.8.1.1 cover the equipment normally classified as safety-related electrical (Class 1E) and add no further transformers to the list of SSCs important to license renewal. However, other Technical Specifications may require non-safety-related components, such as the recirculation loop equipment, to be operable. If there are LCOs for these components, any transformers directly associated with these loads (i.e., located in the direct power supply path) would be included within the definition of important to license renewal. For example, in Figure 3-1, non-safety-related transformer 1 may be important to license renewal because it is potentially part of the supply path to the non-1E 480-Vac load centers (which could supply power to one of the loads covered by these additional LCOs). If these load centers do not feed equipment covered by a Technical Specification LCO, then the associated transformers are not considered important to license renewal. However, the additional administrative burden of treating some of these transformers differently than others, coupled with the potential for errors if the lesser aging management requirements were inadvertently applied to transformers that must retain functionality, may dictate that all transformers be subject to the same aging management techniques.

Evaluation of other LCOs may add more transformers to the list of components important to license renewal. However, in most cases, the types of transformers that are added will be the same or very similar to those used in safety-related applications. Hence more devices will be covered, but essentially the same aging management techniques will apply.

3.2 Listing of Components Evaluated

Each transformer component determined to be important to license renewal in Section 3.1 must be evaluated to determine if it will degrade during the license renewal period.

The following components and systems are basic to power and distribution transformers (with exceptions as noted):

- Metal Enclosure (Tank) and Cover¹
- Primary and Secondary Windings
- Magnetic Core
- Insulation System
- Bushings
- Cooling System²
- Fluid Preservation and Sampling System³
- Tap Changers
- Protection and Monitoring Systems
- Auxiliary Electrical Devices

¹ The tank assembly is not common to all power and distribution transformers; many air-ventilated dry-type units are equipped simply with a metal housing.

² Only applicable to transformers with a forced cooled rating.

³ Liquid-immersed transformers only

All of the applicable components listed above are described further in Section 3.4. The control and power cabling (connecting the transformer to other equipment external to the transformer), protective relaying, associated switchgear, and the fire suppression system are not within the scope of this document (see Section 3.3).

3.3 Component Boundaries

The component boundaries for the transformers covered by this report include the entire transformer assembly and its components described as follows:

- **Metal Enclosure (Tank) and Cover** - includes all exterior and interior portions of the transformer enclosure (tank) assembly and cover, as well as gaskets used to seal the tank, and any attached components or hardware.
- **Magnetic Core** - includes core and core mounting hardware.
- **Windings** - includes the primary, secondary, and tertiary (as applicable) transformer windings as well as any tap or series windings which may be present. Electrical connections (up to the point of connection with the bushings) are also included.
- **Insulation System** - includes the liquid or gas fill; also includes solid insulation and any resin encapsulations or insulating coatings applied to windings.
- **Bushings** - includes winding lead, insulation, oil and inert gas charge, rain shield, housing, and all electrical connections, gaskets, and hardware.
- **Cooling System** - includes cooling fans, pumps, radiators and heat exchangers, piping, and associated isolation and flow control valves.
- **Oil Preservation and Sampling System (for oil-immersed type only)** - includes inert gas bottle, regulator, conservator tank, diaphragm (air cell), sampling valves, and associated system instrumentation.
- **Tap Changers** - includes tap changer motor, contacts, gears and mechanism, braking system, voltage sensing equipment, control circuitry, and associated electrical devices (load tap changer); contacts, operating handle, and mechanism (no-load tap changer).
- **Protection and Monitoring Systems** - includes bushing current transformers, temperature detectors, gas detectors and fault gas monitors, pressure relief valves, liquid level indicators, and fault pressure relays. (Note: Fire protection systems are not covered by this guideline.)
- **Auxiliary Electrical Devices** - includes starters/contactors, thermal overload relays, molded-case circuit breakers, control and timing relays, fuses and fuse holders, and associated wiring (if mounted on the transformer) used to control auxiliary electrical loads such as cooling fan and pump motors.

It should be noted that not all components described above are installed on each transformer; many are applicable to one type of transformer (i.e., liquid-immersed or dry-type) or one design (such as sealed-tank or conservator systems).

3.4 Description of Components Evaluated

Power and distribution transformers are the two principal categories of transformer used in nuclear generating stations to provide power to onsite loads. Power transformers are primarily used for four functions: (1) to directly transform the main generator output voltage to that of the offsite transmission (230 to 500 kVac), (2) to transform main generator output to that of the primary load centers (typically 4 kV) for use by plant auxiliary electrical equipment, (3) to directly transform offsite power source voltage to that of the primary load centers, and (4) to step-down intermediate voltages (i.e., 13 kV) to primary load center voltage for further distribution to low-voltage plant loads. [3.10, 3.11, 3.12] Distribution transformers generally convert the medium-voltage present at primary load centers to low-voltage (i.e., 480 Vac) for distribution to secondary load centers (such as Motor Control Centers (MCCs) or individual plant loads). Equipment evaluated in this AMG includes power transformers as described in (3) and (4) above, as well as on-site distribution transformers used to convert medium voltages to low voltages.

Power transformers are generally rated above 500 kilovolt-amperes (kVA) or above 67 kV. Alternatively, distribution transformers are rated at/below 500 kVA or at/below 67 kV. [3.13] It should be noted, however, that categorization of a transformer as either power or distribution is largely a function of its individual application. Differences in design and configuration are incidental to the rating and application of the individual equipment. Figure 3-3 shows a typical liquid-immersed power transformer.

Startup transformers (or reserve station service transformers) supply power from an offsite high voltage source to various plant safety and non-safety loads. Startup transformers are primarily used during unit startup, cooldown, and shutdown periods; however, several plants supply both safety and non-safety loads from the startup/station service transformers during normal operation.

Unit auxiliary transformers (also known as normal station service transformers) are transformers which supply power to auxiliary loads during unit operation; the supply to these devices is typically the main generator output. Unit transformers (also known as generator step-up or main transformers), are large transformers used to connect the generator output to the transmission system. (Note: Unit and unit auxiliary transformers were not considered to be within the definition of "important to license renewal" for most plants, and therefore were not included as part of this guideline. However, the generic guidance and aging management techniques contained herein could be applied to these components as well.) Depending on the individual application, ratings for startup, unit auxiliary, and unit transformers generally range from several megavolt-amperes (MVA) to several hundred MVA.

Figure 3-3. Typical Liquid-Immersed Power Transformer.[3.14]

As indicated above, distribution transformers (also commonly referred to as load center or unit substation transformers) are used in nuclear plants to reduce medium voltages present at primary load centers (typically 13- or 4-kV) to low voltage for use by plant loads. Numerous different distribution transformers may be used to supply these low voltage systems, depending on the individual plant. Transformers of this type are typically on the order of several hundred kVA to several MVA. [3.12, 3.15]

3.4.1 Description of Predominant Types of Equipment in Grouping

3.4.1.1 General Description of Power and Distribution Transformers

Both power and distribution transformers can be divided into two general types, based on their design: dry-type and liquid-immersed. Each of these types of transformer, as well as their general operating principles, are described in the following subsections.

Liquid-Immersed Transformers

A liquid-immersed transformer consists of a magnetic core assembly which is surrounded by windings and immersed in fluid having both good heat transfer and insulating properties (typically mineral or silicone oil). The liquid-immersed transformer has several advantages including compact design and high capacity, and may be of either single phase or multi-phase design. Transformers with ratings above 10,000 kVA or 34.5 kV are usually of the liquid-immersed type. Requirements for the design, construction, and operation of liquid-immersed distribution and power transformers are contained in ANSI STD C57.12.00-1987.* [3.16]

The vapor-cooled transformer, another variant of the liquid-immersed transformer, employs a low-boiling point fluid for transfer of the heat generated in the windings. Heat generated via winding losses (discussed below) induces boiling of the fluid; this latent heat is then rejected via an external heat exchanger. The vapor is then condensed and returned to the transformer tank. Vapor-cooled transformers can also be equipped with cooling fans to increase their kVA rating. [3.12, 3.15, 3.17]

Dry-Type Transformers

Dry-type transformers, unlike the liquid-immersed models described above, generally utilize air or gas in conjunction with a solid material (such as a film coating or paper tape) as winding insulation. General operating and design requirements for dry-type distribution and power transformers are contained in ANSI STD C.57.12.01-1989.* [3.18] As with the liquid-immersed type, dry transformers can be of either single- or multi-phase design. They are available in a multitude of different enclosure configurations (based on their application), such as the ventilated, non-ventilated, sealed-tank, gas-filled, or resin-encapsulated designs. Each of these configurations is described below.

* Previous versions of these standards (as well as previously withdrawn standards) may be applicable to those transformers constructed prior to stated issuance date.

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Ventilated dry-type transformers are suitable for most indoor applications. Air may be circulated through the windings by natural convection or forced via fans; the use of fans generally increases the maximum kVA rating of the transformer (based on the added heat dissipation capability). Dust or other contaminants may foul these ventilation systems, however, and the filters must be cleaned at regular intervals to ensure proper airflow. Figure 3-4 shows a typical ventilated dry-type distribution transformer.

Enclosed, non-ventilated transformers may be used in moderately contaminated industrial environments. These transformers have characteristically low heat generation rates (losses) due to the use of high efficiency windings. This precludes the need for external ventilation.

Figure 3-4. Typical Ventilated Dry-Type Distribution Transformer.[3.19]

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Sealed-tank transformers (Figure 3-5) are designed to function in the most severe environments; unlike the enclosed/non-ventilated models described above, they are completely sealed from the outside environment and hence are essentially immune from the effects of dust, moisture, or other contaminants. These transformers also have high efficiency windings to minimize heat losses.

Gas-filled transformers are sealed units and use nitrogen, or a fluorogas as the insulation system. Fluorogases are especially desirable as they are non-combustible and will tend to mitigate the effects of an internal transformer failure.

Figure 3-5. Sealed Dry-Type Transformer.[3.19]

Resin encapsulated transformers (a variant of the dry transformer) may also be used in relatively harsh environments where ventilated transformers may not be suitable. In this design, the windings are either cast or dipped in an organic resin, thereby protecting the windings from damaging external influences. These transformers are equipped with high-efficiency windings to minimize heat generation within the resin encapsulation. Figure 3-6 shows the internals of a typical resin-encapsulated dry-type transformer. [3.12, 3.15, 3.20]

Figure 3-6. Laminated Transformer Core (wound).[3.21]

3.4.1.2 Basis of Transformer Ratings

Power and distribution transformers are usually described in terms of their physical attributes (or ratings), such as primary/secondary voltage, volt-ampere rating, frequency, and temperature rise. For example, a transformer might be designed to transform 500 kVA of power from 4-kVac to 480-Vac with a standard temperature rise of 65°C [149°F]. Transformers in nuclear plants are generally selected to operate within their ratings, except for brief transient periods (such as during motor starting or fault clearing). Operation beyond these ratings may adversely impact the longevity of the equipment, depending on the duration, magnitude, and frequency of the out-of-rating condition.

In general, power/distribution transformer ratings are based on the output of the transformer. Despite their kVA rating, a transformer's continuous load limits are determined by the current rating of the secondary windings. Transformers with secondary winding "taps" (device used to vary the electrical point of connection to the winding and therefore the transformation ratio) are limited based on the rating of the tap in use. At secondary voltages above tap voltage rating, the kVA rating establishes the allowable load for the transformer. At voltages below tap voltage rating, the tap current rating acts as the limiting factor. [3.12, 3.15]

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Transformer insulation is designed to withstand voltages to which the windings may be subjected during its anticipated service conditions. These voltages include transient voltages (due to breaker operation, lightning-induced surges, as well as normal power-frequency voltages which may be present). The basic lightning impulse insulation level (BIL) of a transformer is a measurement of the transformer insulation system's capability to withstand applied voltages which is comparable to that of a (non-direct) lightning impulse. The criteria for these voltages can be found in ANSI STDs C57.12.00 and C57.12.90. [3.16, 3.18] Several wave shapes for the voltages are specified in order to approximate various lightning conditions the transformer might encounter. Required transformer transient voltage capability is also dependent on whether lightning arresters are installed on the equipment.

Normal and abnormal operating conditions for liquid-immersed and dry type transformers are defined in ANSI STDs C57.12.00-1987 and C57.12.01-1989, respectively. Transformer operating conditions considered unusual include high ambient temperatures (above 40°C [104°F], 24-hr average above 30°C [54°F], or less than -30°C [-22°F]), high altitude (above 1000 m [3300 ft]), operation at high secondary voltage (110% no-load, 105% when operating with load of power factor 0.8 or greater), primary phase voltage and/or secondary phase voltage imbalance, over-excitation, unusual maintenance problems, excessive or abrasive dust, salt spray, excessive moisture, abnormal vibration/shocks, and restricted air flow.

The term "standard temperature rise" refers to the average winding temperature rise which, in "usual" ambient temperature conditions, is within the long-time withstand capability of the insulating materials. For liquid-immersed transformers, that rise is typically 65°C [149°F] (with 15°C [27°F] hot spot allowance). For dry type transformers, the average temperature rise is typically 80°C [144°F] to 150°C [270°F] (with a 30°C [54°F] hot spot allowance) based on the type of insulation used. Normal ambient reference temperature is 30°C [54°F].

3.4.1.3 Transformer Losses

Power and distribution transformers are highly efficient; the typical transformer is anywhere from 98% to 99.8% efficient. [3.15] Per ANSI STD C57.12.90-1987, transformer efficiency is defined as the useful power output divided by the total power input, and is therefore dependent on the energy lost to various components within the transformer itself. Energy losses in power and distribution transformers are of three major types: no-load losses, load losses, and cooling-system losses (only applicable to units with forced cooling). Each of these losses is discussed below.

No-load losses (core losses) are primarily related to transformer core materials, design, and construction techniques; they are present at any time while the transformer is energized, regardless of load. These losses are due to several effects, including eddy current formation and hysteresis within the core magnetic material. Eddy (or circulating currents) are generated within the core by the magnetic flux produced by alternating current flowing through the transformer windings; this flux produces an electromotive force (emf) in the core which results in a secondary current (and ultimately energy loss via heat dissipation). These losses may be mitigated by layering the core materials with insulation such that large circulating paths are not formed.

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Specific grades of ferrous material will provide different losses based on their individual physical properties. Generally, losses for various core materials are empirically determined (on a Watts per pound basis) for a given magnetic flux density. [3.15]

Hysteresis losses stem from the residual magnetism induced in a ferromagnetic material; the relationship between the magnetic flux density and the magnetic field intensity varies for the cases of increasing and decreasing exciting current. Each time the exciting current alternates, the magnetic dipoles (elementary magnets) present in the material are reversed; however, a counter magnetomotive force (mmf) is required to reduce the residual magnetism in the core to zero. This phenomenon results in energy being dissipated within the core, ultimately producing heat. [3.15]

Load losses, unlike core losses, are directly related to the load placed on the transformer. Ohmic heating (I^2R) and eddy currents occurring in the winding conductors constitute the bulk of load-related losses, although stray losses may contribute as well. Stray losses are in effect eddy current losses which occur in other transformer materials; they are produced by virtue of magnetic flux "leaking" from the core to other components (such as core mounting hardware or the tank) and generating circulating currents. Load losses increase as the square of the load current, hence they are most significant at high current levels.

Losses related to the cooling system include power used to operate cooling system components (such as oil pumps, space heaters, circulation fans, etc.). These losses will generally not vary with load, unless the efficiency of the auxiliary component is somehow affected by the load level of the transformer (for example, a pump may use slightly more or less power based on fluctuations in the density of the oil, which is a function of transformer load). Cooling system losses may also vary with changes in ambient temperature; higher losses may be associated with higher ambient temperatures due to additional cooling requirements (i.e., fans and pumps). (Note: Cooling losses are not considered part of transformer total losses per ANSI STD C.57.12.00-1987).

For power transformers (especially the larger units), load-related losses are more significant than either no-load or cooling losses. For distribution transformers (which typically may operate at low loads for a substantial portion of their operating lives), core losses can comprise a substantial percentage of the total transformer losses.

Electrostatic corona is another potential loss mechanism for power and distribution transformers; this effect occurs when large potential gradients exist between conducting elements separated by air. Electrostatic corona may be internal or external to the transformer. Internal corona is more significant from the perspective of component degradation (i.e., damage to the transformer windings or other conductors), whereas external corona will generally have little deleterious effect on component longevity yet may produce significant losses. Accordingly, external corona effects are not considered within the scope of this guideline and are not considered further. Internal corona is discussed in Section 4.1 below. [3.12, 3.15]

3.4.1.4 Specific Description of Transformer Components

Transformer subcomponents identified in Sections 3.2 and 3.3 are described in the following paragraphs.

3.4.1.4.1 Metal Enclosure/Tank

Liquid-immersed transformer enclosures or tanks are constructed of low alloy carbon steel, usually between 3.2 mm and 12.7 mm (1/8 in and 1/2 in) thick. Individual tank components are joined by shielded arc, submerged arc, or inert gas arc welding processes to form a sealed, leak-proof enclosure for the insulating medium. The tank is constructed, depending on the type, of a slip-on vertical housing assembly which is joined to the supporting base; the tank cover is usually welded to the vertical portions of the tank, with one or more plates bolted on top to allow access to the interior of the tank. The tank base is generally rectangular or square in shape, with the vertical dimension larger than the width or depth to accommodate the phase winding assemblies and core mounting brackets. The tank may also be equipped with a secondary fluid-filled compartment adjacent to the main enclosure for auxiliary devices such as the load-tap changer. Expansion spaces in the wall of the tank (risers) are often included to permit expansion of the insulating fluid; some units also have specially designed "corrugated" walls which act as radiators for dissipating heat generated by the transformer during operation (Yukon coolers). Penetrations for bushings and other associated equipment are generally either on the top (cover) or side of the tank, depending on individual design and application requirements.

Pressure conditions within the tank will vary, based on the design of the transformer. For example, sealed transformer tank pressure varies between less than one atmosphere during cooldown conditions and two atmospheres during rated conditions. The modified conservator design, in contrast, maintains essentially atmospheric pressure due to the free interchange of air in the conservator tank air cell. Protective devices associated with the tank include the fault (or sudden) pressure relay and pressure relief valves, which are installed to preclude the tank from experiencing greater-than-design pressures and possible rupture. Liquid-immersed tanks are also generally equipped with several drain valves and pressure connections, which facilitate the installation, maintenance, and testing of the unit; For example, pressure connections may be used to dry the transformer windings (draw a vacuum in the tank) prior to initial use.

For ventilated dry-type transformers, the enclosure is typically of low-grade steel frame and sheet construction; components may be both welded and bolted together; because the enclosure is not required to maintain pressure or leak-tight integrity, many of the design requirements associated with liquid-immersed or sealed-dry type units are not present. The enclosure has several ports containing filters or gratings for ventilation air induction, as well as heated air exhausts. The location, number, and arrangement of these ventilation ports, as well as the type of filtering mechanism used (if any), will vary based on the presence of forced cooling and other design considerations.

Sealed dry-type units are somewhat similar in design to the liquid-immersed tank enclosures; however, they are typically much smaller, and have few penetrations or access points.

Another consideration in the construction of the transformer tank is the finish of the exterior components; the internal temperature rise of the transformer can be significantly affected by the low-temperature emissivity of the external finish. For example, polished metal finishes generally have very low emissivity factors which translate to reduced heat dissipation as compared to higher emissivity finishes. Paint and similar coatings, on the other hand, have relatively high emissivities and are therefore more effective at radiating heat. Variations in color, type, and texture of the coating applied can also affect emissivity.

For transformers exposed to intense solar radiation, the choice of external finish is also important. Lower emissivity also generally indicates less absorption of incident radiation, hence the lower emissivity coatings will also absorb less incident solar energy. Therefore, the environment in which the transformer operates (with respect to ambient temperatures and exposure to solar radiation) should be evaluated to determine the finish which best balances heat dissipation with energy absorption. [3.12, 3.15, 3.22, 3.23, 3.24, 3.25, 3.26, 3.27]

3.4.1.4.2 Core

The magnetic core assembly provides several functions for the transformer, including providing an efficient path for magnetic flux and physical support of the primary and secondary windings. Under load, the core provides the necessary magnetic coupling between the primary and secondary winding, thereby allowing generation of a voltage in the secondary winding and a counter-voltage in the primary winding. To facilitate this function, the cores of both power and distribution transformers are constructed from a ferrous material (such as grain-oriented silicon steel, which has particularly good magnetic properties). Thin layers of this material are coated with an insulation and are pressed together to form a core. This layered construction is used in large part to minimize the effects of eddy (secondary) currents in the conducting material; increasing the number of laminations reduces the total loss due to eddy currents proportionately. Figure 3-7 shows a typical laminated transformer core.

Core dimensions for both power and distribution transformers are standardized to some degree; generally cores are sized in discrete steps. A welded or bolted metal frame is used to support the core and coils to prevent shifting, misalignment, or vibration during shipping and operation. Transformer cores are also grounded (usually to the tank for liquid-immersed, or to the frame/enclosure for dry-type) with a strap at a single point to preclude electrostatic charge effects. This type of connection allows megger testing by isolating the core from ground.

Transformer windings and cores are of two primary configurations; the core-form and shell-form. These designs are discussed in Section 3.4.1.4.3 below.

Amorphous alloy cores are a relatively new approach to reducing core losses as described in Section 3.4.1.3 above. These cores utilize certain alloys which, when solidified in the proper fashion, produce an amorphous (as opposed to crystalline) atomic structure which substantially reduces the core losses associated with more conventional materials and formation techniques. Transformers equipped with these cores are present in nuclear applications only on a trial basis, and are not encountered in most plants. [3.12, 3.15, 3.27]

Figure 3-7. Cast-Coil Dry-Type Transformer Internals.[3.28]

3.4.1.4.3 Windings

Transformer windings (or coils) consist of primary and secondary windings; these windings, in conjunction with the core described above, accomplish transformation of the alternating input voltage of the primary to that of the output winding (secondary). This transformation is achieved by way of the interaction of the changing currents and magnetic fields in both sets of windings and the magnetic core. The desired output voltage is established by altering the voltage transformer ratio (ratio of input to output voltage) which depends primarily on the number of turns in the primary and secondary windings. In transformers where the input voltage exceeds the output voltage, the transformer is termed "step-down." Where the output exceeds the input, the transformer is termed "step-up." The winding carrying the higher voltage is usually referred to as the "HV" winding, whereas that carrying the lower voltage is the "LV" winding. Note that either the primary or secondary may be the HV or LV winding. A tertiary winding may also be provided in addition to the primary and secondary for neutral stabilization and harmonic suppression. In addition, transformers may have multiple secondary windings with the same or different transformation ratios.

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The physical winding configuration can vary between transformers. "Core-type" (also known as core-form) transformers generally have windings which are cylindrical in shape and concentrically oriented with the core. Primary and secondary windings on core-type transformers may be interwoven. "Shell-type" (or shell-form) arrangements use large, disc-shaped coils which are stacked to form the necessary winding configuration (i.e., groups of primary and secondary windings). Functional differences between the two types of core/winding arrangement are minimal, however shell-form transformers are typically used only in units with higher current and power ratings.

Winding conductors may be fabricated from either copper or aluminum; the primary advantage to using aluminum conductors as opposed to copper is cost. Although aluminum conductors are usually less expensive, they also have physical and electrical properties which are less desirable than their copper counterparts. In general, an aluminum conductor has a higher volume resistivity, temperature coefficient of resistance, and coefficient of linear expansion than a copper equivalent. The density of aluminum, however, is substantially lower than that of copper, thereby reducing weight. These properties must be taken into consideration during the design of the transformer.

Windings are generally retained in proper alignment by a variety of clamping systems and components, including tie-rods, rings, plates, leg irons, and jack screw systems, depending on the type and size of transformer. Maintenance of winding alignment is essential due to the extreme forces to which the windings may be subjected during short circuit or impulse conditions, both in the longitudinal and radial directions.

As with the physical configuration described above, the electrical arrangement of the windings may also vary between individual units. Windings in a three-phase power and distribution transformers may be connected in either delta or wye configuration, depending on the application. Winding types may also be mixed within a given transformer; for example, delta-wye, wye-delta, and delta-delta combinations are all commonly used. There are advantages and disadvantages associated with each configuration; these factors are a major consideration during selection of the transformer, and are discussed in References 3.12, 3.16, and 3.18. Startup transformers often use a grounded wye on the HV winding to permit the use of graded insulation (i.e., insulation which is applied in greater thicknesses in areas of highest stress concentration). In addition, the LV windings may also be wye connected to provide for a three-phase, four-wire system or for neutral grounding. Most unit (main) transformers are connected in delta on the primary (LV) side and in grounded wye on the secondary (transmission) side. [3.12, 3.13, 3.15, 3.16, 3.18, 3.22, 3.29]

Standard conventions for transformer terminal identification are identified in ANSI STD C.57-12.70-1978. [3.30] The phase relationship between primary and secondary windings is usually a multiple of 30 degrees, however special phase values are not uncommon. ANSI Standards recommend that the high voltage winding lead the low voltage winding by 30 degrees; this is independent of the transformer configuration (i.e., whether the primary or secondary is the high voltage winding).

3.4.1.4.4 Insulation System

As indicated in Section 3.4.1.1, power and distribution transformers are of two primary types; dry and liquid-immersed. Based on the type of transformer, the physical characteristics and functions of the insulating system will vary; however, many basic similarities exist. The primary function of the insulating system in both dry and liquid transformers is to electrically isolate the primary winding from the secondary winding, the individual turns of a winding from each other, and each of the windings from ground. "Major" insulation refers to that insulation which separates the high-voltage winding from the low-voltage winding and ground; typically, this portion of the insulation will be exposed to substantial electrical stress (which is primarily dependant on construction and spatial considerations within the transformer). Most of the stress imposed upon transformer insulation will be in these applications; turn-to-turn voltages on the same winding may only be a few volts (on adjacent turns) whereas winding-to-winding voltages between different windings may be hundreds of thousands of volts. Accordingly, the major insulation must be designed to effectively insulate these large voltages under all anticipated operating conditions. However, turn-to-turn insulation is also important from the standpoint that breakdown can result in localized hot spots when turns short together; these hot spots can eventually result in further insulation degradation and ultimately transformer failure.

Generally, insulating fluids have substantially higher dielectric strengths than air or gases and are therefore used on the larger units. Dry-type insulation systems are generally reserved for lower power and voltage applications due to their satisfactory electrical performance at these levels, ease of maintenance/operation, and reduced cost as compared to the liquid systems.

Some specific attributes of each of the various types of insulating systems used in liquid-immersed and dry-type transformers are discussed in the following paragraphs.

Liquid-Immersed

The functions of insulating fluids in liquid transformers include heat transfer and electrical insulation. The liquid is used to displace air in the system to increase the system's dielectric strength, corona threshold voltage, and breakdown voltage. Typical insulating fluids are either natural or synthetic organic compounds; commonly used substances are hydrocarbon mineral oils which are refined to give the desired permittivity, viscosity, vapor pressure, and conductivity characteristics. The liquid may also be supplemented with various types of organic solid insulating materials (such as wood-based paperboard) which are used as supports, separators, or fixed insulators. Insulating coatings may also be applied to various components; these are usually an enamel, resin, or paper wrap. Heavy paper wrapping is also used on the electrical connections or leads to the windings.

Older liquid-immersed transformers used highly flammable immersion fluids (such as refined mineral oil) due to their desirable electrical and thermodynamic properties. Nonflammable fluids were later developed for use in transformer applications, the most common being a form of polychlorinated biphenyl (PCB). These fluids have good heat transfer and electrical insulating properties, yet may produce highly carcinogenic byproducts and have lower dielectric strengths than dielectric mineral oil. (Note: Federal Regulations now restrict the manufacture and use of PCBs). Other immersion fluids having high ignition temperatures and

other similar physical qualities have been used as replacements for PCB-based fluids. Examples of these fluids include silicone, tetrachloroethylene, and trichlorotrifluoroethane, and high molecular weight hydrocarbons. [3.12, 3.15, 3.16, 3.31, 3.32, 3.33, 3.34, 3.35, 3.36, 3.37]

Dry-Type

Dry-type transformers operate on the same basic principles as their liquid-immersed counterparts; however, they utilize a different medium for providing insulation between the various sets of windings, the individual turns of a winding, and the winding and ground. In the dry-type transformer, air, gas, or epoxy/resin is used to provide the necessary dielectric; this material may be supplemented with solid insulation, paper, and insulating coatings to ensure complete isolation of the windings and electrical connections. Differences between the dielectric constants of the gas (or resin) and insulating fluids used in liquid transformers must be taken into account in the design and capacity of the transformer.

Fluorogases are the most desirable of the gaseous insulating materials, as they are non-combustible, have good heat transfer properties, and a relatively high dielectric strength. However, fluorogas can only be used in sealed units; transformers insulated with fluorogases are also somewhat more expensive than liquid or dry ventilated transformers. Nitrogen is often used (as opposed to air) in sealed applications for contaminated operating environments. Nitrogen and air-insulated transformers are generally limited to 34.5 kV and below. Due to environmental concerns related to fluorogases, this type of transformer is no longer manufactured.

