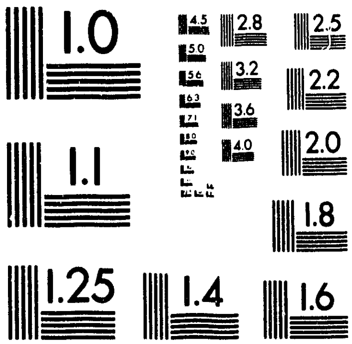
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AGING MANAGEMENT GUIDELINE FOR COMMERCIAL NUCLEAR POWER PLANTS-ELECTRICAL SWITCHGEAR

FINAL REPORT

Prepared by:

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

Authors:

Gary Toman, Robert Gazdzinski and Kimberly Schuler

Under Contract to:

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

Project Managers:

Roger Hill and James Nakos

Abstract

This Aging Management Guideline (AMG) provides recommended methods for effective detection and mitigation of age-related degradation mechanisms in BWR and PWR commercial nuclear power plant electrical switchgear important to license renewal. 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.

Acknowledgments

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AGING MANAGEMENT GUIDELINE FOR ELECTRICAL SWITCHGEAR

1. EXECUTIVE SUMMARY

1.1 Purpose and Objective

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 components important to license renewal either do not age or will not age 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 such that proper function is assured.

The purpose of this Aging Management Guideline (AMG) is to provide effective aging management during both the current licensing period and the license renewal period for medium- and low-voltage electrical switchgear used in safety-related and non-safety-related applications in nuclear power plants. For the purposes of this guideline, medium-voltage switchgear is defined as switchgear with nominal voltage ratings between 13.8-kVac and 4.16-kVac. Low-voltage switchgear is that with a nominal voltage rating between 600-Vac and 460-Vac, or between 250-Vdc and 125-Vdc. An effective aging management program will ensure that switchgear will continue to perform its function or will not prevent 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 degradation mechanisms for medium- and low-voltage electrical switchgear and to provide acceptable guidelines for developing aging management programs for controlling significant degradation 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 the electrical switchgear is in place.

1.2 Scope

Electrical switchgear consist of switching and interrupting devices used to control and protect various types of electrical apparatus and circuits. The switchgear covered by this guideline are metal-clad; molded case circuit breakers are not within the scope of this guideline because of their significant differences from circuit breakers used in metal-clad switchgear. Additional information on molded case circuit breakers (specifically those used in motor control center applications) may be found in the Aging Management Guideline for Motor Control Centers.

Metal-clad switchgear important to license renewal are addressed by this report. The group of switchgear that is important to license renewal includes more equipment than just safety-related switchgear. 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 switchgear 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 switchgear is discussed in Section 3.1. Although the types of switchgear contained in the grouping "important to license renewal" that are not safety-related are essentially the same as safety-related switchgear, they may not have been maintained in the same manner as the safety-related switchgear. Therefore, utilities may choose to extend their maintenance practices used on safety-related switchgear to the additional switchgear 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 switchgear that are contained within the grouping of switchgear important to license renewal are:

- 13-kVac (some plants)
- 4-kVac (most plants; some use 5-kVac or 6.9-kVac)
- 480-Vac
- 250- and 125-Vdc*

The power and control cables connected to switchgear and protective relays used in the electrical switchgear are not included within the scope of this document. The switchgear housings, buswork, secondary and primary disconnects, racking systems, and drawout circuit breakers are within the scope of this document.

1.3 Conclusions of This Study

This study evaluated the stresses acting on switchgear components, the industry data on aging and failure of switchgear components, and the maintenance activities performed on switchgear. The study evaluated the main subsystems within the switchgear, including the housing; buses; primary and secondary disconnects; the circuit breaker operating mechanisms, main and arcing contacts, trip and close latches, and charging mechanisms; and the racking or levering mechanism. The potential aging mechanisms resulting from environmental and operating stresses on switchgear 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 actually experienced aging mechanisms are being identified and managed. Where an aging mechanism was properly managed, the procedures were deemed to be

* The 13- and 4-kVac, 480-Vac, and 125-Vdc designations will be used through the remainder of this document even though some plants use systems with slightly different nominal voltages.

"effective." Where an aging mechanism was not fully managed or not considered, additional plant-specific activities to manage the aging mechanism were identified.

Specific recommendations concerning inspection frequencies and mean time between failure of components of electrical switchgear were not possible because of limitations in the data used. The data were not sufficiently detailed or comprehensive enough to provide confident recommendations. As a result, Section 5 only provides a range of recommended inspection frequencies for electrical switchgear.

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

Evaluation of the components of the switchgear, the stressors acting upon the components, and the operational history data indicates that nearly all switchgear components have 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. The following list provides a summary of the components and aging mechanisms, coupled with the maintenance and surveillance technique that manages the aging mechanism. A full tabulation of components, aging mechanisms and maintenance techniques is provided in Table 5-1. Information on inspection frequencies is provided in Section 5.2 and other locations in Section 5. Appendix A provides definitions of the terminology used throughout the report.

Component	Aging Mechanism	Maintenance and Surveillance Technique
Metal Housing System	Material degradation	Visual inspection for rust, corrosion, and loose or damaged fasteners or cracked welds; cleaning, painting, and preservation of housing and associated hardware
Primary Insulation	Loss of electrical properties	Visual inspection for embrittlement and cracking; insulation resistance and hi-potential testing; inspection of connections for tightness and signs of overheating
Racking Mechanisms	Wear of tracks, levering system, and racking gear	Cleaning of mechanism parts; visual inspection of mechanism and hardware; lubrication; operational testing
Arcing Contacts	Contact deterioration	Cleaning of contact surfaces; visual inspection; tolerance checks and adjustments
Main Contacts	Contact deterioration and loss of tolerances (improper mating)	Cleaning of contact surfaces; visual inspection; refinishing or replacement; tolerance adjustment and lubrication as appropriate
Stored Energy Operating Mechanisms	Lubrication failures, loss of tolerances, deterioration of subcomponents	Visual inspection; verification of freedom of motion of components; measurement of contact closing times; visual inspection of puffer system; cleaning of components; inspection of components; evaluation of tolerances
	Wear of spring charging mechanisms	Cleaning of components; visual inspection of motor, ratchet system, etc. for damage and wear; continuity checks for limit switches; verification of freedom of motion of spring release armature

Component	Aging Mechanism	Maintenance and Surveillance Technique
Solenoid Operated Mechanism	Thermal damage of operating coil from prolonged energization	Visual inspection of coil; verification of freedom of motion of armature (verification of proper operation of auxiliary switches upon closure of circuit breaker)
Arc-Chute	Material degradation, dielectric breakdown	Cleaning of assembly; visual inspection for damage, burns, cracks, and contamination; measurement of dielectric strength; replacement of components as necessary
Primary Disconnects	Disconnect wear and spring relaxation	Cleaning of primary disconnects; visual inspection for wear, misalignment, and overheating; refinishing or replacement if necessary; tolerance verification; lubrication as required.
Secondary Disconnects	Spring relaxation, contact wear, disconnect damage	Cleaning of primary disconnects; visual inspection for wear, misalignment, and overheating; refinishing or replacement if necessary; tolerance verification; lubrication as required
Mechanical Interlocks	Wear, physical damage	Visual inspection of contacts and shutter position (as applicable) at each position during insertion into cubicle; verification of appropriate mechanism tolerances
Auxiliary Switch	Contact deterioration	Cleaning of contact surfaces; visual inspection for pitting, wear, and misalignment; measurement of contact resistance and continuity check
Current and Potential Transformers	Insulation failure and overheating	Inspection for tightness of connections, hardware; evidence of overheating; operational, ratio testing; cleaning
Internal Control Wiring	Loss of electrical and mechanical properties, chaffing	Inspection of insulation for cracks, chaffing, damage; inspection of terminations/connections and routing; insulation resistance measurement, cleaning
Shunt Trip Attachment	Coil deterioration, improper tolerance with trip bar	Inspection of coil/hardware for tightness; verification of freedom of movement; operational testing and adjustment/lubrication as required
Overcurrent Trip Device	Loss of calibration	Calibration; cleaning of the overcurrent trip device; inspection of the tightness of the mounting hardware and connections; verification of clearance between the trip lever and the trip bar; adjustment as required; operational testing
Undervoltage Trip Attachment	Constant coil energization, wear, and friction	Visual inspection of coil for deterioration; verification of clearances in trip mechanism; lubrication as necessary

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

1.3.2 Non-significant Component/Aging Mechanism Combinations

The review of switchgear component aging mechanisms identified a potential for structural deterioration of the metal housing of the switchgear. A review of the operational history of the switchgear identified no cases in which switchgear housing failure has occurred to date. In typical nuclear plant applications, this equipment is located in relatively cool, moisture- and contaminant-free environments (i.e., indoors) so that the presence of corrosion or other degradation mechanisms is minimized. Any instances of significant housing degradation would likely be detected during routine plant maintenance and surveillance efforts and addressed so that their continued effects would be mitigated. Based on these observations and assumptions, the conclusion that switchgear housings will not experience significant degradation during the license renewal period is warranted. Therefore, unless the switchgear (and housing) is located in high moisture/corrosive environments, structural deterioration of the metal housing is not a significant aging mechanism. In those cases where the equipment is located in such a corrosive environment, aging of the housing during both the current and license renewal terms may be significant, and must be addressed by appropriate inspection and maintenance practices. Aging mechanisms associated with switchgear housings are further discussed in Section 4.2.2.1.

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

Section 5 of this report evaluates the maintenance procedures for switchgear and concludes that switchgear 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:

- Electrical Device Management. Electrical devices (including motors, relays, and switches) appear to constitute the largest number of the failures noted; routine maintenance does not appear wholly effective at identifying degraded components prior to failure.

- Breaker Refurbishment. The effects of lubrication degradation and wear on certain components can be mitigated only by periodic or condition-based overhaul of the breaker.

- Overcurrent Trip Device. Electro-mechanical overcurrent trip devices appear to be susceptible to loss of calibration; these devices should be checked at intervals frequent enough to assure their continued proper performance.

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

- The switchgear is exposed to temperatures in excess of 104°F for extended periods. Then: The periodicity of maintenance and surveillance must be reviewed to verify that lubricants in the mechanisms have not been adversely affected by the operating temperature.

- The switchgear is required to be qualified for accident environments. Then: The maintenance requirements for aging management must be consistent with maintenance requirements driven by equipment qualification rules (such as periodic replacement of components).

- The switchgear is subject to high cycle operation (e.g., tens of cycles per year for medium-voltage switchgear, hundreds of cycles per year for low-voltage switchgear). Then: The periodicity of maintenance must be reviewed to determine if maintenance should be performed on the basis of the number of operations rather than a fixed period of time.

- The switchgear is subject to the effects of dust storms. Then: The procedures for maintenance of the switchgear must be reviewed to verify that filters protecting the switchgear from dust are changed following dust storms and that the effects of contamination of the switchgear by dust are appropriately controlled.

More detail on these issues is contained in Section 6.

Review of the operation history of plant switchgear as portrayed by Nuclear Plant Reliability Data System (NPRDS), Licensee Event Report (LER), and overhaul data indicates that additional attention may be warranted for some subcomponents of certain manufacturers' switchgear. The data indicate that certain subcomponents degrade or fail at an increased frequency with respect to other subcomponents in the same breaker type. These specific concerns are detailed in Section 6.1.8. Plant-specific review of the operating history of specific switchgear types and applications will determine if these subcomponents require heightened attention. In addition, review of existing plant maintenance procedures should be employed to verify that sufficient depth of detail exists with regard to the inspection and evaluation of these components.

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 Aging Management Guideline (AMG) evaluates electrical switchgear 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 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.

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 medium- and low-voltage electrical switchgear used in safety-related and non-safety-related applications in commercial nuclear power plants. For the purposes of this guideline, medium-voltage switchgear is defined as switchgear with nominal voltage ratings between 13.8-kVac and 4.16-kVac. Low-voltage switchgear is that with a nominal voltage rating between 600-Vac and 460-Vac, or between 250-Vdc and 125-Vdc. An effective aging management program will ensure that each switchgear 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 medium- and low-voltage electrical switchgear 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 switchgear aging evaluations and 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 electrical switchgear. It can also be used as a base document for plants developing a license renewal application.

2. The results in this AMG are based on an extensive literature search. Therefore, nuclear plant personnel can use this AMG as a primary source document for relevant information about electrical switchgear. Some of the references used include:

   - EPRI Reports
   - EPRI NMAC Reports and Maintenance Guides
   - NRC Bulletins, Information Notices, Circulars, Generic Letters and Reports
   - Code of Federal Regulations
   - Vendor Manuals
   - IEEE and ANSI Standards
   - Foreign References and 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 the guideline include:

   - Equipment design differences relevant to aging considerations
   - Equipment obsolescence as it affects aging management
   - Service environments
   - Operating and maintenance history from the INPO NPRDS and NRC LER databases

- Historical overhaul data from refurbishment facilities
- Additional operating and maintenance history from responses to plant surveys

4. Switchgear aging phenomena are described in detail. This will be useful for switchgear maintenance interval and reliability evaluations. The following topics are discussed:

   - Stressors acting on switchgear components
   - Aging mechanism identification
   - Significance of aging mechanisms using "if-then" criteria
   - Age-related degradation of switchgear components
   - Potential failure modes

5. The AMG can be an effective tool for switchgear aging management and personnel training. That is, it:

   - Identifies the need for aging management and compliance with maintenance rule requirements
   - Contains a correlation between the scope and frequency of maintenance practices and switchgear performance and rate of degradation
   - Presents information that can be used in the construction of meaningful life-cycle management charts and to improve the accuracy 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 initiation and progression of equipment aging for use in training personnel responsible for maintenance and inspection activities
   - Identifies concepts, principles, and methods for evaluating switchgear not in the scope of this guideline.

2.3 Contents of Aging Management Guideline

Electrical switchgear consists of switching and interrupting devices used to control and protect various types of electrical apparatus and power circuits. Electrical switchgear is used in various applications throughout a nuclear plant. The emergency core cooling system, the engineered safety system, and the reactor protection system are just a few of the systems that are serviced by electrical switchgear. The switchgear covered by this guideline is metal-clad;

molded case circuit breakers are not within the scope of this guideline because of significant differences from those circuit breakers used in metal-clad switchgear. Additional information on molded case circuit breakers (specifically those used in motor control center applications) can be found in the Aging Management Guideline for Motor Control Centers. The manufacturers and models of switchgear addressed in this document are summarized in Table 2-1.

Table 2-1. Switchgear Analyzed

Manufacturer	Model/Type	Voltage Range
General Electric	AK[a]	Low (600-Vac, 250-Vdc)
	AKR	Low (600-Vac, 250-Vdc)
	AKS	Low (600-Vac, 250-Vdc)
	AM	Medium (15-/4.76-kVac)
	AMH	Medium (15-/4.76-kVac)
Westinghouse	DS[b]	Low (600-Vac)
	DB[c]	Low (600-Vac, 250-Vdc)
	DH	Medium (15-/4.76-kVac)
ITE/Brown Boveri/Gould	K225[d] through K2000	Low (600-Vac, 250-Vdc)
	K600S[e] through K2000S	Low (600-Vac)
	HK	Medium (15-/4.76-kVac)

[a] General Electric AKF breakers are field discharge variants of the standard AK breaker.

[b] Westinghouse DSL breakers use integrally mounted current limiting fuses (DSL-206, 416) or drawout fuse trucks (DSL-632).

[c] Westinghouse DBF breakers are special field discharge variants of the basic DB breaker; DBL breakers are DB breakers equipped with current limiting fuses.

[d] K-Line circuit breakers are manufactured in three frame size categories: small, medium, and large. Large frame sizes (K3000 and K4000) are not addressed in this guideline. Numbers following the "K" designation indicate frame size in amperes.

[e] The "S" suffix indicates use of the Power Shield solid-state trip device; "DON" designation indicates installation of current limiting fuse assembly.

The general classifications of switchgear that are contained within the classification of switchgear important to license renewal are:

- 13-kVac (some newer plants)
- 4-kVac (most plants; some use 5-kVac or 6.9-kVac)
- 480-Vac
- 250- and 125-Vdc.*

The cables and protective relays used in the electrical switchgear are not included within the scope of this document unless they are integral parts of the switchgear.

Section 3.0 lists and describes the components evaluated, component boundaries and discusses manufacturers' design differences. It also includes a discussion of the design requirements that apply to electrical switchgear, including applicable Codes, Standards, and Regulations. Lastly, Section 3.0 includes a detailed study of the operating history of the components evaluated from LER data, NPRDS data, and from other sources.

Section 4.0 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 significant when, if allowed to continue without detection or mitigation measures, it will 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 mechanisms determined.

Section 5.0 discusses effective aging management techniques for aging mechanisms determined to be significant in Section 4.0. 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 manage the significant aging mechanisms is studied. 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 whenever possible.

Section 6.0 discusses management options to deal with action items identified in Section 5.0. Refurbishment criteria are also discussed.

* The 13- and 4-kVac, 480-Vac, and 125-Vdc designations will be used through the remainder of this document even though some plants use systems with slightly different nominal voltages.

2.4 Generic License Renewal Requirements

10 CFR 54.21 [2.2] describes the requirements for the content of technical information in the license renewal application. Section 54.21 states that a supplement to the FSAR must be prepared that contains an Integrated Plant Assessment (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.

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 unique to the license renewal period that ensures that a SSC important to license renewal will continue to perform its required function or will not prevent the performance of a required function during the period of extended operation.

The effective program must:

1. identify and mitigate age-related degradation unique to license renewal

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

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 guideline 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."[2.7] 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 guideline 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 in that these areas are plant-specific in nature and therefore must be considered on a plant-by-plant basis.

This report will evaluate switchgear with respect to the requirements of 10 CFR 54.21 and will provide a discussion of the types of switchgear important to license renewal and the age-related degradation affecting components and subcomponents of the switchgear. The following sections detail the analysis leading to the determination of age-related degradation and the means necessary to address it.

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

To determine the switchgear 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:

   (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 Part 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 medium- and low-voltage electrical switchgear 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, operating cycles, and radiation, on equipment operation were determined. The aging mechanisms associated with those stresses that cause degradation were then determined. This evaluation is contained in Section 4.1.

Second, industry-wide operating experience, particularly that reported in U.S. Nuclear Regulatory Commission (NRC) Licensee Event Reports (LERs), Information Notices, Bulletins, and Circulars and the Nuclear Plant Reliability Data System (NPRDS) data, was examined. A review of the NRC Information Notices, Bulletins, and Circulars 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 then 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 of this guideline.

Additional important information can be gained through analysis of data derived during breaker overhaul/refurbishment. These data are evaluated in detail in each volume of the EPRI NMAC circuit breaker maintenance series. [2.3, 2.4, 2.5, 2.6] The results presented in these guides 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 NPRDS and NRC documentation in conjunction with the overhaul data presented in the NMAC maintenance guides) provides a comprehensive characterization of equipment aging by using actual plant and vendor data to substantiate and refine those aging mechanisms postulated to occur due to 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 failure 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 sufficient time to have an effect 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.

To provide a basis for the discussions of stressors, aging mechanisms, and failure modes, Section 3 describes switchgear components that are in common use in the nuclear industry. Appendix A provides definitions of aging terminology used in this report.

2.7 References

2.1 10 CFR 54.3, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants - Definitions," Federal Register, Vol. 56, No. 240, pages 64976-64977, December 13, 1991.

2.2 10 CFR 54.21, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants - Contents of Application - Technical Information," Federal Register, Vol. 56, No. 240, page 64978, December 13, 1991.

2.3 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Asea Brown Boveri/Halliburton NUS Corporation, Volume 1, Part 1, Draft Report, August 1992.

2.4 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 2, Final Report, July 1992.

2.5 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 3, Final Report, December 1992.

2.6 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 4, Draft Report, September 1992.

2.7 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 switchgear that is 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 switchgear deemed safety-related is important to license renewal. This grouping would typically include safety-related 4-kVac,* 480-Vac,** and 125-Vdc*** switchgear. Paragraphs 2 and 3 of the definition of systems and components important to license renewal generally would not bring additional switchgear into the scope of important to license renewal.

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] 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."

This LCO causes the electrical distribution equipment between the offsite transmission network and the onsite Class 1E (safety-related) distribution 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 the traditional safety-related equipment grouping indicated. Figure 3-2 indicates the scope of electrical equipment important to license renewal, with the start-up transformers and the switchgear between the start-up transformers and the safety-related emergency switchgear included in the scope.

The switchgear between the start-up transformers and the safety-related buses has been traditionally considered non-safety-related. In some plants, this switchgear will be identical to the safety-related emergency switchgear. In others, it may be of a higher voltage class or of a different manufacturer. In some newer plants, this may be 13-kV switchgear with step-down transformers in place between this switchgear and the safety-related switchgear. It should be noted that inclusion of this switchgear in the scope of license renewal will add further support equipment to the scope of important to license renewal. The dc control systems for this switchgear would come within the scope of important to license renewal as would heating, ventilation, and cooling equipment for the area around the switchgear. (Note: These support

* Some plants have 5-kV or 6.9-kV medium-voltage systems instead of 4.16-kV systems.

** Some plants have 525-Vac or 625-Vac systems instead of 480-Vac systems.

*** Some plants have 250-Vdc systems in addition to or instead of 125-Vdc systems.

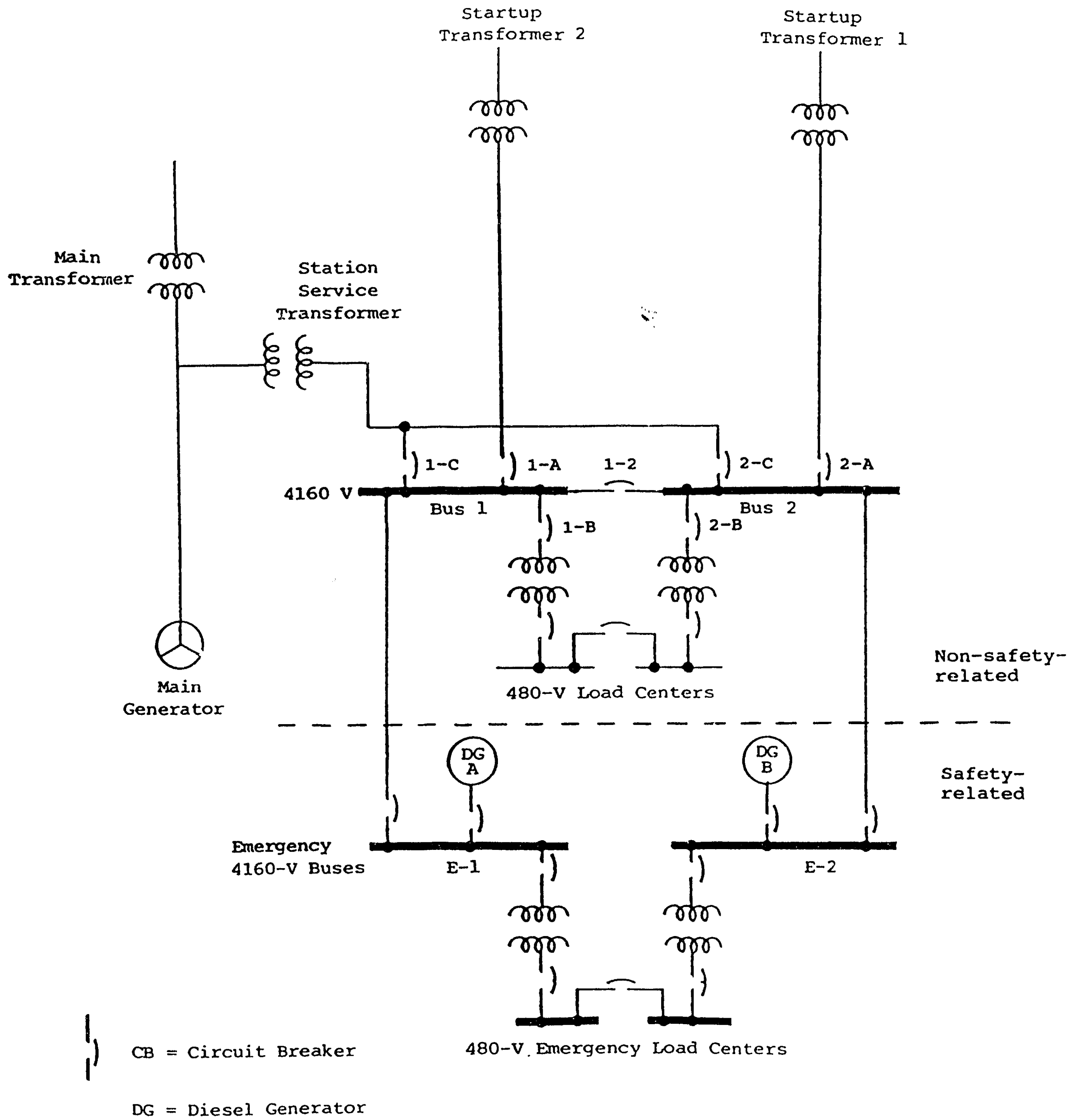


Figure 3-1. Simplified Nuclear Power Plant Electrical System.

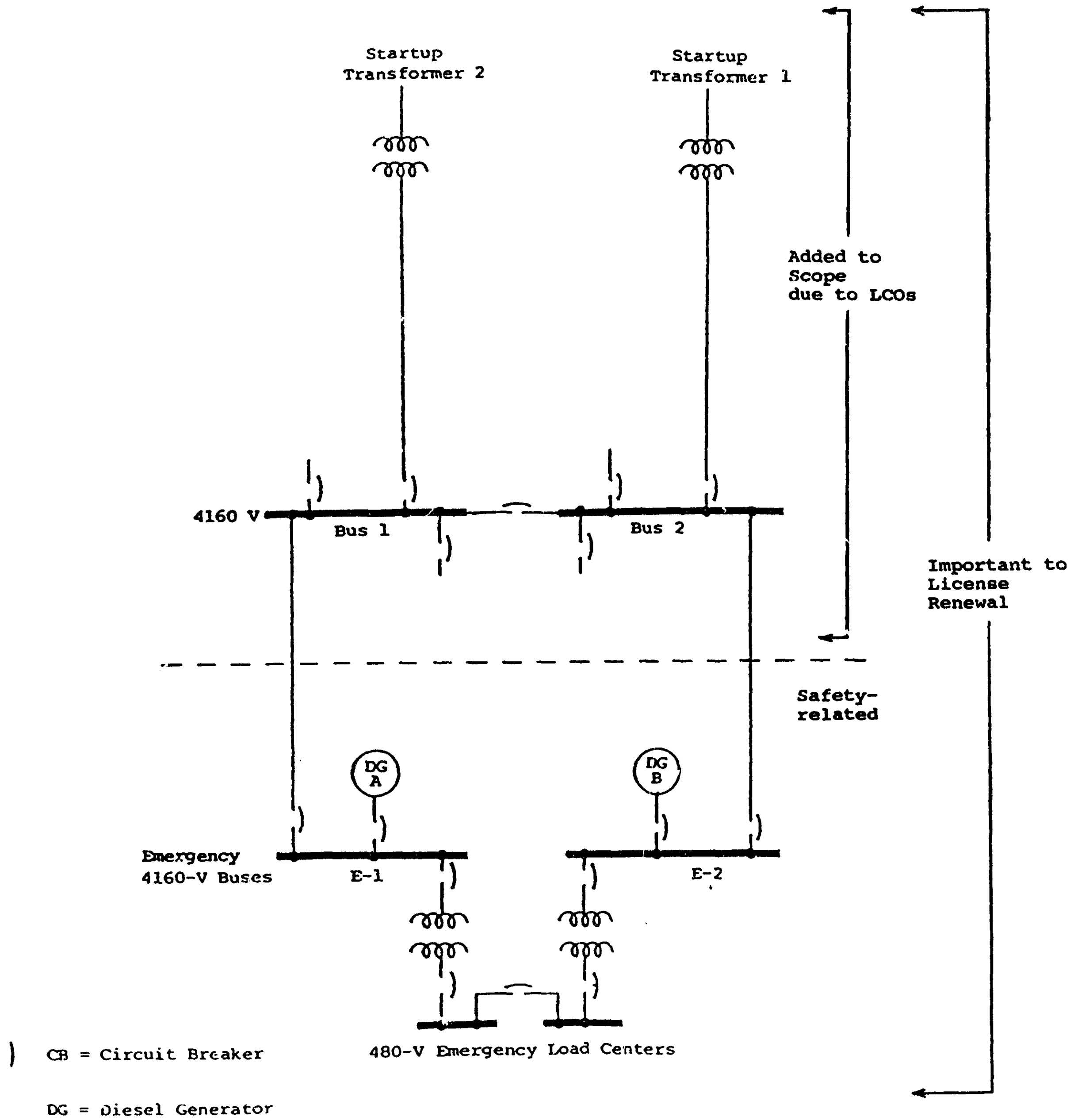


Figure 3-2. Scope of Electrical Equipment Important to License Renewal.

systems are not within the scope of this document.) The current maintenance and surveillance of these non-safety-related switchgear may be somewhat different from that of safety-related switchgear. Maintenance procedures may be less stringent or performed at a different periodicity. Therefore, a utility implementing a license renewal program will have to evaluate these differences to affirm that aging degradation is appropriately managed for these non-safety-related components that are important to license renewal.