Resin insulation is used primarily in environments where gas-insulated dry-type units may not be otherwise suitable; in these transformers the winding coils are dipped or cast in resin which solidifies and acts as a permanent winding insulator. These units characteristically are constructed with low-loss cores and windings, due to the effect of high temperatures on epoxy resin. Resin-encapsulated transformers are currently produced with voltage ratings up to 44-kVac and power ratings of 10 MVA. [3.12, 3.15, 3.18, 3.20, 3.25, 3.38, 3.39]

3.4.1.4.5 Bushings

Bushings are insulating devices used on liquid-immersed transformers to insulate and seal the winding terminal connections as they pass through the outer metal enclosure/tank. These devices are bolted or attached to the exterior of the tank or cover, and penetrate into the interior of the tank. Each bushing consists principally of a cylindrical conductor protected by a porcelain weather casing (exterior) and insulating varnish (interior). Many bushings also include a condenser wrap to reduce voltage stress for tank penetration. See Figure 3-8.

There are two primary types of bushings, based on the configuration used to connect the bushing to the transformer winding; the fixed-conductor type and the draw-lead type. In the fixed conductor type, a central tube or rod conducts current from the top bushing terminal to the bottom terminal. The bottom terminal is connected to the transformer winding lead. In a draw-lead bushing, the winding lead is connected directly to the top terminal; this is accomplished by drawing the lead through the body of the bushing. Although the designs differ in some regards, the functional operation of the two types of bushing is similar.

Figure 3-8. Typical High-Voltage (HV) Oil-Filled Bushings.[3.40]

Bushing characteristics may also vary based on their voltage and current ratings. Low current bushings are generally of the draw lead type. High current bushings typically use a hollow core or solid rod type conductor. A condenser generally consists of kraft paper wrapped around the bushing cone. The kraft paper either has a conducting print on one side, or includes a foil wrapped between the layers of the paper. High voltage bushings usually maintain an internal reservoir of oil to preserve the insulating qualities of the bushing. The bushing is charged at greater-than-atmospheric pressure with nitrogen or another inert gas to permit thermal expansion/contraction of the oil. Bushings may also be equipped with an oil sight glass or level gauge, depending on the configuration. A skirted non-conducting porcelain weather shield is used over the upper external portion to provide a long surface path from the terminal to the ground flange, as well as facilitate moisture (and contaminant) run-off from the shield. Highly moisture-laden or contaminated environments may dictate the use of bushings having longer porcelain rain shields. The bushing segment located below the mounting flange is also usually constructed of porcelain, and is immersed in the transformer insulating fluid. Bushings may also be equipped with either a power factor or potential tap, depending on their voltage application. This tap is electrically connected to the print or foil of the condenser. These taps are used during maintenance and testing, and must be grounded while not in use.

Sealing of the bushing is normally accomplished via soldering, brazing, or welding, as well as the use of seals and gaskets for some joints. Springs are often used in the construction of the bushing to supply adequate pressure on sealing surfaces to maintain the necessary leak-tight integrity.

HV bushings are usually selected to have the same BIL as that of the transformer high voltage winding. Transformer bushings are manufactured and tested in accordance with the requirements of ANSI/IEEE STDs 24-984 and 21-976, respectively. [3.12, 3.15, 3.41, 3.42, 3.43, 3.44, 3.45, 3.46]

3.4.1.4.6 Cooling Systems

Power and distribution transformers operate under varying ambient and operating conditions; the ability of the transformer to distribute and dissipate heat must be considered in the design of the unit. Normal transformer load, coupled with high ambient temperature, incident solar radiation, and potential winding "hot spots," can produce excessive internal temperatures. Accordingly, transformer ratings and operating limits must be chosen to prevent damage to the winding insulation by these high temperatures. Conversely, providing the transformer with an increased heat dissipation capability will allow a comparable increase in capacity (with no adverse affects on the insulation).

Various cooling system designs have been used on power and distribution transformers; however, most of these systems fall into one of two major categories. Self-cooled systems, as the name implies, rely exclusively on convection and natural circulation to transfer heat energy generated in the core/winding regions to the surrounding environment; no external means of heat removal are employed. Forced-cooled systems, on the other hand, utilize forced fluid or air flow to aid in the heat transfer process. A typical forced-cooled system may use a pump to circulate the liquid insulating medium through a heat exchanger (liquid-immersed), or a fan to force air through the transformer enclosure (dry-type) or external radiator. Self-cooled only systems have

the advantage of not depending on any additional equipment for their operation; however, their capacity may be accordingly restricted due to thermal limitations on the windings/insulation (Note: transformer capacity is dependent upon system design factors as well as cooling). Forced-cooled systems have higher capacities, yet are dependent on their cooling systems for operation; loss of cooling requires that the transformer be shut down or that the load be reduced significantly. Hybrid systems (i.e., those which have both self- and forced-cooled ratings) seek to capitalize on the advantages of both; in the event that adequate cooling can not be maintained, the unit can still be operated at its self-cooled rating.

Cooling system designs used in nuclear plant power and distribution transformers are described in the following paragraphs; it should be noted that other combinations of cooling systems may be used, depending on the manufacturer and type of application.

Liquid-Immersed Transformers

- **OA (Oil-immersed, Self-cooled)** - In this type of transformer, oil is used as the cooling medium and circulates via natural circulation and convection within the tank. The tank surface and structure may also be varied (i.e., smooth surface, corrugated, etc.) for given transformer ratings in order to provide sufficient surface area for heat radiation. Separate radiators (heat exchangers) may also be supplied with the larger units.
- **OA/FA (Oil-immersed, Self-cooled/Forced Air-cooled)** - These transformers are similar to the standard OA type unit described above, yet have additional cooling capacity in the form of forced airflow. This additional airflow is accomplished by using one or more motor-driven fans which blow air over the cooling surfaces to increase the rate of heat transfer. The cooling fans are thermostatically controlled (usually by either a top-liquid or winding hot-spot equivalent thermal relay; see Section 3.4.1.4.7 below) such that they operate singly or in combination under specific load and temperature conditions. (Note: OA/FA/FA transformers are similar to the OA/FA type with the exception that the former use forced air cooling for both the first and second stages.)
- **OA/FOA/FOA (Oil-immersed, Self-cooled/Forced Oil, Forced Air-cooled/Forced Oil, Forced Air-cooled)** - Additional heat rejection capability can be added to a liquid-immersed transformer by using some combination of forced airflow and pumps. The use of pumps allows more rapid and even distribution of fluid within the transformer tank, thereby increasing the thermal efficiency. As with the OA/FA type described above, the use of fans allows increased airflow over the cooling surfaces. The fans and pumps are controlled in stages; the first stage uses only a portion of the available pumps and fans, whereas the second stage employs all of the available cooling capacity. This type of transformer also maintains a self-cooled rating as well.
- **OA/FA/FOA (Oil-immersed, Self-cooled/Forced Air-cooled/Forced Oil, Forced Air-cooled)** - These units use forced air cooling on the first stage and forced oil/forced air on the second stage.

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- **FOA (Oil-immersed, Forced Oil-cooled with Forced Air-cooler)** - In the FOA type, both oil pumps and fans are designed to operate simultaneously and continuously. Heat transfer from the oil to the heat sink (air) is often accomplished via a separate external oil-to-air heat exchanger. No self-cooled rating exists; hence loss of the forced oil/air system(s) renders the transformer inoperative.
- **OW (Oil-immersed, Water-cooled)** - In this type of transformer, oil flowing over immersed cooling tubes is cooled by water flowing through the tube. Typically, the oil flow is driven by natural circulation and the water by pump, hence the unit has no self-cooled rating. Such transformers often have double tube sheet heat exchanges with concentric tubes to provide additional protection from water contamination of the oil; inter-tube or tubesheet leakage can therefore be readily detected. (Note: These types of transformers are rarely used in nuclear plants).
- **FOW (Oil-immersed, Forced Oil-cooled with Forced Water-cooler)** - Similar to the FOA type described above, except water is used as the cooling medium.

Radiators used for cooling of the transformer insulating fluid are generally of the tube or fin type which allow air to flow around the exterior of a tube carrying the heated insulating fluid. Numerous tubes with fins are used in each radiator unit to maximize the available heat transfer area and provide efficient fluid cooling (see Figure 3-9). Forced air systems use fans to blow air across the exterior of the tubes (either in a transverse or longitudinal direction) to further aid heat transfer.

Valves are also included to allow isolation of the radiator or cooler for maintenance or removal without draining the tank. These valves are usually of the flapper or gate type to minimize flow resistance.

Dry-Type Transformers

In contrast to the liquid-immersed variants, all dry-type transformers have self-cooled ratings; some are also equipped with fans to provide a forced-cooling rating. Those units designed to operate in contaminated environments (such as non-ventilated and sealed dry transformers) make use of high efficiency windings and cores to minimize heat generation; these units rely strictly on their internal atmosphere and components for heat dissipation. The following are the major types of dry transformer cooling systems:

- **AA (Dry-type, Self-cooled)** - In this common design, thermal gradients and the natural circulation of air assist in dissipating heat generated in the windings and core. Heat is transferred primarily by convection to the external environment.
- **AFA (Dry-type, Forced Air-cooled)** - Similar to the AA type described above, yet fans are used to circulate air throughout the enclosure.
- **AA/FA -(Dry type Self-cooled/Forced Air-cooled)** - a combination of the AA and AFA; one rating is assigned for natural circulation and a second rating for forced circulation.

Figure 3-9. Cooling System Radiator on Liquid Transformer.[3.19]

As indicated above, power and distribution transformers often have both a self-cooled rating and one or more forced-cooled ratings, depending on their configuration. The standard designation for a transformer with multiple ratings lists the equipment kVA ratings followed by the cooling method associated with each rating. For example, the designation 25,000/27,000/30,000 kVA, OA/FA/FOA indicates a transformer with a self-cooled rating of 25,000 kVA, a forced-air rating of 27,000 kVA, and a forced oil-air rating of 30,000 kVA.

Transformers with ratings of several MVA and above may have a single forced cooling rating and no self-cooled rating. Some unit auxiliary and most main transformers are of this type. Transformers with no self-cooled rating generally cannot remain energized unless their fans and pumps are operating; this is due to the fact that virtually all of the cooling capacity of the transformer is dependent on the forced cooling equipment. Transformers with both self-cooled and forced-cooled ratings are often used in equipment whose load varies significantly (such as station service transformers); their need for auxiliary cooling equipment only during periods of heavy load adds operational flexibility and reduces operating costs. [3.10, 3.11, 3.12, 3.15, 3.16, 3.18, 3.22, 3.23, 3.25, 3.46, 3.47, 3.48, 3.49, 3.50, 3.51]

3.4.1.4.7 Protection and Indicating Devices

Several protection and indicating devices are generally incorporated into the design of transformer; the number and type will vary based on the rating and type (i.e., liquid or dry) of unit. A description of each type of device is included in the following paragraphs.

Fault Pressure Relay

Fault (or sudden) pressure relays are used in liquid-immersed transformers to detect pressure transients produced within the transformer tank during operation. The relay does not act as a pressure relief device; rather it senses the rate of change of pressure within the transformer enclosure. Pressure transients are generally produced by the formation of an internal electrical arc (indicative of an internal fault) or by coil movement in the transformer due to a through fault. Because other events within the transformer (such as mechanical shock, vibration, temperature changes, and pump surges) may produce pressure transients similar (albeit of lower magnitude and rate of rise) to that of an arc, the relay must be capable of differentiating these events from an actual arc pressure transient.

A common design of fault pressure relay uses a series of bellows to mechanically determine the rate of fluid pressurization (Figure 3-10). Pressure transients applied to the sensing bellows result in the displacement of fluid of known viscosity (such as silicone oil) through various orifice channels; at low rates of pressurization, the fluid flows through the different size orifices at nearly equal rates thereby allowing force equilibration. At higher rates of pressurization, the smaller orifices create a significant pressure drop on the downstream side of the orifice, thereby resulting in a force imbalance with those orifices of larger diameter. This force imbalance is applied to a spring-loaded rocker arm assembly which actuates an electrical contact upon displacement from its null position; depending on the configuration of the supporting wiring this contact closure will either provide a remote alarm or cause the transformer to be de-energized. The relay is self-resetting; once the rate of pressure increase is reduced, the differential fluid flow and resulting force imbalance will cease, allowing the rocker arm to return to its null position. These relays are also usually temperature compensated to allow relatively stable pressurization rate detection throughout the design ambient temperature envelope. A bleeder valve and test receptacle are also usually included. The relays are often equipped with flags or targets that indicate that they have operated. [3.12, 3.15, 3.22, 3.23, 3.52]

Fault Gas Monitor

Fault gas monitors may be used on liquid transformers to detect the presence and concentration of combustible gases in the transformer insulating fluid or gas blanket. Arcing, corona discharge, low-energy sparking, severe overloading, and overheating are some of the mechanisms which may produce significant quantities of combustible and non-combustible gases in transformer insulating fluid (oil). These gases, which include carbon monoxide, carbon dioxide, hydrogen, ethane, methane, ethylene, and acetylene, are sensed by a device (usually an electro-chemical element, thermal conductivity meter, permeable diaphragm, or chromatograph) which samples either the oil or gas space above the oil. The output of this sensing element is used to actuate remote alarm and warning devices to alert the operator to high gas concentrations

Figure 3-10. Fault Pressure Relay.[3.52]

prior to failure. See ANSI STD C.57.104-1991 [3.53] for additional information related to transformer gas concentrations and sampling. [3.12, 3.15, 3.16, 3.53, 3.54]

Pressure Relief Device

Mechanical pressure relief valves are used on many transformers to preclude the buildup of potentially damaging pressures within the transformer enclosure. Pressure transients result from both normal and abnormal events within the transformer; the pressure relief is installed primarily to mitigate the effects of large pressure changes resulting from abnormal events such as an internal fault. Although tank/enclosure design pressures (approximately 10 psig) are usually somewhat above pressures normally encountered during routine operation, they are not sufficient to withstand pressures resulting from large internal faults; hence, pressure relief devices are required. The typical pressure relief device (Figure 3-11) utilizes one or more springs held in compression attached to a relief diaphragm; when pressure on the diaphragm is sufficient to

Figure 3-11. Cross Section of Typical Pressure Relief Device.[3.55]

compress the spring(s), the diaphragm will move, thereby relieving the pressure. The valve reseats after pressure is reduced. Gaskets are used on the device to ensure sealing of the diaphragm to its seat as well as the mounting flange to the tank. Due to limitations of relief valve capacity (flow) and differences in pressure between various portions of the tank, several valves are usually necessary to ensure adequate protection. Additionally, a relief may be installed on the load tap changer compartment to alleviate pressures generated by arcing between the moving and fixed contact surfaces during tap-changing. [3.12, 3.15, 3.16, 3.22, 3.23, 3.47, 3.55, 3.56]

Gas Detector

Gas pockets entrained in transformer oil can seriously affect the dielectric strength of the insulation due to the relatively low dielectric constant of the gas with respect to the surrounding oil. Similarly, the formation of combustible and non-combustible gases in the unit can be indicative of abnormal conditions or incipient transformer failure. A gas detector relay is a device which is designed to detect concentrations of gas in the oil and provide a corresponding indication to the operator (see Figure 3-12). Gases produced in transformer insulating fluids are collected for measurement by the detector; the detector then provides external indication and/or remote warning of the accumulation of gas to the operator. Gas detectors are not capable of differentiating between combustible and non-combustible gases, hence the device must be set to actuate upon the detection of any gases. This will provide a warning of incipient dielectric

Figure 3-12. Typical Gas Detector Relay.[3.57]

failure of the insulation, although high gas concentrations may be due to other causes as well. In order to determine the nature and source of the gases detected, subsequent sampling and laboratory analysis must be performed. [3.12, 3.15, 3.22, 3.23, 3.57]

Bushing Current Transformers

A bushing current transformer is a sensing device used in liquid-immersed power and distribution transformers to provide a variety of protective and indicating functions. In general, the device is composed of a short segment of magnetic material with an integral toroidal secondary winding. Figure 3-13 shows a typical bushing current transformer. Bushing current transformers are installed such that the bushing lead passes through the toroid; this lead therefore acts as a single-turn primary winding. The interaction of the magnetic segment and toroidal secondary winding with the lead create current transformation. Several current transformers can be installed on each bushing; each is used for a different purpose such as protective relaying, metering, etc. For example, a common application of a bushing current transformer involves use of the output signal (proportional to load) as an input to the hot spot winding temperature detector (see following subsection). Often, bushing current transformers also have taps allowing variation of the transformation ratio. Bushing current transformer secondary windings are short-circuited (under no-load conditions) to prevent the formation of high secondary voltages which could potentially degrade transformer insulation or injure personnel. [3.12, 3.15, 3.22, 3.23, 3.58]

Figure 3-13. Bushing Current Transformer.[3.59]

Temperature Indicators

Temperature indicators used in transformers may be of several different types, depending on their function, the age of the unit, and other factors. The basic operating principles of these devices are described in the following paragraphs.

Hot Spot and Top Oil Indicators

Two principal configurations of temperature indicators are used in liquid-immersed transformers. The first, the "hot spot" indicator, uses an electrical signal proportional to transformer loading (generally derived from a bushing current transformer) to simulate the temperature rise of the windings over the hottest liquid temperature (tank top). In one model, a heating coil is located in physical proximity to the temperature sensing element (typically a bourdon tube) of the detector; the additional temperature rise generated by the coil is added to the oil temperature sensed by the probe to produce an estimate of winding hot spot temperature. Hot spot indicators may also be equipped with a means of calibration (such as an external shunt resistor). The second type, the "top oil" (or hot oil) indicator, senses the oil temperature at the top of the transformer tank; oil heated by the windings rises to the top of the tank via natural circulation and is subsequently measured by the probe. A typical top oil device uses a bimetallic spiral which senses the oil temperature via a leak-tight well located in the side of the tank. Both types of indicators may operate switches that are often used to control cooling equipment (pumps, fans, etc.), initiate remote alarms, and actuate protective responses such as circuit breaker tripping.

Resistance Temperature Detectors

Resistance temperature detectors (RTDs) are used in transformers for remote sensing of internal component or insulation temperatures. These devices consist of an element whose resistance varies as a function of temperature; this resistance is measured and converted to a signal which is proportional to the temperature. RTDs are generally categorized as either thermistors (semiconducting devices whose resistance is related exponentially to temperature) or platinum resistance thermometers (a platinum wire whose resistance is roughly linear with temperature). RTDs are used when remote indication or recording of transformer internal temperature data is desired. In general, RTDs are not embedded directly in the transformer windings; rather, they are located in the wells of the tank at a level below the minimum oil level.

Thermocouples

Thermocouples are devices which provide an output voltage signal proportional to the temperature being sensed; this voltage is generated at the junction of two dissimilar conductors based on the difference in temperature between it and a reference junction maintained at a reference temperature. These devices are generally embedded in one or both of the windings or core and used to transmit temperature information to a remote monitoring device or alarm. Thermocouples are designated by their constituent materials, which are chosen based on the requirements of the specific application. These devices are inexpensive and respond rapidly to temperature changes, however there are disadvantages to their use. For example, depending on the age and temperature to which the thermocouple has been exposed, the performance and accuracy of the unit will degrade over time. Additionally, the potential generated by the junction is susceptible to several other external effects (such as temperature distribution along the connecting wires, strain, etc.). Accordingly, thermocouples find only limited use in transformer applications.

Other Temperature-Measuring Devices

In addition to the devices described above, other more advanced means of measuring transformer temperatures (especially that of the windings) have been developed. For example, one system utilizes a glass sensor which transmits a varying spectrum of electromagnetic radiation with varying temperature. This light is channeled to an electronic device via fiber-optic cable which interprets and converts the spectrum to a temperature value. Sensing temperature in this fashion allows placement of the detector in physical proximity with the windings, yet still maintains complete electrical isolation. These types of temperature elements are generally employed only on a trial or prototype basis, and are not widespread throughout nuclear plant transformers. [3.12, 3.15, 3.22, 3.23, 3.47, 3.60, 3.61, 3.62, 3.63, 3.64, 3.65]

Flow Indicator

Flow indicators are used in liquid-filled transformers to indicate the status of flow in forced circulation systems. These devices are generally mechanical in nature (i.e., employing a vaned impeller or similar mechanism) and are usually located at the discharge of the pump or pumps being monitored; they may either be continuous (i.e., generate a signal which is

proportional to the existing flow) or discrete (flow/no flow) in nature. The output of the flow detector may be connected to an alarm module to warn the operator of inadequate flow. [3.12, 3.22, 3.23, 3.47]

Liquid Level Indicator

Liquid level indicators are used to indicate the level of the insulating fluid in liquid-immersed transformers. A common design of indicator uses a pivoted float arm located in the tank; this arm is magnetically coupled to a shaft and pointer arrangement outside of the tank thereby allowing a completely sealed interface. When the position of the float changes, the magnetic coupling is rotated which moves the pointer a proportionate amount. The indicator also includes alarm switches which actuate at preset points of travel of the indicator shaft to allow for alarm and monitoring functions. Transformers with inert gas oil preservation systems have indicators mounted at the top of the transformer tank wall, whereas transformers with conservator or constant oil pressure systems utilize indicators mounted on the remote reservoir. [3.12, 3.22, 3.23, 3.66]

3.4.1.4.8 Tap Changers

In many transformer applications, it is desirous to maintain a nearly constant voltage to the systems being supplied. In general, the secondary voltage of a transformer can be most readily controlled by varying the number of turns in either the primary or secondary windings. This variation in turns is accomplished by varying the physical point at which the electrical connection to the winding is made through use of tap changers. Some tap changers can be operated with the transformer in service (load tap changer). Others require the transformer to be de-energized (no-load or de-energized tap changer).

Load Tap Changers

Load tap changers (LTCs) are employed to maintain a constant secondary voltage with a variable primary voltage, to maintain a relatively constant output voltage with varying load, to control the secondary voltage with a fixed primary voltage, or to control the reactive loading of connected systems. LTCs are usually employed to restore voltage after changes in loading or fluctuations in source voltage have occurred.

LTCs can be configured in several different ways; they are usually used to maintain a manually preset secondary voltage. The tap changer may be located on either the transformer primary or secondary winding; each type of application has both benefits and drawbacks which must be considered during selection of a particular design. For example, placement of the LTC on the primary winding prevents limitations on the transformer capacity during heavy load conditions.

Conventional LTCs have multiple taps at a constant spacing (such as 5/8%) both above and below rated voltage; this provides the operator with a range of voltage control. Taps configuration can be altered by the manufacturer to allocate more or fewer taps to one portion of the range; this is commonly done to provide the operator with additional flexibility in cases where the fluctuation of the voltage being controlled is anticipated to be asymmetrical (i.e., where

voltage drop is expected to be much more severe than any voltage rise). The transformer may also have reduced capacity on those taps below rated voltage.

Load tap changers typically use a motor/gear driven commutator assembly to accomplish the winding tap change. Some of these components (such as the moving and fixed contacts) are located in a separate oil-filled compartment adjacent to the transformer main enclosure, whereas others are located external to the tank. In a typical configuration, the voltage being controlled or regulated is sensed by a voltage sensing device or relay, the output of which is fed to the motor control logic. This control logic may use either electro-mechanical or solid state components to accomplish its required function. When the sensed voltage conditions require variation of the tap position, the motor is energized in the appropriate direction and the gear assembly moves the tap changer contacts to the desired position.

Load tap changers must be designed to maintain continuity of current flow during the tap change operation (i.e., make before break); hence, they often use a commutator-type arrangement to provide the necessary electrical contact area. Limit switches are also commonly used to obviate precise motor rotational control and stopping. Frictional or dynamic braking assemblies may also be employed, together with special mechanical couplings (such as fixed ratio or cammed gears) to ensure that the tap changer commutator and contacts will be properly positioned upon deenergization of the tap changer motor. Frictional braking assemblies typically use a shoe (lining) and drum arrangement; forced contact of the lining with the drum results in torque being applied to the drum. In the dynamic system, a resistor/capacitor circuit is used to provide positive braking of the motor. A time delay and dead-band are also usually included in the control logic to prevent excessive hunting of the mechanism during short-term voltage fluctuations and excessive rates of voltage change. Because most tap changer commutators are immersed in the insulating fluid, any arcing generated by the tap changing operation is minimized by the insulating fluid surrounding the contact surfaces.

Other equipment associated with the LTC includes remote tap position control and indication of tap position. Many LTCs also have a manual override feature which allows variation of the tap position via a local external operating mechanism during periods where the automatic portion of the equipment is inoperative. In addition, many tap changer compartments are equipped with pressure relief devices (separate from those used for pressure relief of the main tank compartment) to prevent overpressurization of the tap changer compartment as a result of arcing during the tap changing operation. When used in nuclear plant applications, these devices are normally associated with startup transformers and would not be used on lower-tier distribution transformers.

No-Load (De-energized) Tap Changers

No-load tap changers use manually operated devices used to change the ratio of primary to secondary turns. Unlike the load tap changers described above, no-load tap changers can only be operated when the transformer is de-energized.

Typically, transformers using no-load tap changers are equipped with multiple full capacity taps above and below rated voltage. These taps occur in wider increments than LTCs (usually 2.5% per tap) as there is no requirement to maintain current continuity during switching.

In three phase systems, tap changing for each phase is accomplished simultaneously by the same device.

Variations in the design of no-load tap changers exist from manufacturer to manufacturer, but the basic operating principles are similar. Commonly, tap leads from the transformer windings are connected to a circular group of conductive elements which are rigidly mounted on or between insulating plates (Figure 3-14). A crankshaft assembly is used to rotate a metal block or wedge (moving contact) which is located in the center of the group of conductive elements such that the wedge will contact only two adjacent elements at any given time. Each of the elements is electrically connected to a different tap position, thereby allowing tap changing when the wedge is moved from one combination of elements to another. Contact with one set of rods must be broken before contact is made with another. The mechanism is also designed such that once positioned, no drifting or movement of the contacts or wedge will occur, thereby keeping positive contact until the mechanism is again repositioned. Operation of the tap changer is via an externally mounted operating station, which is connected to the contact assembly via an electrically insulated pinion/gear and shaft arrangement. No load tap changers are also usually equipped with key locks or interlocks to help prevent inadvertent operation while the transformer is energized.

Location of the no-load changer is similar to that of the LTC described above; the switching device is located in the main transformer tank, with the operating station located at some external portion of the enclosure. [3.12, 3.15, 3.16, 3.22, 3.23, 3.26, 3.47, 3.67, 3.68]

Figure 3-14. No-Load Tap Changer Operating Mechanism.[3.69]

3.4.1.4.9 Oil Preservation Systems

Oil preservation systems provide two primary functions in liquid-immersed transformers: to control the level of the insulating fluid, and to exclude moisture and oxygen from the tank.

Oil and other insulating fluids typically used in liquid-immersed type transformers have a significant thermal coefficient of expansion; as the loading of the transformer and ambient temperature vary, so does the temperature of the insulating fluid, thereby affecting the volume of the fluid. Certain undesirable effects may result if the fluid level varies too dramatically, such as a loss of insulating capabilities of the lower bushing assembly, loss of cooling, or overpressurization of the tank. The oil preservation system must therefore provide for such variations in the fluid level.

Insulating fluids also may degrade when exposed to oxygen or water. Reduced dielectric strength can result when water (and other contaminants) are introduced into the insulating fluid. Similarly, oxygen in contact with the fluid (by either diffusion throughout or contact with the surface of the fluid) can adversely affect the fluid's dielectric properties. Oxygen may also accelerate sludge formation, which can eventually clog small cooling passages through the windings and insulation. Obstructions in these cooling passages reduces the local heat removal capacity, thereby creating localized high temperature areas (hot spots). High temperatures generated in the hot spots accelerate the thermal degradation of those components in physical proximity to the winding (such as solid insulation and oil). Accordingly, exposure of the insulating fluid to oxygen and moisture must be controlled.

Three general types of oil preservation systems are in common use: the inert gas system, the sealed-tank system, and the conservator system. Each system is described below.

Inert Gas System

The inert gas system uses a blanket of inert gas to pressurize the void space above the insulating fluid volume to a pressure slightly greater than atmospheric. Leakage occurring in the tank or other components will therefore occur only in the outward direction; this outward leakage prevents the induction of moisture or oxygen, and displaces any other gases which may accumulate over time. As indicated above, variations in loading and ambient temperature will result in changes in the volume of the insulating fluid; this in turn will require either the addition or purging of the inert gas in order to compensate. During periods of contraction, the inert gas is supplied from storage bottles located near the transformer; a regulating valve maintains a slight positive pressure on the void space. During periods of expansion, another valve controls the venting of excess gas, thereby preventing overpressurization. The regulating valves are calibrated so as to prevent simultaneous venting and charging of gas. Periodically, the gas bottle inventory must be verified, and empty bottles replaced or recharged.

Sealed Tank System

The sealed-tank system maintains a constant overall fluid and gas volume throughout the entire operating range of transformer temperature. The transformer tank and other components are tightly sealed, thereby allowing no air or moisture either in or out of the tank. As the

temperature of the fluid and void space gas increase, the fluid expands and the pressure within the tank increases; likewise, a decrease in temperature results in a drop in pressure. If the decrease in temperature is of sufficient magnitude, a vacuum (with relation to atmospheric pressure outside the tank) will be created, thereby potentially drawing outside matter into the tank in the event of leakage. Herein lies the major weakness of this system. Transformers of this type are usually filled and sealed under temperature/pressure conditions at or below the lowest values anticipated during installed life; however, this is not always the case, and several events of moisture/air intrusion via leakage have been recorded. Accordingly, many units are equipped with pressure sensing and alarm devices to alert the operator in the event that the pressure either increases or decreases to unsatisfactory levels.