The remainder of the LCOs in Section 3.8.1.1 of the Standard Technical Specifications cover the equipment normally classified as safety-related electrical (Class 1E) and add no further switchgear to the list of SSCs important to license renewal. However, other Technical Specifications require non-safety-related components, such as the recirculation loop equipment, to be operable. Because there are LCOs for these components, the associated switchgear would be included within the definition of important to license renewal. It is important to note that establishing that one circuit breaker on a bus is important to license renewal may cause the entire switchgear system to be important to license renewal, including all of the circuit breakers within that switchgear. For example, in Figure 3-1, non-safety-related bus 1 would be important to license renewal because it is part of the offsite feed to emergency (safety-related) bus E-1. Circuit breaker 1-A on bus 1 would be important to license renewal because it is in the direct path of the offsite source. Bus-tie circuit breaker 1-2 would also be important to license renewal because it is an alternate path for offsite power in the event that circuit breaker 1-A is open. Circuit breaker 1-B does not feed equipment covered by a Technical Specification LCO; however, failure of this circuit breaker to open because of a fault on its load or flashover of its insulation would cause loss of the entire bus and, therefore, would affect the switchgear important to license renewal. Thus, if one circuit breaker within a switchgear system is important to license renewal, the entire switchgear and its circuit breakers can be important to license renewal. It is important to note that the functions of these additional circuit breakers may be limited to "will not flashover" and "interrupt faults" so that aging management considerations can be limited. However, the additional administrative burden of treating these breakers differently, coupled with the potential for errors if the lesser aging management requirements were inadvertently applied to breakers that must retain all functions, may dictate that all breakers partially or fully important to license renewal be subject to the same aging management techniques.

Evaluation of the LCO may add more switchgear systems and circuit breakers to the list of components important to license renewal. However, in most cases, the types of switchgear and circuit breakers that are added will be the same or very similar to those in safety-related applications. More devices will be covered, but essentially the same aging management techniques will apply.

3.2 Listing of Components Evaluated

Each electrical switchgear 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 are basic to all switchgear:

Switchgear Structures and Circuit Breaker Interfaces:

Metal housing system
Bus and insulators
Primary and secondary disconnects
Circuit breaker levering (racking) mechanism

Removable Circuit Breaker:

Circuit breaker main contacts
Circuit breaker operating mechanism
Circuit breaker arc extinguishing system
Mechanical and electrical interlocks

Circuit Breaker Control:

Protective and auxiliary relays*
Auxiliary switches
Integral current and potential transformers**
Integral meters**
Internal control wiring**

All of the applicable components listed above are described further in Section 3.4. Only control wiring contained within the switchgear housing is included in the evaluation of switchgear components. The control and power cabling connecting the switchgear to other equipment is not within the scope of this document (see Section 3.3).

3.3 Component Boundaries

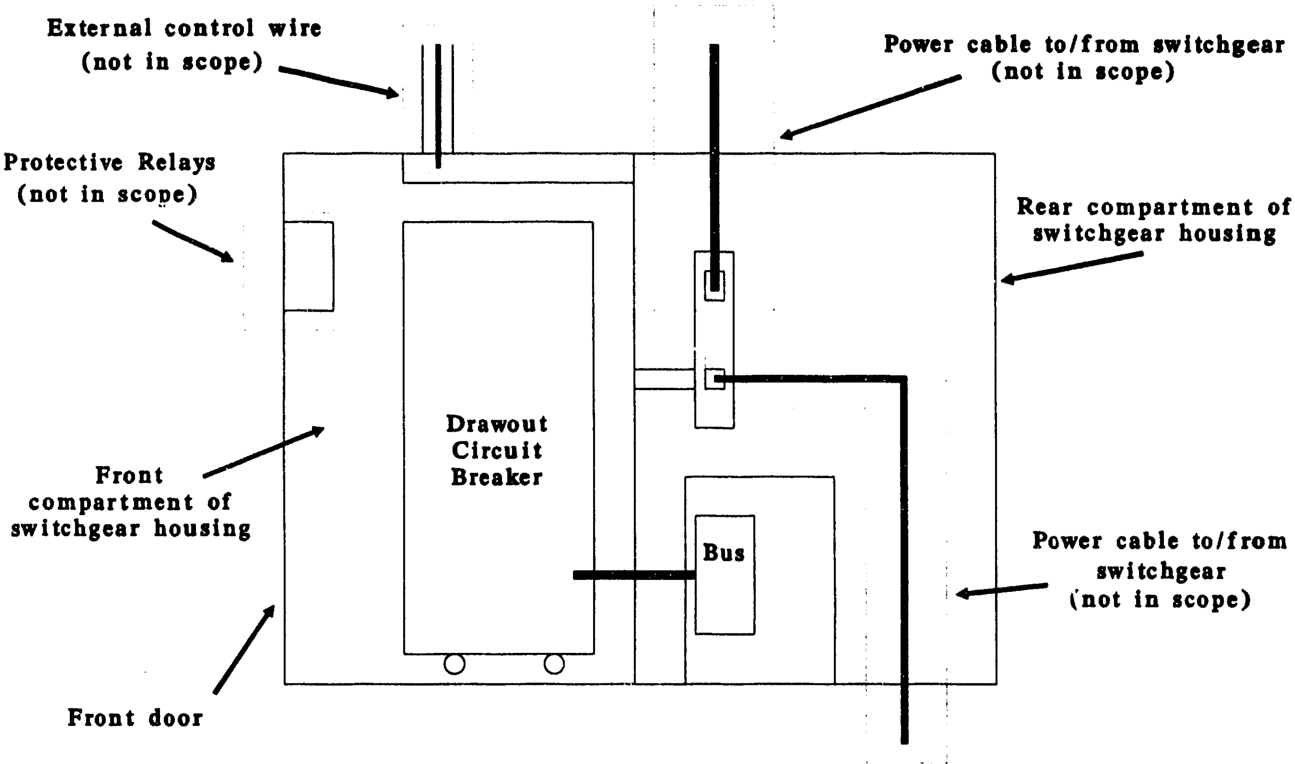
The component boundaries for the medium- and low-voltage switchgear covered by this report include the entire switchgear assembly, as well as the housing, internal wiring, and bus work up to the points at which feed and load power cables attach to the switchgear terminations. Medium- and low-voltage power cables connecting the switchgear to feeds and loads are not within scope. Control wire and cable connecting the switchgear to external control devices is not within scope; however, control wire interconnecting switchgear components within the switchgear housing and on the circuit breaker elements is within scope.

Protective relaying that may be mounted on or in the switchgear is not within scope due to its special nature and complexity; however, integral protective relaying that is part of certain low-voltage circuit breakers is within scope.

* Protective and auxiliary relays are out of the scope of this document.

** The component boundaries given in Section 3.3 limit these components to those that are mounted in or on the switchgear housing.

Figure 3-3 provides a pictorial description of the boundaries of components within the scope of this document.



All components within the switchgear housing are within the scope of this document except as noted above.

Figure 3-3. Definition of Component Boundaries.

3.4 Description of Components Evaluated

Electrical switchgear provides a means for connection and disconnection of a load to a power source as well as the protection of that power source from a fault along the supply circuit. The normal function of switchgear is to serve as a connection point for the supply of power. The secondary function of switchgear is to prevent the damage of equipment and supply circuits in the event of an abnormal occurrence on the power system (interruption of fault currents and, in some cases, disconnection of loads on under- or overvoltage).

3.4.1 Description of Predominant Types of Equipment in Grouping

3.4.1.1 General

3.4.1.1.1 Metal Housing System

Medium-Voltage Switchgear

The stationary switchgear structure is an assembly of steel housing units. The housing units are mounted side by side and connected mechanically and electrically to form a metal-clad switchgear structure. See Figures 3-4 and 3-5. Each unit consists of a formed and welded front enclosure and a rear enclosure having a bolted rear cover. Each enclosure is further subdivided into compartments as described below.[3.2]

The front enclosure contains the circuit breaker compartment. The rear enclosure contains the bus, cable, and transformer compartments. See Figure 3-6. The housing structure may contain space heaters. These heaters are used to keep moisture from condensing on the switchgear components if the unit is located in a potentially moist environment. In all switchgear, the protective and auxiliary relays are located in the front enclosure above the circuit breaker. In some switchgear, these relays are mounted on stationary panels at the top of the cubicle, whereas in others, the relays are mounted on the doors (note: consideration of these protective relays is outside of the scope of this document). Each compartment is separated by grounded metal barriers to isolate the low-voltage components, such as the protective relays, from the primary circuit elements.[3.3]

The circuit breaker compartment contains a mechanical interlock, primary and secondary disconnects, a control wiring trough, a vent, and an instrument panel on the front of the hinged door. See Figures 3-6 and 3-7. The circuit breaker compartment may also contain automatic, grounded, metal shutters that cover the primary disconnects at the back or top of the circuit breaker compartment when the circuit breaker is removed. Medium-voltage circuit breakers roll into the compartment on wheels. See Figure 3-8. The circuit breaker is placed in the connected position using a racking mechanism (see Section 3.4.1.3).

The rear enclosure is made up of the rear frames, tie members, top sheets, and rear covers, all bolted together and to the rear of the front compartment. It is divided into compartments which house the bus, cables, and instrument and control circuits.

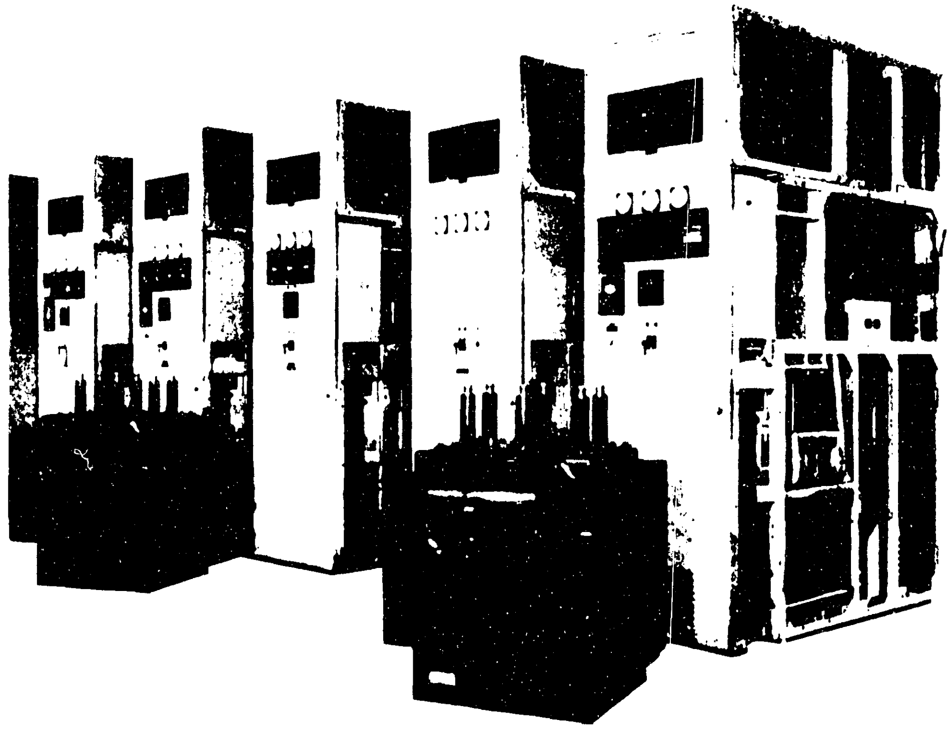


Figure 3-4. Medium-Voltage Switchgear Housing Units, General Electric 15-kV Switchgear [3.4] with Circuit Breakers in Front.

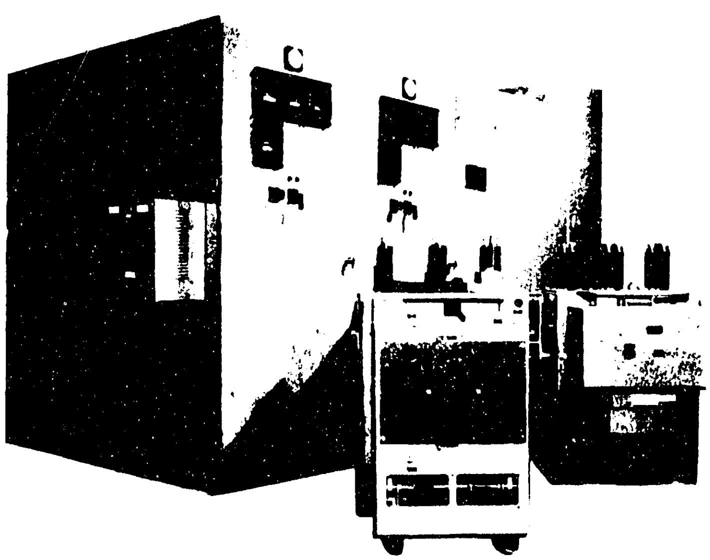


Figure 3-5. Medium-Voltage Switchgear Structure: An Assembly of Housing Units, General Electric 15-kV Switchgear [3.4] with Circuit Breakers in Front.

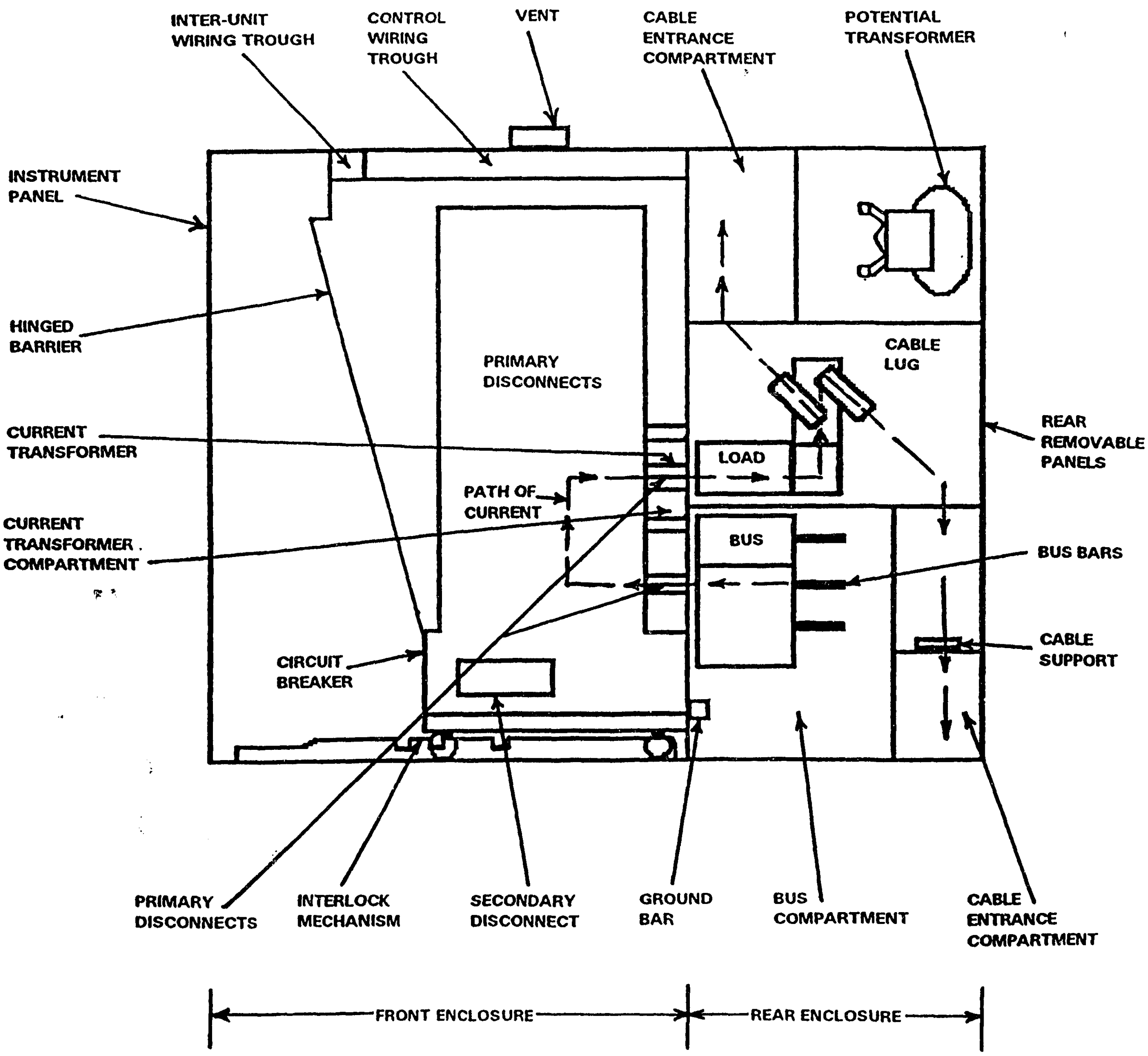


Figure 3-6. Front and Rear Enclosure (Side View) of Medium-Voltage Switchgear Housing Unit, Siemens-Allis Medium-Voltage Switchgear Housing Unit.[3.5]

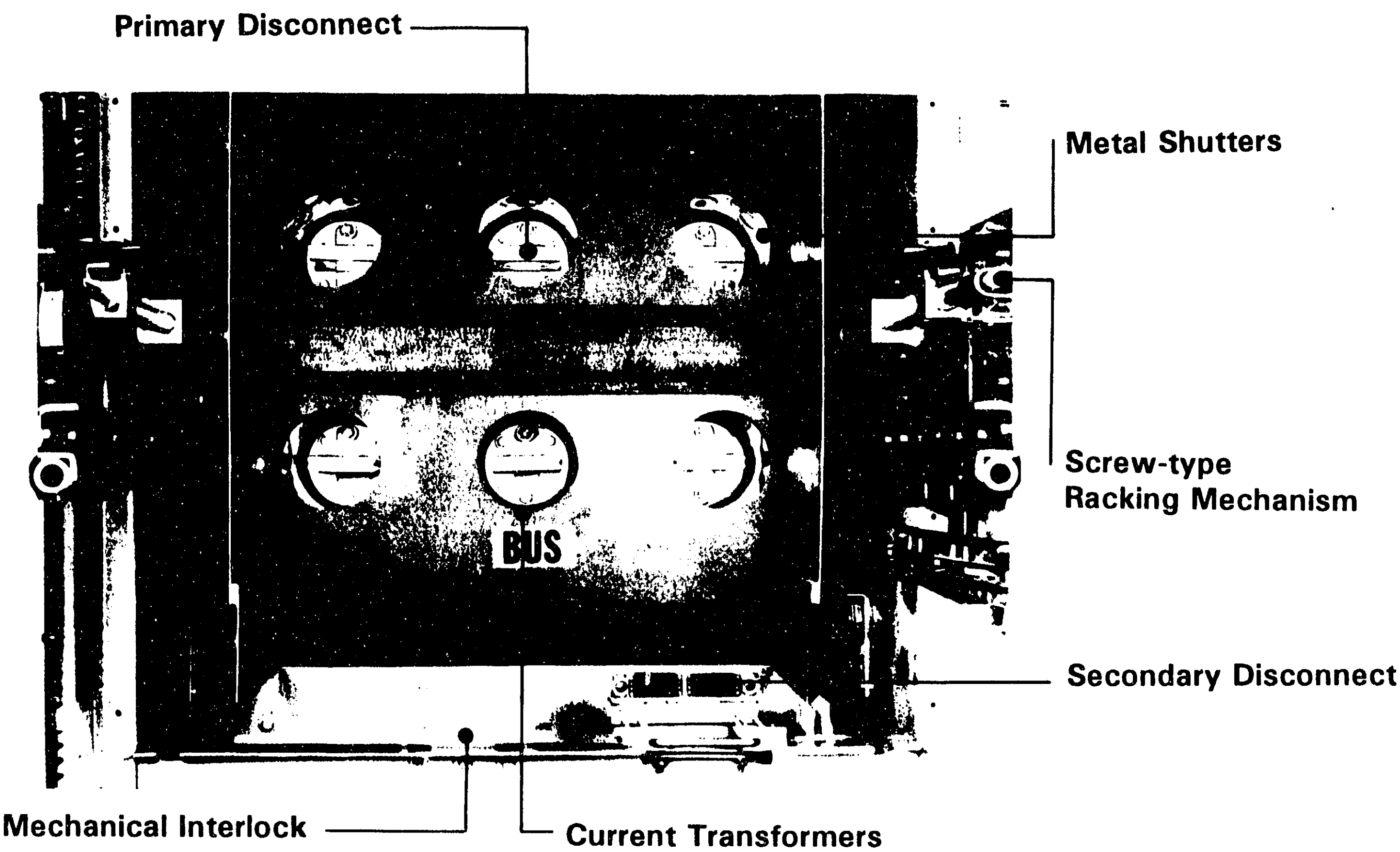


Figure 3-7. Siemens-Allis Medium-Voltage Vacuum Type Circuit Breaker Compartment.[3.6]

(Note: The metal shutters are open and therefore not visible.)

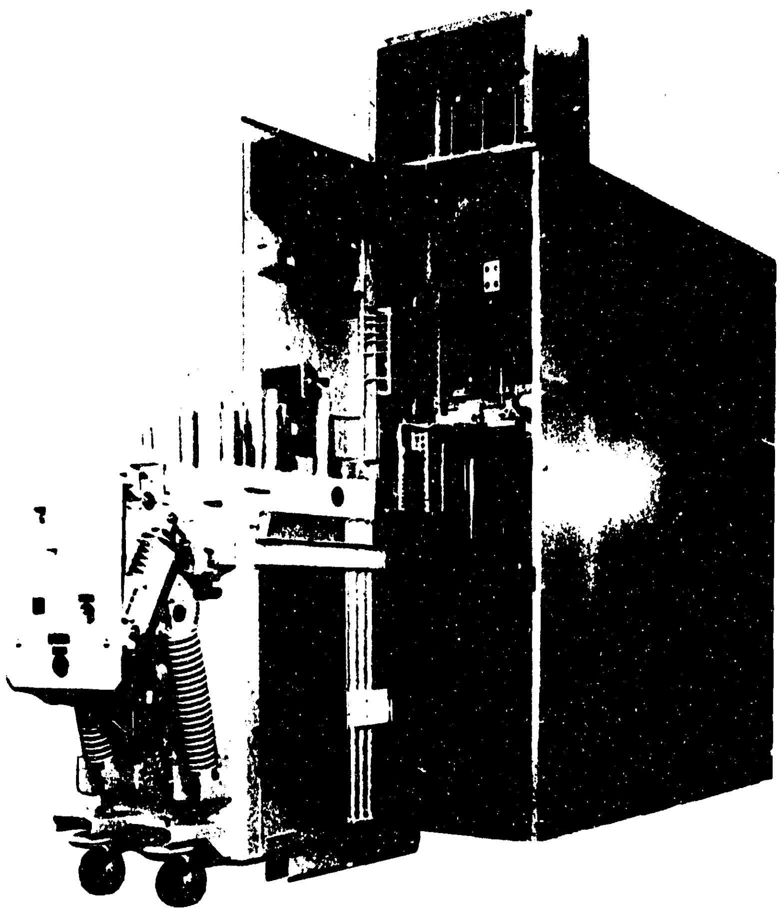


Figure 3-8. General Electric Medium-Voltage Magne-Blast Circuit Breaker and Housing Unit.[3.4]

Low-Voltage Switchgear

The housings of low-voltage stationary switchgear are very similar to those of medium-voltage switchgear. Low-voltage housings differ from medium-voltage housings in that they contain only two compartments within the housing: a circuit breaker compartment and a bus/cable compartment. The circuit breaker compartment and instrument and control devices are located in the front of the housing. See Figures 3-9 and 3-10. The bus and cable compartment is located at the rear of the housing. See Figure 3-11. In this configuration, there are no additional segregated compartments within the housing. Rather, the equipment in each compartment is separated by appropriate distances. Low-voltage circuit breakers are smaller than medium-voltage breakers and are usually lifted for insertion into the circuit breaker compartment. See Figure 3-12. Their small size also permits the use of several breakers, stacked vertically, in the switchgear housing unit. See Figure 3-13. In addition, primary disconnect shutters are optional in low-voltage switchgear circuit breaker compartments. [3.3, 3.7]

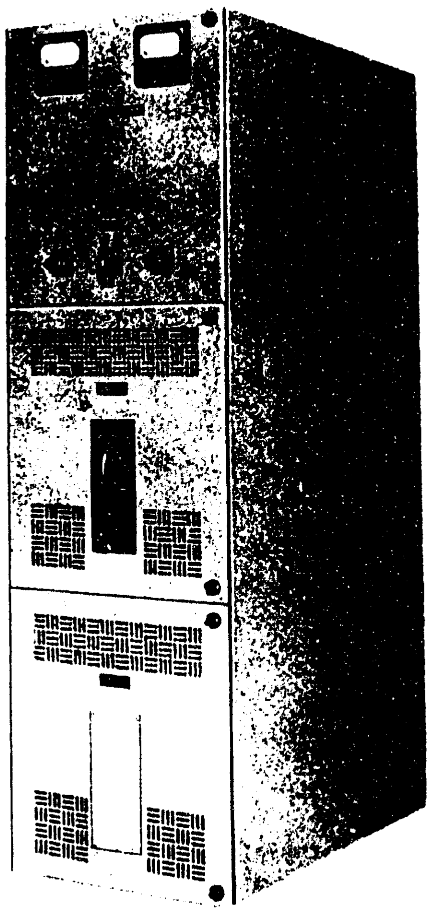


Figure 3-9. Front Enclosure of Low-Voltage Switchgear Housing Unit,
Westinghouse Metal-Enclosed Switchgear Housing Unit
Containing Type DB-50 Circuit Breaker.[3.7]

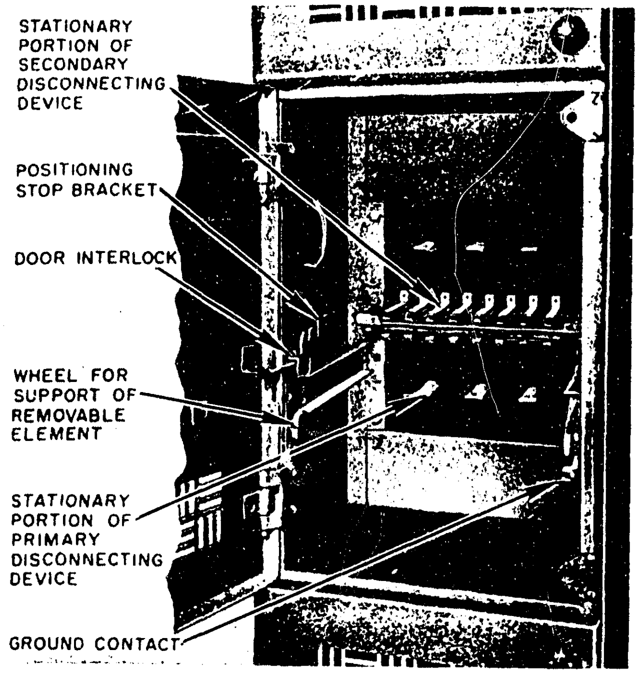


Figure 3-10. Westinghouse Type DB-15 Low-Voltage Circuit Breaker Compartment.[3.7]

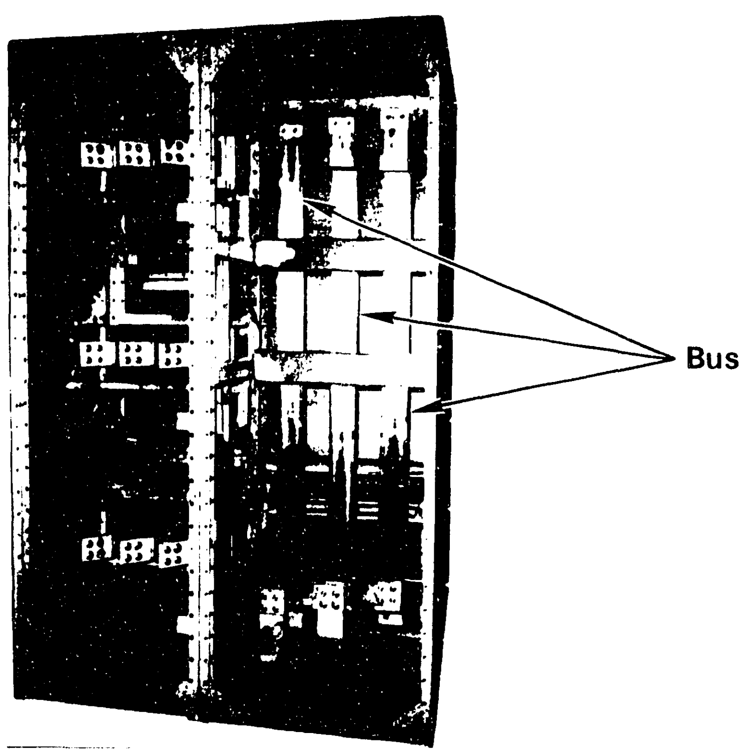


Figure 3-11. Rear Enclosure of Low-Voltage Switchgear Housing Unit, Westinghouse Metal-Enclosed Switchgear Housing Unit.[3.4]