Conservator System

The third type of oil preservation system is the conservator. In this system, the entire volume of the tank is kept continually filled with fluid from a surge tank (conservator) mounted above the main tank. Figure 3-15 shows a typical conservator preservation system. As the volume of the fluid decreases or increases, the surge is made up by or exhausted to the conservator tank. The void space (open to atmosphere) and fluid volume in the conservator are separated by a diaphragm (air cell) which prevents the contamination of the oil by moisture, gases, or other contaminants. Level of the conservator tank is measured via a float-type level sensor; the main tank is always completely filled.

Disadvantages of this system include the potentially limited life of the conservator diaphragm, which may become permeable to gas diffusion and/or develop a leak, and the difficulty in locating the tank such that all other operational and design requirements are met (e.g., satisfactory clearance to bushings and manhole covers located on the top of the tank). [3.12, 3.15, 3.16, 3.22, 3.23, 3.47, 3.56, 3.61, 3.70, 3.71]

3.4.1.4.10 Auxillary Electrical Devices

A variety of electrical devices are used to support the auxiliary systems on power and distribution transformers. Generally, the number and type of these devices will depend on the power and voltage rating of the transformer as well as its type (liquid vs. dry); larger liquid transformers have more auxiliary systems (such as cooling and oil preservation), and hence usually require more electrical components to support them. Separate compartments are often located directly on the exterior of the transformer enclosure or tank to house and protect these electrical components. Typical electrical components associated with power and distribution transformers (other than those already described) include motor starters and contactors, control/timing and thermal overload relays, molded-case circuit breakers, fuses, switches, and wiring. A comprehensive description of these devices is beyond the scope of this document; however, more information is contained in Reference 3.72.

Figure 3-15. Typical Oil Preservation System.[3.70]

3.4.2 Discussion of Manufacturers' Design Differences

For the most part, large liquid power and distribution transformers are somewhat unique; these units were often designed specifically for their intended applications, and therefore may have substantial differences from liquid transformers in other applications (both at the same plant and at other plants). This is especially true with regard to equipment configuration (i.e., which components and systems are installed on each transformer). Yet despite the significant number of different transformer manufacturers and configurations, many similarities between these units can be found. Basic designs for many installed components (such as enclosures, cooling systems, winding and insulation, and bushings) do not vary significantly between manufacturers. Furthermore, many of the protection and monitoring devices from different manufacturers operate on substantially similar principles. Core and other physical dimensions, as well as electrical ratings, are for the most part standardized. Hence, although a substantial number of differences exist between various manufacturer's equipment in terms of overall equipment configuration, few differences exist in the actual design execution of the components.

Dry-type units are generally more consistent in design attributes and features than their liquid counterparts; because the number of possible features and auxiliary devices is substantially reduced from that on the liquid units, greater homogeneity exists. Size is another determinative factor in the specific equipment configuration; in general, the larger the equipment (i.e., power and voltage rating), the more features and auxiliary equipment are included. Small dry-type units (less than 1 MVA) are often "off-the-shelf" models with little or no modification; due to the limited number of features and possible design variations, these models are highly similar.

3.5 Design Requirements: Codes, Standards, and Regulations

3.5.1 Design/Licensing Requirements for Components and Compliance with Applicable Elements of Standard Review Plan, NUREG-0800

3.5.1.1 Design/Licensing Requirements for Transformers

The basic requirements for development of electrical power distribution systems for nuclear power plants are contained in General Design Criteria 17 and 18 of Appendix A to 10 CFR 50. [3.73, 3.74] These criteria provide general guidance with respect to redundancy, independence, and testability of the distribution system. Although these criteria provide guidance concerning attributes of the electrical system, they provide no direct guidance with respect to design or the application of transformers.

FSARs from various plants were reviewed to identify any additional criteria pertinent to power and distribution transformer design. These FSARs provide varying levels of detail about licensing commitments regarding transformers. In general, however, these documents list only ratings and other data specific to the installed equipment, and provide no further references to applicable standards or design commitments other than the applicable 10 CFR 50 Design Criteria discussed above. [3.10, 3.11]

Although few standards are quoted as licensing commitments related to transformer design, many industry standards are quoted as purchase specification requirements. This ensures that the transformer is manufactured and tested to current industry standards before it reaches the purchaser. The following standards (or their predecessors) have been used in purchase specifications:

- ANSI STD C57.12.70-1978 (Reaffirmed 1987), American National Standard Terminal Markings and Connections for Distribution and Power Transformers.
- ANSI STD C84.1-1989, American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz).
- IEEE STD C57.12.00-1987, IEEE General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers (ANSI).
- IEEE STD C57.12.01-1989, IEEE General Requirements for Dry-Type Distribution and Power Transformers Including Those With Solid Cast and/or Resin-Encapsulated Windings.

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- **IEEE STD C57.12.56-1986, IEEE Test Procedure for Thermal Evaluation of Insulation Systems for Ventilated Dry-Type Power and Distribution Transformers (ANSI).**
- **IEEE STD C57.12.80-1978 (Reaff 1992), IEEE Standard Terminology for Distribution and Power Transformers (ANSI).**
- **IEEE STD C57.12.90-1987, IEEE Standard Test Code for Liquid-Immersed Distribution and Power Transformers (ANSI).**
- **IEEE STD C57.12.90-1987, IEEE Standard Test Code for Liquid-Immersed Distribution, Power and Regulating Transformers and Guide for Short-Circuit Testing of Distribution and Power Transformers (ANSI).**
- **IEEE STD C57.12.91-1979, IEEE Test Code for Dry-Type Distribution and Power Transformers.**
- **IEEE STD C57.91-1981 (Reaffirmed 1991), IEEE Guide for Loading Mineral-Oil-Immersed Overhead and Pad-Mounted Distribution Transformers Rated 500 KVA and Less With 65 C or 55 C Average Winding Rise (ANSI).**
- **IEEE STD C57.92-1981 (Reaffirmed 1991), IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers up to and Including 100 MVA With 55 C or 65 C Average Winding Rise (ANSI).**
- **IEEE STD C57.94-1982 (Reaffirmed 1987), IEEE Recommended Practice for Installation, Application, Operation, and Maintenance of Dry-Type General Purpose Distribution and Power Transformers (ANSI).**
- **IEEE STD C57.96-1989 (Reaffirmed 1992), IEEE Guide for Loading Dry-Type Distribution and Power Transformers (ANSI).**
- **IEEE STD C57.100-1986 (Reaffirmed 1992), IEEE Standard Test Procedure for Thermal Evaluation of Oil-Immersed Distribution Transformers (ANSI).**
- **IEEE STD 98-1984 (Reaffirmed 1992), IEEE Standard for the Preparation of Test Procedures for the Thermal Evaluation of Solid Electrical Insulating Materials (ANSI).**
- **IEEE STD 638-1992, [3.75] IEEE Standard for Qualification of Class 1E Transformers for Nuclear Power Generating Stations, provides the requirements necessary to demonstrate the adequacy of new Class 1E transformers, located in a mild environment of a nuclear power generating station as defined in IEEE STD 323-1983. This standard applies to single and three phase transformers rated 601 V to 15,000 V for the highest voltage winding and up to 2500 kVA (self-cooling rating).**

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In addition to those standards discussed above, other "withdrawn" standards (such as National Electrical Manufacturer's Association (NEMA) TR-1 and ANSI STD C57.12.30) may also be applicable. This is due to the fact that many of the transformers used in nuclear plant applications may be of substantial age and therefore were built while these standards were still in effect.

One generic issue that does apply to safety-related transformers is the ability of the equipment to function properly under seismic conditions. Seismic qualification licensing commitments vary with the time of the docketing of the application to the NRC for a construction permit. The earliest plants pre-date explicit seismic qualification requirements for electrical equipment. The applicability of the various versions of Regulatory Guide 1.100 [3.76, 3.77, 3.78] and of IEEE STD 344 [3.79, 3.80, 3.81] was determined on a plant-by-plant basis during the licensing process. The "For Comment" version of Regulatory Guide 1.100 [3.76] indicates that the guidance of IEEE STD 344-1975 [3.80], as amended by the Regulatory Guide, would be applicable to plants with applications for construction permits dated on or before November 15, 1976. Revision 1 to Regulatory Guide 1.100 [3.77] also endorses and amends IEEE STD 344-1975, but does not state explicit dates of applicability. Revision 2 to Regulatory Guide 1.100 [3.82] endorses and amends IEEE STD 344-1987 [3.81], and is applicable to plants whose construction permit was issued after June 30, 1988 or whose operating license application was dated after December 30, 1988.

To address seismic qualification of equipment for plants that pre-date the development of seismic qualification requirements, the industry formed the Seismic Qualification Utility Group (SQUG). This group investigated the effects on electrical equipment of actual earthquakes in various locations in the Americas. Based on these findings, transformers of the type considered in this guideline should withstand the levels of earthquake expected for U.S. nuclear plants, provided the structures are reasonably anchored, that interactions between equipment have been considered (e.g., adjacent equipment would not fall upon or hit the transformer during an earthquake), and that attachments to the transformer (both electrical and mechanical) were sufficiently flexible. [3.83]

Those plants licensed to Regulatory Guide 1.100 and IEEE STD 344 had to seismically qualify the equipment by either test or analysis. Due to the size and weight of power and distribution transformers, seismic qualification is primarily accomplished via analysis. IEEE STD 344 provides guidance on performing seismic analyses and seismic testing of electrical components.

Most power and distribution transformers are located in mild environments that do not experience significant changes in temperature, pressure, humidity, and radiation. As such, transformers are generally not subject to formal environmental qualification requirements.

3.5.1.2 Compliance with Applicable Elements of Standard Review Plan, NUREG-0800

Section 8.1 of NUREG-0800 [3.84] provides a Standard Review Plan (SRP) for electric power systems. Although the SRP did not form the licensing basis for older plants, the

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SRP was reviewed to identify issues and concepts related to aging management for power and distribution transformers.

Table 8-1 of the SRP lists the "Acceptance Criteria and Guidelines for Electric Power Systems." Review of this table indicated that the following documents apply to onsite and offsite AC power systems:

- **General Design Criteria (GDC) 2, "Design Bases for Protection Against Natural Phenomena." [3.85]**
- **General Design Criteria (GDC) 4, "Environmental and Dynamic Effects Design Bases." [3.86]**
- **General Design Criteria (GDC) 5, "Sharing of Structures, Systems, and Components." [3.82]**
- **General Design Criteria (GDC) 17, "Electrical Power Systems." [3.73]**
- **General Design Criteria (GDC) 18, "Inspection and Testing of Electric Power Systems." [3.74]**
- **Regulatory Guide (RG) 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants." [3.87]**
- **Regulatory Guide (RG) 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems." [3.88]**
- **Regulatory Guide (RG) 1.75, "Physical Independence of Electric Systems." [3.89]**
- **Regulatory Guide (RG) 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants." [3.90]**
- **Regulatory Guide (RG) 1.118, "Periodic Testing of Electric Power and Protection Systems." [3.91]**
- **SRP Appendix 8-A, Branch Technical Position (BTP) PSB-1, "Adequacy of Station Electric Distribution System Voltages." [3.92]**
- **SRP Appendix 8-A, Branch Technical Position (BTP) ICSB-11 (PSB), "Stability of Offsite Power Systems." [3.93]**

Each document was reviewed for specific criteria related to the control of aging of transformer components important to license renewal. A summary of the results of each review follows.

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<u>Document</u>	<u>Content</u>
GDC 2	Discusses design requirements of SSCs with respect to natural phenomena (such as earthquakes and floods).
GDC 4	Provides requirement for SSCs with respect to environmental conditions associated with plant operations, maintenance, and accidents.
GDC 5	Provides requirements for sharing of SSCs important to safety.
GDC 17	Provides requirement for electrical system redundancy, independence, and testability.
GDC 18	Provides requirements for electrical system design for periodic testing by component or as a whole.
RG 1.32	Describes methods of complying with GDC 17 and GDC 18 with respect to the design, operation, and testing of safety-related electric power systems in all types of nuclear power plants. The criteria, requirements, and recommendations in IEEE STD 308-1974 are generally acceptable to the NRC staff and provide an adequate basis for compliance.
RG 1.6	Describes the acceptable degree of independence between redundant standby (onsite) power sources and between their distribution systems.
RG 1.75	Describes acceptable methods of complying with IEEE STD 279-71 and GDC 3, 17, and 21 with respect to physical independence of circuits and electrical equipment associated with Class 1E power systems.
RG 1.81	Describes acceptable methods of complying with requirements with respect to sharing of onsite emergency and shutdown electrical systems for multi-unit nuclear power plants.
RG 1.118	Describes a method of complying with the NRC's requirements concerning periodic testing of the protection system and electrical power system for systems important to safety. RG 1.118 also provides supplementary guidance to that included in RG 1.32 regarding periodic testing of electric power systems. The requirements and recommendations contained in IEEE STD 338-1974 are considered acceptable methods for periodic testing of electrical power and protection systems.
BTP PSB-1	Discusses undervoltage protection for Class 1E equipment, Class 1E bus load shedding, safety-related bus voltage level optimization, and verification of analytical techniques.
BTP ICSB-11	Discusses offsite electrical grid transient stability.

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IEEE STD 338-1987, "Criteria for Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems," [3.94] and IEEE STD 308-1980, "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations," [3.95] were also reviewed for their applicability to transformer aging. IEEE STD 308-1980 provides principal design criteria and design features, supplementary design criteria, and surveillance and test requirements for the electrical distribution system. The surveillance and test requirements discussion covers surveillance methods, pre-operational tests, and periodic tests. In Section 7.4 of IEEE STD 308-1980, Periodic Equipment Tests, the standard states that "tests shall be performed to detect within practical limits the deterioration of the equipment toward an unacceptable condition." Although this statement addresses aging, it does not give any specific requirements for transformers.

IEEE STD 338-1987 discusses system design with respect to testability, test program objectives, types of tests to be performed, test methods, test intervals, and test procedures. In both standards, the discussions of testing are general in nature and provide no specific instructions concerning maintenance or aging of transformers.

NUREG-0800, Section 8.2, "Offsite Power System," and Section 8.3 "A-C Power Systems (Onsite)," were also reviewed to determine if they contain provisions pertaining to maintenance or aging of transformers important to license renewal. These sections of the SRP provide guidance for the review of the AC offsite and onsite power systems to ensure that they comply with the requirements of General Design Criteria 2, 4, 5, 17, 18, and 50 and will perform their intended functions during all plant operating and accident conditions. No specific criteria for transformer maintenance or aging were noted.

Overall, the review of the NUREG-0800 and the additional documents above did not produce any criteria related to transformer aging beyond requirements for testability. Thus, NUREG-0800 provides no direct guidance about the control of aging of power and distribution transformers.

3.5.2 Qualification Limits for Components Exposed to Abnormal Environments

Most power and distribution transformers are located in mild environments, areas that experience no significant change in environment as a result of an accident in the plant. However, in some plants, some indoor distribution transformers may be exposed to secondary effects of a loss-of-coolant accident or high-energy-line break outside containment. In nearly all plants, transformers are located in mild environments (or outdoors) and experience a low radiation dose ($< 1.5 \times 10^5$ rd) as a result of an accident. [3.10, 3.11] In most cases, plants having transformers in harsh environment areas are older plants. Typically, the need to qualify the transformer was identified after the plant was in service. Accordingly, generic manufacturers' environmental qualification programs do not exist for the transformers, and plant-specific tests and analyses were performed. In some cases, these qualification programs may have defined specific replacement schedules for components with organic materials. In other cases, the qualification test may have been purely for accident conditions, and no additional normal maintenance requirements may have been imposed. For plants with transformers in potentially harsh environment areas, the specific qualification documentation will have to be considered to determine any additional requirements driven by environmental qualification considerations (e.g., parts replacement schedules) for managing aging during the license renewal period.

3.6 Operating and Service History

A review of U.S. Nuclear Regulatory Commission Information Notices, Circulars, Generic Letters, and Bulletins, and INPO SERs was conducted to determine the industry-wide operating experience with power and distribution transformers. Each applicable Notice, Circular, Letter, Bulletin, and SER is discussed in Section 3.6.1. Those documents that related to transformers yet were not considered applicable to this report (such as failures resulting from improper manufacturing) are listed in Appendix B with a justification for elimination. A summary of the operating experience with power and distribution transformers is given in Table 3-1.

Transformer failure data derived from the INPO NPRDS and NRC LERs were also reviewed. Component failures described in these sources were analyzed in an attempt to identify significant transformer component failure mechanisms and their relative likelihood of occurrence. These analyses are discussed in Sections 3.6.2 and 3.6.3, respectively.

Finally, industry studies and literature were searched for applicable documents relating to power and distribution transformer operating history and failures. Materials identified during this search are discussed in Section 3.6.4.

Table 3-1. Summary of Operating Experience from Information Notices, Circulars, Bulletins, and INPO SERs (Includes data up to June 1993)

Component	Source	Failure	Cause(s)	Corrective Action
Windings	NRC IN 82-53	Winding-to-ground faults	Exposure to other faults on connected loads; operation at overvoltage conditions	None specified
Bushings	NRC IN 82-53	Internal bushing-to-ground faults	Improper bushing storage	Vertical storage of bushing prior to use
	INPO SER 13-85	External bushing-to-ground faults	Airborne contaminants and moisture	Monitor insulator surfaces for deposits; measure resistance to ground; clean and/or coat as required
Windings	NRC IN 83-37	Arcing on winding tap lug	Improper assembly; undiagnosed heat-induced degradation	Replace defective cable connections and clean connectors
Insulation	NRC IN 92-63	Cracking of ceramic insulators	Possible misalignment during installation; other potential causes not identified	Replace cracked insulators

3.6.1 Description of Industry-Wide Operating Experience with Components; NRC and INPO Documentation

The following subsections discuss those NRC and INPO documents detailing failures associated with power and distribution transformers. It should be noted that although some of these failures involved transformers not within the scope guideline (such as main and auxiliary unit transformers), many of the aging and degradation mechanisms described are substantially similar and accordingly were included below.

3.6.1.1 Liquid-Immersed Transformers

IE Information Notice 82-53, "Main Transformer Failures at the North Anna Nuclear Power Station," [3.96] describes seven main transformer failures at North Anna. The failures were determined to be due either to winding to ground faults (3) or high-voltage bushing to ground failures (4). Investigation suggests that the following circumstances contributed to the failures:

1. **Exposure to Fault Conditions.** At least once before their respective failures, several of the transformers involved had been used in operation in a bank of transformers where one of the companion units had failed.
2. **Over-voltage.** Prior to several of the failures, the transformer bank containing the failed transformers had been subjected to several documented and undocumented over-voltage conditions.
3. **Improper Storage.** The high-voltage bushings for these transformers were improperly stored (i.e., in a horizontal position). Improper positioning during transportation and storage periods results in incomplete oil coverage of the inner surfaces of the bushing; the absence of oil allows the gas in the expansion cap to permeate any exposed paper layers. Once gas permeates the paper, the bushings become sensitive to electrical degradation, and a significant time period is then required to re-impregnate the paper with oil. Bushings with this type of degradation are also susceptible to corona discharges during over-voltage conditions.

Many of these failures generated sufficient forces and heat to rupture the transformer's casings. The oil that erupted from two of these breaks ignited; the resulting fires engulfed and shorted out an overhead three-phase bus system.

INPO SER 13-85 [3.97] describes several transformer insulator (bushing) phase-to-ground failures resulting from combinations of condensation, salt accumulation, dust, and chalk powder. The following observations regarding these events were made:

1. Airborne contaminants in combination with condensation can dramatically reduce the phase-to-ground resistance of the external surfaces of bushing insulators. Periodic inspection, phase-to-ground resistance measurement, and cleaning are effective means of avoiding this problem. Spray washdown systems and silicone-based coating compounds may also be effective alternatives.

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INPO SER 24-84 [3.98] describes the failure of several nuclear plant transformers resulting in fires. The following observations regarding these failures were noted:

1. Transformer fires are most commonly caused by degradation of the winding insulation. Arcing which results from small insulation faults intensifies over time, thereby generating significant quantities of gaseous byproducts from the decomposition of insulating materials. These gases increase in concentration and pressure, potentially resulting in explosion and fire with exposure to an ignition source (such as internal transformer faulting).
2. Switchyard transformers which experience periodic overloads are also prone to explosion due to the release and collection of combustible gases. These gases are held in solution in the insulating fluid during operation, and may be released upon transformer trip and subsequent rapid cooldown. Exposure to ignition sources such as internal faulting may trigger the explosion.
3. Contamination of the insulating fluid with water reduces the dielectric strength and facilitates the formation of both combustible and non-combustible gases. This can result in sludge formation and explosive gas mixtures. Periodic laboratory or in-situ analysis can detect such degradation prior to catastrophic failure.

3.6.1.2 Dry-Type Transformers

IE Information Notice 83-37, "Transformer Failure Resulting From Degraded Internal Connection Cables," [3.99] describes a failure due to an in-rush current on a dry-type ITE 4160-/480-Vac transformer initiating major arcing in the transformer winding tap lug causing the transformer failure. The failure was attributed to improper assembly of transformer winding tap cables and long-term undiagnosed, heat-induced degradation. It was believed that the set screw, which attaches the cable to the barrel of the lug, was over-tightened during installation, which caused some strands of the aluminum wire to break, thereby creating a high resistance joint. Arcing is thought to have started in the barrel of the lug as a result of the high resistance joint. Long-term localized heating in the terminal lug over a period of time weakened and degraded the connection.

NRC Information Notice 92-63, "Cracked Insulators in ASL Dry Type Transformers Manufactured by Westinghouse Electric Corporation," [3.100] addresses problems that could result from the cracking of ceramic insulators on ASL Dry Type Power Center 4160/480 V 3-phase transformers. Typically the cracks were found in the center portion of the insulators where a series of annular indentations form rings or skirts. Some of the insulators in the affected transformers were installed off-center and were not perpendicular to the pressure ring, thereby facilitating cracking. The Notice stated that the cracking of the insulators could have a catastrophic effect on the structural integrity of the transformer.

3.6.2 Evaluation of NPRDS Data

To substantiate the stressors and aging mechanisms postulated for power and distribution transformers, actual plant component failure data were reviewed. One of the primary sources of

this type of failure data is the INPO NPRDS. Failure records contained in NPRDS include such information as the voltage rating and manufacturer, type of equipment, date of discovery, cause category, and a brief narrative describing the event. NPRDS data are not focused directly on component aging, as it does not typically address the root cause or mechanism of component degradation. Additionally, not all degradations observed during maintenance activities are identified in the database. Not all plants have provided NPRDS data, and some may not have reported for their entire period of operation. As a result of these limitations, the database cannot be readily used to provide probabilistic information about the reliability of a specific population of components with respect to age-related degradation. However, the data can be used to identify those transformer components that have a high incidence of degradation or failure relative to other components within the same equipment.

By permission of INPO, failure and deterioration data contained in the NPRDS database were reviewed as part of this study. Several hundred reports were identified when the database was searched. Data pertinent to power and distribution transformer component failures were identified; those pertaining to equipment not within scope (such as unit main and auxiliary transformers) were deleted. The remaining reports were then individually evaluated to determine their applicability to aging and aging mechanisms. Failure reports deemed to be applicable were then grouped by transformer type (i.e., liquid-immersed or dry), voltage/power rating, manufacturer, and component; each component failure grouping was then sorted by failure mode, failure cause, and method of failure detection. The following subsections summarize the specific observations by manufacturer and component. A summary of the overall findings of the NPRDS review is provided at the end of this section.

In several cases, the failure mode and/or failure cause were not identified; these reports were tagged as "unidentified." This was especially prevalent with respect to winding failures as the root cause or circumstances surrounding these failures are not always easily identified; in-depth failure analysis (especially on the smaller distribution transformers) is often protracted or not conducted. These type of reports do, however, provide additional perspective as to the fraction of total reports (related to a specific component) that did not contain sufficient information for analysis. In those cases where substantial percentages of the reports cannot be attributed to any failure mode or cause, the degree to which these reports represent the total population may be suspect. For example, if most of the "unidentified" failures for a given component are in fact attributable to one or two modes or causes (as opposed to being proportionately distributed among all of the modes or causes), the data (and results) are accordingly skewed. In sum, the accuracy of the conclusions is, to a degree, related to the percentage of "unidentified" reports present for the individual component.

It should also be noted that "normal aging" was cited in numerous reports as the cause for the component/subcomponent failure. In most cases, this term is not descriptive of the actual failure cause; however, these reports were assigned their own failure cause category so as to differentiate them from other causes and provide some indication of the fraction of total failures that these reports constituted.

Many of the reports pertinent to this analysis required a substantial degree of interpretation; incomplete and even contradictory descriptions of the circumstances surrounding the failure were sometimes noted. In cases where the ambiguity could not be resolved with any

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degree of certainty, the report in question was not used. Due to the uncertainty inherent in some of the data, the relative proportions of various types of failures may differ somewhat from the "actual" values; this potential error was assumed to be evenly distributed (that is, reports erroneously attributed were assumed not to affect one component, failure mode, or failure cause grouping disproportionately in relation to another).

The method of failure detection refers to the circumstances under which the component failure was noted. Different categories of detection method were considered, including detection during maintenance, detection during surveillance testing, during operations, and during in-service inspection. Those failures detected during operation of the equipment were further categorized as to the effect of the detection on the functionality of the transformer. For example, a transformer failure noted during operation which prevented or limited the transformer from fulfilling its required function was categorized separately from a failure detected during transformer operation which had no appreciable effect on the functionality of the unit.

Those NPRDS reports resulting from prior equipment maintenance, modification, or surveillance testing (as differentiated from events detected during these activities) were classified as "maintenance-induced"; failures resulting from maintenance-induced causes were identified in each of the discussions presented below, yet were not included in the component/failure mode/failure cause analysis. Maintenance-induced events, although not strictly an aging mechanism, do constitute a viable mechanism for transformer component degradation over time. Section 3.6.2.2.4 of this guideline discusses maintenance-induced events in further detail.

Protective and monitoring devices (including fault pressure relays, pressure relief valves, gas detectors, and temperature sensors) were included in the following analyses because, in many cases, failure of these components may either result in disruption of the function of the transformer, or place the transformer in an unprotected state, thereby making it vulnerable to damage from certain other component failures. For example, failure of the fault pressure relay will cause a trip of the transformer. Similarly, failure of a pressure relief valve may make the transformer susceptible to tank rupture in the event of an internal fault. In most cases, protective devices are located in or on the transformer (with the exception of remote alarms, indicators, and electrical protective relays) and are therefore considered integral components.

Electrical components (such as motor starters, contactors, etc.) were not explicitly considered in the failure analysis because their applications vary so widely, and in many situations may not be considered as part of the transformer by the reporting facility. In-depth analysis of motor control center (MCC) electrical components (including those commonly used in transformers) is performed in Reference 3.72.

The subsections that follow analyze the NPRDS data in several different ways. As stated above, data was segregated based on the type of transformer (dry-type or liquid-immersed). For each of these two types, the following analyses were conducted:

1. Data for all manufacturers and components are collectively examined to determine the relative proportions of component failures, failure modes, failure causes, and methods of detection (Sections 3.6.2.1.1.1 and 3.6.2.1.2.1).

2. Data specific to each manufacturer are analyzed in a fashion similar to that described in 1 above (Sections 3.6.2.1.1.2 and 3.6.2.1.2.2).
3. Data for all manufacturers are collectively analyzed based on voltage and power rating (Sections 3.6.2.1.1.3 and 3.6.2.1.2.3). (Note: Data specific to each manufacturer was not analyzed based on voltage and power rating due to the fact that some manufacturers may produce transformers which are completely contained within one voltage class; hence any inferences based on these data would necessarily be skewed).

Collectively, these analyses help characterize transformer failures as indicated by the NPRDS database.

Figures 3-16 through 3-23 are pictorial representations of the analyses. These plots show the relative distribution of component failures, failure modes, failure causes, and methods of detection. (Note: Due to the inaccuracies and uncertainties present in the data, as well as the small total number of reports, all percentage values listed in the following sections are rounded to their nearest whole digit.)

3.6.2.1 Liquid-Immersed Transformer Failure Analysis

3.6.2.1.1 Component Failure Analysis (all manufacturers)

A total of 72 events from 32 different nuclear units were recorded for liquid-immersed power and distribution transformers of the type considered by this guideline. Of these 72 events, 6 were considered maintenance-induced, and were therefore discounted from further analysis. Figure 3-16 shows a graphic representation of the failure data compiled for the remaining 66 reports. As shown in the figure, load tap changer failures constituted the highest single percentage of failures (10 reports/15%), followed closely by transformer tank/enclosure components (14%). The next most prevalent component to fail was gas monitoring units (11%); it should be noted that protective and monitoring devices (such as gas detectors, fault pressure relays, pressure relief valves, etc.) collectively comprised 32% of the failures noted. The remaining categories (bushings, insulation, windings, cooling systems, etc.) accounted for the remaining 39% of the total.

The single most common failure mode for liquid-immersed transformers was leakage (20% of all reports), followed by low electrical resistance/short circuit (11%) and failure of winding insulating materials (9%). Eleven of the 66 reports (17%) listed an unidentified failure mode. See Figure 3-17.

Significant failure causes included normal aging (26%) and moisture/dirt contamination (17%); 42% of the reports could not be attributed to any specific cause.

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Figure 3-16. Liquid-Immersed Transformer Component Failures (NPRDS).

Figure 3-17. Liquid-Immersed Transformer Failure Modes.

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The majority of failures noted in the reports were detected during operation of the transformer (see Figure 3-18); 85% of all failures involving liquid-immersed transformers were detected in this manner. Twelve percent and 3% of the total number of reports were detected during maintenance and surveillance testing, respectively. Of the failures detected during operation (85%), 36% affected the required function of the equipment; the remaining 49% had no effect on the transformer's required function.