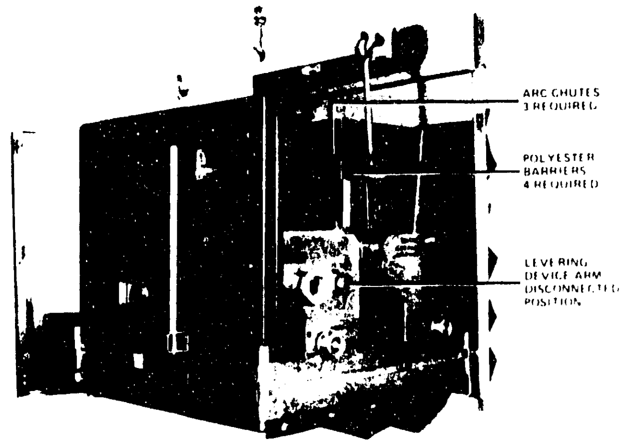


Figure 3-12. Insertion of Westinghouse Low-Voltage Type DS Circuit Breaker into Switchgear Compartment.[3.8]

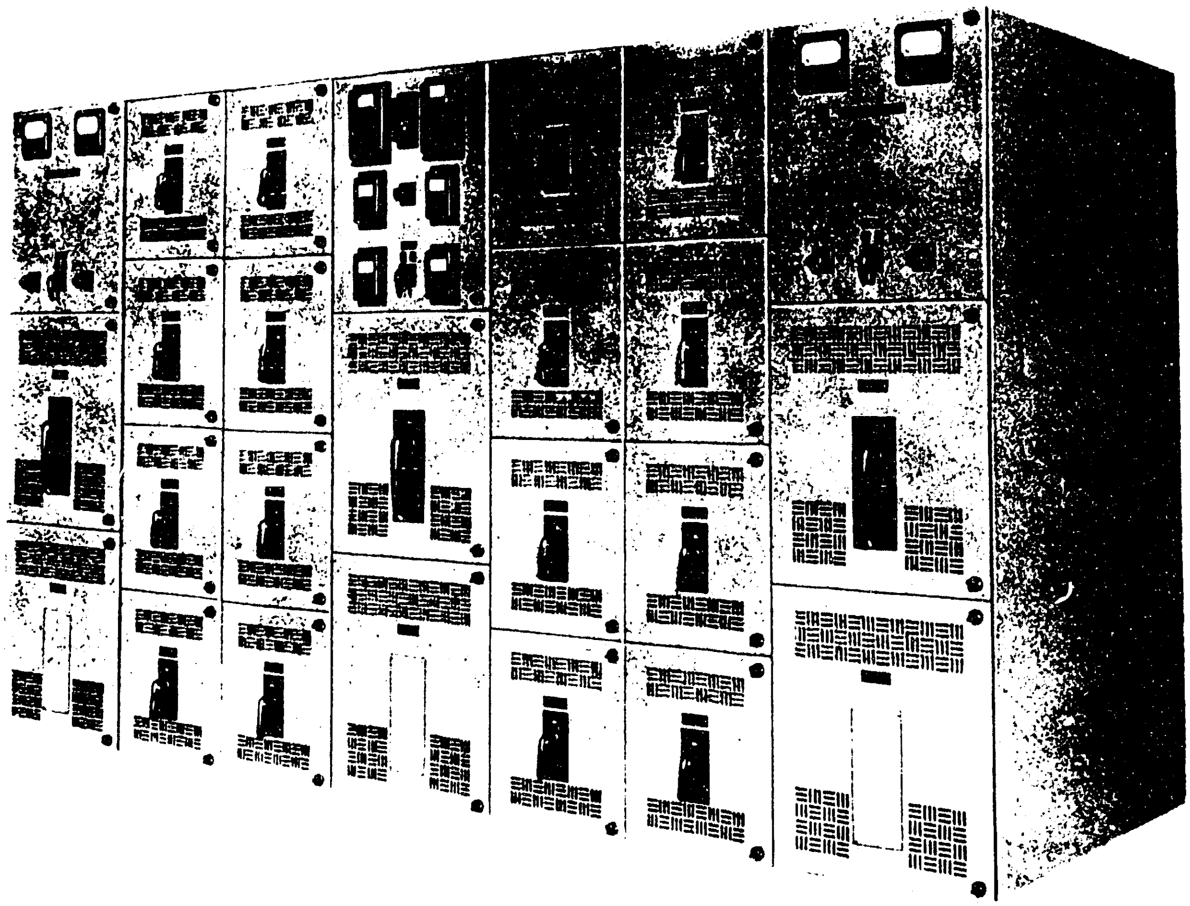


Figure 3-13. Low-Voltage Switchgear Structure: An Assembly of Housing Units, Westinghouse Low-Voltage Switchgear Containing Types DB-25 and DB-50 Circuit Breakers.[3.7]

3.4.1.1.2 Bus and Insulators

Medium-Voltage Switchgear

The bus is a set of conductors that connect all units in the switchgear. The main buses consist of copper bus bars or, in some cases, tin-plated aluminum bars, which are enclosed in a metal compartment. Bus compartments are provided with removable covers for inspection and maintenance. The bus bars are inserted into the bus compartments and bolted at the joints. Bus conductors and connections (joints) are covered with fire-retardant insulating material. The buses are connected to the primary disconnect studs at the back of the circuit breaker compartment. The buses rest on heavy-duty glass polyester supports or insulating boards made of Noryl, Lexan, or Micarta.[3.2, 3.3]

Low-Voltage Switchgear

The low-voltage switchgear buses differ from the medium-voltage buses in that they may not be covered by insulating material. Many low-voltage buses use air insulation with standoff insulators as the insulating system, whereas some low-voltage buses may have insulating covers on their surface.[3.7]

3.4.1.1.3 Circuit Breaker Primary and Secondary Disconnect

Medium- and Low-Voltage Switchgear

The primary disconnect is a plug-in connector that, when in the fully engaged position, connects the main power circuit of the circuit breaker with the bus and load of the metal-clad switchgear. See Figure 3-14. The primary disconnect is required to carry normal load current continuously and abnormal or short-circuit currents for short intervals; however, it is a no-load disconnect and cannot make or break normal or abnormal loads (that is, the main contacts of the circuit breaker must be open when the disconnect is opened or closed).[3.9]

The primary disconnecting devices used in medium- and low-voltage circuit breakers are generally of the finger/stud or finger/stab design. The main terminal studs or stabs are inserted into the contact finger assembly; the spring-loaded fingers slide over the stud or stab and make contact with the stud or stab. The orientation of the primary disconnect device varies with the manufacturer. Some manufacturers locate the stud/stab on the switchgear housing and the contact fingers on the circuit breaker. Other switchgear have the opposite arrangement.[3.2, 3.8, 3.10]

The secondary disconnecting device used on most circuit breakers consists of floating or sliding fingers mounted on the circuit breaker which engage with flat contact segments mounted in the circuit breaker compartment. See Figure 3-14. These disconnects connect the circuit breaker control and position-indicating circuits to the control network of the metal-clad switchgear.[3.7]

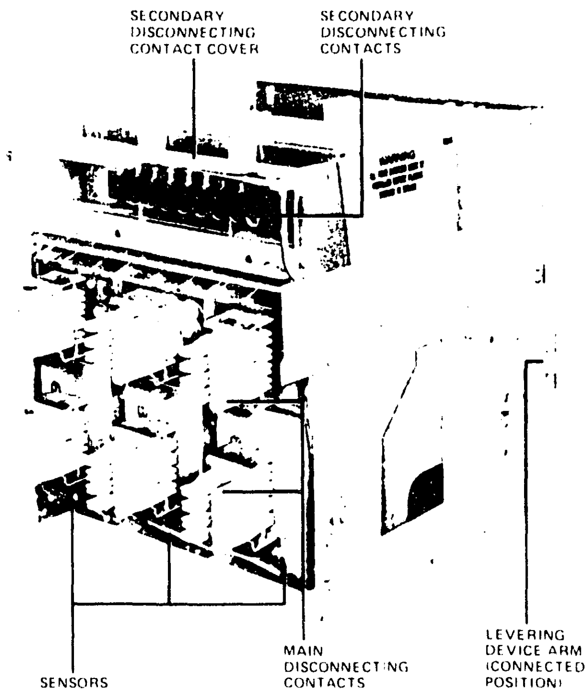


Figure 3-14. Primary and Secondary Disconnects (Finger/Stab Design with Fingers on the Circuit Breaker), Westinghouse Low-Voltage Type DS and DSL Circuit Breakers.[3.8]

As a circuit breaker is racked into the switchgear cubicle, it will pass through the remove, disconnected, and test positions until it reaches the connected position, when both the primary and secondary disconnects are engaged. The disconnects in use at the four breaker positions are as follows:[3.9]

Breaker Position	Disconnects Engaged
Remove	None
Disconnect	None
Test	Secondary disconnects only
Connect	Primary and secondary disconnects

3.4.1.1.4 Circuit Breaker Racking Mechanism

Medium- and Low-Voltage Switchgear

The racking mechanism is used to move the circuit breaker to and from its connected position in the switchgear compartment. Circuit breakers are racked in and out horizontally or vertically. Some circuit breakers are moved in and out by hand, whereas others require an accessory, such as a levering device, to move the circuit breaker between positions once inside the switchgear compartment. The levering device may consist of a metal lever that is inserted into the compartment to move the breaker into position (see Figure 3-15) or it may consist of a mechanical gear assembly that will move the breaker in and out of the cubicle when manually driven by a crank or electrically driven by a drive motor (see Figures 3-16 and 3-7). The type of racking mechanism used varies with switchgear manufacturer. [3.2, 3.8]

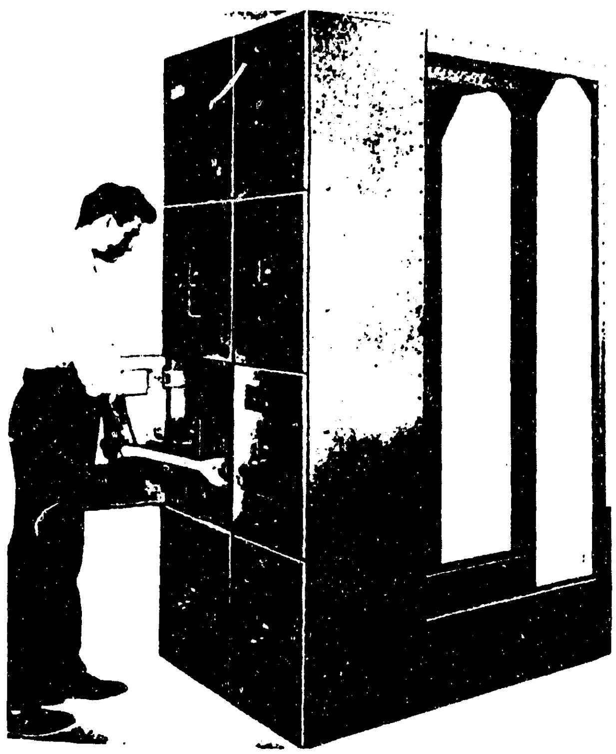


Figure 3-15. Manual Lever Circuit Breaker Racking Mechanism, Westinghouse Low-Voltage Switchgear.[3.7]

Figure 3-16. Worm-Gear Circuit Breaker Racking Mechanism, Westinghouse Low-Voltage Circuit Breaker, Types DS and DSL.[3.8]

3.4.1.2 Circuit Breaker

Medium- and Low-Voltage Switchgear

A drawout circuit breaker is the removable and interchangeable switching and fault interrupting device used to provide control and protection of electrical apparatus and power systems. Such circuit breakers are contained in individual grounded metal compartments and are controlled either remotely or from the switchgear panel. See Figures 3-8 and 3-12.

A "racking mechanism" or levering system is used to insert and remove the circuit breaker from the circuit breaker compartment. Circuit breakers perform their switching and interrupting functions through main contacts, an operating mechanism that closes and opens the contacts, and an arc extinguishing system. The circuit breaker "plugs into" the circuit breaker compartment using primary and secondary disconnecting devices and may be withdrawn for testing, inspection, and maintenance. The energy flowing through the circuit breaker enters through the primary disconnect connects from the power source, flows through the main contacts and moving contact assembly within the circuit breaker, and exits the circuit breaker through the primary disconnect connected to the load. The arc extinguishing system within the circuit breaker provides a means of arc extinction when current interruption is required. The circuit breaker also includes associated control mechanisms. Each circuit breaker component is described below.

3.4.1.2.1 Circuit Breaker Main Contacts

Medium- and Low-Voltage Switchgear

The main contacts carry the power circuit load. When the main contacts close, the power circuit load flows through the circuit breaker. Proper contact mating is essential as it helps to minimize power path contact resistance to prevent the contacts from overheating. Proper mating is achieved through spring loading of the contacts. A compression spring in the closing mechanism bears on the moving contact in the closed position and pushes the contacts together so that good contact mating occurs. Spring loading also facilitates contact "wipe" or cleaning of the contacts as they come together. When the main contacts open, the power flow through the circuit breaker is interrupted or broken via transfer of the power circuit load from the main contacts to the arc extinguishing system. See Figure 3-17.[3.2, 3.8]

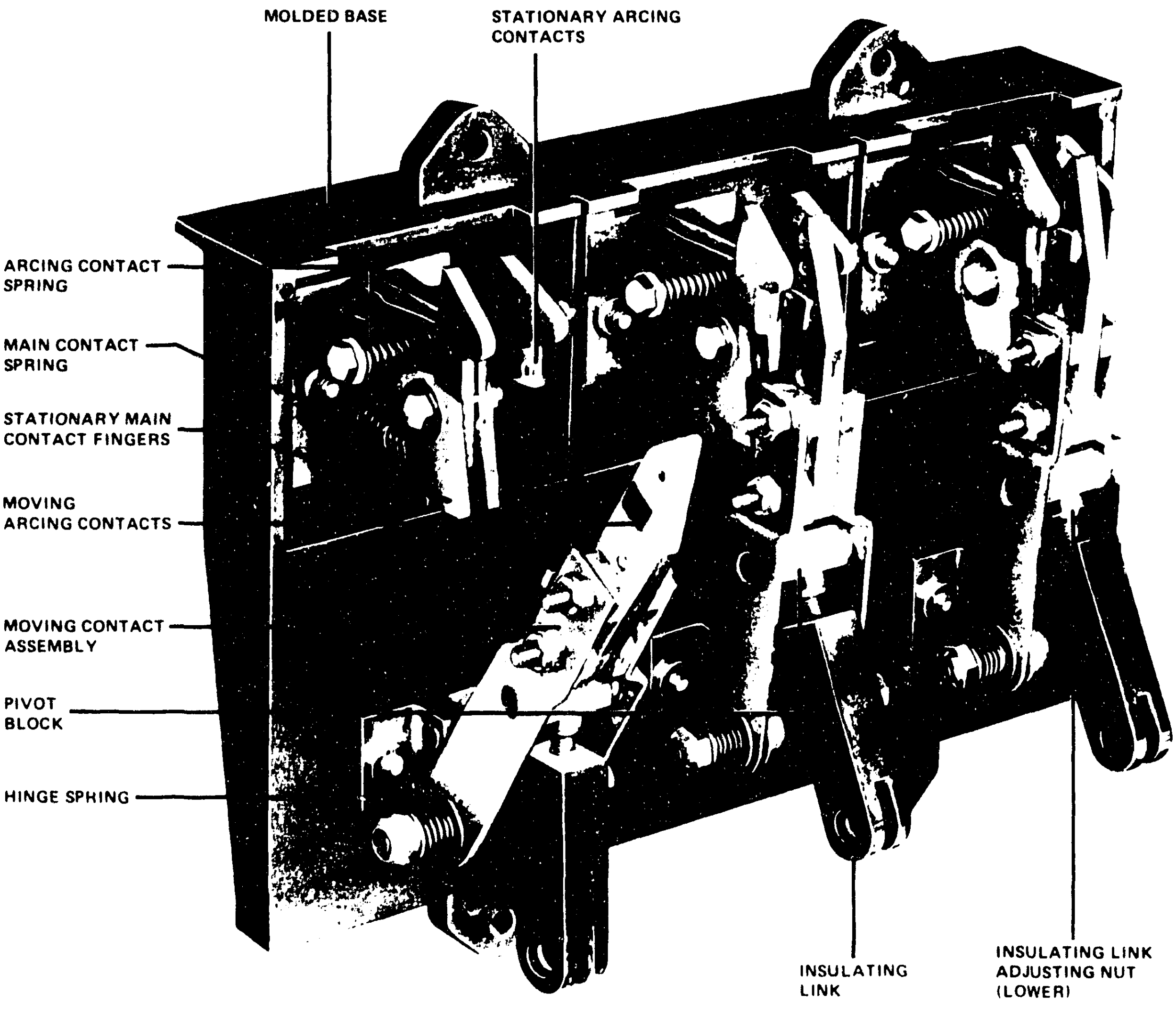


Figure 3-17. Circuit Breaker Main Contacts, Westinghouse Type DS and DSL Low-Voltage Circuit Breakers.[3.8]

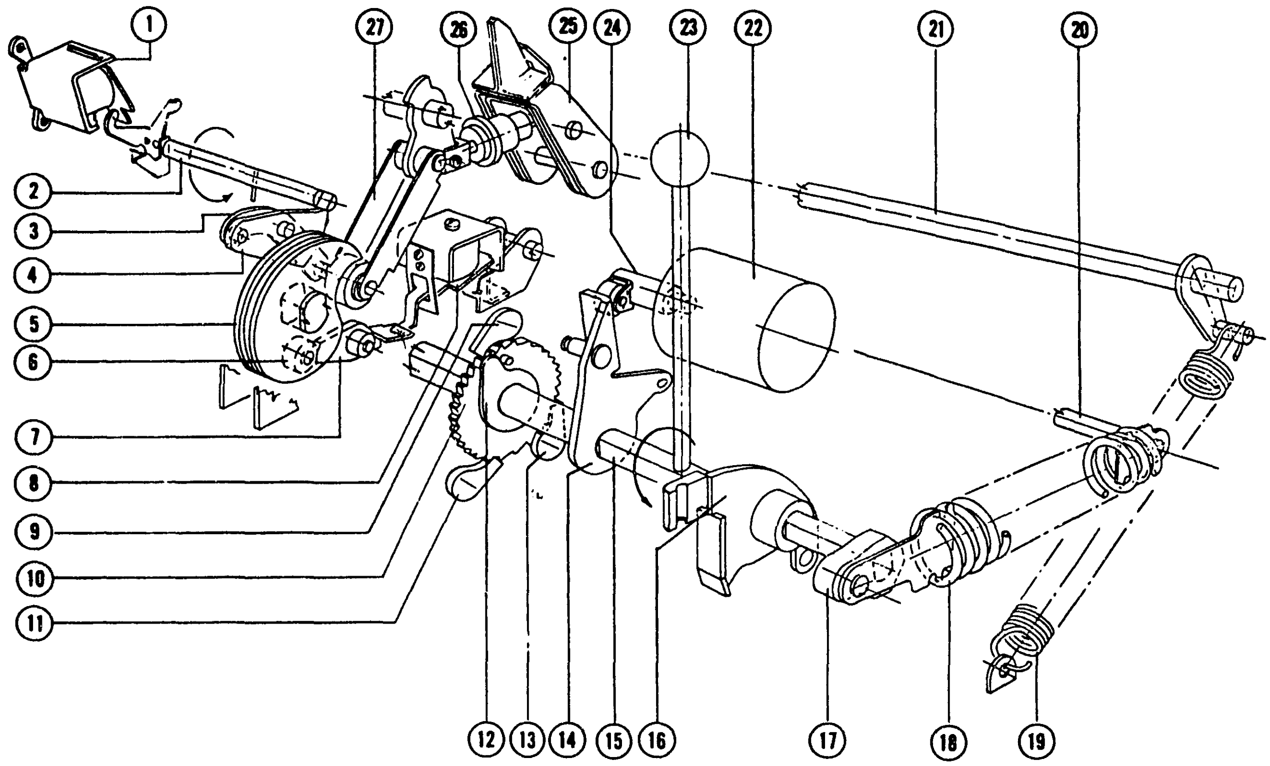
3.4.1.2.2 Circuit Breaker Operating Mechanism

Medium- and Low-Voltage Switchgear

There are two basic operating mechanisms used in switchgear circuit breakers. One mechanism uses a stored energy spring system to provide the closing force. The other mechanism uses a solenoid to provide the closing force. Operations are controlled either electrically from a remote location or locally from the face of the switchgear by the manual close and trip (open) levers on the breaker. A discussion of each mechanism follows.

The stored energy spring mechanism generally consists of a spring charging motor, a closing spring, and a mechanical assembly or linkage. See Figure 3-18. In a stored energy spring closing operation, the closing spring is charged (compressed or extended, depending on the design) by the electric motor and ratcheting mechanism. Upon receipt of a mechanical or electrical closing signal, the close release latch allows the closing spring to act on the mechanical assembly. Discharge of the closing spring causes the mechanism to close the main and arcing contacts and to charge (compress or extend) the opening springs. As soon as the closing springs discharge during closure, the charging motor is energized to recharge the closing springs such that an immediate closure could follow a circuit breaker opening. In an opening operation, the contacts are opened by the mechanical assembly when the trip latch is released. Upon receipt of an electrical or mechanical opening signal, the trip latch releases the prop system that prevented the opening springs from pulling the main contacts open. Once the prop system is released, the main contacts open and the linkage systems and trip latches reset to positions so that they are ready to reclose. During the opening operation, the arc is transferred from the main contacts to the arcing contacts, which carry the arc into the arc-chute. The arcing contacts open after the main contacts to protect the surface area of the main contacts from severe damage by arcing. For this reason, the arcing contacts are considered sacrificial and may be replaced during the service period of the circuit breaker.[3.8]

The solenoid operated mechanism generally consists of a solenoid and a mechanical assembly or linkage. See Figure 3-19. The solenoid operated mechanism differs from the stored energy spring mechanism in that the force used to electrically close the breaker is supplied by an ac or dc solenoid coil. Upon receipt of an electrical closing signal, the solenoid will energize and a plunger will push the mechanical assembly so that the circuit breaker contacts close. Mechanical closing of the solenoid type breaker uses a lever handle to move the mechanism directly. As the mechanism closes, the opening springs charge. To open the circuit breaker contacts, the trip latch must be released. Upon receipt of an electrical or mechanical opening signal, the trip latch will free the opening springs and force the main contacts to open. When the breaker contacts open, the linkage will reset for the next closure.[3.10]



1. Shunt Trip Device
2. Trip Shaft
3. Roller Constraining Link
4. Trip Latch
5. Close Cam
6. Stop Roller
7. Spring Release Latch
8. Spring Release Device
9. Oscillator Pawl
10. Ratchet Wheel
11. Hold Pawl
12. Drive Plate
13. Emergency Charge Pawl
14. Oscillator
15. Crank Shaft
16. Emergency Charge Device
17. Crank Arm
18. Closing Spring
19. Reset Spring
20. Closing Spring Anchor
21. Pole Shaft
22. Motor
23. Emergency Charge Handle
24. Motor Crank and Handle
25. Moving Contact Assembly
26. Insulating Link
27. Main Drive Link

Figure 3-18. Stored Energy Spring Operating Mechanism.[3.8]

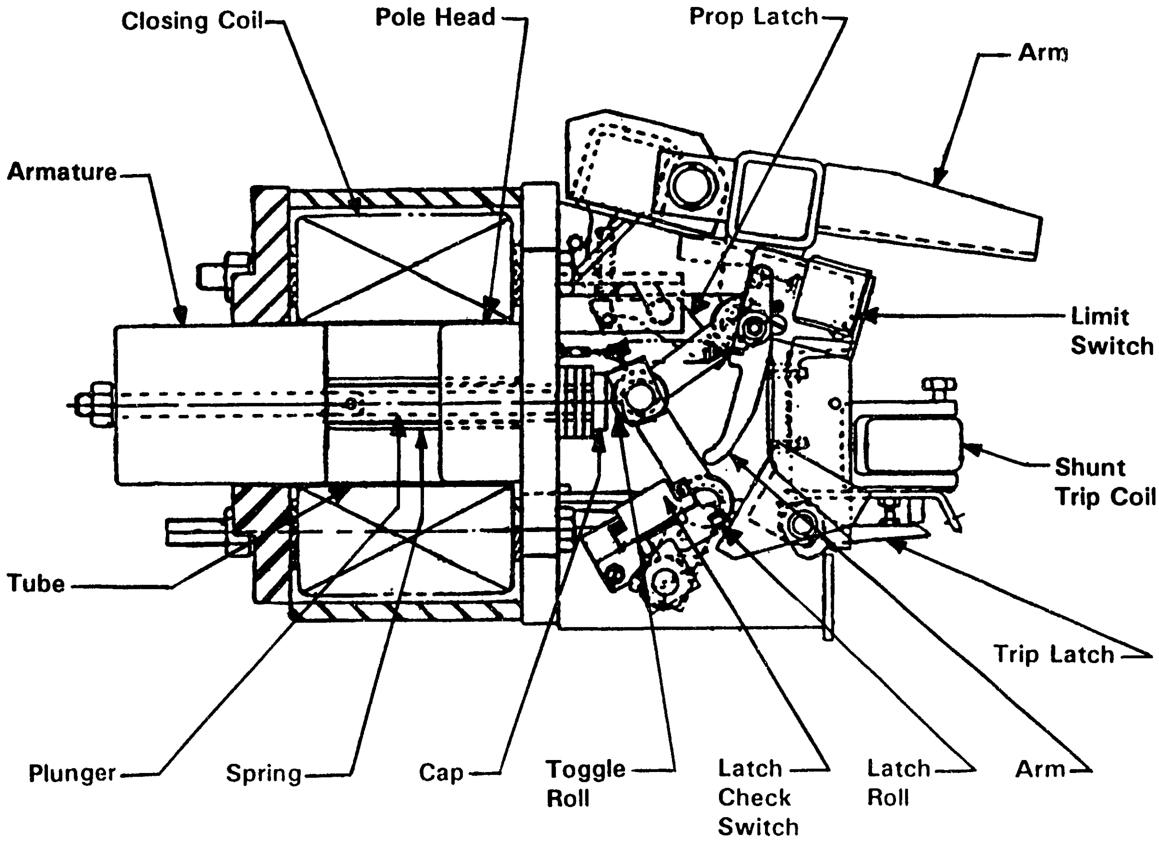


Figure 3-19. Solenoid Operated Mechanism.[3.10]

3.4.1.2.3 Circuit Breaker Arc Extinguishing System

Medium- and Low-Voltage Switchgear

The arc extinguishing system interrupts or breaks and extinguishes normal and fault currents. A basic arc extinguishing system consists of arcing contacts and an arc-chute. The arc extinguishing process begins as the main contacts open and transfer the arc to the arcing contacts. The arcing contacts are usually made of an alloy of a high conductivity material, such as silver or tungsten, which is resistant to damage by the high temperatures that accompany an arc. The arcing contacts are often plated with an additional layer of metal to increase the dielectric strength of the gap between the contacts during opening under load and fault conditions and to reduce the probability of restrike and flashover. See Figure 3-17.[3.9]

Once the arc has been transferred to the arcing contacts, the arcing contacts lengthen and weaken the arc as they open beneath the arc-chute. An arc-chute consists of a series of two sets of plates or fins that are covered by a molded case made of insulating material. The first (or lower) set of plates is made of metal, usually steel. The second set of plates, which are made of an insulating material that can absorb and withstand the heat generated during arc extinction, rests on top of the metal plates within the molded case. The space between the plates provides a path for arc extinction. The arc-chute is usually mounted vertically above the arcing contacts; however, in some cases, the arc-chute is mounted horizontally, adjacent to the arcing contacts. As the arc travels beneath the arc-chute, it is driven onto the metal plates. The arc is then driven further into the arc-chute, where it eventually reaches the insulated plates and is extinguished when a current zero on an ac current occurs or when the arc length is too long and the resistance is too high to support continued current flow. The gases produced during arc extinction are vented to the atmosphere through the top of the arc-chutes. In addition to its arc extinguishing function during current interruption, the arc-chute helps to insulate the individual electrical phases within the circuit breaker from one another. The ability of the arc-chute to contain the arcs greatly reduces the possibility of a phase-to-phase or phase-to-ground fault occurring during current interruption, especially fault current interruption. See Figure 3-20.[3.9]