Figure 3-18. Method of Detection for Liquid-Immersed Transformer Failures.

3.6.2.1.2 Liquid-Immersed Transformer Component Failure Analysis (Manufacturer Specific)

Data for liquid-immersed transformers from six different manufacturers (General Electric, Westinghouse, McGraw-Edison, ITE/Gould/Brown Boveri, Moloney, and Federal Pacific) were included in the NPRDS reports analyzed in this guideline; evaluations of this data are presented in the following sections.

3.6.2.1.2.1 General Electric

A total of 23 failure reports were gathered for General Electric equipment; none of these were induced by maintenance activities (maintenance-induced). Load tap changers, tank/enclosure components, and oil preservation and sampling system components each accounted for 13% (3 of 23) of the total number of reports. The remaining components comprised the remainder of the failures, with no single component having more than two failures.

Leakage of oil or insulating fluid was the most significant failure mode for the GE transformers; 6 (26%) of the 23 applicable reports involved leakage of one component or another.

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No predominant failure causes were noted, with the majority of reports having an unidentified cause. Twenty two of the 23 failures were detected during operation; only 6 of the 22 resulted in the transformer's failure to operate.

3.6.2.1.2.2 Westinghouse

A total of 25 failure reports were gathered for Westinghouse liquid-immersed power and distribution transformers. Two failures were considered maintenance-induced events. Gas monitor units comprised the largest percentage of the remaining failure reports (4 reports/17%). Reports associated with fault pressure relays, tanks/enclosures, and bushings were next most numerous (13% each). The remaining component categories collectively accounted for the remaining 44%.

Failure modes for the Westinghouse transformers included degradation of organic insulating materials, leakage, and electrical short circuits, each comprising 17% of the total number of failures. Seventeen percent of the reports listed no failure mode.

Predominant failure causes included moisture/dirt contamination (39%) and normal aging (22%); 35% of the reports had an unidentified failure cause. Eighteen of the 23 failures were detected during operation; 8 of these 18 (44%) were identified as having prevented the transformer from performing its required function.

3.6.2.1.2.3 McGraw-Edison

A total of 9 reports were applicable to McGraw-Edison transformers; one failure was maintenance-induced. Each of the remaining 8 failures were attributable to a different component; hence, no components were identified as being potentially problematic. Similarly, failure modes, failure causes, and method of detection for McGraw-Edison equipment were seemingly randomly distributed as well.

3.6.2.1.2.4 ITE/Gould/Brown Boveri

A total of 6 reports related to ITE/Gould/Brown Boveri transformers were identified. Of these reports, 2 were related to the tank/enclosure, 2 to the oil sampling and preservation system, one to the bushings, and one to a temperature detector. The failure modes for the two tank failures were both listed as weld failure, with cyclic fatigue as the root cause. The failure mode and cause of the preservation/sampling system failures were leakage due to normal aging. None of the failures affected the required function of the equipment, and none were maintenance-induced.

3.6.2.1.2.5 Moloney

A total of 5 reports were cited for Moloney equipment; all from the same plant. None of these failures were considered maintenance-induced. Four of the 5 reports (80%) were related to failure of the load tap changing mechanism. Additionally, many of the reports had an unidentified failure mode and/or cause, making the identification of any commonality difficult. All failures did result in the inability of the equipment to perform its required function.

3.6.2.1.2.6 Federal Pacific

Only one failure was reported for Federal Pacific liquid-immersed transformers; this was a failure of the insulation system attributed to dielectric breakdown of a phase winding. This failure resulted in the tripping of the transformer.

3.6.2.1.3 Voltage and Power Rating Analysis (all manufacturers)

Data relating to liquid-immersed transformers (all manufacturers) was examined to determine if any relationships between the rate of failure and the voltage/power rating existed. For the purposes of this analysis, transformers were categorized by their voltage as either transmission, inter-bus, or distribution. Transmission transformers were defined as those units which transform transmission voltages (100 kV and greater) to medium- or low-voltages (such as 13.8- or 4-kV) for on-site use. Startup transformers are examples of this type of equipment. Inter-bus transformers, on the other hand, are used to reduce the output voltage of the transmission-type transformers (which may be used to supply large plant loads such as service water or reactor coolant pumps) for use by plant medium or low voltage load centers. An example of this type of transformer might be one which reduces voltage from 13.8-kV to 4160- or 480-V. Finally, distribution transformers were defined as those used to reduce medium voltages (such as those derived from 4160-V load centers) for use by low-voltage (480-V) plant loads.

As indicated in Figure 3-19, of the 66 reports applicable to liquid-immersed transformers, 32 (49%) involved transmission equipment, 26 (39%) involved inter-bus transformers, and 8 (12%) involved distribution transformers. When only the failures detected during operation which resulted in preclusion of the transformer's required function (24 total reports) are considered, the following results are noted: 18 of the 24 reports (75%) involved main power transformers, and the remaining 6 (25%) were related to inter-bus type units (see Figure 3-20).

3.6.2.2 Dry-Type Transformer Failure Analysis

3.6.2.2.1 Component Failure Analysis (all manufacturers)

A total of 32 events from 15 different nuclear units were recorded for dry power and distribution transformers of the type considered by this guideline. Of these 32 events, none were considered maintenance-induced. Figure 3-21 shows a graphic representation of the failure data compiled for these 32 reports. As shown by the figure, primary/secondary winding insulation failures constituted the highest single percentage of failures (15 reports/47%), followed by cooling system components (25%). All other component failures occurred with substantially less frequency, collectively accounting for the remaining 28% of the reports.

The single most common failure *mode* for dry type transformers was degradation/failure of organic insulating material (44% of all reports). Five of the 32 reports (17%) listed an unidentified failure mode. The remaining 39% of the reports were associated with several different failure modes (Figure 3-22).

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Based on 66 Reports

Figure 3-19. Liquid-Immersed Transformer Failures (By Input Voltage Category).

Based on 24 Reports

Figure 3-20. Liquid-Immersed Transformer Failures to Operate^{**}
(By Input Voltage Category).

* High-side winding voltage

** Failure to operate is defined as the inability of the transformer to fulfill its required function.

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Based on 32 Reports

Figure 3-21. Dry-Type Transformer Component Failures.

Based on 32 Reports

Figure 3-22. Failure Modes for Dry-Type Transformers.

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The only significant failure *cause* noted was normal aging (25%); the remaining reports had no identified failure cause.

The majority of failures noted in the reports were detected during operation of the transformer; 84% of all failures involving dry type transformers were detected in this manner. 13% and 3% of the total number of reports were detected during maintenance and in-service inspection, respectively. Of the failures detected during operation, 50% affected the required function of the equipment; the remaining 34% had no immediate effect on the transformer's functionality (Figure 3-23).

Figure 3-23. Method of Detection for Dry-Type Transformer Failures.

3.6.2.2.2 Component Failure Analysis (Manufacturer Specific)

Data for dry-type transformers from four different manufacturers (ITE, General Electric, Westinghouse, and BBC) was included in the NPRDS reports analyzed in this guideline; evaluations of this data are presented in the following sections.

3.6.2.2.2.1 ITE

A total of 15 failure reports were identified for ITE equipment; none of these failures were maintenance-induced. Cooling system components (predominantly fans) comprised 53% of the failures, whereas 40% were attributable to the primary/secondary winding insulation. The remaining components comprised the remainder of the failures, with no single component having more than two failures.

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Degradation of organic insulating material was the most significant failure mode for the ITE transformers; 5 of the 15 applicable reports involved degraded insulation.

Normal aging was the most significant identified failure *cause* (27%); however, a full two-thirds (67%) of the reports failed to identify any cause.

All of the failures noted were detected during operations; of these failures, one-third (5) resulted in failure of the transformer to perform its required function, whereas two-thirds (10) had no immediate effect.

3.6.2.2.2 General Electric

A total of 11 failure reports were generated for GE dry-type power and distribution transformers. None of these failures were considered to be maintenance-induced events. Primary/secondary winding insulation failures comprised the largest percentage of reports (9 reports/82%).

Eight of the 11 reports listed degradation of organic insulating materials as the failure mode. Although the preponderance (82%) of the reports listed no failure cause, nearly all of the failures resulted in preventing the transformer from performing its required function.

3.6.2.2.3 Westinghouse

Three reports related to Westinghouse dry-type transformers were identified. Of these reports, 2 were related to cracking of the bus insulator supports, which was determined to be the result of a manufacturing defect. The remaining failure was related to the installed temperature indicator. None of the failures affected the required function of the equipment, and none were maintenance-induced.

3.6.2.2.4 ITE/Brown Boveri

Only one report was noted for ITE/Brown Boveri dry transformer equipment; this was related to heat damage of the electrical connections to the transformer, and was not maintenance induced. The function of the transformer was affected by this event.

3.6.2.2.3 Voltage and Power Rating Analysis (all manufacturers)

All dry-type transformer failures noted in the NPRDS data were related to transformers of the distribution type (i.e., all similar voltage and power rating). Accordingly, no further sub-classification of the data with respect to these ratings can be made.

3.6.2.2.4 Conclusions from NPRDS Review

As indicated above, the NPRDS data are not specific to aging-related information. In many instances, the scope was limited with respect to the number of plants and the time period reported. Data for many manufacturers was numerically insufficient to substantiate any specific

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inferences. Despite these limitations, however, several observations can be made about the various classes of transformers evaluated.

General Conclusions

1. When considering the failure data for all manufacturers collectively, no one component or subsystem associated with liquid-immersed transformers had a failure rate which was significantly larger than that of other components. Insulation failure and dielectric breakdown, although potentially catastrophic, were no more likely to occur than other types of failures.
2. The majority of all transformer failures (both liquid and dry) were detected during operation of the unit. Of these failures, a significant percentage (40%) resulted in a failure of the transformer to function; however, small distribution-type liquid units were a notable exception (see the following conclusion).
3. Larger transmission and inter-bus liquid-immersed transformers accounted for significantly more failures than the smaller distribution-type liquid units. The relative population sizes of each class of liquid transformer are unknown; however, the data seems to indicate that units with higher voltage and power ratings experience a higher rate of failure. No failures of the smaller distribution type liquid equipment (< 5 MVA) resulted in the transformer's inability to perform its required function(s).
4. For dry-type transformers, failures of the primary/secondary winding insulation and cooling system (fans) are most significant. Degradation of the insulation accounted for nearly half of all failure reports for dry-type equipment; cooling fans comprised one quarter of all reports. Almost half of all the failure reports noted for dry-type transformers also resulted in the failure of the unit to perform its required function.

Manufacturer-Specific Conclusions

1. Based on the failure data provided, no highly problematic components were identified for any manufacturer's liquid-immersed type equipment considered in this guideline. Two considerations related to this observation should be noted, however:
 - Relatively few failure reports were observed for each manufacturer; therefore, inferences concerning the relative dependability of systems or components could not be reliably made. Hence, although no problematic components or systems were identified, it cannot be definitively stated that no such problems exist.
 - Not all manufacturer's equipment is necessarily covered by the NPRDS data (i.e., failures of other manufacturer's equipment may have occurred yet were not reported to the system)
2. For dry-type transformers, failure data for the individual manufacturers was for the most part consistent with the overall failure data (i.e., significant percentages of winding insulation and cooling system component failure); due to the low total

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number of reports, however, no inferences concerning the reliability of a specific manufacturer's transformers or components can be made.

Maintenance-induced events accounted for varying percentages of the total number of failures recorded for each transformer type and manufacturer; although not considered an aging mechanism per se, these events do represent a factor to be considered in the aging of the equipment. A high incidence of maintenance-related degradations and/or failures is potentially indicative of erosion of the skill/knowledge level of personnel maintaining the equipment or relaxed attention to detail and should be addressed in a fashion similar to that of more conventional aging mechanisms.

Maintenance induced events comprised only 8% of the total number of reports relating to liquid-immersed transformers, and 0% of the reports relating to dry-type transformers. Hence, in sum, maintenance-induced events constituted less than 6% of reports related to all types of transformers considered in this guideline. This result indicates that improper maintenance techniques do not appear to be a very significant aging mechanism for either dry or liquid-immersed transformers.

3.6.3 Evaluation of LER Data

NRC LERs are another source of transformer failure and degradation data. LERs are issued by nuclear plant operators when equipment failures and plant operating events meet the reporting requirements specified in 10 CFR 50.73. As with NPRDS data, LERs are not oriented directly toward recording data related to component aging. In addition, the criteria for issuance of an LER do not encompass all component failures (especially those of little or no consequence to plant safety). Hence, evaluation of LER data provides only a partial picture of failure information; accordingly, the data may or may not be representative of general equipment failure behavior. LER data can be used, however, as support for the findings derived from other data sources (such as NPRDS and industry studies), as well as for verification of postulated aging mechanisms.

The LERs used in this analysis covered the period from early 1980 through 1992. The abstracts of approximately 300 LERs were identified via keyword search of the LER database maintained by Oak Ridge National Laboratory. Each of the reports generated by this search was individually reviewed; in cases where the applicability of a given report to a topic could not be reliably determined, the report was discarded. Of the 300 reports reviewed, 23 were ultimately retained as being applicable to power and distribution transformers of the type considered by this guideline. These reports were then categorized by component, failure mode, failure cause, and method of detection; categorization by manufacturer was not practical due to the lack of consistent component manufacturer data, as well as the low number of total reports. Analysis of the LERs (for each type of transformer) are included in Sections 3.6.3.1 through 3.6.3.3 below. It should be noted that the reporting requirements of 10 CFR 50.73 effectively dictate the method of detection of failures; hence, all failures reported in the LERs considered in this analysis were detected during transformer operations, and resulted in the failure of the equipment to perform its required function.

3.6.3.1 Liquid-Immersed Transformers

The data contained in the LER database described 18 events, from 16 separate units, related to liquid-immersed transformers. Of these 18 reports, 8 (44%) were related to failure of the primary/secondary winding insulation, and 5 (28%) were related to failure of the bushings. The remaining 5 reports were distributed among other transformer components. See Figure 3-24. Insufficient information was present in the reports to categorize failures as being applicable to either power or distribution units.

The only significant failure *mode* noted was degradation of organic insulation material (9 of 18 or 50%); 17% of the reports had unidentified modes. Only 7 of the 18 reports (39%) identified the underlying failure *cause*; 5 of these 7 reports listed moisture or dirt contamination as the reason for the transformer failure.

3.6.3.2 Dry-Type Transformers

The LER database contained 5 reports from 5 separate units related to dry-type transformers of the type evaluated in this guideline. All 5 reports (100%) were related to failure of the primary/secondary winding insulation. Degradation of organic insulating materials was the failure mode listed in each report. No common failure cause was indicated.

Figure 3-24. Licensee Event Reports, Liquid-Immersed Power and Distribution Transformers.

3.6.3.3 Conclusions from LER Review

Due to the extremely limited number of LERs applicable to power and distribution transformers of the type considered in this guideline, no real inferences can be made as to the relative reliability or probability of failure of individual transformer components. The following general observations were noted, however:

1. Failures of transformer primary and secondary winding insulation accounted for 57% (13 of 23) of the total number of failures reported. In contrast, winding insulation failures as reported in the NPRDS data were not a large part of the total. Sixty-one percent (14 of 23) of the reports listed degradation of organic insulation as the failure mode. (Note: The one additional insulation degradation was associated with a bushing as opposed to the windings).
2. For liquid-immersed transformers, bushing failure constituted a substantial portion of the reported failures (28%); failure modes for bushings included flashover due to contamination, degradation of insulation, and leakage.

3.6.4 Studies Providing Industry-Wide Operating Experience for Power and Distribution Transformers

3.6.4.1 EPRI NP-5002, "LWR Plant Life Extension"

EPRI NP-5002 [3.101] provided interim results from the pilot plant life extension studies conducted at Surry Unit 1 Pressurized Water Reactor (PWR) and Monticello Boiling Water Reactor (BWR)). These pilot studies were initiated in 1984 to identify specific research and development needs related to plant life extension and to serve as a basis for power system aging and life extension guidelines for the nuclear industry. The study considered many different plant components, including large station transformers. The evaluation of the Surry station transformers, funded by Virginia Power Company, EPRI, DOE, and the Westinghouse Owner's Group, assessed the impact of station transformers on the possibility of extended life operation for Surry Unit 1. The operating, maintenance, test, and outage records for the station transformers were reviewed and evaluated in order to identify degradation processes, assess new monitoring devices and techniques, and identify testing and maintenance methods effective at detecting incipient transformer failures. The findings and conclusions of the study (based on interim results) are discussed in the following paragraphs.

Exposure of Mineral Oil to Oxygen or Moisture

The presence of oxygen and moisture in transformer oil produces a variety of deleterious effects, such as localized reduction of dielectric strength and sludge formation. High moisture content, especially under overload conditions, may affect transformer life via vaporization and bubble formation. Sludge formation can result in plugging of oil flow passages throughout the windings, thereby reducing the heat removal capability of the system and further inducing hot-spot formation and its associated thermal deterioration.

External Short Circuits

Short circuit conditions generated external to the transformer can result in failure of the primary/secondary windings by a number of different mechanisms, including winding distortion, movement, and fracturing of brazed joints. These degradation mechanisms may ultimately lead to turn-to-turn winding shorts, localized hot-spots, or the generation of combustible gases due to deterioration of thermal insulation.

Overloading

Extended periods of overload will result in thermally-induced degradation of cellulose-based insulation components as well as decomposition of the insulating fluid (oil) which generates varying quantities of combustible gases.

Conclusions

Despite the existence of degradation mechanisms described above, no inherent limitation on the useful life of the transformers under evaluation was noted. In general, the service life of the transformer depends to a large degree on 1) the operational conditions to which the unit has been exposed (i.e., the number/duration of overloads, external fault events, etc.), and 2) the type and frequency of inspection and maintenance. However, despite the existence of maintenance and operations records, the remaining transformer useful life can not be accurately determined. Test data may be reviewed at regular intervals to determine if any abnormal rates of degradation (of the type described above) are being experienced. Signs of abnormal degradation may include:

- Reduction of insulating fluid dielectric strength
- Accumulation of moisture and other contaminants in the insulating fluid
- Formation of sludge
- Abnormal combustible gas levels
- Change in winding impedance, excitation current, or transformation ratio from factory test values (indicative of turn-to-turn shorts)
- Increased partial discharge or corona activity level (indicative of electrical breakdown of insulation)
- Abnormal noise/high sound level (indicative of loose and vibrating internal components)

3.6.4.2 NUREG/CR-3122, "Potentially Damaging Failure Modes of High- and Medium-Voltage Electrical Equipment"

NUREG/CR-3122 [3.102] considers the effects and circumstances surrounding electrical faults of transformers, switchgear, and other electrical components used in both nuclear and non-nuclear facilities. The scope was limited to equipment with voltage ratings of 4100 Vac and above. As part of the study, several sources of failure information were consulted. A total of 196 failures related to nuclear plant transformers were identified using the Nuclear Safety Information Center (NSIC) database. In addition to these reports, the study examined proceedings from the Doble Clients Annual Conference (an industry forum for issues and technology related to electrical components) for pertinent data. According to the Doble Conference data, numerous nuclear and non-nuclear liquid-immersed transformer failures (most of which were 13.8 kV and above) have occurred during each of the years 1975-1980; the study lists more than one-thousand failures (predominantly non-nuclear) during this time period. The NUREG also considers several significant transformer failure events recorded for main generator phase output transformers which failed at the North Anna station between 1980 and 1982. (See the discussion of NRC IE Information Notice 82-53 contained in Section 3.6.1.1 above for an analysis of the failures.)

The study concludes that failures of large transformers, although infrequent, usually result from a series of events such as abnormal loading, surges, and improper maintenance. The study also indicates that in general, transformer faults will mechanically damage only that equipment within the immediate physical vicinity of the unit; electrical damage, on the other hand, may be more widespread. Furthermore, primary to secondary winding arcing may expose components connected to the low voltage side of the transformer to potentially damaging voltages and currents. In many instances, incipient failures of transformer components can be detected via installed monitoring equipment or testing.

3.6.4.3 "Life Extension Considerations for Electrical Equipment in Light Water Reactors," by C. F. Bergeron and W. B. Dobson, Stone & Webster Engineering Corporation

This document examined considerations related to life extension of nuclear plant electrical power, instrumentation, and control equipment. Among the equipment evaluated in the study were large power (station) transformers of the liquid-immersed type. The paper relies primarily upon the results of the Surry and Monticello studies (see Section 3.6.4.1 above), as well as previous Stone & Webster Engineering Corporation (SWEC) work on fossil-fired stations as the basis for its conclusions.

Three types of life-limiting factors were considered in this evaluation; physical degradation, obsolescence, and equipment qualification. Physical degradation due to temperature was found to be the most life limiting factor. In addition to the evaluation of the degradation mechanisms, lifetime evaluations of each plant electrical component considered in the study (including transformers) were made. No principal age-related factors were found for the large station transformers studied; there was no apparent limitation noted on their useful life. [3.52]

3.6.5 Overall Conclusions Regarding Equipment Historical Performance

As discussed in the previous sections, five primary sources of information were used in this guideline to characterize liquid-immersed and dry-type transformer historical performance: (1) NRC Notices, Bulletins, Circulars, and Generic Letters, (2) INPO SERs, (3) NPRDS data, (4) LER data, and (5) industry information provided by previous analyses and reports relating to transformers. These sources each provide a somewhat different perspective on transformer component aging. Several limitations are inherent in any comparison of these results, stemming primarily from the variations in equipment types within the population, differing scope of equipment included, classification of failures, and criteria used in the analysis. Accordingly, no statistical inferences can be drawn concerning component failure probability or rate. Yet despite these limitations, several generic observations can be made.

Liquid-Immersed Transformers

1. In general, the larger liquid-immersed type transformers (i.e., startup or inter-bus) appear to be more problematic than the smaller liquid-immersed units, especially with respect to failures which affect the equipment's required function(s).
2. No one component appeared to be overly problematic. The component recording the highest overall instance of failure was the load tap changer, although the percentage of these failures was not significantly larger than that of other components.
3. Failure of the primary and secondary winding insulation does not appear to be a numerically large source of liquid-immersed transformer failures; failures of several other transformer components were equally or more frequent*. It should be noted, however, that insulation failure and dielectric breakdown in general had the most catastrophic and damaging results as well as the highest rate of lost functionality.
4. Contamination of the bushing exterior surface with moisture/and or foreign material has resulted in several cases of bushing flashover or grounding (thereby impacting the equipment's required function); this failure mode may vary in frequency of occurrence depending primarily upon the transformer's external operating environment. Internal bushing failures were rare except in cases of improper storage.
5. The majority of liquid-immersed transformer failures occur/are detected during operation; a substantial percentage of these failures result in the inability of the transformer to perform its required function for one reason or another. An exception to this were the smaller distribution-type liquid units, for which no instances of lost functionality (detected during operation) were noted.

* This observation is based primarily on the data as represented by the NPRDS data base. Although a significant percentage of the failures described by Licensee Event Reports were related to winding insulation, this percentage was considered not to be representative of the overall equipment performance due to the reporting requirements imposed by 10 CFR 50.73.

Dry-Type Transformers

1. Failure of the primary and secondary winding appears to be the most significant failure mode for dry type transformers; failure of cooling system components (primarily fans) also appears to be significant and could lead to winding failure.
2. Failure of dry-type transformer components (i.e., the winding insulation and cooling system) are most frequently detected during operation; they also often result in loss of function.

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4. APPLICABLE STRESSORS AND AGING MECHANISMS

4.1 Determination of Stressors Acting on Components

During operation, power and distribution transformers are exposed to a number of stressors that can lead to deterioration. These stressors may act individually or in combination with one another to produce an aging mechanism. The following discussion of stressors is provided to facilitate development of the discussion of aging mechanisms and age-related degradation that may occur in transformers. The potential stressors are:

- Temperature (ambient and internally generated)
- Voltage
- Mechanical and electrical cycling of auxiliary components
- Non-seismic vibration
- Radiation.

Although not directly producing stress, humidity, dirt, dust, and contamination may magnify the effects of the stresses acting on the transformer and can lead to deterioration of transformer components.

Temperature

Temperature exposure causes thermal deterioration of organic materials used in transformer subcomponents (such as insulators, structural members, and lubricants). Temperatures affecting transformers are associated with the ambient environment and temperature rise resulting from winding, core, and other losses. Elevated temperature existing in various portions of the transformer will cause gradual insulation deterioration; higher temperatures will result in more rapid degradation. Areas with elevated localized temperatures (hot spots) may develop in the windings as a result of blocked spaces or channels between windings, sharp bends in the winding, variations in magnetic flux density, and other factors. These hot spot temperatures can vary significantly from the average temperature of the winding, thereby causing accelerated degradation of any nearby winding insulation or other organic components. In addition, development of a high resistance connection in a primary current-carrying path can cause rapid deterioration of the surrounding insulating material due to ohmic heat generated. Heat generation by control circuits and other low-current components is considered negligible, except with respect to individual components whose temperature may be substantially elevated by internal heat production (such as coils of continuously energized relays).

Temperature effects may be mitigated in varying degrees by the cooling systems serving the transformer; this is based on such factors as the effectiveness of the cooling system, the existence/location of any hot spots, and ambient conditions. Generally, the ambient temperature surrounding indoor transformers is controlled between 21°C [70°F] and 29°C [85°F] and does not reach the 40°C [104°F] normal temperature limit assumed in transformer design and manufacturing standards. Transformers located outside may be subjected to more extreme temperature conditions (such as sustained periods of high temperature resulting from ambient/solar radiation, or sub-zero temperatures). Large power transformers used at nuclear power plants (such as start-up transformers) are frequently located in outdoor areas having

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potentially severe environmental factors. (See Section 3.5.2 for a discussion of these environments). Smaller power transformers and distribution transformers are generally placed indoors, and hence are not subject to such severe conditions.

Voltage and Current

Stressors associated with the electrical functions of transformer components may also lead to age-related degradation. Electrical stressors are caused either by extreme voltage gradients from over-voltage transients, spikes, and fault interruption, or continuous energization at normal voltage levels.

Fault currents and inductive surges/electrical transients can cause stressors which contribute to insulation breakdown and winding/core dislocation. When an electrical pulse is applied to a transformer, the voltage does not distribute uniformly throughout the windings. Based on the type and duration of pulse applied, portions of the winding insulation will be stressed more severely than others. These stressors can ultimately result in localized breakdown of the insulation causing turn-to-turn shorts, flashover to ground, or flashover between phases. Lightning strikes are especially degrading to transformers; lightning may generate voltages in excess of 500,000 volts and 200,000 amperes; hence outdoor transformers and other susceptible equipment must be provided with appropriate protective devices such as lightning arresters. Excessive voltages and currents can also lead to deterioration of the bushings and other insulating components, and provide a source of heat for thermal degradation.

Energization at normal design voltage levels can significantly stress transformer insulation over the long term; the amount and severity of this stress is determined primarily by the dielectric strength of the insulating material used. Dielectric strength is defined as the maximum potential gradient a given material can withstand without breakdown; this value is usually given in terms of the breakdown voltage divided by the material thickness. The dielectric constant (or permittivity) is a measure of a material's ability to insulate against a potential gradient across it; it is a function of the sub-atomic composition of that material which varies with temperature, frequency, and several other factors. For a given potential gradient, the voltage drop across each of the materials interposed between that gradient will vary inversely with the material's dielectric constant; the highest fraction of voltage drop will occur across the material of lowest dielectric constant. Hence materials with lower dielectric constants will usually be limiting in terms of the overall effective dielectric strength of the insulation system. Gas (or air) entrained in the insulating fluid of a transformer is of particular concern in that the dielectric constant of the gas is low in relation to the surrounding fluid; hence, the gas pocket will be stressed more highly than the fluid and other insulation while, at the same time, having a lower dielectric strength. This can cause localized ionization and breakdown at the gas pockets which degrades the insulating material. Similarly, impurities and contaminants, particularly in the presence of moisture, can greatly reduce the dielectric strength of an insulating system. Extreme care must be used both during manufacture and maintenance to minimize the introduction of contaminants into the insulating system.

In some dry-type transformers, voltage and humidity can affect solid insulation that is dirty or deteriorated; this can result in surface tracking paths between phase and ground, and adjacent phases. Moisture in the tracking path will allow larger leakage currents to flow. The

leakage current flow will cause the moisture in the tracking path to evaporate; the leakage current will tend to remain constant such that the current density in the tracking path increases as moisture evaporates. This can result in localized burning of the insulation and ultimately insulation failure. Thermally deteriorated insulation, when exposed to humidity and dirt, may not only lose its surface insulating properties (in the form of surface current tracking), but may also lose its volumetric insulating properties. Thermally deteriorated insulation is most frequently brittle and prone to cracking. Leakage current, in addition to propagation across the surface of the insulation, may travel through the thickness of the insulation eventually resulting in flashover. Reasonable inspection and care of primary insulation systems in dry transformers should allow detection of surface and volumetric deterioration before it becomes severe.

Another phenomenon potentially affecting power and distribution transformers is internal electrostatic corona. This effect results from large potential gradients between conductors separated by air. A high electrostatic flux density results in ionization of the surrounding air; if the gradient is sufficiently large and the separation sufficiently small, complete dielectric breakdown (resulting in continuous discharge) may occur. Corona can occur between conducting surfaces internal to the transformer, such as between winding turns. Corona discharges are usually extinguished when the large voltage difference inducing its formation is reduced; however, the dielectric quality of organic materials may be reduced during each subsequent corona discharge. As a result, subsequent corona discharges will occur at progressively lower voltage levels. This process can continue until the corona extinction voltage level is less than the normal operating level, in which case the discharge will not extinguish and faulting will ultimately occur.

Currents may also be induced in transformer windings and components via geomagnetic interaction. Based on the intensity of the geomagnetic field present at a transformer's installed location, circulating currents of varying magnitude may be produced which can result in both increased losses and additional heat generation within the conductive elements of the transformer. This phenomenon has been identified as the cause of at least one main transformer failure at a commercial nuclear power plant; however, it is not expected to affect any significant portion of the total population of transformers covered by this guideline based on the specific environmental, design, and operational factors required for its occurrence. Accordingly, geomagnetically induced currents are not considered to result in age-related degradation and are therefore not considered further in this document.

Mechanical and Electrical Cycling

Cycling of transformer mechanical and electrical components such as oil pumps, fans, and load tap changers places stress on these components and may cause them to degrade or deteriorate with time. Cycling can vary significantly between individual transformer components, based primarily on their frequency of use. For instance, cooling system components may operate continuously or intermittently based on transformer load and ambient conditions; tap changers or pressure relief valves, on the other hand, may operate very infrequently (for example, only during shutdown conditions or periodic testing). Those components cycled or operated more frequently will experience significantly more wear and cyclic fatigue of mechanical internals, due to both mechanical stresses encountered during operation and any self-induced vibrational stresses such as those from rotating assemblies. Wear of moving parts can result in the loss of tolerances

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or loss of adjustment. Components requiring lubrication (pump motor or fan bearings) may also experience accelerated wear due to deteriorated or displaced lubricants.

Mechanical stress may also be placed on transformer components via continuous heating/cooling. Heating occurs as a result of core, winding, and other losses, as well as changes in ambient temperature and incident solar energy; heat generated in the unit is generally related to the operating load. Cooling results from heat removal by the cooling system, conduction convection/radiation by the transformer enclosure, variations in the ambient/solar conditions, and variations in load. As a result of these competing heating and cooling effects, the temperature of many transformer components (i.e., the insulation, windings, cooling system components, etc.) will fluctuate with time. This fluctuation creates thermal stress on these components in varying degrees, as determined by their material (thermal expansion coefficient) and design, and may eventually result in fatigue of these components. Cyclic fatigue may be manifested as stressing or cracking of both organic and inorganic (i.e., metallic) subcomponents.

Non-Seismic Vibration

Non-seismic vibration may also induce mechanical wear, fatigue cracking, loss of tolerances/adjustment, and loosening of subcomponents. Vibration will produce varying amounts of wear and stress over time depending on a number of factors such as the mass of the subcomponent, its material composition, the frequency of oscillation, the rigidity of its mounting, tolerances between it and other subcomponents, etc. Notches, fatigue cracks, loss of tolerances or calibration, or other manifestations of wear may eventually result from long-term exposure to this type of vibration. For components such as pumps and fans, the vibrations may be self-induced due to the operation of the motor or hydraulic effects. It should be noted that heavy external non-seismic vibration is not normally imposed on power and distribution transformers in that they are not usually located adjacent to large vibrational sources, and are usually mounted on vibration-resistant foundations. Additionally, many transformers use vibration-resistant mountings for their internal components (such as the core and coils assembly) to effectively isolate these components. However, self-induced vibration (AC "hum") of the core and windings may produce loosening or losses of critical tolerances in other components, potentially resulting in their failure.

Radiation

Radiation should not be a significant environmental factor for most transformers because the units are located either in plant areas that are accessible under most design basis conditions or outdoors. Ionizing radiation may reduce a material's dielectric strength and integrity by causing breakdown of insulation polymer chains, cracking of some plastics, and the formation of gas bubbles in oil. Yet for most power and distribution transformers, the maximum integrated normal and accident radiation doses would be expected well below 10^3 gray [10^5 rad] (up to sixty years), which would not cause significant deterioration of transformer materials. Any units used in areas with higher radiation doses (possibly small distribution transformers) are qualified by analyses or tests. Generally, the largest portion of the radiation dose is associated with an accident environment, and little or no radiation-induced damage is expected under normal conditions.

Contaminants/Moisture

Several types of degradation may result from exposure of the transformer to moisture and other contaminants. For example, intrusion of moisture or foreign substances through leaks in transformer components (such as degraded sample valves or relief valve seals) can contaminate the insulating fluid thereby resulting in a variety of deleterious effects ranging from accelerated sludge formation to dielectric breakdown and eventual transformer insulation failure. Dust, salt, and other airborne contaminants can accumulate on bushing exterior surfaces and, in conjunction with moisture or humidity, create the conditions that may lead to bushing flashover. Contaminants and moisture, in combination or acting independently, can result in deterioration of the transformer structural components; the housing may corrode and/or rust if exposed to contaminants and/or moisture such that the structural members and fasteners will weaken. In some instances, foreign matter may also affect the contact surfaces of relays, magnetic contactors, and other electrical components used within the transformer housing, potentially interfering with the performance of a component's required functions. Exposure to contaminants may degrade mechanical components via increased friction (leading to wear), stiffening or freezing of moving components, hardening and deterioration of lubricants, and embrittlement of non-metallic materials. [4.1]

Table 4-1 summarizes the stressors acting upon power and distribution transformers and indicates the aging mechanisms, types of degradation, and failure modes that may result from exposure to these stresses. [4.1, 4.2, 4.3, 4.4, 4.5, 4.6, 4.7, 4.8, 4.9, 4.10, 4.11]

Table 4-1. Stressors, Aging Mechanisms, Potential Failure Modes

(Note: Aging mechanisms, age-related degradations, and failure modes apply to both liquid and dry-type transformers unless otherwise noted.)

Stressor	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Temperature	Acidity of insulating fluid	Thermal deterioration	Loss of mechanical and electrical properties of solid insulation	Dielectric breakdown; flashover	Generally a slow process
	Ohmic heating; winding and core losses	Thermal deterioration; cracking	Loss of dielectric strength of organic winding and electrical connection insulation	Dielectric breakdown; flashover	
	Contaminants	Thermal deterioration of lubricants	Binding and high friction; wear	Seized motor bearings, load tap changer components, valves, and enclosure door hinges	

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Table 4-1. Stressors, Aging Mechanisms, Potential Failure Modes (Continued)

Stressor	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Temperature (continued)	Moisture and contaminants; dielectric stress	Thermal decomposition of insulating fluid (liquid only)	Loss of dielectric strength; sludge and/or gas formation	Localized breakdown and gas formation	Detected by periodic sampling and analysis
Voltage	Contaminants; moisture	Accumulation of contaminants on bushing weather shield	Loss of surface insulating properties; surface tracking	External flashover of bushing between phase and ground	Accelerated in high dust, salt, and moisture environments
	Gas pockets or other low dielectric contaminants	Degradation of insulating fluid (liquid only)	Fluid decomposition and deterioration; gas formation	Localized breakdown of insulating fluid; eventual flashover and possible explosion	Detected by periodic sampling and analysis
	Low dielectric strength contaminants (such as gas or particulates)	Ionization and corona breakdown	Degradation of insulating materials	Dielectric breakdown; flashover	
Current	External fault or surge conditions	Electromagnetic forces on conductors/core	Movement or dislocation of windings and/or core	Loss of spacing of windings; turn-to-turn shorts	Not significant at normal current levels
Mechanical and Electrical Cycling	Deteriorated lubricants in auxiliary components	High friction between moving parts	Wear	Binding of tap changer, pump, or fan motor bearings, and valves	Increases with increasing duty cycle
	Voltage; contaminants	Pitting or erosion of auxiliary device contact surfaces	Degradation of electrical components	Misoperation of load tap changer; loss of cooling components	Increases with number of make/break operations
Non-Seismic Vibration	Loose internal components	Cyclic wear/fatigue	Wear and possible cracking of components; loss of tolerances, misalignment	Binding; component deformation or breakage	

4.2 Determination of Applicable Aging Mechanisms

Aging mechanisms were identified by considering the effects of stressors on each transformer component (Section 4.1) and the operating experience of each component (Section 3.6). Those aging mechanisms considered to be significant are discussed in Section 4.2.1. Those aging mechanisms considered to be non-significant are discussed in Section 4.2.2. Those aging mechanisms that have not yet been experienced because equipment has not aged sufficiently (assuming current preventive maintenance will not prevent failure) are discussed in Section 5.4.2.

4.2.1 Significant Aging Mechanisms

An aging mechanism is significant when, if allowed to continue without detection or mitigation measures, it will cause the component or structure to lose its ability to perform its required function. The following text discusses each significant aging mechanism for both liquid-immersed and dry-type power and distribution transformers. For definitions of aging terminology, see Appendix A.

4.2.1.1 Metal Enclosure (Tank) and Cover

Significant aging mechanisms for the transformer enclosure are:

- material degradation
- deterioration of organic sealing components
- metal fatigue
- loss/over-torquing of fastening components

all leading to a potential loss of structural or leak-tight integrity.

The first aging mechanism, material degradation, can take various forms, including rust or corrosion of metal surfaces and physical damage to enclosure components. Many transformers (especially the larger units) are located outdoors and are therefore exposed to the extremes of temperature, humidity, wind, and solar exposure. Chipping, cracking, or peeling of the enclosure's protective coating exposes the metal allowing the formation of rust and corrosion (most enclosures are fabricated from low-alloy steel which is highly susceptible to this type of effect). Moisture (i.e., condensation) may collect in areas of lower relative temperature such as the interior of the tank, cover, and any external electrical enclosures, thereby facilitating the degradation of these materials.

The second aging mechanism, deterioration of organic components, can occur as gaskets or other organic seals used in the construction of the enclosure degrade due to exposure to heat, ultraviolet radiation, moisture, or chemicals, while under mechanical stress or compression. Polymeric seal materials embrittle and harden with age and exposure, and generally must be replaced periodically, depending on the specific conditions present in their service environment.

The third aging mechanism, metal fatigue, can result from cyclic vibrational or thermal stresses placed on the enclosure (such as repeated heatup and cooldown cycles, operation of cooling system pumps and fans, or ac-induced hum). This can affect areas of high local stress

such as welds, tank edges, etc., resulting in tank leaks (oil or gas-filled units) and potentially a loss of structural integrity.

Loss of fastening components, although not a specific aging mechanism, can also degrade the structural integrity of the enclosure by weakening joints, flanges, and other sealing surfaces or allowing components mounted to the enclosure to vibrate excessively (such as fans or other motors). The loss of fastening components can be caused by equipment vibration during operation or result from improper maintenance techniques.

Because each of the aging mechanisms described above can result in a loss of the structural and/or leak-tight integrity of the transformer tank, they are considered significant for systems which rely on these types of integrity for their operation (i.e., liquid-immersed or sealed dry-type transformers). The most probable result of loss of structural integrity is tank leakage. Insulating fluids or gases may escape or contaminants may enter with the ultimate result of breakdown of the insulation.

4.2.1.2 Primary and Secondary Windings

The significant aging mechanisms for the primary and secondary windings and their electrical connections (in both liquid-immersed and dry-type transformers) are:

- degradation of organic insulating materials
- formation of localized hot spots
- loosening of the winding mounting system
- winding connection (conductor) failure

These mechanisms are discussed for each type of transformer in the following paragraphs. Insulation system aging mechanisms are discussed in Section 4.2.1.4 below.

Liquid-Immersed Transformer Windings

Degradation of organic insulating materials in liquid-immersed transformers occurs as a result of several influences, including exposure to heat, chemicals in the insulating fluid, as well as dielectric stress. Insulation systems in these transformers consist of both solid and liquid materials, each being susceptible to somewhat different aging mechanisms (see Section 4.2.1.3 below). Protective coatings on the windings themselves are subject to thermal degradation due to heating of the windings; these coatings, however, generally have no insulating function and are therefore not necessary for maintenance of the necessary dielectric strength between individual turns of the windings.

Localized high temperatures may occur in transformer windings as a result of poor insulating fluid flow (which acts to cool the windings) and high resistance areas of the winding due to sharp bends, variations in conductor diameter, or improperly made connections. These "hot spots" may have temperatures significantly above the average of the overall winding, and may induce accelerated degradation of surrounding organic materials. Poor insulating (cooling) fluid flow is generally the result of loss of separation between windings, either due to clogging by impurities (such as sludge formed by exposure of the fluid to oxygen), or physical movement

of the winding or supports. High resistance portions of the winding related to variations in conductor diameter are rare in that design of the winding is such as to minimize these effects. However, high resistance connections between windings and leads have been documented.

Loosening of winding mounting system can result from shipping of the transformer, normal operation (vibration), fault-related movement, or maintenance. Materials used to support the windings and core may degrade with time (many are fabricated from solid insulating materials) or loosen thereby allowing movement of the windings in relation to one another or the core under inrush or fault conditions. Core-to-winding and winding-to-winding tolerances are critical to maintaining satisfactory dielectric strength, therefore movement of these components with respect to each other can result in dielectric breakdown and localized discharge.

Although not a specific aging mechanism per se, conductor damage will potentially result in the loss of transformer function. Failure of the winding conductor is generally the result of either a pre-existing manufacturing flaw in the winding, a poorly made electrical connection (such as a braze or crimp), or a severe electrical transient which results from either an internal or external stimulus (such as loss of conductor tolerances described above, or exposure to short-duration transients or surges). Short-duration voltage transients will not affect the windings uniformly. Initially, current will flow preferentially through the shunt capacitance near the line-end of the winding; this produces a substantial voltage drop in these portions of the winding. Additionally, oscillations occur in the windings which affect various portions of the winding and insulation system based on their frequency and characteristics. In general, liquid transformers are more able to withstand severe electrical transients (such as lightning strikes and surge impulse voltages) than their dry-type counterparts (discussed below); this is primarily due to the physical properties of the immersion fluid (as opposed to the insulating medium used in dry transformers).

Dry-Type Transformer Windings

Failure mechanisms for dry-type transformer windings are similar to those for the liquid-immersed units described above, with the exception that the windings are not cooled by insulating fluid; rather, these transformers use air/gas (either forced or natural circulation) or a solid insulating material (such as resin) to dissipate heat generated in the windings. Similar to liquid-immersed units, these transformers may suffer degradation of the winding insulation (and coating, if used) due to thermal degradation induced by the windings and the lack of cooling. Air passages may become plugged with dirt or other contaminants, thereby creating hot spots and their resulting high temperatures. Resin-encapsulated or other sealed windings generally are not subject to this type of degradation, as there are no air passages to become obstructed by foreign materials.

In addition to obstruction of air passages, reductions in the spacing between windings (such as those resulting from movement of the winding due to fault currents, vibration, etc.) can occur and elevate the dielectric stress placed on the insulation present in the gap; this elevated stress in turn increases the potential for dielectric breakdown/corona discharge. A similar phenomenon may occur in resin-encapsulated transformers, where voids (bubbles) present in the resin during formation create areas of low dielectric strength, thereby allowing corona discharge and possible failure with time.

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Airborne chemical vapors (such as paint fumes, solvents, etc.) may also come in contact with the winding surfaces (coatings) and solid insulation, thereby resulting in contamination or deterioration of these substances. Contamination could result in a loss of surface insulating capabilities.

Degradation of winding conductor connections has been documented; IE Information Notice 83-37, "Transformer Failure Resulting From Degraded Internal Connection Cables," [4.12] describes a failure due to an in-rush current on a dry-type ITE 4160-/480-Vac transformer initiating major arcing in the transformer winding tap lug causing the transformer failure. The failure was attributed to improper assembly of transformer winding tap cables and long-term undiagnosed, heat-induced degradation. It was believed that the set screw, which attaches the cable to the barrel of the lug, was over-tightened during installation, which caused some of the aluminum stranded wire to break, thereby creating a high resistance joint. Arcing is thought to have started in the barrel of the lug as a result of the resistance joint. Long-term localized heating of the terminal lug over a period of time weakened and degraded the connection.

Winding loosening and misalignment has been documented; examination of several transformers experiencing sustained overload, fault, and surge conditions has indicated dislocation of the winding turns, solid insulation and spacers, and core. [4.6, 4.7]

Because the primary and secondary windings and their connections are essential to the continued operation of both liquid-immersed and dry-type transformers, the degradation mechanisms described above are considered significant.

4.2.1.3 Magnetic Core

The significant degradation mechanisms for the magnetic core are:

- loosening of the core mounting system
- core material embrittlement

Each of these may result in the inability of the transformer to perform its required function.

Loosening of the core can result from loosening of its mountings due to vibration, shock, or severe electrical transients. Impacts or shocks received during shipping or installation can cause movement of the core on its mountings. Forces induced on the core after installation during electrical transients (by virtue of the magnetic interaction of the core, the windings, any surrounding materials) can be substantial and can loosen or permanently dislocate the core from its initial position. Fault currents (on the order of 10 to 20 times the rated output current) can induce severe forces on the conductors and core, as can surges resulting from proximate lightning strikes. Wear or deterioration of the insulation once dislocation occurs may lead to sufficient insulation damage to allow electrical failure.

Core embrittlement occurs primarily in older cores as a result of the relatively high thermal exposure resulting from core and winding losses. This embrittlement can result in weakening or failure of the laminations by which individual core segments are held together,

thereby potentially creating increased eddy currents and core losses. Although spontaneous core failure due to embrittlement was not noted in any of the documentation reviewed during preparation of this AMG, instances of core embrittlement encountered during repair/refurbishment have been noted. Newer cores appear less susceptible to this phenomenon due primarily to advances in manufacturing techniques, materials science, and reduced core losses (and therefore heat generated) in the newer cores. Because the core and its integrity are essential to the operation of the transformer, core loosening and embrittlement are considered significant.

4.2.1.4 Insulation System

Liquid-Immersed Transformer Insulation

Degradation of organic insulating materials in liquid-immersed transformers occurs as a result of several influences, including exposure to heat, chemicals in the insulating fluid, as well as dielectric stress. Insulation systems in these transformers consist of both solid and liquid materials, each being susceptible to somewhat different aging mechanisms. The most significant degradation mechanisms for the insulating fluid are:

- gaseous formation/dielectric breakdown
- particulate and/or moisture contamination
- high acidity
- oxidation (sludge formation)

The primary degradation mechanisms for solid insulation used in liquid transformers are:

- thermal decomposition of organic materials
- decomposition due to dielectric stress

Due to the importance of the insulating system to the operation of the transformers, these aging mechanisms are deemed significant.

Dielectric stress is produced in the insulating fluid as a result of the potential gradient across various portions of the windings and other components. Generally, the dielectric stress placed upon a material during operation of the transformer is related to its dielectric constant; materials with lower or reduced dielectric constants will experience an elevated stress as compared to other materials with higher constants. For example, gas pockets formed in the insulating fluid are exposed to substantially more dielectric stress than the surrounding insulating fluid; this may result in partial or localized breakdown of the dielectric capacity of the material (partial discharges) which may in turn produce other deleterious effects such as the formation of additional gaseous byproducts, decomposition of the surrounding insulating fluid, and ultimate failure of the insulation system.

Gaseous by-products formed from the breakdown of insulating fluids may include both combustible and non-combustible gases such as carbon monoxide, hydrogen, ethylene, and acetylene. During normal operation, liquid-filled transformers have small concentrations of these and other gases (especially if an inert gas pressurization system is used) dissolved in the insulating fluid. The transformer may experience no adverse effects under these conditions;

however, cooling of the transformer may result in a substantially lower pressure in the tank which may in turn allow additional gas in the insulating fluid to come out of solution, potentially forming pockets of low dielectric strength bubbles in the fluid. It should be noted that for liquid transformers equipped with inert gas systems, the formation of gas bubbles or pockets during cooldown is mitigated through the pressurization of the void space above the insulating fluid with inert gas.

Particulates, contaminants, and moisture introduced into the insulating fluid can result in a number of different effects. Particulates or contaminants entrained in the fluid will eventually be circulated through the winding interstitial regions; this may result in blockage of these passages leading to reduced localized heat dissipation or hot spots. Chemical contaminants in the insulating fluid may have adverse effects on the material properties (such as pH, viscosity, etc.) of the fluid which can in turn result in other adverse effects on transformer components over the long term. Water is especially damaging to the dielectric capability of the insulating fluid; any appreciable concentration may result in failure of the transformer during operation due to dielectric breakdown as described above. Transformer fluids (such as mineral oil) normally can maintain a small amount of water in solution (usually less than 10 ppm at 70°C [158°F]); at these levels there is little if any appreciable effect on the dielectric strength of the insulating fluid. However, increases in the amount of water in the fluid, whether in solution (by virtue of other substances in the fluid such as acids which increase the solubility of water in the fluid) or coalesced in pockets, may dramatically reduce the dielectric strength of the insulating system and result in partial discharge or complete dielectric breakdown.

High acidity in the insulating fluid can have a number of damaging consequences. As indicated above, the acidity of the fluid can affect its ability to maintain water in solution; higher acidity generally equates to more water capable of being held in solution and therefore reduced dielectric strength. High acidity also can affect the deterioration and decomposition of solid insulating materials used as supports and braces in liquid-immersed systems; higher acidity has been demonstrated to accelerate the rate of decomposition of various solid insulations thereby reducing their dielectric capability.

Exposure of the insulating fluid to oxygen (air) can lead to the formation of sludge (a highly viscous, tar-like substance) in the oil as a result of the chemical reaction of the oil with oxygen. This sludge can be damaging to the transformer in that it may block oil channels in the windings (creating hot spots) and reduce the efficiency of the cooling system in general. Dielectric properties associated with the sludge may also differ from those of the host insulating fluid. Various additives such as ditertiary butyl paracresol (DBPC) have been used to inhibit the formation of sludge in oil due to oxygen. Exposure to oxygen will also increase the acidity of the insulating fluid (see preceding paragraph).

Degradation of the insulating fluid in liquid-immersed transformers as described above has been extensively documented. For example, INPO SER 24-84 [4.13] describes the failure of several nuclear plant transformers resulting in fires. See Section 3.6.1 for additional details.

Dry-Type Transformer Insulation

The primary aging mechanisms for the insulation used in dry-type transformers are:

- thermal deterioration/dielectric breakdown

Depending on the configuration of the individual unit, air, inert gas, fluorogas, or resin may be used as the primary insulating substance. In addition, solid insulation used in the support or construction of the core and windings (usually fabricated from resins, mica, asbestos, etc.) and any coatings on the windings themselves (high temperature resins or enamels) will be subject to thermal degradation.

For air-insulated, air-cooled dry-type transformers, degradation of the insulation is less of a concern; free interchange of air provides the transformer with a limitless supply of new insulation. These units are, however, subject to contamination of the windings and interior surfaces with airborne dust and other contaminants entrained in the air (see Section 4.2.1.2. above). This can result in the fouling of airflow paths or closing of gaps causing localized hot spots or corona discharge sites that can result in degradation of the insulation. For sealed systems (including air, inert gas, fluorogas, and resin), the volume of insulating material is finite, and certain of these substances may be subject to thermal degradation. This is particularly true of solid resin-encapsulated transformers; the resin is in direct physical contact with the windings and core (heat source), thereby subjecting it to accelerated thermal aging. Sealed, gas-filled transformers may also develop leaks which allow escape of the insulating gas and possible intrusion of external contaminants.

Thermal deterioration of solid insulation in dry-type transformers has been documented; for example, NRC Information Notice 92-63, "Cracked Insulators in ASL Dry Type Transformers Manufactured by Westinghouse Electric Corporation," [4.14] addresses the cracking of high-voltage winding ceramic insulators on ASL Dry Type Power Center 4160/480 V 3-phase transformers manufactured by Westinghouse. IN 92-63 indicated that an insulator cracking could have a catastrophic effect on the structural integrity of the transformer. [4.1, 4.3, 4.4, 4.6, 4.7, 4.15, 4.16, 4.17, 4.18, 4.19, 4.20]

4.2.1.5 Bushings

Significant degradation mechanisms for bushings include:

- degradation of organic materials
- contamination of insulating surfaces
- deterioration/leakage of inert gas
- electrical connection loosening

Organic components used in bushings may include kraft paper condenser insulating layers (usually soaked in oil or other insulating fluid), various polymeric resins used as insulation, and rubber, asbestos, or composite gaskets used to seal the bushing against leakage or to seal the bushing against the tank. These materials may be subject to a variety of degradation mechanisms such as thermal aging, exposure to ultraviolet radiation (exposed components), exposure to

insulating fluids and other chemicals, and exposure to moisture. Kraft paper insulation is normally designed to operate while impregnated with insulating oil; improper storage or handling of the bushings prior to installation may result in drying out of the paper which can dramatically reduce its dielectric capabilities. Gaskets and seals used in the construction of the bushing may degrade over time with exposure to the elements (humidity, ultraviolet radiation, etc.) as well as heat generated by the bushing conductor, transformer, and incident solar radiation. All organic materials used in the fabrication of the bushing are subject to thermal degradation from these heat sources.

Contamination of insulating surfaces appears to be a significant degradation mechanism for transformer bushings, especially for outdoor units. External protective components such as the porcelain rain shield can accumulate significant quantities of dirt, dust, salt, and other contaminants from the environment; these contaminants, alone or in conjunction with rain, spray, or condensing humidity conditions, can result in the formation of a conductive path (tracking) along the surface of the rain shield which eventually leads to flashover of the bushing.

Depending on the construction of the bushing, it may contain insulating fluid (typically oil), inert gas, or both. Oil in the bushing is not exposed to atmosphere (air in the free space above the oil in the bushing is usually displaced with a charge of inert gas), and is generally not subject to many of the same types of degradation that transformer insulating fluid is. Therefore, unless the bushing seals are damaged, the only applicable degradation mechanisms for bushing fluid are exposure to heat and dielectric stresses. Heat is produced by the conductor (located at the bushing center), as well as from external sources (solar radiation, conduction with the transformer tank, etc.). Dielectric stress results from the potential gradient created between the central conductor and other surfaces. No degradation of the inert gas charge (other than leakage as described in the following paragraph) has been identified.

Leakage of the insulating oil and/or inert gas charge may occur as the seals of the bushing degrade, or as the result of damage or other conditions. Leakage of the insulating fluid from the bushing will eventually result in dielectric breakdown between the bushing conductor and other surfaces on the interior of the bushing. Because the bushing oil reservoir is not connected to the main tank insulating fluid, there is a finite volume of oil in each oil filled bushing. Most of these bushings, however, have some provision for periodic measurement of the oil level (either by gauge, sight glass, or direct measurement) which assists in the detection of this problem. Signs of leakage may also be detected during routine visual inspections or testing.

Additionally, leakage of the inert gas charge and subsequent depressurization of the bushing interior may expose the bushing insulating fluid to various ambient conditions (such as oxygen, moisture, and other contaminants) which may accelerate the deterioration of the fluid; this effect is expected to be small unless there is a significant interchange between the bushing internal and external environments.

Loosening or weakening of the bushing electrical connections may result from improper strain or mechanical stress. Excessive strain on the connectors can deform connecting hardware or other portions of the bushing. Under extreme circumstances, this can result in failure of the connections or damage to other bushing components.

Bushing failure has been documented in several instances; accordingly, the aging mechanisms described above are considered significant. IE Information Notice 82-53, "Main Transformer Failures at the North Anna Nuclear Power Station," [4.21] describes four bushing to ground failures and suggests that the improper storage of the bushings was a significant contributing factor. Additionally, INPO SER 13-85 [4.22] describes several transformer insulator (bushing) phase-to-ground flashovers resulting from combinations of condensation, salt accumulation, dust, and chalk powder. [4.1, 4.3, 4.4, 4.19, 4.23, 4.24]

4.2.1.6 Cooling System

Liquid-Immersed Transformer Cooling Systems

Significant aging mechanisms associated with the cooling system are:

- wear and mechanical fatigue of the pump and fan bearings (motor and pump unit)
- wear and fatigue of the pump impeller/shaft assembly
- degradation of motor winding insulation
- electrical component degradation
- fouling of heat transfer surfaces

Wear and fatigue of the bearings associated with the insulating fluid pump(s) and cooling fan(s) occur as a result of the routine operation of these components. Bearings (such as thrust and journal bearings) are commonly used on both the driven unit (i.e., pump) and the driving motor (for fans these bearings are typically part of the motor); these bearings wear over time due to friction and other stresses placed on them. Bearing longevity is determined by several factors such as the type of bearing, type and frequency of lubrication, and service conditions; wear on bearings may be accelerated by such stresses as frequent motor starting and stopping, undue vibration or transverse/longitudinal load placed on the driven unit (such as an out-of-balance fan), and inadequate or degraded lubrication. In many cases, liquid-immersed transformer oil pumps are partially or totally immersed in the insulating fluid; this assists in the reduction of friction and wear of the bearings. Fan motor bearings may require periodic lubrication, although these are often sealed units.

Wear and fatigue of the pump impeller/shaft assembly may occur after extended periods in service; this generally takes the form of loss of shaft tolerances, vane wear, or pitting, and results in reduced pump efficiency and increased noise and vibration during operation.

Organic winding insulation used in motors of this type is subject to thermal aging similar to that of the transformer insulation system described in Section 4.2.1.4 above.

A variety of different electrical devices are used in the cooling systems of transformers, including fan and pump motor contactors, thermal overload relays, thermostatic sensors and switches, general purpose relays, fuses, and control wiring. In general, the aging mechanisms applicable to each component will depend on the type of component and its operating environment. Aging mechanisms for these components are discussed in Section 4.2.1.10 below.