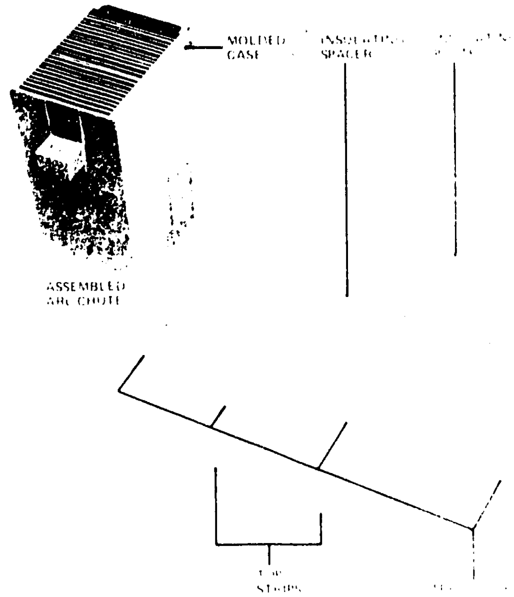
Two naturally occurring phenomena, the thermal effect and the presence of a magnetic field, aid in current interruption. The thermal effect, which occurs because of the higher local temperatures of the arc, refers to the establishment of an upward air flow through the arc-chute. As the warm, ionized air around the arc rises, it is replaced by cooler air. This cool, un-ionized air helps to cool and weaken the arc and move it into the arc-chute. The presence of a magnetic field also helps to move the arc into the arc-chute. A magnetic field is established by the arc as it passes between the arcing contacts. The magnetic field can exert a force on the ionized particles of the arc. The arc-chute can be configured so that the force created by the magnetic field moves the arc in the direction of the arc-chute air gaps. Magnetic plates are used to create this type of magnetic field.[3.9]

Although the arc extinguishing process described above is sufficient for low power circuit breakers, high power circuit breakers may require additional assistance in current interruption. Two common ways of increasing the interrupting capability of circuit breakers are to provide air flow from an external source and to increase the force exerted by the magnetic field. Some high power breakers use a puff of air from a piston-cylinder assembly to blow the arc into the arc-chute. These breakers are often referred to as puffer breakers. Other high power breakers use magnetic blowout coils or a permanent magnet to augment the force created by the magnetic field. As the arc moves into the arc-chute, the blowout coils become energized by the current in the primary circuit and produce an additional magnetic field. This magnetic field provides additional force to move the arc into the arc-chute compartments for extinction.[3.9, 3.10]

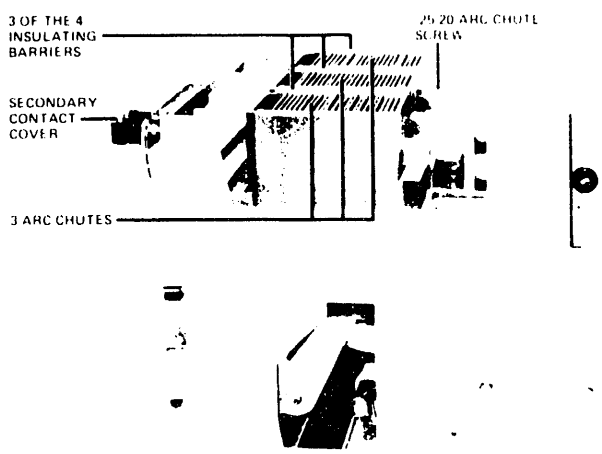
3.4.1.2.4 Circuit Breaker Mechanical Interlocks

Medium- and Low-Voltage Switchgear

The circuit breaker is provided with mechanical interlocks to ensure that only the circuit breaker with the correct voltage, current, and interrupting ratings for the particular switchgear application is inserted into the switchgear compartment. Because the primary disconnects cannot be used to interrupt current, these interlocks also assure that the main contacts of the circuit breaker are always open when the circuit breaker is placed into or removed from its compartment. If insertion or removal of a circuit breaker is attempted with the main contacts closed, the interlock will cause the circuit breaker to trip open first.[3.2, 3.7]



Types DS and DSL.[3.8]



Arc-Chute Mounted on a Westinghouse Type DS Circuit Breaker.[3.8]

Figure 3-20. Arc-Chute for Westinghouse Low-Voltage Circuit Breakers.

3.4.1.3 Circuit Breaker Control

3.4.1.3.1 Protective and Auxiliary Relays

Protective and auxiliary relays are not within the scope of this document.

3.4.1.3.2 Circuit Breaker Auxiliary Switches

Medium- and Low-Voltage Switchgear

The control circuitry of a metal-clad circuit breaker contains a series of switches that assume positions consistent with the state of the main breaker contacts. These switches are mechanically linked to the operating mechanism that opens and closes the main contacts of the circuit breaker. "A" auxiliary switch contacts are closed when the main breaker contacts are closed, and are open when the main contacts are open. "B" auxiliary switch contacts assume the opposite position to that of the main contacts. These switches are used for logic interlocks and position indication internal and external to the circuit breaker. For example, an "A" switch is used to de-energize the trip latch coil once the circuit breaker is open in order to prevent it from burning out from long-term energization. "Early" close and open "A" and "B" switches are also available for special control functions, such as bus transfer functions.[3.9]

3.4.1.3.3 Current and Potential Transformers

Medium-and Low-Voltage Switchgear

Current transformers are used in medium- and low-voltage switchgear to supply control instruments such as meters and relays with a current proportional to that of the power circuit. A current transformer consists of a short sleeve of magnetic material with a distributed toroidal secondary winding. It is usually mounted on the main conductor, bus, or cable exiting the circuit breaker (at the load side).[3.11]

Potential (voltage) transformers are used in medium- and low-voltage switchgear to step down the power system voltage to a safe level for relaying purposes and to permit reasonable insulation levels in instrumentation circuits. They are also used to power wattmeters and voltmeters. Potential transformers are connected in parallel with the power circuit (phase-to-phase or phase-to-ground) and are usually located in a separate compartment adjacent to the circuit breaker, although some potential transformers are located in a compartment above the current transformers.[3.3]

3.4.1.3.4 Meters

Medium- and Low-Voltage Switchgear

Meters measure current and voltage. They are located on the front panel of the switchgear assembly along with other control and protective devices. Because meters do not have a direct effect on the operability of switchgear, they will not adversely affect the function of the switchgear. Failure of a meter is tolerable, in general representing a minor operational irritant, and replacement at a convenient time will suffice to restore functionality. Therefore, meters are not considered further in this report.

3.4.1.3.5 Internal Control Wiring

Medium- and Low-Voltage Switchgear

The circuit breaker control wiring originates at the secondary disconnects and terminates at meters, relays, and control circuits. Control circuits operate at 120 Vac or 125 or 150 Vdc. Control wiring is generally rated at 600 Vac. The wire is generally run in troughs within the switchgear housing or bundled or tied appropriately to the housing or circuit breaker frame. See Figure 3-6.[3.9] Wiring also exists inside the circuit breaker assembly itself, and assists a variety of functions, including internal protective device actuation, auxiliary contact logic, and charging motor operation.

3.4.2 Discussion of Manufacturers' Design Differences

There are several manufacturers of medium- and low-voltage switchgear, including General Electric (GE), ITE/Gould/Brown Boveri (ABB), Westinghouse, and Siemens-Allis. General Electric, ABB, and Westinghouse switchgear are described in Table 2-1. Siemens-Allis switchgear is not described because of limited use in nuclear power plants. Any differences between the design given in Section 3.4.1 and that of the manufacturer are noted. A summary of the major differences in switchgear designs is provided in Table 3-1.

3.4.2.1 Racking Mechanism

Medium-Voltage Switchgear

There are three types of racking mechanisms used in the equipment under consideration to insert and remove circuit breakers from electrical switchgear: the horizontal manual lever system, the horizontal worm-gear system, and the vertical lift motor-driven system.

General Electric medium-voltage AM circuit breakers are connected at the top of the breaker cubicle. This circuit breaker is horizontally pushed by hand into the cubicle. An elevating carriage, located below the circuit breaker, then raises the breaker into the "connected" position. A reversible elevating motor provides the power necessary to raise or lower the circuit breaker. The breaker may also be lowered manually by an emergency hand crank if the motor is unavailable.[3.12, 3.13, 3.14]

General Electric medium-voltage AMH breakers differ from the standard AM breaker described in the preceding paragraph in that the breaker disconnects are at the rear of the cubicle (as opposed to the top). Racking of the breaker in or out of the cubicle is accomplished horizontally by a manually operated mechanism located in the front of the breaker cubicle. This racking mechanism design is somewhat simpler than that used in the AM breaker.

Westinghouse medium-voltage DH circuit breakers use a horizontal worm-gear racking mechanism. After the circuit breaker is manually pushed horizontally into the circuit breaker

Table 3-1. Manufacturers' Design Differences for Electrical Switchgear

Manufacturer/Voltage Class	Racking Mechanism	Main Contact Open/ Close Mechanism	Arc Extinguishing System	Primary Disconnects	Internal Protective Devices
General Electric Medium-Voltage (AM)	Vertical lift, motor driven system	Stored energy spring	Horizontal arc-chute with magnetic blowout coils and force air	Contact finger/stab assembly	None
Westinghouse Medium-Voltage (DH)	Horizontal worm-gear system	Solenoid	Vertical arc-chute with blowout magnet and coils	Contact finger/stab assembly	Optional undervoltage trip device
Westinghouse Medium-Voltage (DH-P)	Horizontal worm-gear system	Stored energy spring or solenoid	Vertical arc-chute with blowout magnet and coils, and force air	Contact finger/stab assembly	Optional undervoltage trip device
General Electric Low-Voltage (AK)	Horizontal manual lever system	Solenoid	Vertical arc-chute	Contact finger/stab assembly	Optional overcurrent trip device
ITE/Gould/Brown Boveri, Low-Voltage	Horizontal worm-gear system	Stored energy spring	Vertical arc-chute	Contact finger/stab assembly	Optional overcurrent/ undervoltage trip device
Westinghouse Low-Voltage (DB)	Horizontal manual/ manual lever/ worm-gear system	Solenoid	Vertical arc-chute	Contact finger/stab assembly	Optional overcurrent/ undervoltage trip device
Westinghouse Low-Voltage (DS)	Horizontal worm-gear system	Stored energy spring	Vertical arc-chute	Contact finger/stab assembly	Optional Amptector trip unit/undervoltage trip device

compartment, a crank handle is inserted onto the levering shaft. As the crank handle is rotated, the worm-gear assembly moves the breaker from the "disconnect" to "test" to connect" positions.[3.15]

Westinghouse medium-voltage DH-P circuit breakers use a chassis assembly levering device to move the breaker between positions. The chassis assembly consists of a nut, guide tube, and levering shaft. The nut is fastened securely to the guide tube and is housed in a casing that is fastened to the disconnect side of the breaker. The guide tube is a metal tube which is slotted lengthwise. The guide tube receives two rectangular keys that are welded to the levering shaft. As the levering shaft is manually rotated, the guide tube and nut will rotate. The nut will turn onto a screw which is mounted to the rear wall of the breaker compartment and pull the breaker into the final "connect" position.[3.16]

Low-Voltage Switchgear

General Electric low-voltage AK circuit breakers use the horizontal, manual lever system for insertion. The racking mechanism is similar to that used in the Siemens-Allis medium-voltage MA circuit breakers except that there is no break-release pedal. The circuit breaker is moved from the "disconnect" to "test" to "connect" position using the racking lever.[3.17]

ITE/Gould/Brown Boveri low-voltage circuit breakers use a horizontal worm-gear racking mechanism similar to that used in the Westinghouse DH circuit breakers. The only difference between these two racking mechanisms is that the ITE/Gould/Brown Boveri circuit breakers are inserted on rail extensions. The breaker is lifted onto the rail extensions and pushed to the "disconnect" position. A worm-gear levering device is then used to move these breakers horizontally on the rail extensions from the "disconnect" to "test" to "connected" positions.[3.18]

Westinghouse low-voltage DB circuit breakers are racked in and out of the switchgear compartment three ways, depending on the particular model. The DB-15 circuit breaker uses horizontal manual racking. The circuit breaker is lifted and placed directly on the compartment rails and pushed into the connected position. No additional devices are needed to move it between positions. The DB-25 and DB-50 circuit breakers, which have higher ratings and are heavier, are also racked in and out horizontally, but rail extensions and a levering device are required to move them between positions. Larger Westinghouse models, specifically models DB-75, DB-100, and DBF-40, are equipped with wheels so that they roll on the floor. The DB-100 and DBF-40 breakers are pushed by hand horizontally into the housing at floor level. The DB-75 breakers are usually inserted at floor level but can also be inserted on a platform. A worm-gear levering device is required to move these breakers from the "disconnect" to "test" to "connected" positions.[3.19, 3.20]

Westinghouse low-voltage DS circuit breakers are racked into and out of the circuit breaker cubicle on rail extensions. A worm-gear assembly is used to move the breaker between positions.[3.8]

3.4.2.2 Main Contact Open/Close Mechanism

There are two basic types of operating mechanisms used to close circuit breaker main contacts: the stored energy spring mechanism and the solenoid operated mechanism. Most mechanisms use stored spring energy to open the breaker.

General Electric medium-voltage AM circuit breakers use the stored energy spring mechanism. The stored energy spring mechanism is similar to the design discussed in Section 3.4.1.2.2. In this mechanism, the opening springs are compressed during the closing operation. [3.12, 3.13, 3.14]

The Westinghouse medium-voltage DH circuit breakers use the solenoid operated mechanism. This mechanism differs from other designs in that the solenoid coil produces a horizontal pull, instead of a push, on the mechanism closing link. The closing link is attached to a system of links that rotates counterclockwise about the operating center when the solenoid is energized. The motion of the system moves the trip-free lever so that it exerts an upward force on the operating rods and closes the breaker contacts. The opening mechanism is different from that described in Section 3.4.1.2.2 in that it does not use stored spring energy to open the breaker. The breaker is tripped electrically or manually by disengaging the primary latch. This allows the tripping latch to release the linkage so that it collapses under the force of the contact springs. The trip-free lever then rotates clockwise and opens the breaker. The breaker then resets for closure.[3.15]

Westinghouse medium-voltage DH-P circuit breakers use either the stored energy spring or solenoid operated mechanism. The stored energy spring mechanism is similar to that described in Section 3.4.1.2.2. The solenoid operated mechanism is similar to that used in the Westinghouse DH medium-voltage circuit breaker except that stored spring energy is used to open the breaker.[3.16]

Certain General Electric low-voltage AK circuit breakers (e.g., AK 25) use the solenoid operated mechanism. The closing mechanism differs from the Westinghouse design in that the solenoid provides a vertical force. This vertical force extends the operating springs. As the operating springs move past the center of the operating mechanism and are further extended, the blocking cam moves away from the output crank and the springs discharge part of their stored energy, closing the breaker contacts. The solenoid operated breaker is tripped, mechanically or electrically, by displacement of the trip latch. As the trip latch moves off of the trip latch roller, the remaining force in the operating springs causes the mechanism toggle to collapse, which opens the breaker contacts. The linkage resets automatically.[3.17]

ITE/Gould/Brown Boveri low-voltage circuit breakers also use the stored energy spring mechanism. The ITE/Gould/Brown Boveri design is similar to the General Electric design except that it has two closing and two opening springs.[3.18]

The Westinghouse low-voltage DB circuit breakers use a solenoid operated mechanism. The solenoid operated mechanism is similar to that used in the Westinghouse DH circuit breakers, but differs in that the solenoid is vertical; the DB solenoid provides an upward force to push the breaker contacts closed, whereas the solenoid in the DH type pulls on the mechanism linkage to close the breaker contacts. The breaker is tripped mechanically or electrically by rotation of the trip shaft.[3.19, 3.20]

Westinghouse low-voltage DS circuit breakers use the stored energy spring mechanism discussed in Section 3.4.1.6. The opening and closing springs are extended for operation.[3.7]

3.4.2.3 Arc Extinguishing System

The arc-chutes of General Electric medium-voltage AM circuit breakers consist of arc runners, magnetic blowout coils, interleaving fins, and a puffer mechanism. The arc-chute is mounted horizontally adjacent to the arcing contacts. The arc travels from the arcing contacts to the arc runners that are located on each side of the arc-chute. The first set of blowout coils is energized as the arc transfers to the arc runners. The blowout coils produce a magnetic field that helps to move the arc further into the arc-chute. The arc is also moved into the arc-chute by a blast of air from a piston-cylinder assembly. The arc is lengthened and weakened in a gradually deepening serpentine path until it is finally extinguished.[3.12, 3.13, 3.14]

Westinghouse medium-voltage DH type circuit breakers use a vertically mounted arc-chute, which is divided into two main interrupter stacks by an H-shaped blowout magnet, magnetic blowout coils, and a transfer stack. The blowout magnet is located so that the core passes through the center of the arc-chute. The blowout coils are wound about the core of the magnet. One terminal of each coil connects to either of a set of transfer arc runners located on each side of the magnet-coil assembly. The other terminals are joined with a shading coil. The shading coil helps to extend the arc. The transfer stacks are located within the space between the transfer arc runners and the shading coil. The main interrupter stacks consist of a series of insulating refractory plates with inverted V-shaped slots molded into them. The plate slots are offset to form a serpentine path.[3.15]

The arc extinguishing process in the DH type circuit breaker begins when the arc is transferred from the arcing contacts to the main and transfer stack arc runners. The arc is then divided in two by the transfer stack, which extinguishes the middle portion of the arc between the transfer stack arc runners. As the two remaining arcs move up the transfer stack, blowout coils are placed in series with the arc and energized. The two arcs are then driven into the arc-chute plates by the magnetic field produced by the blowout coils and a magnetically induced blast of gas. De-ionization and extinguishment of the arcs occur as the arcs are driven deeper into the arc-chutes.[3.15]

The Westinghouse DH-P type circuit breaker uses an arc-chute similar in design to that of the DH breaker. It differs from the DH breaker only in that it uses a piston-cylinder, air-puffer mechanism instead of a magnetically induced blast of air to drive the arc into the arc-chute plates for extinction.[3.16]

General Electric low-voltage AK circuit breakers use a vertical arc-chute, which consists of a series of crosswise, vertical steel splitter plates with an inverted V-notch inside a molded case. Arc interruption is achieved using natural processes. As the arcing contacts separate and the arc is lengthened, the thermal effect and natural magnetic field produced by the arc help to move it into the arc-chute plates. Once inside the plates, the arc is lengthened, weakened, and extinguished. The hot, ionized gases that accompany arc interruption exit the arc-chute through a muffler at the top of the assembly. The muffler contains serpentine-shaped strips of perforated, copper-plated steel. The serpentine path allows safe and controlled escape of the ionized gases at a cooler temperature.[3.17]

ITE/Gould/Brown Boveri low-voltage circuit breakers use a vertical arc-chute that is similar to the General Electric AK arc-chute design in two ways: (1) it consists of a series of crosswise, vertical steel splitter plates with an inverted V-notch inside a molded case and (2) it uses natural processes for arc interruption. The ITE/Gould/Brown Boveri arc-chute differs from the General Electric AK design in that the ionized gases are exhausted to the atmosphere directly through the splitter plates as extinguishment occurs.[3.21]

The Westinghouse arc-chute used in the low-voltage DB and DS type circuit breakers is similar to the ITE arc-chute design. The Westinghouse arc-chute consists of vertical, steel splitter plates with an inverted V-notch that are oriented crosswise in a molded case. Arc interruption occurs through natural processes. The ionized gases that accompany arc interruption are exhausted directly through the splitter plates.[3.7, 3.19, 3.20]

3.4.2.4 Primary Disconnects

The General Electric medium-voltage AM circuit breakers use the contact finger and stud disconnect. The contact fingers are located on the switchgear housing and the studs are located on the top of the circuit breaker. These disconnects consist of several silver-plated copper fingers supported longitudinally at their center by a non-magnetic metal spider. The fingers slide over the circuit breaker studs to a semi-circular groove machined in the outward end of the breaker studs. A set of garter springs provides the pressure needed to slide the fingers into the stud groove. A double set of stainless steel garter springs holds the fingers in place in the grooved stud end. The articulated action of the sliding contact fingers permits considerable misalignment of the breaker studs with no loss of contact pressure.[3.12, 3.13, 3.14]

Westinghouse medium-voltage DH and DH-P circuit breakers use the finger and stab primary disconnect design. Several groups of circular, movable finger clusters are located at the back of each circuit breaker. These fingers slide over stabs located at the back of the circuit breaker compartment. Contact pressure is maintained by a set of compressive springs that encircle the contact fingers.[3.15, 3.16]

General Electric low-voltage AK circuit breakers use the contact finger and stab disconnects. Each disconnect assembly consists of two pairs of opposed contact fingers. When engaged with the stationary stud of the enclosure, the disconnect fingers exert a set amount of force against the stationary stab through the action of compression springs.[3.17]

ITE/Gould/Brown Boveri low-voltage circuit breakers use the finger and stab primary disconnect design. The fingers are arranged in circular or straight line groups. The fingers slide over stabs located at the back of the circuit breaker compartment.[3.18]

The Westinghouse low-voltage DB and DS circuit breakers have disconnects that are similar to the General Electric AK disconnects. Each disconnect assembly consists of two pairs of opposed contact fingers. When engaged with the stationary stud of the enclosure, the disconnect fingers exert a set amount of force against the stationary stab through the action of compression springs.[3.7, 3.19, 3.20]

3.4.2.5 Internal Protective Devices

Internal protective trip devices are commonly used on low-voltage circuit breakers; that is, the protective relays are located on the drawout breaker rather than being separate devices located on the switchgear housing as in medium-voltage systems. Generally speaking, these internal protective devices are designed to protect against either overcurrent or undervoltage conditions.

Overcurrent trip devices can be divided into two major classifications: (1) electromechanical devices and (2) solid-state devices. Many General Electric (e.g., Type AK-15/25), ITE/Gould/Brown Boveri (e.g., K225), and Westinghouse (e.g., Model DB) breakers use simple overcurrent devices (unless retrofitted with solid-state overcurrent devices). More modern circuit breakers use current transformers and internal electronic devices such as the Amptector (Westinghouse), Power Shield (ABB), or MicroVersa (General Electric) trip units.

Electromechanical overcurrent devices utilize a magnetic element in conjunction with a mechanical armature and retarding force/damping mechanism. The full current of the main circuit flows through the coil of these electromechanical overcurrent devices. This current generates a force on the magnetic element; this force overcomes the force of the retarding device, and the armature assembly trips the breaker via a mechanical trip lever arrangement. The damping mechanism is used to control the time delay of the trip to allow momentary inrush currents (such as are encountered during motor start) without tripping of the breaker. Large overload currents will instantaneously trip the breaker.

Solid-state overcurrent devices sense current from the conductor(s) via a separate current transformer, the output of which is fed to the solid-state detector unit. Circuitry within the unit senses the input from the sensor and, based on the settings of the unit, controls the overcurrent tripping characteristics of the breaker. The output of the solid-state unit is fed to an electromechanical actuator unit that physically displaces the trip mechanism upon appropriate signal from the control unit.

Undervoltage trip attachments are used only on those low-voltage circuit breakers that are installed in reactor trip applications. An undervoltage trip attachment is a device that, upon de-energization, causes the circuit breaker to trip. They are most frequently used in nuclear power plants on reactor trip breakers so that as long as the undervoltage trip attachment remains energized, the power flows to the reactor control rod drive mechanisms. To trip the reactor, the devices are de-energized. The undervoltage trip attachments are fail safe in that a loss of power causes the reactor to trip. Undervoltage trip attachments are relatively unsophisticated in their design and operation compared with undervoltage protective relay schemes used for medium-voltage switchgear control; as previously discussed, protective relays are not within the scope of this document.[3.7, 3.19, 3.20]

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 Switchgear

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. These criteria provide general guidance with respect to redundance, 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 of the application of switchgear.

The FSARs for various plants provide varying levels of detail about licensing commitments regarding switchgear. For medium-voltage switchgear (e.g., 4.16 kVac), FSARs for the older plants essentially state the continuous rating of the bus (e.g., 2000 A) and the incoming (source) breakers (e.g., 2000 A) and feeder (load) breakers (e.g., 1200 A). They also state the interrupting rating for the source and load circuit breakers (e.g., 250 MVA). No standards are discussed that would dictate design of the switchgear or its application. For 480-Vac switchgear, similar ratings are provided (e.g., bus and breaker normal rating 1600 A with a 25,000 A RMS symmetrical minimum interrupting rating). Again, no standards are discussed relating to design.[3.22]

FSARs for newer plants provide similar information; however, they tend to cite certain ANSI standards with respect to determination of short-circuit currents available from the electrical system. These FSARs cite various ANSI switchgear standards concerning short-circuit currents and interrupting capabilities, including C37.010-1972, "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," and C37.13-1973, "IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures;" or C37.06-1971, "Preferred Ratings and Related Required Capabilities for AC High-Voltage Circuit Breakers Rated on Symmetrical Current Basis," and C37.04-1969, "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."[3.23] These standards provide much more guidance concerning design of switchgear than just short circuit or interrupting capability guidance. They govern normal and transient voltage ratings, expected operating cycle capability, and temperature limitations to be placed on switchgear components.

In general, although few standards are quoted as licensing commitments related to switchgear design, many industry standards are quoted as purchase specification requirements. This ensures that the switchgear is manufactured and tested to current industry standards before it reaches the purchaser. The following standards have been used in purchase specifications:

- ANSI/IEEE C37.010, "Application Guide for AC High-Voltage Circuit Breakers"
- ANSI/IEEE C37.4, "Alternating-Current Power Circuit Breakers"

- ANSI/IEEE C37.5, "Methods for Determining Values of a Sinusoidal Current Wave, a Normal-Frequency Recovery Voltage, and a Guide for Calculations of Fault Current for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis"

- ANSI/IEEE C37.6, "Schedules of Preferred Ratings and Related Required Capabilities for AC High-Voltage Circuit Breakers"

- ANSI/IEEE C37.9, "Test Code for Power Circuit Breakers"

- ANSI/IEEE C37.11, "Requirements for Power Circuit Breaker Control"

- ANSI/IEEE C37.13-1974, "Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures"

- ANSI/IEEE C37.16-1980, "Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage Power Circuit Breakers and AC Power Circuit Protectors"[3.24]

- ANSI/IEEE C37.20, "Switchgear Assemblies Including Metal-Enclosed Bus"

- ANSI/IEEE C37.50-1981, "Test Procedures for Low-Voltage AC Power Circuit Breakers Used in Enclosures"[3.25]

- ANSI/IEEE C37.51-1979, "Conformance Testing of Metal-Enclosed Low-Voltage AC Power Circuit Breaker Switchgear Assemblies"

- ANSI/IEEE C37.90-1978, "Relays and Relay Systems Associated with Electric Power Apparatus"

- ANSI/IEEE C57.13, "Requirements for Instrument Transformers"

- ANSI/IEEE C68.1-1968, "American National Standard Techniques for Dielectric Tests"

- NEMA SG-3-1981, "Low-Voltage Power Circuit Breakers"

- NEMA SG5-81, "Power Switchgear Assemblies"

- NEMA ICS 1-109-1985, "General Standards for Industrial Control and Systems - Tests and Test Procedures"

- NEMA ICS-4-1983, "Terminal Blocks for Industrial Control and Systems - Tests and Test Procedures"

- UL 1066-1985, "Standard for Low-Voltage AC and DC Power Circuit Breakers Used in Enclosures"

- AWS D1.1-1988, "Structural Welding Code"
- ICEA S-66-524-1983, "Cross-Linked-Thermosetting-Polyethylene-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy."

The ANSI standards C37.50 and C37.16 prescribe requirements for performing manufacturing qualification tests for the circuit breakers. In these tests, the basic design is confirmed as being acceptable by testing the interrupting capability, the load and no-load cycling capability, and the voltage withstand capability of the circuit breakers. For example, these standards require a 480-Vac circuit breaker with a 1600 A normal rating to be tested to verify that it can withstand 500 operating cycles between servicing, 800 close-open cycles at full normal current, and an additional 3200 cycles at no load without having to replace components. This indicates that servicing should be performed at least every 500 cycles. (Note: Servicing in this context means to adjust, clean, lubricate, and tighten.) Therefore, with a combination of design qualification cycling tests and appropriate periodic servicing, a life of approximately 4000 cycles should be achievable for this class of circuit breaker before refurbishment or replacement is necessary.[3.24] This estimate is based in part on the assumption that the conditions under which a given breaker is cycled vary with respect to load (i.e., some cycles will occur under no-load conditions, some under full load, etc.). It should also be noted that as the normal current rating for a circuit breaker increases, the number of operating cycles required for manufacturing qualification under the standards decreases.