Another potential aging mechanism for liquid transformer cooling systems is fouling of heat transfer surfaces. Most of the larger liquid-filled units utilize some sort of radiator to dissipate heat generated in the insulating fluid; heat transfer surfaces (i.e., fins or tubes) on these components may become fouled with dirt, debris, or other materials such that either the surface is insulated or airflow around the surface is obstructed. This can be easily prevented by periodic inspection and cleaning of these components (see Section 5). [4.2, 4.4, 4.5, 4.19]

Dry-Type Transformer Cooling Systems

Aging mechanisms for dry-type transformers are:

- wear of the fan motor bearings
- degradation of fan motor winding insulation materials
- electrical component degradation

These aging mechanisms are analogous to those discussed for liquid-immersed transformers in the preceding paragraphs.

4.2.1.7 Oil Preservation and Sampling System

The aging mechanisms for the oil preservation and sampling system are:

- deterioration of organic and inorganic materials
- wear
- loss of component adjustment

The primary organic materials used in the oil and preservation systems include gaskets and seals used to maintain the leak-tight integrity of any preservation and sampling system components (such as piping, flanged connections, inert gas bottle connections, etc.), as well as the separation diaphragm or air cell (used in the modified conservator design). Exposure of these materials to elevated temperatures (such as those from the heated insulating fluid or from incident solar radiation) results in thermal degradation; this may also be exacerbated by exposure to moisture, chemical contaminants, and possibly ultraviolet radiation (exposed materials on outdoor transformers). The separation diaphragm used in conservator systems may also become permeable to gaseous diffusion with time such that it may allow appreciable exposure of the insulating fluid to oxygen and other airborne gases.

Material degradation of inorganic system components can occur due to exposure to the elements (sun, moisture, salts, etc.), normal operation, and damage from other external sources. For transformers located outdoors, exposed preservation and sampling system components such as the conservator tank, piping, and valves are susceptible to rust, corrosion, and exposure to ultraviolet radiation. Heat transferred to these components by the insulating liquid or solar radiation accelerates corrosion, as does exposure to moisture/high humidity. Additionally, paint or other protective coatings applied to these surfaces may eventually bubble, chip, or peel, exposing the underlying surface to corrosion.

Wear can occur in a number of preservation/sampling system components, including frequently operated sampling and isolation valves, fittings, and pressure regulating valves used to maintain gas pressure (inert gas design). Subcomponents susceptible to wear include valve stems, seats, and packing, as well as other mechanically operated devices or fittings. This can result in valve leakage or binding, and malfunction of the regulating valve(s).

Loss of adjustment can result in the improper operation of the inert gas pressure regulating system; generally, this system must be adjusted such that the lowest possible purge pressure (accounting for deadband and setpoint variance) does not overlap the highest possible charge pressure; this would result in rapidly emptying the inert gas supply used to pressurize the void space above the insulating fluid. Loss of the adjustment of regulating valves can result from wear of the valve internals, mechanical agitation or shock, and changes in the ambient environment. [4.1, 4.4, 4.19, 4.24]

4.2.1.8 Tap Changers

Load Tap Changers

Load tap changers are typically constructed of numerous different mechanical and electrical components such as motors, gears, contacts, contactors, relays, solid state devices, and braking assemblies. The primary aging mechanisms for tap changing devices are:

- wear of mechanical components
- deterioration/failure of electrical components
- degradation of organic insulating materials
- loss of adjustment of braking systems
- wear of main contact surfaces
- tap changer compartment leakage

Wear of tap changer mechanical components may occur as a result of normal operation as well as abnormal operation. The main power circuit components of a load tap changer components are mounted in a separate tank chamber and are immersed in insulating fluid, therefore requiring no lubrication. In some models, however, tap changer motors and other mechanical assemblies (such as the braking system) are located in a separate compartment and have greasable bearings which must be periodically lubricated in accordance with the manufacturer's requirements. Exposure of this lubricant to elevated temperatures generated by both the operation of the motor/assembly itself and external sources (such as the transformer windings) can result in the deterioration, hardening, and separation of the lubricant with time. This deterioration results in increased friction and therefore accelerated wear.

In addition to wear of the bearings and lubricated mechanisms, the braking assembly linings of the tap changer (where equipped) may also degrade with use due to friction. These linings utilize friction to accomplish braking of the mechanism, hence by design they will degrade with use. Wear due to friction is the only real degradation mechanism for these components. Brake lining materials may vary from transformer to transformer, and hence the wear characteristics may differ.

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Based on the type of braking mechanism used, loss of adjustment may occur with time such that the effectiveness of the system is impaired. Generally, braking system effectiveness can be gauged by the torque required to turn the mechanism under braked and unbraked conditions. When properly adjusted, the brake will have minimum braking torque and still provide positive braking; an optimum setting uses less than half of the design torque of the system. This gives a considerable margin for adjustment as the linings wear. As the system is operated, frictional wear of the linings, along with vibration and other mechanical stresses placed on the components, can result in a loss of this adjustment.

Wear may also occur on the main contact surfaces due to the motion of the moving contacts in relation to the stationary contacts during normal tap changer operation. This wear is generally a function of the frequency of operation of the tap changer unit and load current levels, and may be significant for transformers with numerous or repeated use of the tap changer over the course of their installed lifetime.

Degradation may occur in any organic insulating materials used in the construction of the tap changer. These will include insulation used in the motor windings, insulators surrounding or mounted to the main contacts, and materials used in related electrical components such as relays, contactors, and wiring. Normally, the primary degrading influence on these materials is heat; thermal aging of organic insulating materials can reduce their dielectric as well as mechanical properties.

Electrical devices used in the load tap changing mechanism may include switches, relays, contactors, terminal blocks, breakers or interrupting devices, fuses, minor electrical components (such as resistors and capacitors), solid state components, and wiring. Degradation and aging mechanisms associated with these components are described in Section 4.2.1.10 below; a complete discussion is contained in Reference 4.2.

4.2.1.9 Protection and Monitoring Systems

As discussed in Section 3 of this guideline, numerous protection and monitoring devices are used in power and distribution transformers; the number and type of these devices installed on any given transformer depends on the rating of the equipment as well as its plant application. For the larger liquid-filled units, most if not all of the devices described are used in one form or another. In contrast, smaller dry units may have few or no built-in protective/monitoring components. Many of the devices are only applicable to the liquid type transformer; for example, a liquid level indicator would not be found on a dry system. Although the specific characteristics of individual protection and monitoring devices change from manufacturer to manufacturer, the general operating principles are often quite similar. Hence, the degradation discussed in the following paragraphs describe generic component aging mechanisms, and therefore must be considered in light of the individual application. [4.1, 4.4, 4.5, 4.19, 4.23]

Fault Pressure Relay

As described in Section 3.4, the fault (or sudden) pressure relay is used on liquid filled transformers to detect the pressure transients associated with internal faults. These faults generate rapid increases in pressure within the tank. The significant aging mechanism for these relays is

degradation of organic seals and gaskets. Wear or failure of internal relay mechanical components (such as springs, bellows, rocker arms, etc.) and failure of relay internal electrical components (switch contacts, wiring terminations, etc.) are considered non-significant, and are discussed in Section 4.2.2 below.

Degradation of organic materials used to seal the relay (both internally and to its transformer tank mounting flange) occurs as a result of exposure to heated insulating fluid or solar radiation over long periods of time; sustained exposure to heat and/or sun will eventually embrittle and harden the gaskets such that leakage may occur. In many designs, the sensing bellows and upper relay components are isolated from the hot insulating fluid (there is essentially no flow through the upper bellows portion of the relay), thereby exposing the gaskets in these regions to lower temperatures. Many of the gasket materials are also specifically designed for extended operation in contact with transformer insulating fluids. However, constant exposure of the gasket, which seals the upper and lower chambers from one another to hot insulating fluid, may result in its eventual failure.

Pressure Relief Devices

Aging mechanisms for pressure relief devices are:

- relaxation of the compression springs
- deterioration of organic sealing gaskets

Only the latter is considered to be significant. See Section 4.2.2.4.

Degradation of the organic seals of the pressure relief device may have an impact on the operation of the transformer over the long term. Due primarily to thermal degradation, these seals may harden, embrittle, and otherwise degrade to the point where they are incapable of performing their sealing function. Under conditions where the internal tank pressure is higher than that of the ambient (such as during a fault), the contents of the transformer tank will leak outward through the degraded seal causing a loss of inert gas and possibly even insulating fluid. Given a leak, the flow of gas may be inward or outward depending on variations in atmospheric and tank pressures (tank pressure may increase upon heating of fluid from operations or solar radiation). If the leak is small, the loss of inert gas and fluid (if any) will be slow and therefore present no threat to transformer operation. However, under vacuum conditions (such as those which might be encountered in the sealed tank type systems), leakage through the seal would be inward, thereby potentially introducing contaminants (such as air, moisture, and particulates) into the transformer tank and insulating fluid. These contaminants could cause accelerated aging of the fluid and eventual dielectric breakdown as described in Section 4.2.1.4 above. Although it is expected that periodic fluid sampling would identify such contamination, the frequency of sampling may not be sufficient in all cases to mitigate the effects of substantial water or oxygen intrusion in a short period of time. For this reason, degradation of the pressure relief seals is considered significant for the sealed tank design.

Bushing Current Transformers

Bushing current transformers (BCTs) are relatively simple devices; the only significant aging mechanism applicable to these units is degradation of organic insulating materials used in the windings. By virtue of their location (normally circumferentially located around the bushing center conductor), they may be subject to somewhat elevated temperatures resulting from heat generated in the BCT windings and any heat generated by the bushing conductor (which acts as the primary winding) during operation. Cracking, hardening, and low insulation resistance may result from long-term thermal exposure. Thermal decomposition of cellulose insulation may also result in increased moisture content in the transformer fluid (coincident with increased carbon dioxide levels).

The output signal from the bushing current transformer may be used in a variety of capacities, such as protective relaying, load indication, or load simulation for hot spot temperature detectors. Bushing current transformers used in differential relay applications may induce tripping of the unit if the load current is sufficient to pick up the relay. Similarly, since temperature indicators may be used to trip the unit in the event of a high temperature signal, failure of the bushing current transformer supplying one of these temperature instruments may potentially impact the required function of the transformer. In some cases, failure of the BCT will simply remove the input used to simulate the heat under load, and therefore will be unlikely to initiate a protective action upon failure. However, this mode of failure may also provide an erroneously low hot spot temperature indication, which may mask an actual high temperature condition. In other cases, shorting of the secondary windings may increase the current output of the transformer, giving an erroneously high temperature reading and thereby potentially tripping the transformer. Based on these possible failure modes, degradation of the bushing current transformer winding insulation is considered significant.

Temperature Indicators

The significant failure mechanism postulated for the bourdon tube-type temperature indicator is failure of the hot spot heating coil element.

Failure of the hot spot heating coil element may occur as the element degrades due to exposure to temperatures generated during operation. As previously noted, output from the bushing current transformer is used to generate a temperature rise in the hot spot detector probe which is proportional to the load on the transformer. This is accomplished via current passed through the coil which surrounds the temperature sensor. The metal coil is continually exposed to elevated temperature. Repeated heating and cooling of the element due to load variation induces thermal stresses which may eventually result in open-circuit failure of the element. Accordingly, the peak temperatures to which the element is exposed as well as the magnitude and frequency of load (and therefore temperature) variation are factors which can affect the longevity of the element. It should be noted that failure of the element as described will not directly affect the required function of the transformer; no automatic protective function or trip will occur as a result of low temperature. However, because failure of the coil will produce erroneous temperature readings (low), potentially damaging temperature conditions in the transformer may be masked. Therefore, failure of the element is deemed to be significant. In the event of

suspected heater element failure, other temperature monitoring devices installed in the transformer can be used to verify the correct operation of the hot spot detector.

Fault Gas Monitor

The fault gas monitor's function is to detect concentrations of certain gases produced during fault conditions in the transformer. The monitor provides alarm, indication, and automatic protective action (in certain applications); hence, degradation or failure of the monitor may adversely impact the operation of the transformer from which it samples (see Section 3.6.2.1.1). Due to the complexity of the fault gas monitor system, numerous aging mechanisms can be postulated. Based on these considerations, no specific aging mechanism or failure mode analysis was performed for this system.

4.2.1.10 Electrical Auxillary Devices

Electrical auxiliary devices such as molded case circuit breakers, magnetic contactors, thermal overload relays, switches, terminal blocks, fuses, and wiring may be used on power and distribution transformers for a variety of functions including control of cooling system pumps and/or fans, alarm and monitoring, and load tap changer operation. The use of these components in a given transformer depends on such factors as the size and rating of the unit and its function in the plant electrical distribution system. For example, large liquid-immersed transformers can be expected to have several electrical devices to support auxiliary systems (such as cooling, tap changing, and protection/monitoring); smaller dry-type transformers, which do not have elaborate auxiliary systems, may have only a few such devices. A complete discussion of these devices is contained in the Aging Management Guideline for Motor Control Centers. [4.2]

4.2.2 Non-significant Aging Mechanisms

4.2.2.1 Fault Pressure Relay

Wear or failure of fault pressure relay mechanical components may occur as a result of continual variations in transformer tank pressure with ambient temperature and load. Small pressure fluctuations are considered normal; as a result of these fluctuations the sensing apparatus (typically a bellows) of the relay will move in response, thereby wearing the internal components. Due to the fact that the bellows and internal are immersed in viscous fluid (such as insulating fluid or silicone oil), little wear of these components is expected. Components not immersed in these fluids (such as the rocker arm assembly) could be expected to experience a greater amount of wear; however, these components are typically only actuated upon a fault pressure condition, which is extremely infrequent. Accordingly, the aging mechanism of wear of internal fault pressure relay mechanical components is considered non-significant.

Failure of the fault pressure relay internal electrical devices such as the switch may result from repetitive relay actuations; due to the extremely low number of actuations expected over the course of the unit's installed life, these failures are not significant.

4.2.2.2 No-Load Tap Changers

There are two potential aging mechanisms for the no-load tap changer mechanism;

- commutator contact surface wear
- wear of mechanical components

None of these mechanisms is considered to be significant.

In contrast to the load tap changers described above, no-load tap changers are relatively simple in design and operation. Accordingly, many of the degradation mechanisms pertinent to load tap changers are not applicable. In addition, no-load tap changers are only operated infrequently (when the transformer is de-energized) and some of its constituent components may be immersed in the transformer insulating fluid; for these reasons, little wear or degradation of the no-load tap changer mechanism or contact surfaces is expected. Contact surface and mechanism wear are therefore considered non-significant. [4.4, 4.5, 4.19]

4.2.2.3 Resistance Temperature Detectors (RTD)

Depending on the environment in which the RTD is placed and the materials of its construction, the element may be subject to corrosion of the constituent metals (Fe, Cu, etc.). Additionally, vibration or shock may damage the more sensitive varieties of RTD (such as the glass-encased platinum resistor type). Most transformer RTDs are designed with increased immunity to these types of degradations and are not considered to be susceptible to these types of failure. RTDs may be used for actuation of protective measures such as tripping; failure could therefore preclude a required transformer function. However, due to the lack of identifiable aging mechanisms, these devices are considered highly reliable and not likely to significantly degrade with time or fail. [4.4]

4.2.2.4 Pressure Relief Devices

Pressure relief devices usually consist of diaphragm and spring arrangement which automatically resets upon reduction of the tank pressure below the actuation pressure; an external indicator and alarm switch may also be included. As the device ages, the compression springs (usually maintained in partial compression) tend to relax, thereby lowering the retarding force applied to the diaphragm. This may eventually result in a reduced set pressure and premature lifting of the relief device. This type of degradation is therefore conservative, in that overpressure conditions will be mitigated, albeit at a lower pressure. Severe relaxation of the spring may lead to operation of the relief during normal pressure transients; however, such severe deterioration would be expected to have no significant effect.

4.2.2.5 Thermocouples

Thermocouples may degrade over time based on their physical properties. For example, depending on the thermocouple's age, environmental exposure, and temperature exposure, the performance and accuracy of the unit will degrade over time. Greater age and higher exposed temperature both exacerbate the degradation of the device. Additionally, the potential generated

by the junction is susceptible to several other external effects (such as temperature distribution along the connecting wires, strain, etc.). Generally, thermocouples are not used for continuous monitoring or automatic protective function initiation, therefore their aging is not considered significant to the operation of the transformer. [4.4]

4.2.2.6 Flow Indicator

Standard mechanical flow indicators are susceptible to wear of the internal moving components (such as vanes and flappers). Most transformers, however, use flow indicators on the oil systems (water cooled units, which are rarely used, may use them for indication of water flow); accordingly, these components are continuously lubricated. Additionally, not all of the flow capacity of the transformer is used at all times; hence some flow indicators may experience lower rates of wear due to the fact that the cooling loop or pump that they are monitoring is not in use. The flow indicator generally has no automatic protective function; rather, it actuates alarms or other indications for use by operations personnel. For these reasons, wear of the flow indicator is considered non-significant.

4.2.2.7 Liquid Level Indicator

Due to the relative simplicity and complete leak-tight integrity of the magnetic liquid level indicator design, no substantive aging mechanisms are postulated. Additionally, failure of the indicator would have no direct effect on the required function of the transformer.

4.2.2.9 Gas Detector

Bubble-type gas detecting devices, due to their simple designs, generally are not subject to significant degradation or aging. They are primarily employed to detect quantities of gaseous byproducts (i.e., bubbles) in the insulating fluid of liquid-immersed transformers; upon reaching a specified level, an electrical contact will close thereby actuating an alarm or warning device. There are few moving parts other than the indicator assembly and electrical switch contact (which is expected to be actuated very infrequently). No automatic protective functions are usually associated with these devices and their failure is of no direct consequence with regard to the operation of the transformer; periodic fluid and gas sampling would indicate actual problems if the gas detector failed. More sophisticated gas monitors or detectors (such as those capable of differentiating quantities of various gases present) may be used in the transformer; these are discussed in Section 4.2.1 above.

4.3 References

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5. EFFECTIVE MANAGEMENT OF AGING MECHANISMS

5.1 Listing of Generic Elements of an "Effective" Aging Management Program

Methodologies have been established by the U.S. Nuclear Regulatory Commission for determining if a plant program is effective in detecting and mitigating the effects of aging. These criteria are provided in 10 CFR 54.21 [5.1], and state that an aging management program is effective if:

1. The program is documented, its implementing procedures are approved by onsite review committees, and it is implemented in accordance with plant administrative procedures, and
2. The program ensures identification and mitigation of age-related degradation unique to license renewal for systems and components important to license renewal, and
3. The program establishes specific acceptance criteria against which the need for corrective action is to be evaluated and requires timely corrective action to be taken when the acceptance criteria are not met.

Items 2 and 3 of this methodology criteria will be applied to the maintenance and surveillance techniques and programs discussed in Sections 5.2 and 5.3 to determine if the current programs are effective in mitigating the aging of power and distribution transformers and their components (see Section 5.4).

5.2 Common Maintenance and Surveillance Techniques and Programs Used for Transformers, Including Refurbishment and Replacement

Maintenance and surveillance of transformers is performed to ensure that the characteristics or attributes essential for operation are maintained. The following activities are commonly performed during operation, maintenance and surveillance of power and distribution transformers:

- Periodic observation of temperatures and levels
- Timely investigation and resolution of alarms
- Visual inspection
- Measurement of component properties (such as dielectric strength, oil viscosity, etc.)
- Cleaning
- Adjustments
- Lubrication

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- Operability checks and testing
- Component replacement

Maintenance on transformers is either preventive or corrective in nature. Preventive maintenance is conducted based on either a given periodicity (every refueling cycle, for example) or the actual condition of the installed components (See Section 5.3.2 below). The scope of maintenance activities performed is generally a function of the periodicity of the maintenance; for example, frequent preventive maintenance (such as monthly transformer and bushing inspections) will be limited in scope as compared to maintenance conducted during a refueling outage. Obviously, de-energization of the equipment affords a much better opportunity to perform detailed examinations of many transformer components. Most plants* therefore perform more comprehensive examinations and testing of their large power and distribution transformers each refueling cycle or every few years, and sample insulating fluids either quarterly or semi-annually (or more frequently if conditions warrant). In addition to comprehensive inspection and maintenance during refueling outages, other preventive maintenance may be performed on the equipment on a more frequent basis (such as monthly or yearly) depending on the individual plant. Frequent rounds by operations personnel to observe temperatures and overall condition are also used to supplement these activities. It should be noted that most plants will rarely perform invasive internal inspections or disassemble transformers on a regular basis; these activities are usually scheduled as a result of component failure or other concern identified via the trending, fluid analysis, or thermography programs.

In contrast to the liquid-immersed units, usually only a portion (for example, one-quarter to one-third) of the dry-type transformers are examined or otherwise maintained during any given maintenance cycle. Due to the relative simplicity of the dry units as compared to the larger liquid-immersed models, maintenance of these transformers is greatly simplified. This results in a 5-8 year interval for most smaller transformers.** Some plants choose to maintain their safety-related transformers each refueling period. Most plants employ time-based maintenance schedules, due primarily to the simplicity of administering such schedules, the plant and operating conditions necessary to perform such maintenance, and the lack of component degradation/failure information necessary to justify condition-based programs. In many cases, the preventive maintenance activities (especially of safety-related transformers) coincide with the refueling outages, when transformers and their components can be removed from service with less effect on the safety and operations of the plant.

Corrective maintenance occurs on an as-needed basis, usually as a result of component failure or some other deficiency noted by way of sampling or thermography; it is performed to

* Based on a sampling of maintenance organizations and procedures associated with several different nuclear plants.

** Maintenance intervals for safety-related and non-safety-related dry-type transformers vary from plant to plant, yet generally appear to fall within the range of 4-10 years. Some plants perform maintenance on all similar type transformers at a fixed interval (for example, every 5 years), while others use a rotating schedule which examines a portion of the total population each refueling cycle.

repair an in-service failure or mitigate the effects of an incipient failure. Simple troubleshooting and repair/replacement of the faulty component is dictated in most cases.

To more comprehensively describe the maintenance and surveillance techniques commonly used to maintain transformers, vendor and utility maintenance procedures from a number of different sources were reviewed. In addition, personnel from appropriate plant maintenance organizations were contacted for additional insight on maintenance practices employed for each of the varying types of transformer. The results of these investigations follow. Common maintenance and surveillance techniques are discussed for each component. Note that certain subsections and discussions apply to specific types of transformers and components; for example, the discussion of oil preservation systems does not apply to dry-type transformers, and so forth.

5.2.1 Transformer Tank and Enclosure

The common maintenance practices currently used to maintain the tank components and fittings are visual inspection, cleaning and vacuuming, lubrication, pressure testing of tank, component replacement, and verification of the tightness of components. The visual inspection performed helps manage one of the enclosure aging mechanisms: material degradation. Visual inspection for rust/corrosion, leaks, and loose or broken parts assures the structural integrity of the enclosure by identifying degradation before it significantly weakens the metal housing components. Cleaning of the transformer structure and compartments is also performed. Mechanical fittings (such as hinges, etc.) are inspected and lubricated as necessary. Door gaskets and seals are also inspected for deterioration and signs of leakage.

Visual inspection and weld repair manage a second tank aging mechanism; metal fatigue. Cracked or broken parts and leaking seams or welds may be indicative of metal fatigue; this type of deterioration can affect tank structural and leak-tight integrity. Although metal fatigue generally cannot be prevented (except by periodic replacement of susceptible components), its effects can be mitigated through early detection and component replacement/repair. Weld repair is a common practice used on metal transformer tanks (as well as other components such as radiators and pipes) to correct cracked or broken welds; it basically involves either reforming the defective weld in place or applying a patch (usually used for large defects only). Conditions necessary to support weld repair will vary based on the location and magnitude of the crack; some welds can be repaired with the transformer filled, whereas others will require partial or complete draining of the tank.

Pressure testing of the tank enclosure may be conducted upon initial installation or upon restoration from major maintenance which may have violated tank pressure integrity. This helps manage the aging mechanisms of the gaskets and seals as well as weld fatigue and material degradation.

The final aging mechanism for the metal housing system, loss of fasteners, is managed by verification of the tightness (or torque) of anchoring and housing fasteners and replacement of lost or stripped fasteners. Verification of the tightness of components and replacement as required ensure that the enclosure components and fittings will remain tightly fastened to one another and also helps prevent leakage. [5.2, 5.3, 5.4, 5.5, 5.6, 5.7, 5.8, 5.9, 5.10, 5.11, 5.12]

5.2.2 Core

The maintenance practices related to transformer cores are the core-to-ground test (megger), and verification of core mounting system integrity and applicable tolerances.

The core-to-ground test is used in core-form transformers to check the core to ground insulation level. In most dry transformers, the core is grounded by a single strap which can be readily disconnected. In liquid units, tank entry is usually required, and core testing would be performed only at time of construction or after significant internal repairs. Low resistance readings are indicative of foreign material between the core and the tank or other problems with the core insulation system, and would require correction prior to return to service.

Verification of the core mounting system integrity helps control loosening or dislocation of the core due to non-seismic vibration during normal operation or forces generated by external electrical transients such as faults. Critical tolerances and dimensions may be checked to ensure no movement of the core or windings has occurred. However, these practices are not usually used except during periods when the core and windings are completely accessible (i.e., major corrective maintenance or scheduled internal inspections). Core loosening is not a commonly expected condition. [5.13]

5.2.3 Primary and Secondary Windings

Common surveillance and maintenance practices currently used to maintain transformer primary and secondary windings are electrical testing, visual inspection, and cleaning.

Visual inspection of the windings and surrounding insulation of dry-type transformers helps manage material degradation of the windings and insulation. Cuts, abrasions, discoloration, or cracking of the winding insulation may indicate areas of potential or existing low dielectric strength. Additionally, the ends of the windings are inspected for loose or otherwise degraded insulation and support and bracing materials and adequacy of electrical connections. In many cases, the winding turns themselves are not exposed (i.e., they are surrounded by insulating layers of paper, resin, etc.) hence visual inspection of most portions of the winding is impossible. In liquid immersed units, the windings are immersed in the insulating fluid, and thus may not generally be viewed unless the unit is drained or disassembled.

The windings of dry-type units may also be checked for rigidity and proper alignment (if accessible) with respect to one another and the core; this helps manage misalignment and loosening of the windings due to normal vibration and exposure to any electrical transients which may have stressed the winding mountings or retainers.

Electrical tests performed on the windings of both liquid and dry transformers may include evaluation of the insulation resistance, winding ratio, and insulation power factor. Insulation resistance (megger) testing is performed in the field on each winding with the other winding grounded, and from one winding to another. This test indicates the condition of the winding insulation as well as the presence of any moisture. Transformer winding ratio (or turn ratio test) is used to verify the transformation ratio of the primary to secondary windings at all tap settings. Power factor testing is used to detect insulation degradation; it measures the real

and reactive components present between the primary and secondary windings as well as each of the windings to ground. Generally speaking, a significant increase in the power factor (after correction for temperature) is indicative of substantial insulation degradation or the presence of moisture or other contamination. For most dry-type units, extensive electrical testing is only performed upon initial installation; insulation resistance testing is the primary periodic test used to verify winding condition. [5.2, 5.7, 5.13, 5.14, 5.15, 5.16, 5.17, 5.18, 5.19]

5.2.4 Insulation System

Liquid-Immersed

Common surveillance and maintenance practices currently used to monitor and maintain liquid transformer insulating fluids are sampling and analysis, purification, or replacement.

The scope of transformer insulating fluid testing generally depends on the type of fluid used as well as the size and/or functional importance of the unit being evaluated. Sampling and testing of the insulating fluid for large liquid-immersed power transformers may include tests for sludge, acidity (neutralization number), inhibitor content, combustible gas content, flash point, water content, viscosity, pour point, color, refractive index, specific optical dispersion, interfacial tension, resistivity, saponification (foaming), and corrosive sulfur content. This testing is normally conducted either quarterly, semi-annually, or after anomalous indications during operation and maintenance, or from thermographic analysis. The transformers are provided with sample valves that are used to fill special vials with insulating fluid. The fluid is then sent to either a utility or independent laboratory for evaluation. The volume of the samples is small in comparison with the transformer volume; therefore frequent makeup is not required to replace the fluid taken during sampling. Each analysis is used to detect various types of contamination or deterioration, thereby helping to identify degradation of the oil due to exposure to high winding temperatures, oxygen, dielectric stress, moisture, and contaminants. The nature of the findings derived from sampling indicates the type of problem and the most likely corrective action. For example, high moisture content could indicate in-leakage at the tank boundary. Identification and repair of the leak would be required and treatment of the fluid would be necessary. The resistance of oils to partial discharges is also commonly evaluated by tests which measure the amount of decomposition gas evolved under specified conditions.

Excessive water is especially damaging to transformer insulating fluids, as it may produce significant degradation of the dielectric strength of the insulation system. Water content (measured in parts per million) is evaluated to ensure excessive levels of water do not exist in the insulating fluid. It should also be noted, however, that some water content (generally a few ppm) is desirable in that it helps prevent embrittlement and degradation of organic materials (such as solid insulation) in contact with the insulating fluid.

Exposure of transformer fluid to oxygen or air will generally result in increased acidity and sludge formation due to oxidation. An inhibitor is normally added to the fluid to mitigate the effects of oxidation; insulating fluid inhibitor content is checked to assure adequate concentrations to assure that oxygen does not attack the fluid.

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Decomposition of certain materials (such as oil and solid insulation) during normal operation or partial discharge conditions produces both combustible and non-combustible gases such as hydrogen, methane, carbon monoxide, carbon dioxide, as well as particulate contaminants. Analysis of dissolved gases in the insulating fluid or inert gas blanket is used as an effective means of detecting this decomposition. These tests may be performed periodically (via sampling) or continuously (via an installed gas analyzer or similar instrument).

Power factor testing of the insulating fluid is also commonly conducted; this is usually performed in the field using a special test apparatus designed to hold a small sample of the fluid. This test is used to detect increases in the power factor that indicate degradation and/or decomposition of the insulating fluid.

Visual inspection of the insulating fluid may be used to identify gross levels of contamination, water, or other impurities. Samples of the fluid taken during maintenance or for analysis may be viewed directly at the transformer site or sent to a testing facility for more comprehensive testing (as described above). Water, sludge, and other impurities may be visible directly to the naked eye if present in sufficient concentrations.

Industry experience has developed a system for classification for insulating fluids based on their degree of degradation:

Group I — Oil that is satisfactory for continued use.

Group II — Oil that requires only minor reconditioning for continued use.

Group III — Oils requiring reclamation or disposal.

Group IV — Oils suitable for disposal only.

Reconditioning is defined as the removal of water and solid contaminants from the fluid. Reclamation, on the other hand, is chemical treatment or other processes to remove byproducts of fluid deterioration. Mobile systems for reconditioning transformer insulating fluid may be brought to the location of large transformers; fluid from the transformers can be circulated through a series of filters and dryers in the system, or vacuum treated to remove gas and moisture. These devices are not used on a regular basis but rather upon indication of problems or following invasive work on the unit.

Based on the results of the analyses described above, various actions may be required. For fluids which exhibit excessive levels of contaminants, water, dissolved gases, or low dielectric breakdown voltage, several techniques are available to recondition the fluid to acceptable levels. These include purification via centrifuge, use of a blotter filter press (for small quantities of particles or contaminants), and spraying of the heated fluid into a vacuum chamber to remove water and volatile acids (vacuum dehydration). In the event that the degradation is more severe, reclamation techniques may be employed. These techniques generally involve the use of Fuller's earth, a naturally occurring clay which is used for its absorbency and ability to remove acids and other contaminants from the fluid. If necessary, the fluid may also be replaced with new fluid after purging the old fluid and cleaning the interior surfaces of the tank.

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Because a large portion of the degradation occurring in liquid transformer insulating fluid is thermally induced, temperatures associated with the transformer are also monitored to ensure adequate cooling and to operation within normal parameters and to help detect transformer overloading. Sustained operation at elevated temperatures can also rapidly degrade any solid insulation used in the construction as well; therefore, temperature monitoring and control is an important element of maintenance programs.

In addition to the maintenance techniques described above, many plants trend parameters associated with the insulating fluid such as tank level, insulating fluid temperature, gas concentration, and water content. [5.2, 5.3, 5.4, 5.7, 5.13, 5.14, 5.15, 5.16, 5.20, 5.21, 5.22, 5.23, 5.24, 5.25, 5.26, 5.27]

Dry-Type Transformers

Common surveillance and maintenance practices currently used to maintain dry-type transformer insulation are visual inspection, insulation resistance testing, and cleaning.

Visual inspection of the windings is conducted similar to that for dry-type transformers described in Section 5.2.3 above.

Insulation resistance testing is conducted at some plants periodically to verify insulation resistance levels and detect the presence of gross amounts of foreign substances (such as moisture or contaminants). Normally, winding-to-winding and winding to ground readings are taken. In addition, high potential (hipot) testing may be conducted subsequent to the insulation resistance test. It should be noted that electrical testing of dry-type transformers may not be used as a means of preventive maintenance at all plants; some operators perform electrical testing only at installation or after significant maintenance activities on the transformer. This is especially true of the smaller, non-safety related dry units.

Cleaning is conducted to remove the accumulated dirt, grease, and other contaminants on the windings and insulation; dirt can impede airflow and reduce the heat transfer from the windings, and contaminants may deteriorate the surfaces of any organic insulation or coatings which they come in contact with. Air under vacuum or pressure is normally used to remove accumulated dirt and dust; this is supplemented with wiping of the windings with a dry cloth to remove grease or sludge deposits. Care must be taken in using compressed air to blow clean transformer windings. Some dusts are abrasive and forced air cleaning may incrementally erode winding insulation. [5.13, 5.14, 5.15, 5.28, 5.29, 5.30, 5.31, 5.32]

5.2.5 Bushings

Common maintenance practices currently used to maintain transformer bushings are visual inspection, power factor tests, and cleaning.

Visual inspection of the bushing detects any chipping, cracking, discoloration, or other degradation of the porcelain weather shield, as well as any leakage of the oil from the bushing. Dirt, moisture, and other contaminants (such as salt) accumulated on the weather shield can also be readily noted and removed. Electrical connections to the bushing are inspected as well to

ensure adequate connection tightness. Inspection of the bushings need not always be conducted with the transformer de-energized; plants sometimes utilize binoculars or other means of viewing the components from a safe distance.

Power factor testing of the bushing is used to detect any degradation of the bushing insulating system and oil fill. With normal capacitance, the power factor is a direct indication of the power lost in the insulation. Normal bushing power factor readings are extremely low, therefore any substantial power factor reading is indicative of contamination or deterioration of the bushing insulation. These readings are also sensitive to distortion by external influences such as moisture or dirt accumulation on the weather shield, or the connection of external parts (conductors) to the bushing; care must be exercised during power factor testing to eliminate the effects of such external influences.

Bushing oil levels are also trended to detect any leakage of the bushing over time which may not otherwise be detected by visual inspection. In certain applications, provision exists for the addition of small quantities of oil to the bushing in the event of leakage. [5.2, 5.3, 5.4, 5.13, 5.33, 5.34, 5.35, 5.36]

5.2.6 Cooling System

Common liquid-immersed transformer cooling system components include fans, pumps, heat exchangers or radiators, tank surfaces, piping, valves, thermostatically controlled switching devices, as well as temperature and vibration monitoring equipment. The maintenance practices currently used to maintain these components are visual inspection, monitoring, component adjustments, lubrication, and cleaning.

Visual inspection for physical damage, dirt, corrosion, leakage, or other degradation is conducted both during scheduled maintenance and during normal operation. Air passages (radiator fins) on oil coolers are examined to ensure they are clear and free from dirt which may hinder heat transfer, and to verify no leakage of insulating fluid. Fans are verified to operate properly (in the correct direction) with no excessive temperature, noise, or vibration; fan blades are also cleaned as required. Fan guards should be secure, and fan motors are periodically lubricated (if necessary). Mounting hardware is checked to ensure that the components are securely affixed to their supports. Cooling system isolation valves are inspected, and any sources of system leakage (i.e., valve packing, gasketed joints, etc.) are adjusted or repaired as necessary. Fluid pump bearing monitors may also be used to remotely detect unusual pump vibration during operation, depending on the design and type of transformer.

External surfaces of cooling system components are cleaned to remove dirt and contaminants; steam cleaning may also be used to clean dirt and accumulation from various transformer surfaces. Any exposed surfaces are painted or otherwise treated to preclude degradation due to rust or corrosion. [5.2, 5.3, 5.4, 5.13, 5.37, 5.38, 5.39, 5.40, 5.41, 5.42]

5.2.7 Oil Preservation and Sampling System

The common maintenance practices currently used to maintain transformer oil preservation and sampling system are visual inspection, component adjustment, component repair/replacement, and cleaning.

Visual inspection of fluid preservation and sampling system components such as piping, valves, conservator tanks, and desiccant systems is used to manage degradation of these components due to rust, corrosion, cracking (fatigue), and wear. Exposed components are painted as required. Joints, flanges, and valves are inspected for signs of leakage due to deteriorated gaskets or worn parts. Painting is used to control rust and corrosion of exposed materials susceptible to these forms of degradation. Conservator tank air cell diaphragms are inspected for embrittlement, cracking or leakage which may be indicative of the need for replacement. (Note: Indication of air cell deterioration may also be present in the transformer fluid analysis; fluid analysis results consistent with exposure to air may be traceable to failure of the diaphragm).

Pressure regulating valves are periodically tested for functionality and adjusted; nitrogen cylinders associated with inert gas systems are monitored and recharged/replaced when necessary. Worn regulating valve components are also replaced or the valve removed and repaired.

In addition to the measures described above, trending of preservation and sampling system parameters are often conducted; these parameters include transformer gas pressure, nitrogen bottle pressure (as applicable), and ambient temperature/pressure. [5.2, 5.3, 5.4, 5.13, 5.43, 5.44, 5.45]

5.2.8 Tap Changers

Common maintenance practices currently used to maintain transformer tap changer assemblies are visual inspection, component adjustment, fluid sampling, and cleaning. With many transformer designs, access to the tap changer components located within the enclosure (tank compartment) is usually restricted to those times when the enclosure is open for other reasons (such as corrective maintenance or scheduled internal inspection). In some cases the tap changer compartment must be filled under vacuum similar to the main tank. Electrical and mechanical tap changer components outside the tank/tap changer compartment, however, are usually readily accessible for inspection and maintenance.

Tap changer moving and fixed contacts are inspected for signs of wear. Contact surfaces of electrical components (such as relays and contactors) are inspected for signs of burning. Contact armature mechanisms are verified to operate freely. Degraded contact surfaces are polished or burnished as required and contact tolerances are re-adjusted. Tap changer brake linings are inspected for wear and adequate remaining shoe thickness; the braking mechanism is adjusted as necessary to ensure adequate brake operation (see Section 4.2.1.8 for additional information regarding brake adjustment).

Sampling of the fluid contained in the load tap changer (LTC) compartment is conducted in addition to sampling of the main tank insulating fluid; these volumes are typically separated and subject to somewhat different operating conditions. Reduced dielectric and increased power

factor are usually the primary indicators of LTC fluid deterioration. Additionally, high ethylene levels in the LTC compartment fluid is also considered an indicator of hot spots in the LTC itself.

Although not part of the tap changer mechanism, tap changer compartment pressure relief valves are also manually verified to be operable. Any screens or filters are also inspected for signs of clogging or debris which might impede pressure relief. Care must also be taken during painting to ensure the valve is not inadvertently painted shut. [5.2, 5.3, 5.4, 5.13, 5.46]

5.2.9 Protection and Monitoring Devices

Fault Pressure Relay

Common maintenance practices currently used to maintain transformer fault pressure relays are visual inspection and functional testing.

Visual inspection of the fault pressure relay is used to detect damage or degradation of relay components, seals, and gaskets, as well as leakage. Functional testing is employed to verify the operation of the relay(s) under fault pressure conditions. This functional testing generally involves connection of an external pressure test rig to various ports on the relay which allow the application of pressure to the internal bellows assembly. [5.47, 5.48]

Pressure Relief Device

Common maintenance practices currently used to maintain transformer pressure relief devices are visual inspection and functional testing.

Visual inspection helps control degradation of the relief valve seals and gaskets; these components are inspected for dirt, cracking, or other conditions which could prevent the valve from sealing properly thereby potentially allowing moisture or external contaminants to penetrate into the tank and insulating fluid. Freedom of movement of the valve diaphragm is verified to ensure the valve will operate under actual high pressure conditions. Similarly, valves are inspected for any obstructions (such as debris or paint) which could inhibit the valve from operating or relieving at design capacity.

Depending on the scope of maintenance being conducted, the relief valve(s) may even be removed from the transformer tank to allow bench testing to verify their functionality; valves may be removed (and temporarily replaced with blind flanges) or "gagged" during tank pressure testing to allow sufficient buildup of tank pressure. Care must be exercised to preclude the introduction of any contaminants into the transformer when removing, testing, or replacing the pressure relief device. [5.13, 5.49]

Bushing Current Transformers

The maintenance techniques noted for bushing current transformers are visual inspection of the exterior of the bushing for signs of insulation cracking or other degradation, and insulation and coil resistance testing. These activities are conducted when the transformer is de-energized

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and opened for maintenance with the bushing(s) removed to allow access to the current transformers. [5.50]

Temperature Indicators, Liquid Level Indicator, and Gas Detector Relay

No maintenance techniques (other than periodic verification of instrument calibration and functionality) were noted for RTDs, thermocouples, or bourdon-tube type temperature detectors. [5.19, 5.26, 5.51, 5.52, 5.53, 5.54]

Fault Gas Monitor

Due to the complexity of the typical fault gas monitoring system and the relative infrequency of use in nuclear plant liquid-immersed transformers, maintenance techniques applied to these units were not considered as part of this AMG.

Electrical Components

Maintenance techniques applied to electrical components used in transformer auxiliary systems are analogous to those described in Reference 5.55. See Section 5 of this reference for additional information.

5.3 Other Common Maintenance and Surveillance Techniques and Programs

Other common maintenance and surveillance techniques applied to power and distribution transformers and their components include infrared thermography, replacement, rebuilding, and upgrading. These techniques are discussed in the following sections.

5.3.1 Infrared Thermography

Infrared thermography is a maintenance and surveillance technique used to detect and evaluate component heating. All materials radiate infrared energy. The hotter the component, the more energy radiated. Infrared detectors can sense infrared radiant energy and produce electrical signals proportional to the temperature of the targeted component. The instruments use optics to gather and focus energy from the targets onto infrared detectors. Instruments are currently available that have sensitivities on the order of $\pm 0.1^{\circ}\text{C}$ [$\pm 0.2^{\circ}\text{F}$] with rapid response times. Infrared detectors are available in two basic types: spot measuring and scanning. The spot measuring devices are pointed at a target area and provide either an analog or digital indication of the temperature of the target. The scanning devices provide a pictorial representation of the temperature of the area under observation. Variations in intensity or color of the image indicate the relative temperature. Some systems provide capability to store images for comparison to subsequent measurements or evaluation at a later time. Reference 5.56 provides a detailed description of the systems. The advantage of infrared thermography for use on power and distribution transformers is that temperatures can be observed and evaluated while the equipment is energized.

For transformers, spot measuring devices would be of limited use because manual scanning of components and tedious recording of individual component temperatures would be

required. Scanning systems with recording capability are much easier to use because an area or component with elevated temperature can be readily compared to surrounding components and sections of the system to determine what is causing the increased temperature. If thermographic scans were performed previously, comparisons can be made and variations in thermal images can be evaluated to determine if these hotter areas are developing or changing. In transformers, abnormally hot electrical connections, bushings, and cooling system components could be indicative of problems either within the individual component or the transformer itself. For example, an excessively hot bushing might indicate a crimped, damaged or corroded internal electrical connection that could cause overheating leading to further damage or failure. Identifying such high temperature components could allow correction of the condition before significant damage occurred. At a minimum, more frequent observation could be performed of the suspect component to determine if the condition is stable or worsening.

Although infrared thermography is a valuable tool for evaluating the condition of components, it is not a panacea and should be used in conjunction with other techniques. Many aging mechanisms do not produce significant amounts of heat and may not be easily identified from thermal scans. For example, localized hot spots deep in the windings of the transformer would not be observable on the tank surface, but could be identified by fluid/gas analysis. Also, use of thermography requires a skilled operator who understands the technique, the materials being evaluated, and the equipment under observation. Distance from the target and the target's emittance, reflectance, orientation, and size all affect the thermal image. For example, a shiny surface will reflect infrared radiation from other areas, which can substantially affect results. Therefore, interpretation of results may require considerable skill or the operator may have to modify the target by covering it with a non-reflective material. If thermography is performed while a transformer is loaded in a manner other than normal (e.g., major loads out of service), the resulting evaluation may not indicate actual problems. Therefore, the operating status of the transformer needs to be considered when comparing and evaluating results.

Knowledge of thermography techniques, the types of aging mechanisms that could be indicated by heating, and combining thermography with other proven techniques such as visual inspection would make thermography a valuable tool for evaluating transformer condition. [5.56]

5.3.2 Replacement, Rebuilding, and Upgrade

Replacement, rebuilding, and upgrading are three alternative maintenance techniques that may be used to manage transformer aging. These techniques are described below.

Replacement

Replacement is used to control transformer aging in two primary situations; (1) individual component degradation or failure, and (2) catastrophic failure requiring replacement of the entire transformer. Replacement of individual components (such as pumps and fan motors) may be used when significant degradation or failure of those components occurs. Unit replacement, on the other hand, generally results from a major fault or explosion within the transformer; these failures are characterized by extensive damage to both the structure and components of the unit. Methods of dealing with each of these types of failures are described in the following paragraphs.

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Non-catastrophic failure of transformer components occurs with substantially higher frequency in all classes of equipment as compared to catastrophic failure. In many cases, minor transformer components (such as fan motors, gaskets, seals, bushings, and small electrical components) which have failed are simply replaced as opposed to being repaired. This is due to a number of factors including the expense of replacement versus repair, the amenability of certain components to being repaired (i.e., relays and other components may be sealed thereby precluding maintenance or repair), and the importance of the required function provided by the component to the safe operation of the transformer. Critical components (such as the fault pressure relay) upon whose proper operation depend the functionality or safety of the transformer will likely be replaced in the event of malfunction or degradation, or may even be replaced periodically as a preventive measure. Other larger or longer-lived components (such as the tank and piping systems) will usually be repaired as necessary and therefore may be used throughout the life of the unit.

Due to the variety of different functions and operating conditions for components within a given transformer, degradation of components generally occurs at differing rates. For example, whereas a cooling pump may last the life of the transformer, a fan motor contactor may experience a substantial number of cycles over a certain period of time; accordingly, the contactor may fail more frequently than the pump. Components are therefore continually replaced throughout the life of the transformer based on their individual operating conditions and limitations. For many components (such as cooling fans and pumps), sufficient redundancy exists such that failure of one of these components can be tolerated with little or no adverse effect on transformer operation; replacement of the component is conducted after failure. Other components, however, either do not have sufficient redundancy or are of such importance to the operation of the transformer that their failure can not be tolerated. Components in this category include bushings and windings. Hence for these components, replacement or repair prior to failure is essential to ensure continued operation and limit the possibility of catastrophic failure.

In the event that the transformer suffers a catastrophic failure which heavily damages or destroys one or more major components of the unit (such as the tank, core, or windings), complete replacement of the transformer as a whole is usually dictated. The time required to repair or rebuild the transformer and the depth of damage will determine if replacement is required. Severe damage will tend to make repairs non cost-effective. Lesser damage may indicate that the transformer should be rebuilt and used as a spare.

Rebuilding

In cases of moderate damage or reduced capability, rebuilding of the transformer may be considered. Unlike simple component replacement described above, rebuilding seeks to restore the entire transformer to its original condition. Here, extensive disassembly and component replacement are conducted; although many of the structural and auxiliary components may be retained and repaired, new components are also fitted where necessary. Generally, the decision to rebuild a unit as opposed to simply repairing it depends on three considerations; the age of the transformer, the size of the transformer, and any existing or anticipated future needs for the equipment.

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Very old transformers are usually not good candidates for rebuilding, due to their potentially high core and load losses, weakened or embrittled components, and the lack of availability of spare parts. Likewise, smaller transformers (below 5 MVA) may also prove to be cost-prohibitive to rebuild.

Upgrading

Another option available to the nuclear plant operator is transformer upgrading; this is a process by which the capability of the transformer (measured in terms of parameters such as temperature rating and load/core losses) is increased over that of its initial configuration during the rebuilding process. For example, during upgrading, the unit may be rewound with insulation rated to a higher temperature (i.e., 65°C [149°F] vs. 55°C [131°F]), windings may be replaced with larger, more efficient conductors, or the core itself may be replaced with one having substantially lower losses. Many plants rebuilding a failed transformer will also seek to upgrade to some degree; although the upgrading process is often significantly more expensive than simple rebuilding, the potential gains resulting from reduced losses and increased reliability may warrant the additional expenditure. [5.57]

5.4 Programs and Techniques Applied to Components

5.4.1 Evaluation of Current Programs

Section 5.1 lists the three criteria that determine if a maintenance program is effective in managing aging. With respect to Criterion 1, procedures from a number of power plants were reviewed. These reviews indicate that power and distribution transformer maintenance programs are documented. The maintenance of station transformers may be performed by different segments of the utility organization. The safety-related distribution transformers will be controlled by station procedures under the overview of the onsite review committee. However, the startup transformer maintenance may be controlled and performed by organizations outside of nuclear operations having experience with larger units.

With respect to Criterion 2, the maintenance procedures were reviewed to determine if they were effective in controlling and mitigating the effects of the aging mechanisms identified during the operating history review described in Section 3.6 and in Chapter 4. These procedures are described in Section 5.2. The results of this review are summarized in Table 5-1. The procedures required that inspection and maintenance activities be performed that would control each of the aging mechanisms identified in Section 4.2. The results of the operating history review described in Section 3.6 were evaluated to determine if further consideration or attention should be given to inspection and maintenance of certain components. In general, the review indicated that current maintenance programs using procedures that are consistent with Section 5.2 and Table 5-1 are effective in managing aging of power and distribution transformers. Conditions requiring plant-specific confirmation of effectiveness are described in Section 5.4.2.

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Table 5-1. Common Maintenance and Surveillance Techniques

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Metal Enclosure (Tank) and Cover(s)	Material degradation from corrosion	Visual inspection of enclosure components and hardware; cleaning of exterior and interior enclosure surfaces (where accessible); painting of rusted or corroded portions of structure		Note 1
	Deterioration of seals and gaskets	Visual inspection for embrittlement, cracking, or signs of fluid leakage; replacement as necessary		Note 1
	Metal fatigue	Visual inspection for metal cracking or deformed/broken components; leak testing of enclosure (liquid or sealed dry-type only); weld or patch repair of cracked welds or leaking joints as necessary	Pressure retention specification during pressure testing	Note 1; pressure testing/repair as required
	Loss of fastening components	Visual inspection for missing screws, nuts, washers, and other fastening components; replacement as necessary		Note 1
Primary and Secondary Windings	Degradation of organic supports and spacers	Visual inspection of spacers, supports, and other insulating materials; insulation resistance testing; power factor testing; gas and oil evaluation (liquid only)	Insulation resistance; insulating fluid power factor; insulating fluid gas content	Note 2
	Formation of localized high temperature areas (hot spots)	Monitoring of hot spot, top oil, and other temperature indications; sampling and analysis of transformer insulating fluid for indication of decomposition byproducts and gases (liquid only); purification or replacement of insulating fluid as required; cleaning of windings and insulation (dry-type)	Temperature limits on indicators, insulating fluid content limits	Note 1; sampling quarterly, semi-annually, or more frequently as required
	Loosening of winding mounting systems	Visual inspection of winding mounting system for loose or damaged components; measurement of critical winding tolerances	Winding design tolerances	Note 2
Magnetic Core	Winding (conductor) failure	Visual inspection for overheating or breaks in insulation/conductor; resistance and continuity testing	Winding resistance	Note 2
	Loosening of core mounting system	Visual inspection of core mounting; core-to-ground test; measurement of critical core/winding tolerances	Core design tolerances	Note 2

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Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Insulation System (liquid-immersed)	Dielectric breakdown of insulating fluid	Sampling and analysis for dielectric strength, power factor, water/impurity content, and combustible/non-combustible gases, as well as other analyses as applicable	Dielectric strength (breakdown voltage), power factor, water/impurity content, gas content; other criteria as applicable	Quarterly or semi-annual fluid sampling (or more frequently as required by analysis results or other indications)
	Particulate and/or moisture contamination	Visual inspection of insulating fluid for signs of impurities or water; dielectric strength and power factor testing; laboratory analysis for water content	Dielectric strength (breakdown voltage), power factor	Same as above
	High acidity	Sampling and laboratory analysis (neutralization number)	Neutralization number	Same as above
	Oxidation and sludge formation	Visual inspection of insulating fluid; laboratory analysis for sludge and inhibitor content; maintenance of seals and air-tight integrity of tank and oil preservation system components	Sludge and inhibitor content	Same as above
(dry-type)	Thermal deterioration of organic materials	Insulation resistance and power factor testing		Note 3
(liquid and dry)	Thermal deterioration of solid organic insulating materials	Load and temperature control; acidity monitoring; gas and oil evaluation; analysis of insulating fluid for decomposition byproducts; visual inspection for discoloration, cracking; insulation resistance testing	Insulating fluid gas content and acidity	Quarterly or semi-annual fluid sampling (or more frequently as required); visual inspection of solid insulation only conducted during invasive procedure
Bushings	Degradation of organic materials	Power factor and capacitance testing	Power factor, capacitance	Every refueling cycle; during other maintenance when unit de-energized (as required)

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Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Bushings (continued)	Contamination or deterioration of porcelain exterior surfaces	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning, coating, or replacement as necessary		Note 1
	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required	Bushing oil level	Note 1
	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain	Fastener torque; strain	Every refueling cycle; during other maintenance when unit de-energized (as required)
Cooling System	Wear/fatigue of the pump and fan motor bearings, shaft, and impeller	Visual inspection of fan motor, housing, and rotating assembly for loose/missing parts or other damage; inspection of pump impeller for cracking, pitting or erosion; verification of normal fan or pump operation (no vibration, abnormal noise, overheating, etc.); periodic lubrication; bearing or component replacement as required		Note 1
	Degradation of motor winding and lead insulation	Winding insulation resistance testing; replacement of motor and/or leads as required	Insulation resistance, absence of cracks in insulation of cable	As required
	Electrical auxiliary component degradation	Visual inspection and cleaning of contactor mechanisms, contact surfaces, wiring and terminations, and other minor electrical components; functionality testing; replacement as necessary	Functionality of component	As required
Fluid Preservation and Sampling System (liquid only)	Fouling of heat transfer surfaces	Visual inspection and cleaning of radiator fins, tubes, and other heat transfer surfaces; verification of adequate air or cooling water flow	Transformer temperature limits	Note 1

Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Fluid Preservation and Sampling System (continued)	Deterioration of organic and inorganic materials	Visual inspection of piping, valves, coolers, and welded seams for cracking, rust, corrosion, or other deterioration; cleaning and painting; functionality testing; replacement as required	Functionality of components	Note 1
	Wear of mechanical components	Inspection for component looseness or loss of adjustment; measurement and adjustment of component tolerances; lubrication; replacement as required		Note 1
	Loss of component adjustment	Verification of proper pressure regulating valve setpoints and operation; cleaning and adjustment as required	Maintains pressure as required	As required
Tap Changers (Load Tap Changer; liquid only)	Wear of mechanical components	Verification of component tolerances and adjustment	Component tolerance/adjustment specifications	Note 2
	Deterioration or failure of electrical components	Visual inspection and cleaning of tap changer electrical components and contact surfaces; electrical and functionality testing; replacement as necessary	Functionality of tested components; no significant degradation of contact surfaces	Note 2
	Degradation of organic insulating materials	Visual inspection of components for cracking or other loss of mechanical properties; insulation resistance testing	Insulation resistance	Note 2
	Loss of adjustment of braking systems	Visual inspection of brake linings for wear; verification of proper braking system adjustment and torque; replacement of brake linings when required	Proper brake function	Note 2
	Wear of main contact surfaces	Visual inspection of moving and stationary contact surfaces for wear or contamination; cleaning, reconditioning, or replacement as necessary		
	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level	Adequate oil level	Note 1

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Table 5-1. Common Maintenance and Surveillance Techniques (Continued)

Component	Aging Mechanisms	Maintenance and Surveillance Techniques	Acceptance Criteria	Periodicity
Fault Pressure Relay (liquid only)	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation; functional testing		Note 1; functional testing as required
Bushing Current Transformers	Degradation of organic insulating materials	Insulation inspection; insulation resistance testing	Insulation resistance	Note 1
Pressure Relief Devices (liquid and sealed dry-type only)	Degradation of seals	Periodic testing for functionality; visual inspection for seal degradation	Relief valve functionality	Note 1
Temperature Indicators	Failure of hot spot heating coil element	Periodic verification of temperature sensor functionality and accuracy	Temperature sensor functionality	As required

Notes:

1. Conducted during routine operations or during scheduled maintenance or surveillance activities; periodicity varies.
2. Not a routine maintenance item; generally accomplished only during invasive maintenance procedures requiring disassembly, draining, and/or untanking.
3. Usually performed each refueling cycle on a rotating basis for larger dry-type transformers. Smaller units may only be tested during installation or after significant maintenance.

Figure 5-1 shows failures for liquid-immersed transformers of the type considered in this AMG (i.e., excluding main and unit auxiliary transformers) for the years 1981-92. All failures relating to liquid-immersed transformers for a given year were divided by the number of plants in operation during that year to obtain the number of failures per plant per year. This rate was also calculated for that subset of failures which were detected during plant operation and which resulted in preclusion of the transformer function. As shown in the figure, the highest failure rate observed was 0.17 failures per plant per year (1985); if extrapolated, this would result in approximately one liquid transformer component failure per plant every 6 years. The projected number of failures which would preclude transformer function would be even lower, on the order of approximately one failure per plant every 11 years. Failure rates for years other than 1985 are all less than 0.082 failures per plant per year, indicating one failure per plant every 12 years or more. Additionally, the overall trend in failure rate for this equipment does not appear to be increasing.

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Figure 5-1. Liquid-Immersed Transformer* Failures by Year (NPRDS).

Figure 5-2 shows a similar analysis for dry-type transformers. Failure rates for these transformers were even lower than those noted for the liquid transformers (peak failure rates of approximately one failure per plant every 15 years, and one failure which precludes transformer function per plant every 27 years). Again, no increasing overall failure rate trend is discernable. (Note: The lower failure rates identified for the dry-type transformers may be in part related to the size of the population, which is considered to be substantially smaller than that of the liquid-immersed transformers).