One generic issue that does apply to safety-related switchgear 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 [3.26, 3.27, 3.28] and of IEEE Standard 344 [3.29, 3.30, 3.31] was determined on a plant-by-plant basis during the licensing process. The "For Comment" version of Regulatory Guide 1.100 [3.26] indicates that the guidance of IEEE Standard 344-1975 [3.30], as amended by the Regulatory Guide, would be applicable to plants with applications for construction permits dated by November 15, 1976. Revision 1 to Regulatory Guide 1.100 [3.27] also endorses and amends IEEE Standard 344-1975, but does not state explicit dates of applicability. Revision 2 to Regulatory Guide 1.100 [3.30] endorses and amends IEEE Standard 344-1987 [3.31], and is applicable to plants whose construction permit is issued after June 30, 1988 or whose operating license application is dated after December 30, 1988.

To address seismic qualification of switchgear 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. With respect to switchgear covered by this report, SQUG concluded that the switchgear would withstand the levels of earthquake expected for U.S. nuclear plants, provided the structures were reasonably anchored, that interactions between equipment had been considered (e.g., adjacent equipment would not fall upon or hit the switchgear during an earthquake), and that the conduits and wires connected to the switchgear were flexible.[3.32]

Those plants licensed to Regulatory Guide 1.100 and IEEE Standard 344 had to seismically qualify the equipment by either test or analysis. Most of the switchgear designs for more modern plants were actually subjected to seismic tests. IEEE Standard 344 provides guidance on performing seismic analyses and seismic testing of electrical components. IEEE Standard 344-1975 indicates that when physical testing is performed, five operating basis earthquakes and one safe shutdown earthquake shall be simulated on a specimen. If single axis testing is to be performed, the testing is to be performed for each principal axis. Multi-axis simultaneous testing is also allowed and has become the preference of the industry.

Most switchgear is located in mild environments that do not experience significant changes in temperature, pressure, humidity, and radiation. As such, switchgear as a class is generally not subject to formal environmental qualification programs. In certain plants, some low-voltage switchgear is located in areas that can experience moderately harsh environments in the event of an accident. The environmental qualification of these components is discussed in Section 3.5.4.

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

Section 8.1 of NUREG-0800 [3.33] provides a Standard Review Plan (SRP) for the review of electric power systems. Although the SRP did not form the licensing basis for the older plants, the SRP was reviewed to identify the issues and concepts related to aging management for switchgear.

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 ac power systems:

- General Design Criteria (GDC) 17, "Electrical Power Systems" [3.34]
- General Design Criteria (GDC) 18, "Inspection and Testing of Electric Power Systems" [3.35]
- Regulatory Guide (RG) 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants" [3.36]
- RG 1.118, "Periodic Testing of Electric Power and Protection Systems" [3.37]
- Branch Technical Position (BTP) PSB-1, "Adequacy of Station Electric Distribution System Voltages" [3.33].

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

Document	Content
GDC 17	Provides requirement for electrical system redundance, 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 Standard 308-1974 are generally acceptable to the NRC staff and provide an adequate basis for compliance.
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 Standard 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.

IEEE Standard 308-1980, "Criteria for the Periodic Testing of Nuclear Power Generating Station Safety Systems,"[3.38] and IEEE Standard 338-1977, "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations,"[3.39] were also reviewed for their applicability to electrical switchgear aging. IEEE Standard 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, preoperational tests, and periodic tests. In Section 7.4 of IEEE Standard 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 electrical switchgear.

IEEE Standard 338-1977 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 electrical switchgear.

Section 8.3 of NUREG-0800, "A-C Power Systems (Onsite)," was also reviewed to determine if it contained provisions pertaining to maintenance or aging of electrical switchgear components important to license renewal. This section of the SRP provides guidance for the review of the ac onsite power system to ensure that the system complies with the requirements of General Design Criteria 2, 4, 5, 17, 18, and 50 and will perform its intended functions during all plant operating and accident conditions. No specific criteria for electrical switchgear maintenance or aging are provided.

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

3.5.2 Qualification Limits for Components Exposed to Abnormal Environments

Most medium- and low-voltage switchgear is 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 switchgear may be exposed to secondary effects of a loss-of-coolant accident or high-energy-line break outside containment. In nearly all plants, the medium-voltage switchgear is located in equipment rooms that are not exposed to significant increases in temperature and would not experience significant radiation doses during accident conditions. In a few plants, medium-voltage switchgear may experience a moderately low radiation dose (1.5×10^5 rd) [3.40] as a result of an accident. Although most low-voltage switchgear is likewise located in mild environment areas, more instances exist of this type of switchgear being located in areas having elevated accident environments. This condition exists because low-voltage switchgear units are frequently distributed around a power plant where they may be adjacent to rooms that are subject to high-energy-line breaks or be in the vicinity of piping that contains circulating radioactive liquids. These units may be subjected to radiation doses of a few megarads and moderately high temperature (160° to 180°F), high humidity conditions as a result of an accident in an adjacent area. In most cases, plants having switchgear in harsh environment areas are older plants. The need to qualify the switchgear frequently was identified after the plant was in service. Accordingly, generic manufacturers' environmental qualification programs do not exist for the switchgear, 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 switchgear 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, and Bulletins was conducted to determine the industry-wide operating experience with electrical switchgear components. Each applicable Notice, Circular, and Bulletin is discussed in Section 3.6.1 by component. Those Notices, Circulars, and Bulletins that apply to switchgear but were not considered applicable to this report (e.g., defects due to improper manufacturing) are listed in Appendix B with a justification for elimination. A summary of the operating experience with electrical switchgear is given in Table 3-2.

Table 3-2. Summary of Operating Experience from Information Notices, Circulars, and Bulletins

Component	Source	Failure	Cause	Corrective Action
Bus and Insulator	Notice 89-64	Tracking (4160 V)	Noryl insulation deterioration	Replaced bus bar; replaced defective bus joint compound; modified bus enclosure; improved and increased cleaning and periodic inspection
Stored Energy Spring Operating Mechanism	Bulletin 79-09	Binding in trip shaft mechanism (GE AK-2)	Inadequate preventive maintenance	Cleaned and relubricated trip shaft mechanism
	Bulletins 83-01, 83-04, and 83-08	Binding of trip bar latch assembly (West. DB-50 and GE AK-2)	Improper lubrication, hardened and contaminated grease in bearings, excessive wear of moving parts	Cleaned and relubricated trip bar latch assembly
	Notice 87-12	Binding in main mechanism (GE AKF)	Improper lubrication, out-of-adjustment condition	General Electric recommended special maintenance practices for the AK series circuit breakers, including performance of maintenance and inspection every 12 months or at each refueling outage with a complete overhaul every 5 years, the use of only specified lubricants, and the use of only qualified maintenance technicians to perform maintenance
	Notices 87-35; 87-35, Sup. 1; and Bulletin 88-01	Binding of operating mechanism	Abnormal wear, broken weld from substandard manufacturing practices	Recommended short- and long-term inspections to identify weld problems
	Notice 88-42	Loose spring charging motor mounting bolts	Bolts not properly torqued at time of installation	Removed bolts, cleaned and coated with Locktite, torqued to proper value

Table 3-2. Summary of Operating Experience from Information Notices, Circulars, and Bulletins (continued)

Component	Source	Failure	Cause	Corrective Action
Stored Energy Spring Operating Mechanism (continued)	Notice 88-44	Binding in spring release device (West. DS-416)	Undetermined	Replaced device and verified that clearances were sufficient to preclude further binding
	Notice 90-41	Broken prop springs (GE Magne-Blast & AK)	Metal fatigue crack in spring	Replaced springs; some utilities established replacement intervals to prevent fatigue failure
	Notice 91-15	Failed to close due to incorrect configuration springs (GE-AK)	Improper assembly during refurbishment or servicing caused springs to become disengaged during operation	General Electric recommended that service centers verify spring orientation after refurbishment or servicing
Undervoltage Trip Device	Bulletin 79-09 and Circular 81-12	Failure to operate due to binding and out-of-adjustment condition (GE AK)	Inadequate preventive maintenance	Cleaning and relubrication corrected the problem; recommended that surveillance procedures for the trip test be revised as necessary to provide independent testing of UV device function and shunt trip function
	Bulletin 83-04	Binding within UV trip mechanism (GE AK)	Binding and out-of-adjustment conditions	Recommended verification of UV trip function independent of shunt trip function during maintenance; verify that maintenance program conforms to latest Westinghouse recommendations
	Bulletin 85-58, Sup. 1	Exceeded established response time (GE AK)	Movement of laminated armature sections	Replacement of UV device and institution of program to measure the air gap between laminations and the pole face on a yearly basis
Undervoltage Trip Device	Bulletin 83-01	Failure to open (West. DB-50)	Sticking	Utilities were required to perform surveillance test of UVTA function independent of the shunt trip function and to review Westinghouse maintenance procedures for conformance to latest recommendations.

Table 3-2. Summary of Operating Experience from Information Notices, Circulars, and Bulletins (continued)

Component	Source	Failure	Cause	Corrective Action
Undervoltage Trip Device (continued)	Bulletin 83-08	Failure of UV devices and associated linkages (West. DB and DS, GE AK, and other types in other safety-related applications)	Improper lubrication, inadequate adjustment of spring tension, excessive wear of moving parts	Utilities were required to identify all subject breakers in reactor trip and other safety-related applications and perform the following: (1) review design of the device and connecting linkage and evaluate design margin adequacy, (2) review surveillance procedures, (3) review operating experience, and (4) take actions as necessary
		Failure to close during testing (West.)	UVTA latch wear	Perform lubrication as required
Control Circuit	Notice 83-50	Failure to close due to malfunctioning control circuitry	Dirty or corroded contacts, malfunctions in the spring charging motor	Recommended improvements in local surveillance, maintenance procedures, and training of operations personnel
Cell Switches	Notices 87-61 and 87-61, Sup.1	Failure to close (West. DS)	Deformation of the spring retainer in the spring-return mechanism due to tensile stress	Recommended verification of switch operability through a continuity check of a spare set of contacts when the breaker is racked out and replacement of the spring or spring retainer after approximately 10 years of service if deformation has occurred

Switchgear failure data derived from the Nuclear Plant Reliability Data System (NPRDS) and NRC Licensee Event Reports (LERs) were also reviewed. This information was further supplemented with NPRDS, overhaul, and LER data contained in the EPRI NMAC Circuit Breaker Maintenance series.[3.41, 3.42, 3.43, 3.44] Switchgear component failures were analyzed in an attempt to identify significant failure mechanisms and their likelihood of occurrence. This analysis is discussed in Section 3.6.2.

3.6.1 Description of Industry-wide Operating Experience with Components

3.6.1.1 Metal Housing System

There were no reports of metal housing system failure in the Bulletins, Circulars, and Information Notices.

3.6.1.2 Bus and Insulators

NRC Information Notice 89-64, "Electrical Bus Bar Failures," [3.45] reported the failure of a 13.8-kV bus bar and a 4160-V bus bar. The failure of the 13.8-kV bus bar, a phase-to-ground fault, was attributed to cracked and brittle Noryl insulation and dirt that had accumulated in the bus enclosures. The cracking and dirt accumulation, combined with the presence of moisture, led to arc tracking, which caused a phase-to-ground fault to occur. The failure of the 4160-V bus bar insulation was also caused by Noryl insulation deterioration. The deterioration was the result of a manufacturing defect in which "black" bus bar joint compound contaminated the insulation. After several years, the contamination caused the insulation to crack.

The bus failures were remedied by the following measures: (1) replacement of bus bar sections with bus bars having a different insulating material, (2) replacement of defective bus joint compound, (3) modification of bus enclosures to restrict moisture and dirt accumulation, and (4) implementation of enhanced periodic inspections and cleaning of bus bars and their housings.

3.6.1.3 Primary and Secondary Disconnects

There were no reports of primary or secondary disconnect failure in the Bulletins, Circulars, and Information Notices.

3.6.1.4 Racking Mechanism

There were no reports of racking mechanism failure in the Bulletins, Circulars, and Information Notices.

3.6.1.5 Main Contacts

There were no reports of main contact failure in the Bulletins, Circulars, and Information Notices.

3.6.1.6 Operating Mechanism

IE Bulletin 79-09, "Failures of General Electric Type AK-2 Circuit Breakers in Safety-Related Systems,"[3.46] discusses the failure of General Electric AK circuit breakers to trip open on demand. The failures were attributed to binding within the circuit breaker trip shaft assembly. The binding was caused by inadequate preventive maintenance programs at the affected utilities. Cleaning and relubrication of the trip shaft bearings were required to correct the problems.

IE Bulletin 83-08, "Electrical Circuit Breaker with an Undervoltage Trip Attachment (UVTA) in Use in Safety-Related Applications Other Than the Reactor Protection System," [3.47] analyzed the testing of reactor trip breakers required by Information Bulletins 83-01, "Failure of Reactor Trip Breakers (Westinghouse DB-50) to Open on Automatic Trip Signal," [3.48] and 83-04, "Failure of the Undervoltage Trip Function of Reactor Trip Breakers."[3.49] Although most of the problems reported in Bulletins 83-01 and 83-04 were caused by faulty undervoltage trip devices, the following problems with circuit breaker operating mechanisms were also discussed: (1) improper lubrication of the circuit breaker trip bar latch assembly, (2) hardened and contaminated grease in circuit breaker trip shaft bearings, and (3) excessive wear of moving parts in the trip bar latch assembly due to infrequent lubrication. Cleaning and relubrication of the breaker trip shaft assembly corrected the problems with the assembly.

IE Information Notice 87-12, "Potential Problems with Metal-Clad Circuit Breakers, General Electric Type AKF-2-25,"[3.50] examines the failure of General Electric AKF-2-25 circuit breakers to open on demand. Mechanical binding of the main mechanism (cam arrangement), resulting in shunt trip coil burnout, was the main cause of the failures. A failure evaluation determined that improper lubricants had been used and the breakers were out of adjustment.

General Electric issued Service Information Letter Number 448 to address the special maintenance practices developed for the entire AK breaker series. In addition, General Electric recommended the following: (1) perform maintenance and inspection every 12 months or at each refueling outage (with breaker overhaul every 5 years), (2) use only specified lubricants on the circuit breakers, and (3) use only qualified, properly trained maintenance technicians to perform maintenance on these breakers.

NRC Information Notice 87-35, "Reactor Trip Breaker, Westinghouse Model DS-416, Failed to Open on Manual Initiation From the Control Room,"[3.51] discusses breaker failure due to mechanical binding of the operating mechanism. The binding that occurred also caused shunt trip coil failure because it did not allow the shunt trip coil to de-energize. The shunt trip coil eventually burned and opened. A failure investigation revealed that a broken weld and abnormal wear caused the mechanism to bind.

NRC Information Notice 87-35, Supplement 1, "Reactor Trip Breaker, Westinghouse DS-416, Failed to Open on Manual Initiation from Control Room,"[3.52] analyzes the mechanical binding reported in Notice 87-35 in greater detail. The broken weld was located on the main drive link between the center pole lever and the pole shaft (the pole shaft connects the poles of all three phases so that they open and close simultaneously). The weld failure allowed the main linkage to move laterally and jam at or near full closure. A large number of operating cycles (3000 or more) caused wear that allowed sufficient rotation of the main roller axis such that wedging occurred and the breaker failed to open.

NRC Bulletin 88-01, "Defects in Westinghouse Circuit Breakers,"[3.53] discusses one additional weld failure that caused mechanism binding and the detection of broken welds during routine maintenance in response to Notice 87-35, Supplement 1. The center pole lever weld failure reported in Bulletin 88-01 freed the center moving contact assembly such that it could move independently of the pole shaft that drives the other two moving contact assemblies. The failure caused electrical single phasing problems (i.e., only two out of the three poles closed properly) and resulted in erratic operation of the connected equipment. An engineering analysis of the failed weld concluded that the failure occurred because of excessive porosity. The broken center pole lever welds identified during routine maintenance, which had not yet caused breaker failure, were caused by an extensive lack of fusion of the weld to lever as a result of improper weld technique.

Bulletin 88-01 concluded that failures of the operating mechanism center pole lever-to-pole shaft welds were a result of substandard welding during manufacturing. All licensees with Westinghouse DS breakers were directed to perform short-term and long-term inspections of the breaker closing mechanism to identify any weld problems. Short-term inspections were to consist of main pole lever inspections. Long-term inspections were to consist of inspections of the pole shaft welds and a direct check of the alignment of the breaker closing mechanism. Although the cause of the weld failures was substandard workmanship, the failures were age-related in that sufficient operating cycles were required for fatigue failure of the welds to occur.

NRC Information Notice 88-42, "Circuit Breaker Failures Due to Loose Charging Spring Motor Mounting Bolts,"[3.54] discusses the failure of an emergency diesel output circuit breaker to close. The failure was attributed to loose charging spring motor mounting bolts. The loose bolts allowed the motor to become detached from the breaker frame. As a result, the motor did not charge the closing spring and the breaker would not close. The utility determined that the charging spring motor mounting bolts had not been sufficiently torqued by the vendor. The bolts were removed, cleaned, coated with Locktite, and torqued to alleviate the problem. Although the root cause of the breaker failure was an installation deficiency, the loosening of the bolts holding the motor to the breaker frame was induced by mechanical stress and vibration occurring cumulatively during the period of installation, and can therefore be considered an age-related failure that can be managed through appropriate practices.

NRC Information Notice 88-44, "Mechanical Binding of Spring Release Device in Westinghouse Type DS-416 Circuit Breakers,"[3.55] examines the failure of two DS-416 tie and feeder circuit breakers to reclose on demand during load sequencing. The breakers failed to reclose due to mechanical binding between the spring release lever and the edge of the breaker casing window. The binding prevented the lever from making contact with the spring release latch that releases the breaker closing springs. Thus, the closing coil, which becomes energized and moves the lever, could not deenergize; it overheated and burned out. Although the root cause of the binding was not determined, the utility replaced the spring release device in the breakers that had signs of binding and verified that the clearances between the lever and the casing were sufficient to preclude further binding.

NRC Information Notice 90-41, "Potential Failure of General Electric Magne-Blast and AK Circuit Breakers,"[3.56] discusses operating problems with prop springs. A prop spring holds the prop in position when the breaker is closed so that it prevents the operating mechanism from tripping the breaker. A broken prop reset spring caused failure in three different types of General Electric circuit breakers: an AM-4.16 kV, an AM-4.16-350-1H, and an AMH-4.76. In each case, the broken prop reset spring rendered the circuit breaker unable to remain closed. In the AM-4.16-kV circuit breaker, the spring failed as a result of a metal fatigue crack that initiated at a surface lap in the wire. The utility decided to prevent this type of failure by replacing prop springs every 2000 cycles. In the General Electric AM-4.16-350-1H circuit breaker, the spring failed as a result of a fatigue crack that had occurred at the end of the coil, where the wire was bent at 90° to form the hook. The circuit breaker had operated for 1400 cycles before failure. The spring was replaced and the breaker was returned to service. The cause of prop spring failure for the General Electric AMH-4.76 circuit breaker was not determined, but the circuit breaker had operated for 1625 cycles before failure. The utility replaced the prop reset springs on all safety-related circuit breakers with more than 900 cycles of operation.

NRC Information Notice N91-15, "Incorrect Configuration of Breaker Operating Springs in General Electric AK-Series Metal-Clad Reactor Trip Circuit Breakers,"[3.57] describes the failure of General Electric AK-series metal-clad circuit breakers used in reactor trip applications.* In one event, the utility determined that a reactor trip breaker failed to close due to incorrect configuration of the operating springs. Inspection of the remaining reactor trip breakers at the same utility revealed that the configuration of the operating springs was incorrect on three additional breakers. In a second event, reported by a different licensee, a reactor trip breaker failed because the two operating springs were disengaged. Inspection of the remaining reactor trip breakers found one other reactor trip breaker with the same problem.

General Electric inspected one of the failed breakers and confirmed that improper assembly during manufacturing or servicing was the cause of the reported failures. Because General Electric maintenance instructions provide neither instructions nor sufficient information to verify if the operating springs are correctly oriented, General Electric notified its service centers that refurbish breakers to verify if the operating springs are correctly oriented.

3.6.1.7 Arc Extinguishing System

There were no reports of arcing contact or arc-chute failure in the Bulletins, Circulars, and Information Notices.

3.6.1.8 Mechanical Interlocks

There were no reports of mechanical interlock failure in the Bulletins, Circulars, and Information Notices.

* Although not an age-related condition, this is a potential problem that should be covered by good maintenance.

3.6.1.9 Circuit Breaker Controls

Circuit breaker control components within the scope of this document (i.e., internal protective devices, auxiliary switches, internal wiring, etc.) are discussed collectively in the following paragraphs.

The majority of control failures reported in the Information Notices, Circulars, and Bulletins have been failures of either the General Electric electromagnetic type or the Westinghouse latch type undervoltage (UV) trip attachment. Because these devices are primarily used in reactor trip breakers, the failures reported for these devices are unique to the reactor trip application. (Note: UV attachments are not the same as protective undervoltage relays used on medium-voltage bus protection systems.)

IE Bulletin 79-09, "Failures of General Electric Type AK-2 Circuit Breakers in Safety Related Systems,"[3.46] addresses failures of General Electric AK-2 circuit breaker UV devices. The failures were attributed to binding and out-of-adjustment conditions in the UV device linkage mechanism. A failure investigation determined that the binding and out-of-adjustment conditions resulted from inadequate preventive maintenance programs. Cleaning and relubrication of the mechanism corrected the problem. The Bulletin required licensees to review their preventive maintenance programs for the UV device.

IE Circular 81-12, "Inadequate Periodic Test Procedure of PWR Protection System," [3.58] addresses the same problem: UV device failure due to binding. In this case, the binding was caused by an out-of-adjustment condition. This failure was attributed to an inadequacy in the periodic test procedure. The procedure did not verify the trip function of the UV coil trip independent of shunt trip coil. The Circular does not require any response, but does recommend that the procedure for surveillance trip testing of circuit breakers be reviewed and revised as necessary to provide independent testing of each trip function.

IE Bulletin 83-04, "Failure of the Undervoltage Trip Function of Reactor Trip Breakers," [3.49] also discusses the failure of General Electric AK-2 type UV devices to trip their associated reactor trip breakers during testing. The failures were also attributed to either binding or out-of-adjustment conditions within the linkage mechanism of the UV device and were not detected during previous testing because the shunt trip and UV device trip functions were not verified independently. The Bulletin also directed utilities to perform a surveillance test of the UV trip function independent of the shunt trip function and to review the maintenance program for conformance with the latest manufacturer's recommendation.

IE Information Notice 85-58, Supplement 1, "Failure of a General Electric Type AK-2-25 Reactor Trip Breaker,"[3.59] discusses a defect in the General Electric AK-2-25 UV device, which caused the UV devices to fail to meet their required response times.* A failure analysis revealed that several laminated sections had slipped down and effectively eliminated the air gap between the movable armature and the pole face. The physical contact between the lamination

* Although not an age-related condition, this is a potential problem that should be covered by good maintenance.

and pole face allowed the armature to be held down by residual magnetism after dc power was removed. The residual magnetism caused the UV devices to exceed their required response time. Corrective action involved replacing the UV trip devices and instituting a program to measure the air gap between the lamination and pole face on a yearly basis (there were no previous instructions in General Electric literature pertaining to the air gap between the lamination and pole face).

IE Bulletin 83-01, "Failure of Reactor Trip Breakers (Westinghouse DB-50) to Open on Automatic Trip Signal,"[3.48] discusses the failure of the Westinghouse DB-50 undervoltage trip attachment (UVTA) to open its associated reactor trip breaker on demand. The failure was attributed to sticking of the UVTA. The Bulletin required all PWR utilities with the subject UVTAs to perform a surveillance test of the UVTA function independent of the shunt trip function and to review the maintenance program for conformance with the recommended Westinghouse program.

IE Bulletin 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Feature in Use in Safety-Related Applications Other Than the Reactor Trip System,"[3.47] addresses failures of both Westinghouse DB-50 UVTAs and General Electric AK-2-25 UV devices, reported in Bulletins 83-01 and 83-04, respectively. The results of the testing required by Bulletins 83-01 and 83-04 indicated that most failures can be attributed to the UVTAs and UV devices and their associated linkages. Because UVTAs and UV devices provide only a limited force to trip the breaker, problems of alignment and lubrication can result in a failure of the breaker to perform its intended function. Some of the problems identified as causes for failure to trip included: (1) improper lubrication of linkages and other moving parts within the UVTA or UV device, (2) inadequate adjustment of spring tension of the UVTA or UV device, and (3) excessive wear of moving parts within the UVTA or UV device because of infrequent lubrication of the moving parts or improper adjustment of the spring tension.

Further investigation revealed that some PWRs and BWRs employ similar undervoltage features in other safety-related applications. These applications may include the engineered safety features systems and the 120-Vac uninterruptible power source from the motor generator sets in BWR plants. Circuit breakers supplied by manufacturers other than Westinghouse or General Electric may be used in some plants for these non-reactor trip breaker applications.

In addition to failure to trip, Bulletin 83-08 discussed failure of a Westinghouse breaker to close on demand. This failure occurred during life cycle demonstration tests conducted by Westinghouse and was directly related to the UVTA latching mechanism. The failure occurred on a new UVTA that was initially lubricated in accordance with the latest Westinghouse recommendation but which, for test purposes, was not subsequently lubricated. This failure to close occurred after 571 trip and reclose operations, and was attributed to normal latch wear. The latch wear placed the breaker mechanism in a trip-free condition such that the breaker could not be closed electrically or mechanically. This failure does not represent a safety concern in reactor trip breaker applications, but there is a concern that such failures could, in other applications, prevent the performance of a safety related function.

To address the problems reported in Bulletin 83-08, utilities were required to identify safety-related applications other than reactor trip breaker applications of all Westinghouse type

DB and DS and General Electric type AK-2 circuit breakers with the UV features discussed in Bulletins 83-01 or 83-04. Utilities were also required to identify similar applications of other types of breakers by other manufacturers that use a UV feature. For each circuit breaker type identified, utilities were to review the design of the UVTA or UV device and connecting linkage and evaluate design margin adequacy in view of safety applications, describe the current breaker surveillance program, review operating experience with the circuit breakers and UVTA or UV device, and describe any preventive or corrective measures taken or intended to be taken based on the review.[3.47]

As stated above, most of the failures reported in the Information Notices, Circulars, and Bulletins pertained to the UVTA. There are three Notices, however, that address control circuit problems. A discussion of each Notice follows.

NRC Information Notice 83-50, "Failures of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand,"[3.60] describes the results of a study conducted by the NRC to determine the causes of 108 circuit breaker failures to close on demand between January 1977 and August 1982. The study concluded that the failure of the circuit breakers to close on demand was caused by malfunctioning circuit breaker control circuitry. Failures were attributed to dirty or corroded contacts and malfunctions in the spring charging motor or associated spring position switch contacts. In addition, nearly 25% of the tabulated events involved the diesel generator output breaker. Generally, there are more permissive interlocks associated with the closing circuit of these breakers, and this indicates that failure to close on demand increases with increasing control circuit complexity. The results of the study suggest that improvements in local surveillance, maintenance procedures, and training of operations personnel could improve the functional performance of circuit breakers to close on demand.

NRC Information Notice 87-61, "Failure of Westinghouse W-2-Type Circuit Breaker Cell Switches,"[3.61] discusses potential problems resulting from the failure of these switches. The W-2-type cell switches are available as optional equipment for all Westinghouse DS switchgear cabinets. In the event reported, erroneous input into the emergency diesel generator logic system prevented the emergency diesel output breaker from closing. The utility identified deformation of the spring retainer in the spring-return mechanism of the cell switch as the root cause of the erroneous input. The spring retainer is continuously under stress whenever the breaker is racked in and releases whenever the breaker is racked out. Its deformation allowed a loss of spring tension that rendered the cell switch unable to spring-return to the racked out position when the breaker was racked out for maintenance. This provided the erroneous signal to the emergency diesel generator logic system and prevented the emergency diesel breaker from automatically closing. Subsequent inspections revealed that 35 out of 37 similar W-2-type switch spring retainers in the 480-volt system breakers exhibited some sign of deformation. All of the cell switches had been in use for close to 15 years.

Westinghouse determined that the deformation of the spring retainer in the spring-return mechanism of the cell switches was related to the aging of the component and that the failure mechanism was the continuous stress that the spring retainer experiences while the breaker is racked in. Westinghouse recommended that proper cell switch operation be verified through periodic visual inspections or testing whenever the breaker is racked out.

NRC Information Notice 87-61, Supplement 1, "Failure of Westinghouse W-2-Type Circuit Breaker Cell Switches,"[3.62] reports a change in Westinghouse recommendations concerning verification of cell switch operability from that given in Notice 87-61. Westinghouse determined that the W-2 cell switch may give the physical appearance of being in the proper position when the contacts have not actually changed state and that an electrical continuity check was the only reliable method to determine W-2 switch operability. As a result, Westinghouse recommended that switch operability be determined by a continuity check of a spare set of contacts whenever the breaker is in its racked-out position and that proper operability of the safety-related contacts be verified as part of the normal surveillance program. In addition, Westinghouse recommended that spring retainers of the switches with the spring under tension during normal operation be checked for deformation after approximately 10 years of service and that the complete switch or the spring retainer assembly be replaced if one of the spring retainer tabs was found to be deformed when compared with the opposite tab of the retainer assembly.

3.6.2 Evaluation of NPRDS, LER, and Overhaul Data

3.6.2.1 NPRDS Data

To substantiate the stressors and aging mechanisms postulated for electrical switchgear, actual plant component failure data were sought. One of the primary sources of this type of failure data is the Nuclear Plant Reliability Data System (NPRDS). Failure records contained in NPRDS include such information as the voltage class and type of equipment, date of discovery, cause category, and a brief narrative describing the event. NPRDS data do not, however, focus directly on component aging, as the data do 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 those which have 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 switchgear subcomponents that have a high incidence of degradation or failure relative to other subcomponents within the same equipment.

By permission of the Institute for Nuclear Plant Operations (INPO), a limited review of failure and deterioration data contained in the NPRDS database was conducted as part of this study. Switchgear data were requested to be sorted by voltage class, manufacturer, and model number. Reports pertaining to dc systems were included with those related to low-voltage ac systems because of similarities in the equipment (i.e., many of the low-voltage ac switchgear are also suitable for use in dc systems). Each of the failure reports generated by these sorts was then individually evaluated to determine its applicability to aging and aging mechanisms. Failure reports deemed to be applicable were then grouped by component; each component failure grouping was then sorted by failure mode (if known). The findings of this limited review (detailed in Tables 3-3 through 3-8) were then supplemented and compared with those generated in conjunction with the EPRI NMAC maintenance guide series (Section 3.2). The following subsections summarize the specific observations of both the Aging Management Guideline and NMAC NPRDS reviews by manufacturer and voltage class. It should be noted that the breaker and subcomponent classification schemes used in the NMAC analysis (i.e., frequently vs.

infrequently operated) are somewhat different than those in this study; despite these differences, the conclusions derived from the data concerning relative component failure frequency and degradation mechanisms are directly comparable and in agreement. A summary of the overall findings of the NPRDS review is provided at the end of this section.

3.6.2.1.1 General Electric 480-V Switchgear

The data from the General Electric 480-V portion of the NPRDS database covered five plants for the period from March 1983 to December 1990. Failure events were recorded for service periods ranging from 1 to 17 years from initial date of installation. Of 54 event reports, 35 involved failure to operate (would not open or close), 18 involved detection of degradation before failure occurred, 1 involved the inability to return equipment to service, and 1 resulted from improper maintenance. Of the 35 failures, 11 (31.4%) were associated with overcurrent trip devices, indicating that these devices were having an unusually strong effect on the failure rate. These failures were predominantly related to the electromechanical trip device (9 out of 11 events) rather than the solid-state devices (2 out of 11 events). The failures were predominantly unexpected trips, the lack of trips associated with failure to remain in calibration, or degradation of the trip device dashpot (leaking). The operating mechanisms were responsible for 7 failures to close, representing 20% of the operational failures. These events were related to wear and deterioration of lubrication. Problems with control devices (such as shunt trip attachments and closing coils) caused 5 events (14.3% of the operating problems). Table 3-3 lists the failures by classification. There were no events recorded in which the primary insulation system failed.

Review of the NMAC NPRDS analysis revealed similar results, in that a high incidence of breaker operating mechanism failures (primarily caused by contaminated or deteriorated lubrication) and electrical control device failures (including both solid-state and electromechanical trip devices) was noted (see Section 3.2 of References 3.41, 3.42, 3.43, and 3.44).

3.6.2.1.2 Westinghouse 480-V Switchgear

The data from the NPRDS database covered five plants during the period September 1985 through November 1991. Failure events were recorded for service periods ranging from 1 to 17 years from initial date of installation. Equipment covered by these reports included both Westinghouse Model DB and DS breakers. Of 30 event reports, 21 involved failure to operate (would not open or close), 5 involved detection of degradation before failure occurred, 1 involved the inability of equipment to be returned to service, and 3 resulted from improper maintenance. Despite the relatively low total number of reports, some observations concerning breaker subcomponents can be made. Of the 21 failures noted, 6 (28.6%) were associated with control devices. Of these 6, 3 spring release device failures (associated with high-cycle applications at the same plant) were identified. Although other portions of the switchgear experienced failures (including several caused by unknown causes), a significant number of events for particular components was not noted. However, dirt, lack of lubrication, and wear appear to be common causes among these reports. Data related to pole shaft weld failure were not included based on manufacturing defects. Table 3-4 provides a listing of the events for the Westinghouse 480-V switchgear by subsystem. There were no events recorded in which the primary insulation system failed.

Table 3-3. NPRDS Data for General Electric 480-Volt Circuit Breakers (Data from five plants during period from March 1983 through December 1990)

Number of Events	Problem	Effect on Operation	Comments
Racking Mechanism			
1	Racking mechanism bent	Failure to close	Returned to service; racking mechanism prevented breaker from closing
Main Contacts			
1	Dirty contacts	No immediate effect[a]	
Arcing Contacts			
1	Burnt/cracked arcing contacts	No immediate effect[a]	Replaced circuit breaker
Secondary Disconnects			
2	Dirty/corroded secondary disconnects	Failure to close	
1	Secondary disconnects pitted and burned	Spurious opening	
1	Loose connection	Failure to close	
Operating Mechanism (Opening and Closing)			
1	Closing coil spring not in proper position	Failure to close	
1	Hardened grease in linkage	Failure to close	
1	Lack of lubrication and dirt in operating mechanism	Failure to close	
1	Worn breaker linkage	Failure to close	
1	Latching mechanism out-of-adjustment	Failure to close	
2	Closing prop would not drop into place	Failure to close	
Charging Mechanism			
1	Lack of lubrication on charging mechanism bearing	Failure to close	
4	Charging motor gear box oil leak	No immediate effect[a]	Replaced gasket

Table 3-3. NPRDS Data for General Electric 480-Volt Circuit Breakers (Data from five plants during period from March 1983 through December 1990) (continued)

Number of Events	Problem	Effect on Operation	Comments
Control Devices			
4	Shunt trip device worn out	Failure to open; spurious opening	The failures occurred at the same plant
1	Shunt trip coil failure	Failure to open	
1	Closing coil burned	No immediate effect[a]	Replaced coil
Overcurrent Trip Device			
4	Trip device out-of-adjustment	Failure to operate as required	Two of the failures occurred at the same plant, on the same breaker, 5 years apart
1	Trip device dashpot failure	Failure to close	
2	Solid state trip device failure	Failure to open; failure to operate as required	
3	Trip device out of calibration	Failure to remain closed; failure to open	Two of the failures occurred at the same plant, on the same breaker, 4 years apart
1	Trip device coil bad	Failure to remain closed	
1	Trip device coil bad	No immediate effect[a]	Replaced trip device
8	Trip device dashpot leaking oil	No immediate effect[a]	Replaced trip device; this degradation occurred at the same plant
1	Trip device failure	No immediate effect[a]	Out of calibration; replaced
Trip Mechanism			
3	Trip latch out-of-adjustment	Spurious opening	Two of the failures occurred at the same plant, on the same circuit breaker, 4 months apart
Auxiliary Contacts			
1	Auxiliary relay contact burned	No immediate effect[a]	Replaced auxiliary relay contactor
Miscellaneous			
1	Dirty circuit breaker	Failure to close	
2	Unknown	Failure to close	

Table 3-3. NPRDS Data for General Electric 480-Volt Circuit Breakers (Data from five plants during period from March 1983 through December 1990) (continued)

Number of Events	Problem	Effect on Operation	Comments
Maintenance/Calibration Deficiency			
1	Racking mechanism bent and out of alignment	Failure to rack in	

Summary

Description	Number
Total number of events	54
Events affecting operation (failures)	35
Inability to return to service	1
Events with no immediate effect (observed during maintenance/testing)	18
Maintenance-induced events[b]	1

Breakdown of Events Affecting Operation

Failed Subsystem	Number / % of Total
Overcurrent Trip Device	11 / 31.4
Operating Mechanism	7 / 20
Control Devices	5 / 14.3
Secondary Disconnect	4 / 11.4
Trip Mechanism	3 / 8.5
Miscellaneous	3 / 8.5
Charging Mechanism	1 / 2.9
Racking Mechanism	1 / 2.9
Total Number of Failures	35 / 100

[a] Component failure had not affected breaker safety function; however, continued degradation could have affected circuit breaker operation.

[b] Maintenance-induced events are included in the total number of events; however, they are excluded from the breakdown of events affecting operation because they are not considered aging mechanisms. The effect of maintenance-induced events is discussed further in Section 3.6.2.1.7.

Table 3-4. NPRDS Data for Westinghouse 480-Volt Circuit Breakers (Data from five plants during period from September 1985 through November 1991)

Number of Events	Problem	Effect on Operation	Comments
Main Contacts			
1	Out of tolerance	No immediate effect[a]	Condition was corrected by contact replacement
Primary Disconnects			
1	Loose pins and springs on disconnects	Failure to close	Breaker arced during operation
1	Arcing on bus bar to circuit breaker from loose connections	No immediate effect[a]	Condition was corrected by replacing damaged bus bar and circuit breaker; ultimate effect if uncorrected would have been serious
Secondary Disconnects			
1	Bent contact fingers	Failure to close	
Operating Mechanism (Opening and Closing)			
1	Binding in spring release mechanism	Failure to close	
1	Anti-bounce latch failed due to insufficient lubrication	Failure to close	
1	Latch stuck	Failure to close	
Charging Mechanism			
1	Spring recharging limit switch dirty and out-of-adjustment	Failure to close	
1	Dirt, dust, and grease in spring charging mechanism	Failure to close	
1	Cut-off switch lever worn and contacts not making up	No immediate effect[a]	Breaker remained operable with degraded motor operation
Trip Mechanism			
1	Dirt on trip relay lever	Failure to remain closed	

Table 3-4. NPRDS Data for Westinghouse 480-Volt Circuit Breakers (Data from five plants during period from September 1985 through November 1991) (continued)

Number of Events	Problem	Effect on Operation	Comments
Control Devices			
1	Shunt trip coil failure	Failure to open	
3	Spring release coil failure	Failure to close, failure to operate	The breaker failures, which occurred at the same plant, appear to be due to a high cycle application
1	Loose relay coil caused prolonged energization of the close coil and control fuse blowout	Failure to operate	
1	Anti-pump relay coil failure from wear	Failure to operate	
Overcurrent Trip Device			
1	Current sensor failure	Failure to open	
2	Amptector failed testing	No immediate effect[a]	Out of calibration
Miscellaneous			
1	Close test button sticking	Failure to close	
2	Loose control wire	Breaker inoperable, failure to close	
1	Unknown	Spurious opening	
1	Unknown	Breaker could not be returned to service	Alternate breaker trip function degraded
1	Unknown	Failure to close	
1	Unknown	Slow to trip	
Maintenance/Calibration Deficiency			
1	Use of incorrect parts	Failure to close	
1	Amptector set incorrectly	Spurious opening	Procedural error
1	Spring charging motor switch wire was pinched under the Amptector unit during previous maintenance	Breaker was grounded and operation degraded	

Table 3-4. NPRDS Data for Westinghouse 480-Volt Circuit Breakers (Data from five plants during period from September 1985 through November 1991) (continued)

Number of Events	Problem	Effect on Operation	Comments

Summary

Description	Number
Total number of events	30
Events affecting operation (failures)	21
Inability to return to service	1
Events with no immediate effect (observed during maintenance/testing)	5
Maintenance-induced events[b]	3

Breakdown of Events Affecting Operation

Failed Subsystem	Number / % of Total
Control Devices	6 / 28.6
Miscellaneous	6 / 28.6
Operating Mechanism	3 / 14.3
Charging Mechanism	2 / 9.5
Trip Mechanism	1 / 4.8
Overcurrent Trip Device	1 / 4.8
Primary Disconnects	1 / 4.8
Secondary Disconnects	1 / 4.8
Total Number of Failurs	21 / 100

[a] Component failure had not affected breaker safety function; however, continued degradation could have affected circuit breaker operation.

[b] Maintenance-induced events are included in the total number of events; however, they are excluded from the breakdown of events affecting operation because they are not considered aging mechanisms. The effect of maintenance-induced events is discussed further in Section 3.6.2.1.7.

Comparison of the results of the NMAC NPRDS analysis (for Westinghouse low-voltage Model DB and DS breakers) with those described in the preceding paragraph revealed several differences; upon closer examination of the data, however, many of these anomalies can be reconciled. NMAC noted that breaker operating mechanism failures (primarily caused by contaminated/deteriorated lubrication and wear), electrical device failures (including switches, motors, control relays, and secondary disconnects), and problems with the overcurrent trip device were the predominant forms of failure in this class of breaker (see Section 3.2 of References 3.41 and 3.44). Some component failures contained in Table 3-4 of this guideline are enveloped by the NMAC category of "electrical devices." For example, charging mechanism electrical components (i.e., spring charging limit switch) and secondary disconnects are individually classified in Table 3-4; when these failures are recharacterized and grouped together as "electrical device" failures, the results are consistent with those obtained by the NMAC analysis. Additionally, no differentiation between Model DB and DS breakers was made in this guideline; this may also account for some of the discrepancies.

3.6.2.1.3 ITE/Brown Boveri/Gould (ABB) 480-V Switchgear

The data from the NPRDS database covered six plants during the period March 1977 through April 1992. Failure events were recorded for service periods ranging from 1 to 15 years from initial date of installation. Of 13 events, 9 involved failure to operate (would not open or close), 1 involved detection of degradation before failure occurred, and 3 involved improper maintenance. A low total number of failures (9) present in the chosen data subset precluded any meaningful analysis. Table 3-5 provides a listing of the failure events for the ITE/Brown Boveri/Gould 480-V switchgear by subsystem. There were no events recorded in which the primary insulation system failed.

NPRDS data presented in the EPRI NMAC ABB K-Line maintenance guide (small and medium frame sizes) indicates that electrical control devices (e.g., coils, motors, relays, and contacts) were responsible for the largest percentage of subcomponent failures for this type of breaker, primarily caused by subcomponent part failures/damage and dirty or oxidized contact surfaces. Other significant failure categories were the operating mechanism (degraded or contaminated lubrication) and the overcurrent trip devices (faulty control unit for solid-state devices, out-of-calibration for the electromechanical units). [Section 3.2 of Reference 3.43] Although statistical inferences cannot be made from the data contained in Table 3-5, evidence of periodic electrical control device, operating mechanism, and overcurrent trip device failure is present.

3.6.2.1.4 General Electric 4.16- and 13.8-kV Switchgear

The data from the NPRDS database covered eight plants during the period February 1974 through March 1992. Failure events were recorded for service periods ranging from less than 1 year to 21 years from initial date of installation. Of 114 events, 77 involved failure to operate (would not open or close), 23 involved detection of degradation before failure occurred, 7 involved an inability to return the equipment to service, and 7 resulted from improper maintenance.

Table 3-5. NPRDS Data for ITE/Brown Boveri/Gould 480-Volt Circuit Breakers (Data from six plants during period from March 1977 to April 1992)

Number of Events	Problem	Effect on Operation	Comments
Operating Mechanism (Opening and Closing)			
2	Dirty/worn roller on closing mechanism	Failure to close	
1	Worn/jammed anti-bounce latch	Failure to close	
Charging Mechanism			
1	Broken charging motor disconnect switch	Failure to close	
Trip Mechanism			
1	Faulty magnetic latch	Failure to open	
1	Stuck manual trip button (dirt)	Failure to open	
Overcurrent Trip Device			
2	Failed solid-state trip device	Failure to operate	Inoperative long-term trip
Miscellaneous			
1	Unknown problem	Failure to close	
1	Cracked insulation on overload elements	No immediate effect[a]	
Maintenance/Calibration Deficiency			
1	Damage to charging spring locking lever	Failure to close	
1	Limit switch damaged by improper installation of manual actuation lever	Failure to close	Modification
1	Faulty replacement solid-state trip device	No immediate effect[a]	Failed replacement component

Table 3-5. NPRDS Data for ITE/Brown Boveri/Gould 480-Volt Circuit Breakers (Data from six plants during period from March 1977 to April 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments

Summary

Description	Number
Total number of events	13
Events affecting operation (failures)	9
Inability to return to service	0
Events with no immediate effect (observed during maintenance/ testing)	1
Maintenance-induced events[b]	3

Breakdown of Events Affecting Operation

Failed Subsystem	Number / % of Total
Operating Mechanism	3 / 33.3
Trip Mechanism	2 / 22.2
Trip Device	2 / 22.2
Charging Mechanism	1 / 11.1
Miscellaneous	1 / 11.1
Total Number of Failures	9 / 100

[a] Component failure had not affected breaker safety function; however, continued degradation could have affected circuit breaker operation.

[b] Maintenance-induced events are included in the total number of events; however, they are excluded from the breakdown of events affecting operation because they are not considered aging mechanisms. The effect of maintenance-induced events is discussed further in Section 3.6.2.1.7.

Of the 77 failures described above, 29 (37.7%) were associated with the spring charging mechanism. Of the 29 events, 13 were associated with charging motor limit switches and control relays; 9 were charging motor failures; and the remainder of the events were related to failures of the ratchet or other mechanical components in the spring charging subsystem. The predominant causes of these failures were out-of-adjustment subcomponents, wear of subcomponents, and electrical device (e.g., motors, switches) failures.

A significant component failure rate was also noted for the operating (opening and closing) mechanism. A variety of different components contributed to failures of this subsystem (weak/broken prop springs, linkage out-of-adjustment/binding, etc.); although no single weak component was identified, the operating mechanism, in general, displayed a high failure rate in relation to the other subsystems (with the exception of the charging mechanism discussed above). Primary causes of operating mechanism failures included the deterioration/lack of lubrication and wear of subcomponents.

Also of note were several electrical component failures; these failures were found in most every subsystem within the breaker (such as the charging mechanism and cubicle interlocks). There was one event recorded in which the primary insulation system failed. In this event, the B-phase isolator of a 4160-volt breaker failed to ground due to a high level of surface contamination (airborne dust from nearby concrete drilling).

Table 3-6 provides a listing of the events for the General Electric 4.16- and 13.8-kV switchgear by subsystem. As of the time of this writing, the EPRI NMAC NPRDS analysis was not available for comparison.

3.6.2.1.5 Westinghouse 4.16- and 13.8-kV Switchgear

The data in the NPRDS database covered four plants during the period November 1977 through October 1991. Failure events were recorded for service periods ranging from 2 years to 12 years from initial date of installation. Of 21 events, 12 involved failure to operate (would not open or close), 4 involved detection of degradation before failure occurred, 1 involved the inability to return equipment to service, and 4 resulted from improper maintenance. Of the 12 failures, 4 (33.3%) were associated with electrical control devices (closing coil). The remainder of the 12 failures were distributed among the subsystems of the switchgear with no subsystem experiencing a high number of failures. Dirt and degraded lubrication were cited in several reports as root causes. The low total number of events recorded during the time period in question does not indicate the presence of a significant failure mechanism; similarly, no real inferences concerning component failure can be drawn from the data. Table 3-7 provides a listing of the events for the Westinghouse 4.16- and 13.8-kV switchgear by subsystem. There were no events recorded in which the primary insulation system failed. As of the time of this writing, EPRI NMAC NPRDS data were not available for comparison.

Table 3-6. NPRDS Data for General Electric 4160- and 13,800-Volt Circuit Breakers (Data from eight plants during period from February 1974 through March 1992)

Number of Events	Problem	Effect on Operation	Comments
Racking Mechanism			
1	Misalignment and wear of breaker elevating mechanism, drive motor, chain, and idler	Failure to rack in	
1	Worn tension roller	Failure to rack in	
1	Racking motor drive cog out-of-adjustment	Failure to close	
1	Premature closure of travel limit switch	Prevented circuit breaker from completing racking	
1	Connector missing that engages with racking motor	No immediate effect[a]	Installed a new connector
Shutter Mechanism			
1	Shutter mechanism springs weakened from aging and cyclic fatique	Breaker could not be returned to service	
Main Contacts			
1	Breaker contacts out-of-adjustment	No immediate effect[a]	Adjusted contacts
Arcing Contacts			
3	Arcing contacts broken	No immediate effect[a]	Replaced arcing contacts
Secondary Disconnects			
1	Dirt and moisture on contacts	Failure to operate	
1	Corroded contacts	Failure to close	
1	Pins on secondary disconnect compressed	Failure to close	
Arc-Chute			
1	Phase isolator fault to ground from surface contamination	Failure to operate/faulted condition	Flashover of primary insulation
1	Box barrier cracked	No immediate effect[a]	Repaired box barrier
Operating Mechanism (Opening and Closing)			
2	Manual close mechanism binding	Failure to close	
2	Broken prop spring	Failure to close	
1	Sluggish prop spring	Spurious opening	

Table 3-6. NPRDS Data for General Electric 4160- and 13,800-Volt Circuit Breakers (Data from eight plants during period from February 1974 through March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments
Operating Mechanism (Opening and Closing) (continued)			
1	Snap ring and washer for latching rod out of place	Failure to close	
1	Spring discharge assembly binding on trip shaft	Failure to close	
1	Sheared cotter pin on closing spring mechanism	Failure to close	
2	Latch monitoring switch stuck open from wear	Failure to operate	
1	Breaker latch release switch striked plate gap exceeded tolerance	Failure to close	
1	Detached closing latch spring	Failure to close	
1	Plunger and stroker assembly out-of-adjustment	Failure to operate	
1	Operating mechanism roller out-of-tolerance	No immediate effect[a]	Adjusted mechanism
1	Circuit breaker linkage out-of-adjustment	No immediate effect[a]	Adjusted and tightened linkage
1	Latch monitoring switch bad	No immediate effect[a]	Replaced switch
2	Dirty contacts on latch monitoring switch	No immediate effect[a]	Replaced contacts
Charging Mechanism			
1	Gear box and spring charging motor wear	Failure to close	
1	Charging motor gear damage due to excessive clearances	Failure to close	
1	Charging motor gears stripped	Failure to close	
2	Closing spring charging motor brush bad	Failure to close	
1	Worn nylon bushing on spring charging motor	Failure to close	
1	Short circuit in spring charging motor winding	Failure to close	

Table 3-6. NPRDS Data for General Electric 4160- and 13,800-Volt Circuit Breakers (Data from eight plants during period from February 1974 through March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments
Charging Mechanism (continued)			
1	Spring charging motor shorted and burned up	Failure to close	
1	Spring charging motor defective	Failure to close	
1	Defective motor relay switch in spring charging mechanism	Failure to close	
5	Charging motor limit switch out-of-adjustment	Failure to close	
1	Charging motor circuit switch burnt up	Failure to close	
1	Charging motor switch sticking from a lack of lubrication	Failure to close	
4	Charging motor switch failure from wear	Failure to operate	
3	Ratchet drive and pawl out-of-adjustment	Failure to close	
1	Fractured ratchet handle clutch spring	Failure to operate	
1	Charging ratchet not contacting ratchet wheel due to lack of lubrication	Failure to close	
1	Interlock roller did not allow springs to charge due to a lack of lubrication	Failure to close	
1	Broken stop block in closing spring charging mechanism	Failure to close	
1	Mechanical arm wear in spring charging mechanism	Failure to charge the closing springs	
2	Defective interlock switch in spring charging mechanism	No immediate effect[a]	Replaced switch
1	Loose screws on spring charging motor and dirty slide contacts	No immediate effect[a]	Tightened screws and cleaned contacts
Trip Mechanism			
1	Trip latch return spring weak	Failure to remain closed	
4	Trip armature travel out of specification	No immediate effect[a]	Adjusted trip armature travel

Table 3-6. NPRDS Data for General Electric 4160- and 13,800-Volt Circuit Breakers (Data from eight plants during period from February 1974 through March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments
Control Devices			
1	Shunt trip coil burn out	Failure to open	
1	Shunt trip coil failure (stuck plunger) due to carbon in cubicle	Failure to open	Residual carbon dust in cubicle jammed plunger mechanism
1	Trip coil wear	Failure to open	
1	Loose connections on trip coil	Spurious opening	
Cell Switch/Cubicle Interlocks			
1	Cell switch out of alignment	Failure to operate	
2	Cell switch actuating arm bent	Failure to operate	
2	Cell switch misaligned	Failure to close	
1	Dirty interlock limit switch contacts	Failure to close	
1	Stiff limit switch control arm	Failure to rack in	
1	Interlock switch defective	Failure to close	
1	Interlock switch mounting bolts loose	Failure to close	
1	Trip lever on travel limit switch loose	Failure to rack in	
Mechanical Interlock			
1	Mechanical interlock out-of-adjustment	Failure to close	
1	Mechanical interlock out-of-adjustment	No immediate effect[a]	Adjusted the mechanical interlock assembly
1	Mechanical interlock assembly bent	No immediate effect[a]	Replaced the assembly
1	Loose bolts and insufficient lubrication on the mechanical interlock	No immediate effect[a]	Tightened bolts and lubricated
Auxiliary Contacts/Switches			
1	Auxiliary switch stuck open	Failure to close	
1	Auxiliary switch misalignment	Failure to close	
1	Auxiliary switch malfunction	Failure to close	
2	Auxiliary contacts did not make	Failure to close	

Table 3-6. NPRDS Data for General Electric 4160- and 13,800-Volt Circuit Breakers (Data from eight plants during period from February 1974 through March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments
Auxiliary Contacts/Switches (continued)			
1	Auxiliary contacts dirty	Failure to close	
1	Auxiliary contacts out-of-adjustment	Failure to close	
Miscellaneous			
1	Blown fuse	Failure to rack in	
2	Loose fuse block and fuses	Failure to close, failure to operate	
1	Wire shield causing ground	Spurious opening	
2	Unknown	Spurious opening	
4	Unknown	Failure to close	
1	Fuse block insulation breakdown	No immediate effect[a]	Replaced fuse block
Maintenance/Calibration Deficiency			
1	Switch installed incorrectly	Failure to operate	
1	Improper grease used on mechanism wheels	Failure to close	
1	Wires were disconnected from the lugs on the terminal block	Failure to operate	
1	Jumpers mislabeled — used wrong parts	Failure to operate	
1	Wire broken when circuit breaker pulled from cubicle	No immediate effect[a]	Replaced wire
1	Insulation of control wire crushed against cabinet frame	No immediate effect[a]	Replaced damaged wire and rerouted
1	Cell switch linkage bent during racking operation	No immediate effect[a]	Repaired switch

Summary

Description	Number
Total number of events	114
Events affecting operation (failures)	77
Inability to return to service	7
Events with no immediate effect (observed during maintenance/testing)	23
Maintenance-induced events[b]	7

Table 3-6. NPRDS Data for General Electric 4160- and 13,800-Volt Circuit Breakers (Data from eight plants during period from February 1974 through March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments

Breakdown of Events Affecting Operation

Failed Subsystem	Number / % of Total
Charging Mechanism	29 / 37.7
Operating Mechanism	13 / 16.9
Miscellaneous	9 / 11.7
Cell Switch/Cubicle Interlocks	8 / 10.4
Auxiliary Contacts/Switches	7 / 9.1
Control Devices	4 / 5.2
Secondary Disconnects	3 / 3.9
Racking Mechanism	1 / 1.3
Arc-Chute	1 / 1.3
Mechanical Interlock	1 / 1.3
Trip Mechanism	1 / 1.3
Total Number of Failures	77 / 100

[a] Component failure had not affected breaker safety function; however, continued degradation could have affected circuit breaker operation.

[b] Maintenance-induced events are included in the total number of events; however, they are excluded from the breakdown of events affecting operation because they are not considered aging mechanisms. The effect of maintenance-induced events is discussed further in Section 3.6.2.1.7.