It should be noted that no estimate of the population of transformers of the type covered by this AMG was made as part of this analysis; additionally, the fraction of the plant population reporting to NPRDS in a given year is not known. Therefore, the failure rate information derived above can not be relied upon as a foundation for Mean Time Between Failure (MTBF) or other similar analyses. However, even with substantial variations in the number of plants operating such equipment (or reporting associated failures), or in the fraction of actual failure events which are reported, the projected failure rate is still reasonably low. For example, increasing the number of liquid transformer failure reports by a factor of 2 (only 1 of every 2 events assumed to be reported to NPRDS) and decreasing the number of reporting plants by the same factor still only results in one liquid transformer-related failure per plant every 1.5 years and one failure which precludes transformer function per plant every 3 years.** Note also that most plants can be assumed to have more than one liquid-immersed transformer which falls within the scope of this AMG; therefore, these rates are likely to be extremely conservative.

* Does not include Main or Unit Auxiliary Transformers.

** Based on the 1985 peak failure rate(s).

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Figure 5-2. Dry-Type Transformer Failures by Year (NPRDS).

Based on the data discussed above, it is believed that maintenance practices employed during the period of evaluation were, in general, effective at managing the age-related degradation of both the liquid and dry-type transformers covered in this AMG.

Each maintenance procedure was also reviewed for compliance with Criterion 3 (which specifies the need for specific acceptance criteria and timely corrective action). Each procedure contains acceptance criteria against which the need for corrective action is to be evaluated and required timely corrective action to be taken when the acceptance criteria are not met. In Table 5-1, activities requiring tolerances and acceptance criteria to be contained in procedures are so indicated.

The review of the significant aging mechanisms versus established maintenance practices indicated that all significant aging mechanisms are considered and controlled with a limited number of potential exceptions that are discussed in Section 5.4.2. This conclusion is supported by the review of operating history that indicates few repetitive failures associated with any one specific transformer component for a given manufacturer's model line (or for all manufacturers collectively).

5.4.2 Potentially Significant Component/Aging Mechanism Combinations Not Addressed by Current Programs

Review of the aging mechanisms identified in the operational review contained in Section 3.6 and Section 4.2 in comparison with the transformer maintenance methodology verified that nearly all component/aging mechanism combinations are addressed by current programs. The following lists those cases where additional efforts appear to be necessary.

Conditions for a Fully Acceptable Program

If the transformer is located in a mild environment area (not subject to an elevated temperature/steam condition or elevated radiation levels under accident conditions), is in an area where temperatures do not exceed 40°C [104°F] for significant periods (or 30°C [86°F] average temperature for any 24-hour interval), is not subjected to abnormal electrical loading or severe transients, is not exposed to high external concentrations of dust or other contaminants, then maintenance and surveillance procedures that are consistent with those described in Section 5.2 and Table 5-1 will be effective in managing aging, with the following possible exceptions:

- **Dielectric Breakdown of Insulating Fluid.** Many of the more damaging failures (such as explosions and fires) occurred as a result of dielectric breakdown of the insulating fluid. This breakdown can be precipitated by various conditions such as moisture contamination and gaseous formation in the fluid (or accumulation of gases in the void space above the fluid), and may be detected by various types of laboratory and/or in-situ analysis.
- **Bushing Flashover.** Bushing contamination and subsequent flashover is due primarily to airborne dust and/or salt spray accumulation on exterior bushing surfaces acting in combination with rain or high humidity. Even low concentrations of dust and contaminants result in significant accumulations over time and can induce flashover when combined with moisture.
- **Thermal Deterioration of Solid Insulation.** Solid insulating components used in the construction of both liquid and dry-type transformers are subject to thermal deterioration; this deterioration is a function of the temperature to which it is exposed as well as the condition of the insulating fluid in which it is submerged (for liquid-immersed units).

As indicated above, transformers located in the following environments may* require further plant-specific activities, which are described in Section 6:

- Exposure to normal temperatures in excess of 40°C [104°F] for significant periods (or 30°C [86°F] average temperature for any 24-hour interval).
- Exposure to abnormal electrical loading conditions (such as loading in excess of nameplate kVA, unbalanced ac voltages, fault conditions, lightning-induced surges, etc.).
- Exposure to environments containing high levels of dust, dirt, or other airborne contaminants such as salt or chemical vapor.

* These activities may not be required for those transformers specifically designed for extraordinary ambient conditions (such as high temperature, dust, etc.).

5.5 References

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- 5.3 Proprietary Plant Procedure, "Maintenance Procedure for the Reserve Station Service Transformers," Revision 0, June 29, 1988.
- 5.4 Proprietary Plant Procedure, "Outdoor Transformer and Grounding Transformer PM During Refueling Outage," Revision 1, October 4, 1990.
- 5.5 General Electric Co. Instruction Book GEK-48320, "Transformer Instructions," June 1982.
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- 5.20 Proprietary Plant Procedure, "Emergency Auxiliary Transformer Service Test," Revision 0, April 4, 1991.
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6. OTHER MANAGEMENT CONSIDERATIONS

6.1 Identification of Effective Management Options to Deal with Action Items Identified in Section 5.4.2

As described in Section 5.4.2, there are several component-specific and service-related conditions that may require plant-specific activities to establish an effective aging management program for certain transformer components. These conditions and activities are described in the following subsections.

6.1.1 Component-Specific Conditions

Dielectric Breakdown of Insulating Fluid. Failure data for large liquid-immersed transformers indicate that failures were primarily detected during transformer operation, and frequently resulted in preclusion of the transformer's required function(s). Many of the more damaging, catastrophic failures (such as explosions and fires) occurred as a result of dielectric breakdown of the insulating fluid in one form or another. This breakdown can result from various conditions in the fluid, such as moisture contamination and gas formation. Generally, the breakdown can begin in small, localized portions of the fluid (such as gas or water pockets), and subsequently expand in scope until catastrophic flashover or fault occurs. During the initial stages of this phenomenon, small amounts of gas (such as hydrogen, nitrogen, and acetylene) are formed through chemical decomposition of the insulating fluid and/or impurities and distributed throughout the fluid. These gases may also be released from solution during cooldown of the transformer (due to the reduced solubility at lower temperature), thereby forming potentially flammable or explosive pockets of gas in the void space above the insulating fluid. Gas and water contamination can be detected by various types of laboratory analyses as well as in-situ fault gas monitoring and fluid sample inspection. Accordingly, periodic fluid analysis and gas monitoring coupled with trending of these parameters appear to be the most effective means of early identification of incipient degradation in large liquid-immersed transformers.

Bushing Flashover. Bushing flashover has been observed on several nuclear plant transformers. Contamination and subsequent flashover is due primarily to airborne dust, contaminant, or salt spray accumulation on exterior bushing surfaces; this accumulation provides a tracking path which, by itself or acting in combination with moisture, produces a surface current flow along the bushing insulator surface. Eventually this current flow is sufficient to flash over between the two conductors, resulting in damaging fault currents and potential loss of the transformer's required function(s). Even low concentrations of airborne contaminants can produce this phenomenon; hence, it is not strictly limited to environments with high levels of contaminants (although these environments do accelerate the process). Surface contamination (and flashover) can be avoided by periodic cleaning and inspection of the bushing insulator surface. If bushing external contamination is a problem, special coatings such as silicone grease may be used to counter these effects. Particulate matter that is deposited on the coating is enveloped by the coating thereby reestablishing the insulating properties of the bushing surface.

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Deterioration of Solid Insulation. Solid insulation is used in both liquid and dry-type power and distribution transformers to provide electrical insulation as well as structural integrity to the core and winding assembly. This insulation is typically composed of organic materials (such as paper, resins, or wood fiber) that are subject to degradation. Degradation of solid insulation results from two primary sources; exposure to heat generated within the transformer/windings (liquid and dry-type) and exposure to the insulating fluid in which the material is immersed (liquid only). Because of the integral nature of the solid insulation in the construction of the transformer, and the constant exposure of the material to the stresses described above, degradation of solid insulation proceeds essentially unimpeded during the life of the unit. However, variations in the stresses placed on the insulation can make substantial differences in its longevity. For example, exposure to insulating fluid with a constantly high acidity will accelerate the rate of deterioration, as will exposure to elevated average operating temperatures. Accordingly, careful chemistry control of the insulating fluid (by means of periodic sampling, analysis, and corrective action as required) and routine monitoring/verification of the operating temperature of the unit can make significant differences when taken over the life of the transformer.

Accordingly, operators with liquid-immersed and dry-type transformers installed at their nuclear plants should consider implementing the following actions as applicable:

1. Review and evaluate the adequacy of existing maintenance, analysis, and testing programs with relation to the manufacturer's recommendations and other industry guidance; specific care should be taken to ensure that comprehensive insulating fluid analysis and bushing cleaning are conducted with sufficient frequency so as to assure the proper condition of the fluid and bushings. Additionally, operating procedures should require checking transformer operating temperature and loading at least daily to confirm operation within prescribed limits. Large units should be equipped with appropriate alarms and these alarms should be given appropriate attention. If existing operating, testing, and maintenance procedures are not adequate, upgrade the programs as necessary.
2. If significant failures are noted for transformers or their components, conduct a comprehensive root-cause evaluation. Implement those corrective actions necessary to mitigate the effects of the identified causes.

[6.1, 6.2, 6.3, 6.4]

6.1.2 Service-Related Conditions

Transformer Exposed to Abnormal Electrical Loading. Under ANSI/IEEE STDs C57.12.00-1987 and C57.12.01-1979 [6.5, 6.6] (applicable to liquid-immersed and dry-type transformers respectively), electrical loading conditions such as loading in excess of nameplate kVA, unbalanced ac voltages, and fault conditions constitute unusual service conditions. Analysis of several significant transformer failures (such as the North Anna events) indicates that exposure of transformers to abnormal electrical loading conditions may be a significant contributing factor to the premature failure of the equipment. Conditions generated in the transformer at the time of the abnormal electrical loading (for example, gases coming out of solution from the insulating

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fluid due to rapid cooldown after a fault trip, or the reduction of critical winding tolerances due to forces generated on the windings during external faults) may create conditions which substantially increase the transformer's probability of failure. Accordingly, transformers subjected to unusual service conditions should be comprehensively evaluated immediately after the abnormal occurrence to ensure that significant damage or degradation has not occurred. This evaluation may consist of electrical testing (such as insulation impedance testing), visual inspection and/or verification of critical parameters of potentially affected components, and in-situ and laboratory analysis of insulating fluids as appropriate.

Transformer Exposed to High Ambient Temperatures. Applicable ANSI/IEEE standards specify that transformer exposure to temperatures in excess of 40°C [104°F] (or 30°C [86°F] for any 24-hour period) for extended periods are considered unusual service conditions. Sustained high temperatures may degrade insulation and other organic components (such as gaskets and seals) used in the construction of the transformer. The adequacy of maintenance and surveillance procedures to identify adverse effects on the insulation system and other organic components (such as solid insulation and gaskets) must be verified.

Transformer Exposed to High Levels of Contaminants. If the transformer is subject to environments containing high levels of dust, dirt, or other airborne contaminants (such as salt or chemical vapor), the procedures for maintenance of the transformer must be reviewed to verify that (1) any filters protecting the transformer from dust or particulates are inspected and cleaned at sufficient intervals (dry-type), (2) heat transfer surfaces (such as radiator cooling fins) are periodically inspected and cleaned to preclude fouling, (3) periodic inspection of the primary/secondary windings for signs of contamination and/or degradation and any required cleaning is conducted (dry-type), and (4) inspection and cleaning of the bushing surfaces is conducted at sufficient intervals to preclude instances of surface tracking and possible flashover (alternatively, appropriate coatings may be used).

6.2 Additional Considerations for Transformer Maintenance

Due to the substantial cost and effort associated with maintaining nuclear plant electrical equipment, extension of the interval between periodic maintenance activities is desirable. However, before such an extension can be made, a technical justification for the extension should be developed. Factors to be considered in the extension of maintenance periods include the added cost of the study and evaluation necessary to justify the extension, the benefit associated with the extension (in terms of parts/labor saved and possible increases in equipment performance), and the potential for reduced reliability and resulting equipment damage.

It is difficult to develop reliability data and a meaningful mean time between failure for electrical components of the type used in power and distribution transformers. Therefore, development of a statistically justifiable periodicity for transformer maintenance is problematic. However, several types of information related to transformer aging and failure can be evaluated, which, when taken collectively, may provide a suitable basis for the judicious extension of equipment maintenance and component replacement intervals. These factors are briefly described in the following paragraphs.

6.2.1 "As-found" Equipment Condition

An important factor in the determination of the effectiveness of existing maintenance practices is the use of component condition information derived from maintenance activities. Transformer maintenance, inspection, and testing represent important opportunities for collecting information on the actual physical condition of components. By observing and recording the conditions of various components, evaluations of the sufficiency of the current maintenance periodicity and practices can be made more precisely. For example, significant wear of a transformer component detected during maintenance may indicate that the current interval specified should not be lengthened (at least with respect to this component). Conversely, little or no evidence of wear or other degradation may indicate that an extension of the interval is acceptable. "As-found" condition data may also be useful in the determination of periodic component replacement. Information concerning the as-found condition of transformer components can be readily gathered during scheduled maintenance periods (for example, using prepared data sheets listing each significant subcomponent and the possible range of observed conditions), and can be compared with previous data for that same equipment (or data taken from other equipment of the same class) to identify trends and potential problem components.

6.2.2 Equipment Environment

Review of the historical data (contained in Section 3.6) suggests that the ambient and operating environment to which the transformer is exposed may be an important determinant in the rate of degradation of various components and the transformer as a whole. The specific environment in which the equipment operates should be characterized in terms of factors such as operational loading and duty cycles, temperature, humidity, and contaminant levels and composition; accordingly, these considerations should be factored into the determination of appropriate maintenance intervals if they present significant opportunities for component degradation. Benign environments would indicate the potential for lengthening periods. High loading or number of duty cycles, elevated temperature, or high humidity or contaminant levels would tend to indicate a shorter periodicity.

6.2.3 Plant Maintenance Organization Input

Discussions with plant maintenance personnel can provide valuable insight into the problems and deficiencies encountered with the equipment during normal operations as well as during maintenance. Although much of the relevant history of a given transformer or component may be recorded in one form or another, plant personnel familiar with the maintenance of the equipment may be aware of conditions or problems that are not readily identifiable from databases or other documentation. Unless explicit descriptions of component condition have been recorded during prior maintenance, the only method of recalling this information is through personnel actually associated with maintaining the equipment. So-called corporate knowledge of the deficiencies or better-than-expected condition of plant transformers and their components may provide additional valuable information not otherwise available to the maintenance planner as input for changing the maintenance interval.

6.2.4 Plant-Specific Failure Data

Plant-specific failure data provide important empirical information with regard to the failures actually experienced by the plant equipment. This information is especially significant as the effects of environment, maintenance practices, operations, and any other external influences are present in the failure data. To effectively use these data, it is necessary to separate those events that have caused a failure of a transformer or constituent component to fulfill its required function (or would have caused the transformer to fail had the deficiency not been detected prior to operation) from those induced by maintenance or having no real effect on the operation of the equipment. The net result of this process can be used to estimate the relative failure rate of transformers and their components and identify potentially problematic devices. The absence of a significant number of component failures may also support increasing the length of the period between maintenances. It should be noted that this type of estimate does not generally allow statistical inferences to be made due to the small population size and other limitations inherent in the data.

Another consideration when reviewing plant-specific failure data relates to the age of the equipment in question. It should be noted that this study made no attempt to correlate failure rates or performance with equipment installed age due to the limited availability of this type of information. However, some empirical evidence (derived primarily from nuclear plant operator observations) does exist to indicate that power and distribution transformers may experience higher component failure rates when the unit is either very new or very old (as opposed to when "middle aged"). This behavior may be the result of several factors relating to the initial break-in and aging of components in the transformer. If such behavior is observed, it may also be factored into any interval extension decision.

6.2.5 Conclusions

Although no one factor described above will in itself constitute a sufficient basis for extension of a maintenance interval, consideration of each of these factors may collectively provide adequate justification. Obviously, more weight should be given to those elements derived from plant-specific information (such as "as-found" condition reports) as opposed to generic industry-wide data. The more completely the aging mechanisms and failure modes of individual transformer types and their components can be described and understood, the more confidently maintenance planners will be able to determine the appropriate maintenance and replacement schedules for their equipment. Accordingly, data that are consistently recorded and specifically focused on items related to aging and degradation will be extremely beneficial in this process.

6.3 References

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APPENDIX A ACRONYMS

A	Ampere
AA	Air (self)-cooled; dry-type
AFA	Dry-type, forced air-cooled
AMG	Aging Management Guideline
ANSI	American National Standards Institute
AWS	American Welding Society
BCT	Bushing current transformer
BIL	Basic Impulse Level
BTP	Branch Technical Position (U.S. NRC)
BWR	Boiling water reactor
CFR	Code of Federal Regulations
Class 1E	Class 1 Electrical Equipment (IEEE designation for safety-related)
Cu	Copper
DBPC	Ditertiary butyl paracresol
DG (EDG)	Diesel generator (emergency)
DOE	U.S. Department of Energy
emf	Electromotive force
EPRI	Electric Power Research Institute
FA	Forced air cooling
Fe	Iron
FOA	Forced oil/air cooling
FOW	Forced oil/water cooling
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GE	General Electric
HV	High voltage
ICEA	Insulated Cable Engineers Association
IE	Inspection and Enforcement (former NRC Division)
IEEE	Institute of Electrical and Electronics Engineers

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INPO	Institute for Nuclear Power Operations
IPA	Integrated Plant Assessment
IR	Industry Report
IR	Infrared
kVA	Kilovolt-ampere
kVac	Kilovolts alternating current
kW	Kilowatts
LCO	Limiting Condition for Operation
LCM	Life Cycle Management
LER	Licensee Event Report
LTC	Load tap changer
LV	Low voltage
LWR	Light Water Reactor
MCC	Motor Control Center
MTBF	Mean time between failure
MVA	Megavolt-amperes
MVAR	Megavolt-amperes, reactive
NEMA	National Electrical Manufacturer's Association
NMAC	Nuclear Maintenance Applications Center
NPRDS	Nuclear Plant Reliability Data System
NUMARC	Nuclear Management and Resources Council
NRC	U.S. Nuclear Regulatory Commission
NSIC	Nuclear Safety Information Center
OA	Oil-immersed, self-cooled
OW	Oil-immersed, water-cooled
PCB	Polychlorinated biphenyl
PLIM	Plant Lifetime Improvement
PWR	Pressurized water reactor
RAT	Reserve auxiliary transformer
rd	Rad (unit of radiation)
RG	Regulatory Guide

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RMS	Root mean square
RTD	Resistance Temperature Detector
SCs	Structures and components
SER	Significant Event Report
SNL	Sandia National Laboratories
SQUG	Seismic Qualification Utility Group
SRP	Standard Review Plan
SSCs	Systems, structures, and components
SST	Station service transformer
Std	Standard
SWEC	Stone & Webster Engineering Corporation
UAT	Unit auxiliary transformer
UT	Unit transformer
UL	Underwriter's Laboratories
UV	Undervoltage
Vac	Volts alternating current
Vdc	Volts direct current

APPENDIX B DEFINITIONS[B.1]

accelerated aging artificial aging in which the simulation of natural aging approximates, in a short time, the aging effects of longer-term service conditions

acceptance criterion specified limit of a functional or condition indicator used to assess the ability of an SSC* to perform its design function

age (noun) time from fabrication of an SSC to a stated time

age conditioning simulation of natural aging effects in an SSC by the application of any combination of artificial and natural aging

age-related degradation synonym for **aging degradation**

aging (noun) general process in which characteristics of an SSC gradually change with time or use

aging assessment evaluation of appropriate information for determining the effects of aging on the current and future ability of SSCs to function within acceptance criteria

aging degradation aging effects that could impair the ability of an SSC to function within acceptance criteria

aging effects net changes in characteristics of an SSC that occur with time or use and are due to aging mechanisms

aging management engineering, operations, and maintenance actions to control within acceptable limits aging degradation and wearout of SSCs

aging mechanism specific process that gradually changes characteristics of an SSC with time or use

artificial aging simulation of natural aging effects on SSCs by application of stressors representing plant pre-service and service conditions, but perhaps different in intensity, duration, and manner of application

breakdown synonym for **complete failure**

characteristic property or attribute of an SSC (such as shape, dimension, weight, condition indicator, functional indicator, performance or mechanical, chemical, or electrical property)

* SSC = system, structure, or component

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combined effects net changes in characteristics of an SSC produced by two or more stressors

common cause failure two or more failures due to a single cause

common mode failure two or more failures in the same manner or mode due to a single cause

complete failure failure in which there is complete loss of function

condition the state or level of characteristics of an SSC that can affect its ability to perform a design function

condition surrounding physical state or influence that can affect an SSC

condition indicator characteristic that can be observed, measured, or trended to infer or directly indicate the current and future ability of an SSC to function within acceptance criteria

condition monitoring observation, measurement, or trending of condition or functional indicators with respect to some independent parameter (usually time or cycles) to indicate the current and future ability of an SSC to function within acceptance criteria

condition trending synonym for **condition monitoring**

corrective maintenance actions that restore, by repair, overhaul, or replacement, the capability of a failed SSC to function within acceptance criteria

degradation immediate or gradual deterioration of characteristics of an SSC that could impair its ability to function within acceptance criteria

degraded condition marginally acceptable condition of an unfailed SSC that could lead to a decision to perform planned maintenance

degraded failure failure in which a functional indicator does not meet an acceptance criterion, but design function is not completely lost

design basis conditions synonym for **design conditions**

design basis event any of the events specified in the station's safety analysis that are used to establish acceptable performance for safety-related functions of SSCs; events include anticipated transients, design basis accidents, external events, and natural phenomena

design basis event conditions service conditions produced by design basis events

design basis event stressor stressor that stems from design basis events and can produce immediate or aging degradation beyond that produced by normal stressors

design conditions specified service conditions used to establish the specifications of an SSC (generally includes margin of conservatism beyond expected service conditions)

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design life period during which an SSC is expected to function within acceptance criteria

design service conditions synonym for **design conditions**

deterioration synonym for **degradation**

diagnosis examination and evaluation of data to determine either the condition of an SSC or the causes of the condition

diagnostic evaluation synonym for **diagnosis**

environmental conditions ambient physical states surrounding an SSC

error-induced aging degradation aging degradation produced by error-induced conditions

error-induced conditions adverse pre-service or service conditions produced by design, fabrication, installation, operation, or maintenance errors

error-induced stressor stressor that stems from error-induced conditions and can produce immediate or aging degradation beyond that produced by normal stressors

failure inability or interruption of ability of an SSC to function within acceptance criteria

failure analysis systematic process of determining and documenting the mode, mechanism, causes, and root cause of failure of an SSC

failure cause circumstances during design, manufacture, test, or use that have led to failure

failure evaluation synonym for **failure analysis**

failure mechanism physical process that results in failure

failure mode the manner or state in which an SSC fails

failure modes and effects analysis systematic process for determining and documenting potential failure modes and their effects on SSCs

failure trending recording, analyzing, and extrapolating in-service failures on an SSC with respect to some independent parameter (usually time or cycles)

functional conditions influences on an SSC resulting from the performance of design functions (operation of a system or component and loading of a structure)

functional indicator condition indicator that is a direct indication of the current ability of an SSC to function within acceptance criteria

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inservice inspection methods and actions for assuring the structural and pressure-retaining integrity of safety-related nuclear power plant components in accordance with the rules of this Section [ASME Code, Section XI]

inservice life synonym for **service life**, (especially in discussions involving ASME Code Section XI)

inservice test a test to determine the operational readiness of a component or system [ASME Code, Section XI]

inspection synonym for **surveillance**

installed life period from installation to retirement of an SSC

life period from fabrication to retirement of an SSC

life assessment synonym for **aging assessment**

life cycle management synonym for **life management**

life management integration of aging management and economic planning to: (1) optimize the operation, maintenance, and useful life of SSCs; (2) maintain an acceptable level of performance and safety; and (3) maximize return on investment over the useful life of the plant

lifetime synonym for **life**

maintenance aggregate of direct and supporting actions that detect, preclude, or mitigate degradation of a functioning SSC, or restore to an acceptable level the design functions of a failed SSC

malfunction synonym for **failure**

mean time between failures arithmetic average of operating times between failures of an item [IEEE Std 100]

natural aging aging of an SSC that occurs under pre-service and service conditions, including error-induced conditions

normal aging natural aging from error-free pre-service or service conditions

normal aging degradation aging degradation produced by normal conditions

normal conditions operating conditions of a properly designed, fabricated, installed, operated and maintained SSC excluding design basis event conditions

normal operating conditions synonym for **normal conditions**

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normal stressor stressor that stems from normal conditions and can produce aging mechanisms and effects in an SSC

operating conditions service conditions, including normal and error-induced conditions, prior to the start of a design basis accident or earthquake

operating service conditions synonym for **operating conditions**

operational conditions synonym for **functional conditions**

overhaul (noun) extensive repair, refurbishment, or both

performance indicator synonym for **functional indicator**

periodic maintenance form of preventive maintenance consisting of servicing, parts replacement, surveillance, or testing at predetermined intervals of calendar time, operating time, or number of cycles

planned maintenance form of preventive maintenance consisting of refurbishment or replacement that is scheduled and performed prior to failure of an SSC

post-maintenance testing testing after maintenance to verify that maintenance was performed correctly and that the SSC can function within acceptance criteria

preconditioning synonym for **age conditioning**

predictive maintenance form of preventive maintenance performed continuously or at intervals governed by observed condition to monitor, diagnose, or trend an SSC's functional or condition indicators; results indicate current and future functional ability or the nature and schedule for planned maintenance

premature aging aging effects of an SSC that occur earlier than expected because of errors or pre-service and service conditions not considered explicitly in design

pre-service conditions actual physical states or influences on an SSC prior to initial operation (e.g., fabrication, storage, transportation, installation, and pre-operational testing)

preventive maintenance actions that detect, preclude, or mitigate degradation of a functional SSC to sustain or extend its useful life by controlling degradation and failures to an acceptable level; there are three types of preventive maintenance: periodic, predictive, and planned.

qualified life period for which an SSC has been demonstrated, through testing, analysis, or experience, to be capable of functioning within acceptance criteria during specified operating conditions while retaining the ability to perform its safety functions in a design basis accident or earthquake

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random failure any failure whose cause or mechanism, or both, make its time of occurrence unpredictable [IEEE Std 100]

reconditioning synonym for **overhaul**

refurbishment planned actions to improve the condition of an unfailed SSC

remaining design life period from a stated time to planned retirement of an SSC

remaining life actual period from a stated time to retirement of an SSC

remaining service life synonym for **remaining life**

remaining useful life synonym for **remaining life**

repair actions to return a failed SSC to an acceptable condition

replacement removal of an undegraded, degraded, or failed SSC or a part thereof and installation of another in its place that can function within the original acceptance criteria

residual life synonym for **remaining life**

retirement final withdrawal from service of an SSC

rework correction of inadequately performed fabrication, installation, or maintenance

root cause fundamental reason(s) for an observed condition of an SSC that if corrected prevents recurrence of the condition

root cause analysis synonym for **failure analysis**

service conditions actual physical states or influences during the service life of an SSC, including operating conditions (normal and error-induced), design basis event conditions, and post design basis event conditions

service life actual period from initial operation to retirement of an SSC

servicing routine actions (including cleaning, adjustment, calibration, and replacement of consumable) that sustain or extend the useful life of an SSC

simultaneous effects combined effects from stressors acting simultaneously

stress synonym for **stressor**

stressor agent or stimulus that stems from pre-service and service conditions and can produce immediate or aging degradation of an SSC

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surveillance observation or measurement of condition or functional indicators to verify that an SSC currently can function within acceptance criteria

surveillance requirements test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within the safety limits, and that the limiting conditions of operation will be met [10 CFR 50.36] (for use only when specific regulatory and legal connotations are called for)

surveillance testing synonym for **surveillance**, **surveillance requirements**, and **testing** (use only when specific regulatory and legal connotations are called for)

synergistic effects portion of changes in characteristics of an SSC produced solely by the interaction of stressors acting simultaneously, as distinguished from changes produced by superposition from each stressor acting independently

testing observation or measurement of condition indicators under controlled conditions to verify that an SSC currently conforms to acceptance criteria

time in service time from initial operation of an SSC to a stated time

useful life synonym for **service life**

wearout failure produced by an aging mechanism

References

- B.1 EPRI TR-100844, "Nuclear Power Plant Common Aging Terminology," prepared by MPR Associates, Inc., November 1992.

APPENDIX C

DOCUMENTS NOT RELATED TO EQUIPMENT AGING

Table C-1 lists NRC Information Bulletins, Circulars, and Notices, and other non-NRC documents that were determined to be unrelated to aging degradation of power and distribution transformers. A justification for designating these Bulletins, Circulars, Notices, etc., as unrelated to transformer aging degradation is provided.

Table C-1. NRC Bulletins, Circulars, and Notices and Other Documents Not Related to Transformer Aging Degradation

Document/Title/Date	Justification
INPO SER 29-87, "Loss of Offsite Power from Transformer Deluge," October 22, 1987	Non-age-related degradation of deluge system
NRC IE Information Notice 86-87, "Loss of Offsite Power Upon an Automatic Bus Transfer," October 10, 1986	Direct-current saturation during loading
INPO SER 47-85, "Loss of Offsite Power," October 25, 1985	Design error
NRC Information Notice 84-84, "Deficiencies in Ferro-Resonant Transformers," November 27, 1984	Ferro-resonant transformers not within scope of this guideline
NRC IE Bulletin 79-23, "Potential Failure of Emergency Diesel Generator Field Exciter Transformer," September 12, 1979	Design error; EDG transformers not within scope of this guideline

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