Table 3-7. NPRDS Data for Westinghouse 4160- and 13,800-Volt Circuit Breakers (Data from four plants during period from November 1977 through October 1991)

Number of Events	Problem	Effect on Operation	Comments
Insulation			
1	Circuit breaker insulation breakdown	No immediate effect[a]	Breaker was repaired

Table 3-7. NPRDS Data for Westinghouse 4160- and 13,800-Volt Circuit Breakers (Data from four plants during period from November 1977 through October 1991) (continued)

Number of Events	Problem	Effect on Operation	Comments
Racking Mechanism			
1	Breaker not racking in properly	Failure to close	
1	Racking mechanism broken from wear	Breaker could not be racked in	
Operating Mechanism (Opening and Closing)			
1	Insufficient lubrication and wear of operating linkage	Failure to close	
1	Infrequent exercise and dry lubricants caused binding in the main contact operating assembly	Failure to open	Insufficient preventive maintenance
Charging Mechanism			
1	Charging motor limit switch failure	Failure to close	
1	Charging spring latching mechanism sticking	Failure to close	
1	Charging motor limit switch arcing	No immediate effect[a]	Limit switch was replaced
Control Devices			
2	Dust and dirt on relay caused binding and close coil failure	Failure to close	These failures occurred at the same plant, on the same breaker, one month apart; the relay was replaced and the breaker returned to service
1	Closing coil failure	Failure to close	
1	Closing solenoid jammed	Failure to operate	
Arc-Chute			
2	Cracked arc-chute	No immediate effect[a]	Replaced arc-chute
Cell Switch			
1	Cell switch linkage problem	Failure to open	
Miscellaneous			
2	Unknown	Breaker would not remain closed	The failures occurred at the same plant, on the same breaker, 20 days apart; maintenance was performed during the subsequent plant outage

Table 3-7. NPRDS Data for Westinghouse 4160- and 13,800-Volt Circuit Breakers (Data from four plants during period from November 1977 through October 1991) (continued)

Number of Events	Problem	Effect on Operation	Comments
Maintenance/Calibration Deficiency			
1	Use of wrong parts	Spurious opening	
1	Bent auxiliary switch operating pin	Failure to close	
1	Bent trip lever on bottom of unit	No immediate effect[a]	Straightened trip lever
1	Shutter mechanism damage	No immediate effect[a]	Shutter linkage and pivot point were repaired

Summary

Description	Number
Total number of events	21
Events affecting operation (failures)	12
Inability to return to service	1
Events with no immediate effect (observed during maintenance/ testing)	4
Maintenance-induced events[b]	4

Breakdown of Events Affecting Operation

Failed Subsystem	Number / % of Total
Control Devices	4 / 33.3
Operating Mechanism	2 / 16.7
Charging Mechanism	2 / 16.7
Miscellaneous	2 / 16.7
Cell Switch	1 / 8.3
Racking Mechanism	1 / 8.3
Total Number of Failures	12 / 100

[a] Component failure had not affected breaker safety function, yet continued degradation could have impacted circuit breaker operation.

[b] Maintenance-induced events are included in the total number of events; however, they are excluded from the breakdown of events affecting operation because they are not considered aging mechanisms. The effect of maintenance-induced events is discussed further in Section 3.6.2.1.7.

3.6.2.1.6 ITE/Brown Boveri/Gould (ABB) 4.16- and 13.8-kV Switchgear

The data in the NPRDS database covered 10 plants during the period December 1973 through March 1992. Failure events were recorded for service periods ranging from 1 to 19 years from initial date of installation. Of 50 events, 32 involved failure to operate (would not open or close), 13 involved detection of degradation before failure occurred, 2 involved inability to return to service, and 3 resulted from improper maintenance. Of the 32 failures, 15 (46.9%) were related to the charging mechanism. Of these 15 charging mechanism failures, 8 were associated with the charging motor or its electrical connections, with the remainder (7) attributed to charging motor control switches and relays. Failures/deficiencies associated with electrical control devices (6, 18.8%) were also noted. Hence, when the charging system and control device failures are viewed collectively, electrical components appear to have the most significant failure rate in this class of equipment. Table 3-8 provides a listing of the events for the ITE/Brown Boveri/Gould 4.16/13.8-kV switchgear by subsystem. There were no events recorded in which the primary insulation system failed. As of the time of this writing, EPRI NMAC NPRDS data were not available for comparison.

Table 3-8. NPRDS Data for ITE/Brown Boveri/Gould 4160- and 13,800-Volt Circuit Breakers (Data from ten plants during period from December 1973 to March 1992)

Number of Events	Problem	Effect on Operation	Comments
Racking Mechanism			
1	Broken racking mechanism coupling	Breaker could not be returned to service	
Arc-Chute			
1	Damaged arc-chute	No immediate effect[a]	Replaced arc chute
Arcing Contacts			
2	Cracked arcing contact	No immediate effect[a]	
Primary/Secondary Disconnects			
1	Dirty stationary block contact fingers	Failure to close	
2	Secondary disconnect assembly cracked	No immediate effect[a]	
1	Broken tulip contacts	No immediate effect[a]	Misalignment during rack in
1	Broken power stab contacts	No immediate effect[a]	
Operating Mechanism (Opening and Closing)			
1	Mechanical binding of operating mechanism	Failure to close	
1	Hardened lubricant binding closing link	Failure to close	

Table 3-8. NPRDS Data for ITE/Brown Boveri/Gould 4160- and 13,800-Volt Circuit Breakers (Data from ten plants during period from December 1973 to March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments
Operating Mechanism (Opening and Closing) (continued)			
1	Cracks in puffer piston assemblies	No immediate effect[a]	
Charging Mechanism			
4	Shorted charging motor switch	Failure to close	Charging motor continued to run
2	Broken charging spring motor toggle switch	Failure to close	
1	Failed charging control device	Spurious trip	
1	Binding of contact brush spring on charging motor	Failure to close	Bent spring
1	Bad brushes on charging motor	Failure to close	
1	Shorted windings on charging motor	Failure to close	
1	Burned terminal lug to charging motor	Failure to close	Loose connections
2	Failed charging motor wire	Failure to close	Bolt on switch arm rubbed insulation through insulation; arcing
1	Defective connection on charging motor	Failure to close	
1	Loose bolt on charging motor	Failure to close	Insufficient torque
Trip Mechanism			
1	Binding of trip mechanism due to dirt	Failure to close	Cleaned/lubricated
Control Devices (including closing coil)			
1	Dirty closing coil contacts	Failure to close	
1	Defective closing coil assembly	Failure to close	
1	Shorted control device	Failure to close	Insufficient information
1	Failed control relay	Failure to close	
1	Failed "Y" coil	Failure to open	
1	Failed shunt trip device coil	Failure to open	
2	Breaker control device failed	No immediate effect[a]	Insufficient information
1	High resistance in "Y" coil	No immediate effect[a]	

Table 3-8. NPRDS Data for ITE/Brown Boveri/Gould 4160- and 13,800-Volt Circuit Breakers (Data from ten plants during period from December 1973 to March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments
Auxiliary Contacts/Switches			
1	Control device lever/limit switch arm out of tolerance	Failure to close	
1	Dirty and corroded trip circuit "A" contact	Failure to open	
Potential Transformer			
1	Shorted B-C Phase winding on potential transformer	Spurious undervoltage trip	
1	Shorted windings on potential transformer	No immediate effect[a]	
Miscellaneous			
1	Test position switch linkage failure	Failure to operate in test position	Binding on retaining washer
1	Short in disconnect switch	Breaker could not be returned to service	
2	Unknown	Failure to close	
1	Unknown	Spurious trip	
1	Cell switch out of position	No immediate effect[a]	Breaker would not move freely while racking
Maintenance/Calibration Deficiencies			
1	Damage to main and secondary disconnect contact blocks	Failure to close	Misalignment during rack in
1	Stuck manual trip button	Spurious trip	Cover misalignment
1	Broken shuttle mechanism lift-pin	No immediate effect[a]	

Summary

Description	Number
Total number of events	50
Events affecting operation (failures)	32
Inability to return to service	2
Events with no immediate effect (observed during maintenance/ testing)	13
Maintenance-induced events[b]	3

Table 3-8. NPRDS Data for ITE/Brown Boveri/Gould 4160- and 13,800-Volt Circuit Breakers (Data from ten plants during period from December 1973 to March 1992) (continued)

Number of Events	Problem	Effect on Operation	Comments

Breakdown of Events Affecting Operation

Failed Subsystem	Number / % of Total
Charging Mechanism	15 / 46.9
Control Devices	6 / 18.8
Miscellaneous	4 / 12.5
Operating Mechanism	2 / 6.3
Auxiliary Contacts	2 / 6.3
Trip Mechanism	1 / 3.1
Potential Transformer	1 / 3.1
Primary/Secondary Disconnects	1 / 3.1
Total Number of Failures	32 / 100

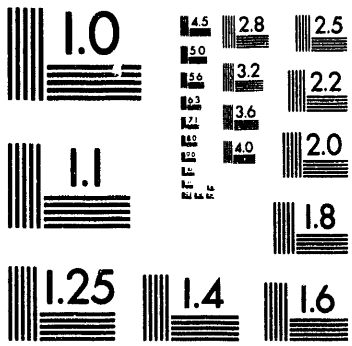
[a] Component failure had not affected breaker safety function, yet continued degradation could have impacted circuit breaker operation.

[b] Maintenance-induced events are included in the total number of events; however, they are excluded from the breakdown of events affecting operation because they are not considered aging mechanisms. The effect of maintenance-induced events is discussed further in Section 3.6.2.1.7.

3.6.2.1.7 Conclusions from NPRDS Review

As indicated above, the NPRDS data are not specific to aging-related information. In many instances, the scope of the Aging Management Guideline data was limited with respect to the number of plants and the time period reported. In these instances, other supporting data (such as that contained in the EPRI NMAC Maintenance Guide series) were used to further reinforce the conclusions drawn regarding postulated aging mechanisms. As a result of the review of the NPRDS data, several observations can be made.

In general, the largest percentage of failures reported in each breaker class was related to electrical/control devices. Included in this category were such components as switches, motors, control relays, undervoltage and shunt trip devices, auxiliary contacts, and secondary disconnects. These failures were generally distributed across several different breaker subsystems (for each individual manufacturer/class of breaker). In many instances, electrical device failures could be traced to associated mechanical device problems (e.g., binding in the charging mechanism causing the charging motor to remain energized continuously).


1.0
4.5
2.8
2.5
5.0
3.2
5.6
2.2
6.3
3.6
7.1
4.0
8.0
2.0
1.1
1.8
1.25
1.4
1.6

2 of 2

Operating mechanism failures were also noted in several breaker classes. The more failure-prone components in the operating mechanism(s) were not readily identified; as previously discussed, the failure events associated with these mechanisms were caused by a variety of problems affecting different components. However, the relatively high failure rate of components in the operating mechanism (compared with other subsystems) can be primarily attributed to (1) inadequate, contaminated, or otherwise degraded lubrication and (2) their relative complexity, high number of moving parts, and harsh operating conditions (repetitive high-energy impact, vibration, and applied torque) with respect to other switchgear subsystems.

Several failures were also associated with spring charging mechanisms (particularly in General Electric and ABB medium-voltage applications). The more failure-prone components in the charging system(s) included the charging motor assembly (motor windings, brushes, and electrical connections) as well as associated limit switches and relays. Some evidence of charging mechanism susceptibility to lack of or improper lubrication is also present. As with the operating mechanism, portions of the spring charging mechanism are subject to relatively extreme stresses (high mechanical stress/torque and impacts) as evidenced by several reports of broken, damaged, or worn charging mechanism mechanical components

The NPRDS data used in this study also indicated that, after adjustment for reporting plant sample size and duration of data collection period, the number of failure events (total) recorded for General Electric medium-voltage breakers was significantly higher than that associated with the same class of Westinghouse or ITE/Brown Boveri/Gould equipment. Several explanations of this result are possible, including (1) the number of General Electric systems in use throughout the industry significantly exceeds that of other manufacturers, (2) the number of plants with General Electric equipment that reported to NPRDS was substantially higher than that of plants with other manufacturers' equipment, or (3) General Electric equipment of this class actually had a higher failure rate than comparable Westinghouse or ITE/Brown Boveri/Gould equipment. Because this information was not contained within NPRDS or otherwise readily available, no inferences were made as to the relative reliability or failure rate of one system as opposed to another. Therefore, only the failures associated with one class/manufacturer of breaker were examined with respect to other failures within that same class.

For the General Electric 480-V switchgear, nearly one third of all failure events were associated with overcurrent trip devices. These failures were primarily related to the electromechanical trip device (rather than the solid-state devices), and were mostly unexpected trips or lack of trips associated with calibration (drift). Other classes of breaker examined also exhibited trip device failures and out-of-calibration conditions, yet none was as pronounced as that noted for the General Electric low-voltage switchgear.

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

Although not specifically an issue of breaker functionality, events resulting in the inability to return the breaker to service after the completion of testing or maintenance are significant in that they preclude operation and require immediate correction. The fraction of these instances compared with the total number of events was small in all classes of breakers examined.

Also of note in the data was the lack of any substantial number of events involving primary insulation breakdown (flashover); only one instance of flashover was recorded for all breaker classes (see Section 3.6.2.1.4). This sole occurrence was caused by excessive deposition of external contamination on the interior surfaces of the breaker phase insulators; hence, although not a common event, flashover must be considered in cases where the potential for internal breaker contamination exists. Based on the limited number of occurrences, however, it appears that existing maintenance practices adequately address this phenomenon.

3.6.2.2 Licensee Event Report (LER) Data

NRC Licensee Event Reports (LERs) are another source of switchgear failure and degradation data. LERs are issued by nuclear plant operators when equipment failures and plant operating events meet 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 a partial picture of failure information that is likely to be representative of general failure tendencies, but is not statistically sound. LER data can be used, however, as support for the findings derived from other data sources (such as overhaul data and NPRDS) as well as for verification of postulated aging mechanisms.

The LERs used in this study cover the period from early 1980 through early 1992. Reports were sorted by manufacturer and voltage class, and then individually evaluated based on the information presented in the report's abstract. Those reports containing pertinent failure data were then categorized by subcomponent failure and aging mechanism, and the results tabulated in Tables 3-9 through 3-14. Where available, the results of the EPRI NMAC LER analyses are also included. It should be noted however, that the EPRI NMAC data do not cover the same time period as the data analyzed in this Aging Management Guideline; hence, some differences in the results can be anticipated. Detailed analyses of the LERs (for each type of breaker) are included in Sections 3.6.2.2.1 through 3.6.2.2.7 below.

3.6.2.2.1 General Electric 480-V Switchgear

Table 3-9 tabulates the number of failure events (for each combination of failed component and failure mode) for General Electric low-voltage switchgear. Examination of the data indicates that the highest percentage of failures for this type of breaker are associated with the operating and trip mechanisms due to deteriorated or contaminated lubrication. Another component of interest is the reactor trip breaker UVTA. UVTA failures noted in the data were mostly a result of either being out of adjustment or a result of previous maintenance efforts. These results appear consistent with the EPRI NMAC data, which indicate that operating mechanism and undervoltage device failures were most significant in these breakers (Section 3.3

of Reference 3.42). These results also support the findings derived from the NPRDS data discussed in Section 3.6.2.1.1 above.

Table 3-9. Licensee Event Report (LER) Data, General Electric Low-Voltage Systems

Failed Component[a]	Failure Mode (see definitions below)													
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13
Main Contacts	**1**	0	0	0	0	**1**	0	0	0	0	0	0	0	0
Operating Mechanism	**11**	**4**	0	**2**	0	**2**	0	0	0	0	0	**2**	0	**1**
Trip Mechanism	**10**	**5**	0	**1**	0	0	0	0	0	0	0	**1**	**1**	**2**
OCTD (electromech.)	**3**	0	0	**1**	0	0	0	0	0	0	0	**1**	0	**1**
OCTD (solid state)	**1**	0	0	0	0	0	0	0	0	0	0	0	0	**1**
UVTD	**11**	**1**	**1**	**3**	0	0	0	0	0	0	0	**3**	0	**3**
Closing Coil	**5**	**1**	0	**1**	0	**1**	0	0	0	0	0	**1**	0	**1**
Auxiliary Contacts	**2**	0	0	0	0	**2**	0	0	0	0	0	0	0	0
Wiring	**2**	0	0	0	0	0	0	0	0	0	0	**2**	0	0
Elec. Control (misc.)	**1**	0	0	0	0	**1**	0	0	0	0	0	0	0	0
		11	**1**	**8**	**0**	**7**	**0**	**0**	**0**	**0**	**0**	**10**	**1**	**9**

Failure Modes Defined

1 Inadequate/contaminated lubrication
2 Mechanical binding
3 Out of adjustment
4 Loose
5 Worn-out component (end of life)
6 Heat damage
7 Deformed
8 Broken weld
9 High electrical resistance (including pitted/dirty contacts)
10 Electrical fault
11 Improper maintenance
12 Other
13 Unknown

[a] No failures of the primary disconnects, racking mechanism, mechanical interlocks, charging mechanism, or of unknown cause were noted in the LERs for this class of breaker. Additionally, no failures of the primary insulation, secondary disconnects, arcing contacts, arc-chutes, or shunt trip device were noted in the LERs for any class of equipment covered in this guideline.

3.6.2.2.2 Westinghouse 480-V Switchgear

Table 3-10 tabulates the number of failure events (for each combination of failed component and failure mechanism) for Westinghouse low-voltage switchgear. Although some indication of increased frequency of failure for operating/trip mechanisms and overcurrent trip devices exists, the low number of reports present precludes any meaningful inferences or conclusions. EPRI NMAC LER data were not available for comparison. However, as discussed in Section 3.6.2.1.2 above, operating mechanism and electrical control device failures (trip devices, switches, relays, etc.) were most significant as indicated by NPRDS data. Hence, the NPRDS and LER data appear consistent.

Table 3-10. Licensee Event Report (LER) Data, Westinghouse Low-Voltage Systems

Failed Component[a]	Failure Mode (see definitions below)													
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13
Primary Disconnects	**1**	0	0	0	0	0	0	0	0	**1**	0	0	0	0
Racking Mechanism	**1**	0	0	0	0	0	0	0	0	0	0	**1**	0	0
Mechanical Interlocks	**1**	0	0	0	0	0	0	0	0	0	0	**1**	0	0
Operating Mechanism	**4**	0	**1**	**2**	0	0	0	0	**1**	0	0	0	0	0
Charging Mechanism	**3**	0	**1**	**1**	0	**1**	0	0	0	0	0	0	0	0
Trip Mechanism	**4**	0	**2**	**2**	0	0	0	0	0	0	0	0	0	0
OCTD (electromech.)	**5**	**1**	0	0	0	**1**	0	0	0	0	0	0	0	**3**
UVTD	**1**	0	0	0	0	**1**	0	0	0	0	0	0	0	0
Closing Coil	**3**	**1**	0	0	0	**1**	0	0	0	0	0	0	0	**1**
Elec. Control (misc.)	**2**	0	0	0	**1**	0	0	0	0	0	0	0	0	**1**
Unknown	**1**	0	0	0	0	0	0	0	0	0	0	0	0	**1**
		2	**4**	**5**	**1**	**4**	**0**	**0**	**1**	**1**	**0**	**2**	**0**	**6**

Failure Modes Defined

1 Inadequate/contaminated lubrication
2 Mechanical binding
3 Out of adjustment
4 Loose
5 Worn-out component (end of life)
6 Heat damage
7 Deformed
8 Broken weld
9 High electrical resistance (including pitted/dirty contacts)
10 Electrical fault
11 Improper maintenance
12 Other
13 Unknown

[a] No failures of the main contacts, solid-state overcurrent trip device, auxiliary contacts, or internal wiring were noted in the LERs for this class of breaker. Additionally, no failures of the primary insulation, secondary disconnects, arcing contacts, arc-chutes, or shunt trip device were noted in the LERs for any class of equipment covered in this guideline.

3.6.2.2.3 ITE/Brown Boveri/Gould 480-V Switchgear

Table 3-11 tabulates the number of failure events (for each combination of failed component and failure mechanism) for ITE/Brown Boveri/Gould low-voltage switchgear. Because of the very low number (12) of reports applicable to this class of equipment, no inferences can be made as to relative component failure rate or aging mechanisms. EPRI NMAC LER data were not available for comparison.

Table 3-11. Licensee Event Report (LER) Data, ITE/Brown Boveri/Gould Low-Voltage Systems

Failed Component[a]	Failure Mode (see definitions below)													
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13
Racking Mechanism	1	0	0	1	0	0	0	0	0	0	0	0	0	0
Operating Mechanism	2	1	0	0	0	1	0	0	0	0	0	0	0	0
Charging Mechanism	1	0	0	0	0	1	0	0	0	0	0	0	0	0
Trip Mechanism	2	0	0	0	0	0	0	0	0	0	0	1	0	1
Closing Coil	2	1	0	0	0	1	0	0	0	0	0	0	0	0
Elec. Control (misc.)	1	0	0	0	1	0	0	0	0	0	0	0	0	0
		2	0	1	1	3	0	0	0	0	0	1	0	1

Failure Modes Defined

1 Inadequate/contaminated lubrication
2 Mechanical binding
3 Out of adjustment
4 Loose
5 Worn-out component (end of life)
6 Heat damage
7 Deformed
8 Broken weld
9 High electrical resistance (including pitted/dirty contacts)
10 Electrical fault
11 Improper maintenance
12 Other
13 Unknown

[a] No failures of the primary disconnects, mechanical interlocks, main contacts, overcurrent trip devices (electromechanical or solid-state), undervoltage trip devices, auxiliary contacts, internal wiring, or of unknown cause were noted in the LERs for this class of breaker. Additionally, no failures of the primary insulation, secondary disconnects, arcing contacts, arc-chutes, or shunt trip device were noted in the LERs for any class of equipment covered in this guideline.

3.6.2.2.4 General Electric 4.16- and 13.8-kV Switchgear

Table 3-12 tabulates the number of failure events (for each combination of failed component and failure mechanism) for General Electric medium-voltage switchgear. As indicated by the data, four component categories comprised the majority of deficiencies noted. These categories are (1) breaker operating mechanisms, (2) trip mechanisms, (3) charging mechanisms (and associated electrical equipment), and (4) breaker mechanical and electrical interlocks.

Wear and degraded/contaminated lubricant were the primary causes of the operating and trip mechanism failures. These data are consistent with the results of the NPRDS analysis discussed in Section 3.6.2.1.4 above. Causes for charging mechanism failures ranged from components being loose or out of adjustment to simply being worn (this includes electrical components, which were believed to have reached their end-of-life). This also is consistent with the NPRDS findings, which identified charging mechanism failures in this class of breaker as well. (It should be noted that in many cases, the LERs did not explicitly describe the failed component or failure mechanism; hence, no further categorization or comparison of charging mechanism failure data could reasonably be made.)

With respect to interlock mechanisms, close examination of the NPRDS data contained in Table 3-6 indicates that several interlock failures have occurred in this class of switchgear (primarily due to being out of adjustment). Further investigation into the categorization employed in the EPRI NMAC Maintenance Guide on this switchgear permits the same inference. In the NMAC guide, equipment such as electrical switches and auxiliary contacts is classified as "electrical control devices"; hence, some failures listed in this category may, in fact, be caused by interlock switches and associated equipment. These data indicate that interlock switches and mechanisms may be prone to a loss of adjustment.

3.6.2.2.5 Westinghouse 4.16- and 13.8-kV Switchgear

Table 3-13 tabulates the number of failure events (for each combination of failed component and failure mechanism) for Westinghouse medium-voltage switchgear. Due to the very low number (14) of reports applicable to this class of equipment, no inferences can be made as to relative component failure rate or aging mechanisms. EPRI NMAC LER data were not available for comparison.

3.6.2.2.6 ITE/Brown Boveri/Gould 4.16- and 13.8-kV Switchgear

Table 3-14 tabulates the number of failure events (for each combination of failed component and failure mechanism) for ITE/Brown Boveri/Gould medium-voltage switchgear. Because of the very low number (8) of reports applicable to this class of equipment, no inferences can be made as to relative component failure rate or aging mechanisms. EPRI NMAC LER data were not available for comparison.

Table 3-12. Licensee Event Report (LER) Data, General Electric Medium-Voltage Systems

Failed Component[a]	Failure Mode (see definitions below)													
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13
Primary Disconnects	**2**	0	0	0	0	0	0	0	0	0	**1**	**1**	0	0
Racking Mechanism	**1**	0	0	0	0	0	0	**1**	0	0	0	0	0	0
Mech./Elec. Interlocks	**9**	0	0	**6**	**1**	0	0	0	0	**1**	0	**1**	0	0
Operating Mechanism	**9**	**3**	0	0	**2**	**4**	0	0	0	0	0	0	0	0
Charging Mechanism	**10**	0	0	**3**	**3**	**2**	0	0	0	0	0	**1**	0	**1**
Trip Mechanism	**9**	**4**	0	**1**	**1**	**2**	0	0	**1**	0	0	0	0	0
OCTD (electromech.)	**2**	0	0	**2**	0	0	0	0	0	0	0	0	0	0
UVTD	**1**	0	0	0	0	0	0	0	0	0	0	**1**	0	0
Closing Coil	**1**	0	0	0	0	**1**	0	0	0	0	0	0	0	0
Auxiliary Contacts	**2**	**1**	0	0	0	**1**	0	0	0	0	0	0	0	0
Wiring	**1**	0	0	0	0	0	0	0	0	0	**1**	0	0	0
Elec. Control (misc.)	**1**	0	0	0	0	0	0	0	0	0	**1**	0	0	0
		8	**0**	**12**	**7**	**10**	**0**	**1**	**1**	**1**	**3**	**4**	**0**	**1**

Failure Modes Defined

1 Inadequate/contaminated lubrication
2 Mechanical binding
3 Out of adjustment
4 Loose
5 Worn-out component (end of life)
6 Heat damage
7 Deformed
8 Broken weld
9 High electrical resistance (including pitted/dirty contacts)
10 Electrical fault
11 Improper maintenance
12 Other
13 Unknown

[a] No failures of the main contacts, OCTD (solid-state), or of unknown cause were noted in the LERs for this class of breaker. Additionally, no failures of the primary insulation, secondary disconnects, arcing contacts, arc-chutes, or shunt trip device were noted in the LERs for any class of equipment covered in this guideline.

Table 3-13. Licensee Event Report (LER) Data, Westinghouse Medium-Voltage Systems

Failed Component[a]	Failure Mode (see definitions below)													
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13
Primary Disconnects	**1**	0	0	0	0	0	0	**1**	0	0	0	0	0	0
Racking Mechanism	**1**	0	0	0	0	**1**	0	0	0	0	0	0	0	0
Mech./Elec. Interlocks	**4**	0	0	**2**	**1**	**1**	0	0	0	0	0	0	0	0
Main Contacts	**1**	0	0	0	0	0	0	0	**1**	0	0	0	0	0
Operating Mechanism	**2**	0	0	0	0	**2**	0	0	0	0	0	0	[illegible]	0
Charging Mechanism	**1**	0	0	0	0	0	0	**1**	0	0	0	0	0	0
Auxiliary Contacts	**1**	0	0	0	0	0	0	0	**1**	0	0	0	0	0
Elec. Control (misc.)	**1**	0	0	0	**1**	0	0	0	0	0	0	0	0	0
Unknown	**1**	0	0	0	0	0	0	0	0	0	0	0	0	**1**
		0	**0**	**2**	**2**	**4**	**0**	**2**	**2**	**0**	**0**	**0**	**0**	**1**

Failure Modes Defined

1 Inadequate/contaminated lubrication	8 Broken weld
2 Mechanical binding	9 High electrical resistance (including pitted/dirty contacts)
3 Out of adjustment	10 Electrical fault
4 Loose	11 Improper maintenance
5 Worn-out component (end of life)	12 Other
6 Heat damage	13 Unknown
7 Deformed	

[a] No failures of the trip mechanism, OCTD (electromechanical or solid-state), UVTD, closing coil, or internal wiring were noted in the LERs for this class of breaker. Additionally, no failures of the primary insulation, secondary disconnects, arcing contacts, arc-chutes, or shunt trip device were noted in the LERs for any class of equipment covered in this guideline.

Table 3-14. Licensee Event Report (LER) Data, ITE/Brown Boveri/Gould Medium-Voltage Systems

Failed Component[a]	Failure Mode (see definitions below)													
	Total	1	2	3	4	5	6	7	8	9	10	11	12	13
Operating Mechanism	**2**	**1**	0	0	0	0	0	0	0	0	0	0	0	**1**
Charging Mechanism	**2**	0	0	0	**2**	0	0	0	0	0	0	0	0	0
Trip Mechanism	**1**	**1**	0	0	0	0	0	0	0	0	0	0	0	0
OCTD (electromech.)	**1**	0	0	0	0	0	0	0	0	0	0	0	0	**1**
Elec. Control (misc.)	**2**	0	0	0	0	0	0	0	0	0	0	0	0	**2**
		2	**0**	**0**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**

Failure Modes Defined

1 Inadequate/contaminated lubrication
2 Mechanical binding
3 Out of adjustment
4 Loose
5 Worn-out component (end of life)
6 Heat damage
7 Deformed
8 Broken weld
9 High electrical resistance (including pitted/dirty contacts)
10 Electrical fault
11 Improper maintenance
12 Other
13 Unknown

[a] No failures of the primary disconnects, racking mechanism, mechanical interlocks, main contacts, OCTD (solid-state), UVTD, closing coil, auxiliary contacts, internal wiring, or of unknown cause were noted in the LERs for this class of breaker. Additionally, no failures of the primary insulation, secondary disconnects, arcing contacts, arc-chutes, or shunt trip device were noted in the LERs for any class of equipment covered in this guideline.

3.6.2.2.7 Conclusions from LER Review

The results cited in the previous sections (specifically with regard to General Electric and Westinghouse low-voltage and General Electric medium-voltage switchgear) indicate a substantial degree of consistency between the findings of the NPRDS and LER data analyses. As indicated in the preceding NPRDS data review, breaker operating and trip mechanisms appear (in general) to be most susceptible to failure, being identified for several breaker classes. Also of note were the failures associated with the charging mechanisms on General Electric medium-voltage systems (see Section 3.6.2.1.4 above). Reactor trip breaker undervoltage trip attachments on General Electric low-voltage breakers also appear to be prone to improper adjustment (at time of manufacture or during maintenance). This may be due in part to the relative difficulty of properly setting the mechanism tolerances and operating force.

Because of the limited number of reports for some classes of switchgear under consideration, no additional conclusions could be drawn. In analyzing the data available for these classes however, no real inconsistencies between the NPRDS, LER, and overhaul data (discussed in the following sections) were found. Hence, the LER data provide additional substantiation for the general NPRDS findings, as well as specific support for those conclusions concerning a limited number of breaker classes.

3.6.2.3 Overhaul/Refurbishment Data

The third source of information used in the evaluation of aging and age-related degradation mechanisms is breaker overhaul/refurbishment data. This type of data is an important factor in the determination of a breaker's overall condition prior to failure. Overhaul data are assumed to represent a wide spectrum of installations and environments (e.g., both high and low cycle applications, high and low dust environments) and are not subject to the limitations inherent in NPRDS and LERs. Rather, overhaul data present a "snapshot" of a given breaker's condition at a specific point in its calendar and cyclic age. Overhaul information is available from various sources, the foremost being vendor facilities or service centers specializing in the overhaul and refurbishment of electrical switchgear. As discussed in previous sections, overhaul data were not specifically analyzed in this study; rather, the analysis presented in the EPRI NMAC Circuit Breaker Maintenance Guide series was used to support previous findings and gain additional insights into switchgear aging. The significant conclusions of the EPRI NMAC analysis of overhaul data are summarized in the following sections. Detailed descriptions of the methodology used in these analyses are contained in the applicable sections of each NMAC Maintenance Guide.

3.6.2.3.1 General Electric 480-V Switchgear

As discussed in Section 3.1 of Reference 3.42, the General Electric low-voltage breaker subsystems that were noted during overhaul to exhibit deterioration are the operating mechanism, the main current-carrying components, and electrical control devices. Several instances of degraded or failed internal insulation and wiring were also noted. These conditions had not yet adversely affected operation of the circuit breaker prior to overhaul.

The primary cause to which operating mechanism failures were attributed was dried/dirt-contaminated lubricant. Other causes of operating mechanism problems included out-of tolerance mechanical adjustments and loose or damaged parts.

Main current-carrying components include the main and arcing contact assemblies and the primary disconnects. Out-of-adjustment main and arcing contacts, weakened contact springs, and degraded contact surface conditions were all identified as major causes of problems associated with this subsystem.

Electrical devices such as motors, contacts, switches, and relays were cited as the third most numerous cause of deficiencies during overhaul of General Electric low-voltage breakers. Major subcategories of these discrepancies included high control device contact resistance (due to dirt, pitting, and corrosion) and charging motor component failures.

3.6.2.3.2 Westinghouse 480-V Switchgear

Model DB

Problems noted with the Westinghouse Model DB breaker were most often related to the operating mechanism, followed by electrical devices, overcurrent trip devices, and plastic subcomponents (insulators, covers, etc.).

Inadequate or contaminated lubricant, wear, and loose or damaged parts were the primary contributors to defects detected during overhaul associated with the operating mechanism. Electrical/control device degradations were attributed to high resistance switch contacts, failed or damaged parts, and improper adjustment of the shunt trip. The overcurrent trip devices used in these breakers were noted to suffer from calibration deficiencies, failed or damaged subcomponents, and loose mounting. Cracked, split, or broken pieces of plastic subcomponents (including secondary disconnects, auxiliary switch covers, and pole unit bases and links) were also identified.

Model DS

The operating mechanism, electrical/control devices, and plastic subcomponents were the most frequent sources of overhaul discrepancies in the Westinghouse Model DS breaker.

As with the Model DB breaker discussed above, contaminated or deteriorated lubrication and component wear were major causes of operating mechanism problems. In addition, pole shaft weld failure was cited for this class of breaker. Pole shaft weld fatigue is discussed in greater detail in Sections 3.6 and 4.2 of this guideline. High resistance contacts and failed or damaged parts were also identified in electrical control components. Several instances of cracked or broken plastic secondary disconnect components and auxiliary switch covers were also indicated.

3.6.2.3.3 ITE/Brown Boveri/Gould 480-V Switchgear (ABB)

As discussed in Section 3.1 of Reference 3.43, problems were most often cited with degraded breaker lubricant and electrical/control device failure. Components no longer able to hold their adjustment are also often found. ABB low-voltage breakers used in high cycle applications have generally exhibited wear and erosion of the main and arcing contact assemblies, as well as burning of the arc-chute plates. Charging motor brush failure was also been noted. Little wear was seen in the breaker mechanisms.

The data indicate that lubricant aging, separation, evaporation, and hardening are significant causes of component failure (especially in breakers over 10 years of age). Problems with control devices are often related to other problems within the breaker (i.e., failure of some breaker component to actuate as required may induce failure of a control device). Other potential causes of electrical/control device failures include misadjustment and damage due to improper maintenance or handling.

The penetration of dust and humidity into switchgear prior to energization (when these environments are usually most severe) has been noted by ABB to adversely affect the performance of the breaker throughout its operating life. Contamination of lubricant by dust can be especially damaging, inducing a wide variety of subcomponent failures. In many cases, these failures occurred for many years after the equipment was first placed in use.

Data taken from ABB switchgear service center reports also show that some maintenance and surveillance tasks (e.g., component adjustment or calibration) can be performed too frequently, such that components may experience an accelerated degradation to which they would otherwise not be subject. This overfrequent maintenance may be caused, in part, by the integration of manufacturers' bulletins and guidance related to unique, one-time conditions into the routine maintenance procedures. For example, a bulletin issued to correct a particular deficiency (such as an improperly adjusted mechanism) may result in that adjustment being needlessly verified each maintenance interval, potentially causing premature failure of the mechanism. Similarly, improper maintenance techniques may precipitate component failures that would otherwise not occur. Several examples of improper maintenance practices, including the use of solvents to remove old lubricant (which may wash dirt and contaminants into the area requiring lubrication) and the application of "light" lubricants, were cited in the ABB data.

Manufacturing defects have also been detected in a number of breakers; these defects are normally detected prior to shipment. However, errors (including wrong/missing options, wiring errors, and shipping damage) have been identified.

3.6.2.3.4 General Electric 4.16- and 13.8-kV Switchgear

EPRI NMAC overhaul data were not available for this class of equipment. However, information provided by one overhaul facility (documented in Reference 3.63) indicates that operating mechanism lubricant degradation, operating mechanism bearing wear, arc-chute dielectric breakdown, and primary bushing dielectric breakdown are the predominant component degradations identified during overhaul of General Electric Magne-Blast medium-voltage breakers. Operating mechanism wear and lubrication deterioration appear consistent with the

NPRDS and LER findings discussed above. Arc-chute and primary bushing dielectric breakdown, unless catastrophic, will most likely not preclude breaker operation; this could be one possible explanation of the lack of supporting NPRDS and LER failure data for this degradation mechanism.

3.6.2.3.5 Westinghouse 4.16- and 13.8-kV Switchgear

EPRI NMAC overhaul data were not available for this class of equipment. However, information provided by one overhaul facility [3.63] indicates that operating mechanism lubricant degradation, levering device component failure, and contact mounting degradation are the predominant component discrepancies found during overhaul of Westinghouse Model DH and DH-P medium-voltage breakers.

3.6.2.3.6 ITE/Brown Boveri/Gould 4.16- and 13.8-kV Switchgear

EPRI NMAC overhaul data were not available for this class of equipment.

3.6.2.3.7 Conclusions from Overhaul Data Review

Many of the conclusions cited from the review of overhaul data support the findings derived from analysis of the NPRDS and LER data (Sections 3.6.2.1 and 3.6.2.2 above). In addition to these findings, further insight into aging and degradation mechanisms present in electrical switchgear can be gained by a close examination of the overhaul data. These additional insights are discussed in the following paragraphs.

Degradation of the current carrying components (i.e., main and arcing contacts, primary disconnects) was noted in General Electric low-voltage switchgear. This was mostly in the form of worn or out-of-adjustment parts or deteriorated contact surfaces. These types of deficiencies were not detected by review of NPRDS or LER data because no equipment "failure" had yet occurred; that is, the contact components were replaced or repaired prior to failure. This switchgear had, however, significantly degenerated and may have ultimately failed if left in this condition. Hence, these components must be monitored for signs of wear, loss of adjustment, and mating surface deterioration.

Overhaul data presented for the Westinghouse Model DS and DB breakers indicate that plastic component degradation is present. Although this type of aging does not appear to preclude the switchgear from performing its required function(s) (as evidenced by the distinct lack of NPRDS or LER reports citing plastic component failure as the root cause of switchgear malfunction), it should be addressed because (1) cracked or broken plastic parts may induce failures of other switchgear subcomponents (e.g., pieces may obstruct or bind moving parts) and (2) failure of the plastic components may make other components of the switchgear more susceptible to failure (e.g., loss of an auxiliary switch cover may allow foreign material to foul the switch).

ABB low-voltage switchgear overhaul reports indicate that unnecessary or inappropriate maintenance activities (such as over-frequent adjustment, or the use of solvents and "light" lubricants) may subject the breaker to accelerated aging and degradation. Also of note with regard to ABB switchgear is the relative lack of wear of internal switchgear mechanisms in high cycle applications. Main and arcing contact wear (as well as deterioration of the arc-chutes) appear to be the limiting factors in these types of applications.

3.6.2.4 Overall Conclusions of NPRDS, LER, and Overhaul Data Review

Each of the three types of information discussed above (NPRDS, LER, and overhaul) provides a somewhat different, but complementary perspective on switchgear aging mechanisms. All three sources, when viewed collectively, give a more comprehensive picture of switchgear degradation as a function of time, operating, and maintenance conditions. Based on the results of the previous analyses, several general conclusions can be drawn.

1. Lubrication — The presence of fresh, clean lubricant of the proper type is one of the most significant determinants of switchgear longevity and performance. Lubricants are subject to degradation (such as evaporation and separation) based primarily on the length of time installed in the switchgear; other external influences (such as dirt/contamination or excessive temperature) can also cause the lubricant to become ineffectual and lead to premature component failure or wear. Lubrication appears especially critical to the operating and charging mechanisms of switchgear, as these subsystems have numerous close-tolerance and load bearing moving parts. Some evidence also exists to support the inference that in high cycle applications where adequate lubrication has been maintained, wear of the operating mechanism (normally associated with many switchgear failures) is not significant in comparison with other forms of aging occurring in the switchgear (see Section 3.6.2.3.7).

2. Electrical devices — The failure of electrical devices (including motors, coils, relays, and switches) is relatively common in all breaker subsystems, and can be expected to occur throughout the life of the switchgear. Failure of these components can be direct (i.e., failure of the component due to some internal problem with no external influence) or indirect (failure of the component due to some external influence that induces a particular type of degradation in the component). Hence, the control of certain types of aging in the switchgear (lubrication, for example) may actually reduce the incidence of failures of other classes of subcomponents. Failure of the switchgear to operate properly also commonly occurs because of existing out-of-adjustment conditions of electrical components (for example, improperly adjusted cell or limit switches).

3. Overcurrent trip devices — Overcurrent trip devices also appear to be susceptible to failure or loss of calibration. Although electromechanical devices were the primary source of these reports, several instances of solid-state device discrepancies were also noted. In general, it would appear that electromechanical overcurrent trip devices are more prone to losing their calibration than their solid-state counterparts.

4. Overhaul/refurbishment — Normal routine maintenance can be expected to address a large portion of the degradation mechanisms identified for switchgear; periodic breaker disassembly and overhaul is necessary, however, to adequately mitigate the effects of those aging mechanisms not addressed by routine maintenance or

inspection. For example, the presence of degraded or contaminated lubricant (which cannot be seen or removed during partial disassembly) can only be corrected by complete disassembly.

One potentially important element not adequately addressed in the preceding analysis is information pertaining to the number of cycles to which each piece of equipment was subjected during operation, maintenance, and testing (i.e., the "cyclic age" of the switchgear). Little information of this type was recorded in NPRDS or LERs, and overhaul data related to high cycle applications are only marginally applicable to failures (in that detection of impending component failure during overhaul/refurbishment is not always possible). Depending upon the specific breaker application and frequency of system/component use, the number of cycles will vary greatly in breakers of the same manufacture and class. For example, many 480-V applications experience a substantially higher number of cycles per time period than their 4.16- and 13.8-kV counterparts. Although some degradation mechanisms may be relatively independent of the number of cycles (e.g., corrosion), it is nonetheless reasonable to assume that the number of component failures is proportional to both the number of cycles on a given breaker as well as its calendar age, as opposed to the calendar age alone. Hence, any meaningful aging management program must consider not only the installation age, but also the cyclic age of the equipment. At present, few plants use switchgear equipped to monitor and record the number of cycles to which it has been subjected. Several models of new switchgear being produced have operating cycle counters. Additionally, a substantial operating history must be established before any meaningful conclusions concerning cyclic age can be drawn. As an alternative to using cyclic counters, nuclear plant operators can attempt to estimate the cyclic age of much of their switchgear by examining the applications in which switchgear is used; in general, review of the applications will indicate whether or not a given piece of equipment is in fact "high cycle." Supplemental actions (if desired) for potentially high cycle breakers may include a more comprehensive estimate of the switchgear cyclic age using information such as surveillance and maintenance requirements, operational use, and pre-operational testing conducted prior to plant startup. As more data are compiled correlating specific component failures and failure mechanisms to various cyclic ages, maintenance programs can be more accurately tailored to individual switchgear applications.

3.7 References

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4. APPLICABLE STRESSORS AND AGING MECHANISMS

4.1 Determination of Stressors Acting on Components

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

- Temperature (ambient and internally generated)
- Voltage
- Mechanical cycling
- Radiation

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

Temperature exposure causes thermal deterioration of organic materials used in switchgear subcomponents (such as organic insulators, structural members, and lubricants). Temperatures affecting switchgear are associated with the ambient environment and temperature rise from ohmic heating of conductors within the switchgear. Most of the time the control circuits of switchgear are de-energized or carry small currents; therefore, little ohmic heating occurs in the control circuits. However, the primary circuits of the switchgear will normally carry sizable currents. The elevated temperature due to ohmic heating may cause gradual insulation deterioration and may accelerate the evaporation of petroleum-based lubricants used in some circuit breaker bearings such that a non-lubricating soap that could clog the bearings may be left behind. Ohmic heating of primary circuit components can be especially appreciable if high resistance connections develop at terminations, bus junctions, disconnects, or main contacts. Development of a high resistance connection could cause rapid deterioration of the surrounding insulating material. Generally, the ambient temperature surrounding switchgear at nuclear power plants is controlled and remains below the 40°C (104°F) normal temperature limit assumed in switchgear standards. The ambient temperatures are usually between 70° and 85°F most of the year. Switchgear is rarely located in areas having harsh environments. (See Section 3.5.4 for harsh environment discussion.)

Although normal voltage levels do not significantly stress switchgear components, they can cause problems when combined with humidity, dirt, or thermal deterioration. In medium-voltage systems, voltage and humidity can affect energized insulation that is dirty or deteriorated, and cause surface tracking paths between phase and ground and adjacent phases. Dry tracking paths generally have high enough insulation values to prevent immediate flashover. However, moisture in the tracking path will allow leakage current to flow. The leakage current flow will cause the moisture in the tracking path to evaporate due to the ohmic heating. In addition, the leakage current will tend to remain constant such that the current density in the tracking path increases as moisture evaporates. Near the point where there is no longer moisture to conduct the current, localized burning of the insulation can occur. The process is called "dry banding" and causes an incremental amount of damage each time it occurs. Left uncontrolled, arc tracking and dry banding will eventually lead to a conductive track and insulation failure.

Thermally deteriorated insulation, when exposed to humidity and dirt, may lose not only its surface insulating properties (in the form of surface current tracking), but also its volumetric insulating properties. Because thermally deteriorated insulation is most frequently brittle and prone to cracking, leakage current, in addition to propagating across the surface of the insulation, may travel through the thickness of the insulation and can eventually result in flashover. Reasonable inspection and care of primary insulation systems will detect surface and volumetric deterioration before it becomes severe.

Mechanical cycling of the circuit breaker (a cycle equals one open and close operation) places stress on circuit breaker components and may cause the components to degrade or deteriorate with time. The vibration that occurs with each cycle will stress the welds in the circuit breaker frame and operating mechanism and may cause weld fatigue. In most cases, welds have been designed to withstand significantly more cycles than the circuit breakers will experience. Vibration may also cause the components and settings of the circuit breaker operating mechanism to move such that friction may increase and cause the mechanism to bind. Mechanical cycling can also cause wear of the operating mechanism moving surfaces by displacing the dry lubricants between parts such that friction increases and leads to wear and binding.

The circuit breaker main and arcing contacts may also experience deterioration due to mechanical cycling. Cycling under heavy electrical loads and fault currents may significantly damage the main and arcing contact surfaces and can lead to contact burning and erosion. A high number of fault current interruptions may also damage the insulating material in the arc-chutes and cause it to crack or break. Manufacturers generally require that the breaker be inspected and maintained shortly after interruption of fault current.

Mechanical cycling of the spring charging mechanism may lead to failure to close due to wear of the mechanism parts. The ratchet teeth, motor crank and handle assembly, and limit switch contacts may wear with a high number of cycles and prevent closing spring charging.

Mechanical cycling may also cause the circuit breaker racking mechanism to wear. A high number of racking cycles may cause horizontal racking mechanisms to bind due to wear of the guide rails or tracks, wear of the levering system, or wear of the racking gear. Vertical racking mechanisms may experience motor failure as racking cycles increase because of wear of the clutch and drive. In each case, wear of the racking mechanism caused by a high number of cycles would result in failure to connect the breaker for operation. Interlock failure, a condition that is very dangerous for personnel, may also occur with a high number of racking cycles. This type of failure can be caused by wear or misalignment of the interlock parts. The loss of the interlocks would make it possible to remove or place the drawout unit into the cubicle with the main contacts closed. Interlock deterioration can easily be prevented by inspection.

Radiation exposure should not be a significant concern for most switchgear in that the switchgear must be in areas that are accessible under most design basis conditions. Integrated radiation doses would be expected to be well below 10^4 rd (based on a 60-year installed life), which would not cause significant deterioration of switchgear components. Switchgear used in areas with a higher radiation dose is qualified by analysis or test. 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.

As previously discussed, humidity, dirt, and contaminants do not directly produce stress, but they can lead to degradation of switchgear components. Humidity and dirt may cause deterioration of switchgear insulation when combined with voltage and thermal deterioration. Contaminants and moisture, combined or acting independently, can cause deterioration of the switchgear housing. The switchgear housing may corrode and/or rust if exposed to contaminants and/or moisture such that the structural members and fasteners will weaken. The circuit breaker operating mechanism may also deteriorate if exposed to contaminants. The presence of contaminants between moving surfaces could increase friction between moving parts and lead to wear and could also cause lubricant hardening and eventual stiffening or freezing of joints. Contamination of the circuit breaker arc-chute insulating surfaces during current interruption (from deposits of arcing contact material) could lead to the formation of electrical leakage paths and eventual insulation failure.[4.1]

Table 4-1 summarizes the stresses acting upon switchgear and indicates the aging mechanisms, types of degradation, and failure modes that may result from exposure to stresses.

4.2 Determination of Applicable Aging Mechanisms

Table 4-2 lists the potential aging mechanisms for electrical switchgear. Aging mechanisms were identified by considering the effects of stressors on each switchgear 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 electrical switchgear. For definitions of aging terminology, see Appendix A.

4.2.1.1 Primary Insulation System

The primary insulation system consists of the bus and support insulation and the main power path insulation (main contact, arc-chute, and primary disconnect insulation). There are three aging mechanisms for the primary insulation system: loss of electrical and mechanical properties, surface current tracking, and loss of volumetric and surface insulating properties.

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

Stress	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Ambient Temperature	Ohmic heating	Gradual deterioration of insulation[a]	Loss of electrical and mechanical properties	Loss of insulating properties, potential for flashover	Generally a slow long-term process
		Gradual deterioration of greases	Binding of latches and high friction in mechanism	Stalled or slowed trip or close latches resulting in slow or no open or close operation	Generally a slow process; will occur more rapidly in elevated ambient temperatures
	Excessive ohmic heating from high resistance at primary circuit connections	Rapid deterioration of insulation, possible burning	Rapid loss of electrical properties	Flashover of insulation	May occur relatively rapidly
Voltage (Medium-Voltage Switchgear Concern)	Dirt/humidity on insulator surfaces	Surface current tracking on insulation	Decreasing surface resistance dry banding damage	Flashover	Generally a slow process; may be more rapid in presence of thermal deterioration; the effects vary depending upon the configuration of the conductors and insulation
	Thermal deterioration with humidity	Loss of volumetric and surface insulation properties	Increased surface and volumetric leakage currents	Flashover	Of concern for insulations in an advanced state of deterioration
Mechanical Cycling of Circuit Breaker[b]	Poorly made welds in frame or mechanism	Weld fatigue	Cracking of welds	Jamming, slowing, failure to operate	Rarely a problem if welds were properly made, may be prevented by early inspection

Table 4-1. Stresses, Aging Mechanisms, Potential Failure Modes (continued)

Stress	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Mechanical Cycling of Circuit Breaker (continued)		Loosening and movement of components and settings	Loss of tolerances	Binding, high resistance connections, failure to operate	Corrected by periodic adjustment and maintenance
	Deteriorated lubricants	High friction between moving parts	Mechanical wear	Binding and slowing of mechanism and latches causing slow or no open	Slowing most probable, generally not a concern for reasonably maintained circuit breakers
	Operation under fault current	Deterioration of components	Damage to contacts, arc-chute, and mechanism possible	Degraded function	Inspection and appropriate maintenance after fault current operation to ensure continued function
Mechanical Cycling of Charging Mechanism	High levels of cycling	Wear of ratchet, motor, limit switches	Wear of charging mechanism	Failure to charge closing springs, failure to close	Detectable and correctable during maintenance
Mechanical Cycling of Racking Mechanism		Wear of tracks, levering system, racking gear	Binding of drawout unit	Improperly made up disconnects	Detectable and correctable during maintenance
		Wear of motor clutch and drive	Motor failure	Unable to lift breaker makeup disconnects	Detectable and correctable during maintenance
		Wear or misalignment of interlocks	Interlock failure	Loss of interlocks; may be possible to remove or place drawout unit into cubicle with main contact closed	Condition is dangerous to personnel but can be prevented by inspection
Contaminants and/or Moisture (in housing)		Housing material degradation	Corrosion and/or rust	Loss of structural integrity	Detectable by inspection

Table 4-1. Stresses, Aging Mechanisms, Potential Failure Modes (continued)

Stress	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Contaminants (in operating mechanism)		High friction between moving parts	Wear of operating mechanism	Binding of operating mechanism	Detectable by inspection
		Lubricant hardening	Stiffening or freezing of joints	Binding of operating mechanism	Detectable by inspection
		Surface current tracking on arc-chute insulating material	Decreasing surface resistance by dry banding damage	Loss of insulating properties, flashover	Detectable and correctable during maintenance

[a] Bus insulation, bus standoff insulators, and main contact support insulation could be affected. In general, this is not a problem for control wiring.
[b] Some cycling may help to redistribute lubricants and greases and to clean contacts.

Table 4-2. Identification of Potential Aging Mechanisms for Electrical Switchgear

Switchgear Component	Potential Failure Mode	Cause	Stressor	Potential Aging Mechanisms	Result
Metal Housing System	Loss of structural integrity	Structural degradation	Mechanical stress	Material fatigue	Cracked welds, deformation of the circuit breaker rails
		Corrosion/rust	Contaminants and moisture	Material degradation	Rust, pitting, and corrosion of structural members and fasteners
		Missing hardware	Loss of components[a]		Loss of anchoring and structural strength
Primary Insulating System (insulates bus and main power path)	Loss of insulating properties, flashover of insulation	Insulation deterioration	Ambient temperature (with ohmic heating)	Loss of electrical and mechanical properties	Insulation fails and flashes over after a long period of exposure
	Flashover of insulation	Insulation deterioration	Ambient temperature with excessive ohmic heating	Loss of electrical and mechanical properties	Insulation fails and flashes over after a short period of exposure, burning of insulation may occur
	Flashover of insulation	Decrease in surface resistance due to dry banding	Voltage with humidity, dirt, and contaminants	Surface current tracking	Insulation fails and flashes over
	Flashover of insulation	Decrease in volumetric and surface resistance	Voltage with thermal deterioration, humidity, dirt, and contaminants	Loss of volumetric and surface insulating properties	Bus insulation fails and flashes over
Horizontal Racking Mechanism	Failure to insert breaker and makeup disconnects	Binding of drawout unit	Racking cycles	Wear of tracks, levering system, and racking gear	Breaker will not be connected for operation

Table 4-2. Identification of Potential Aging Mechanisms for Electrical Switchgear (continued)

Switchgear Component	Potential Failure Mode	Cause	Stressor	Potential Aging Mechanisms	Result
Vertical Racking Mechanism	Failure to lift breaker to connected position	Lifting motor failure	Racking cycles	Wear of clutch and drive	Breaker will not be connected for operation
Arcing Contacts	Degraded function	Fault current operation	Electrical cycling	Contact deterioration	Arcing contact burn up and vaporization, main contact damage
Main Contacts	Degraded function	Fault current operation	Electrical cycling	Contact deterioration	Contact burning or welding
	Degraded function	High resistance at contact interface	Mechanical cycling	Movement of components and loss of tolerances (poor contact mating)	Contact burning or welding
Stored Energy Spring and Solenoid Operated Mechanism	Slow or no open or close operation	Binding of latches and high friction in mechanism	Ambient temperature	Deterioration of greases	Latch fails to activate mechanism, increase in torque required to move mechanism
	Binding of mechanism and latches, slow or no open or close operation	Mechanical wear of mechanism parts	Mechanical cycling	High friction between moving parts	Binding in spring release latch device, cam assembly, stop roller and main drive link, increase in torque required to move mechanism
	Binding, failure to operate	Loss of tolerances	Mechanical cycling	Movement of components and loss of tolerances	Movement of components due to vibration

Table 4-2. Identification of Potential Aging Mechanisms for Electrical Switchgear (continued)

Switchgear Component	Potential Failure Mode	Cause	Stressor	Potential Aging Mechanisms	Result
Stored Energy Spring and Solenoid Operated Mechanism (continued)	Jamming, slowing, failure to operate	Broken welds	Mechanical cycling	Pole shaft weld fatigue	Pole shaft lever misalignment and eventual failure to properly make contacts, increased trip time, distortion of linkages
	Failure to charge closing springs, failure to close	Motor failure, binding, failure to hold ratchet wheel, failure to rotate cam assembly	Mechanical cycling	Wear of spring charging mechanism components	Wear of ratchet teeth, pawls, and drive plates, grooving on oscillator surface and wear of charging motor crank and handle assembly and carbon brushes
	Failure to open, failure to close, failure to operate	Trip or close coil burn out	Elevated temperature	Prolonged energization of the control coils	Rapid coil burn out with energization beyond design period
Solenoid Operated Mechanism Only	Failure to close	Solenoid coil burn out	Elevated temperature	Prolonged energization of solenoid coil	Breaker cannot perform a closing operation
	Failure to close	Insulation deterioration	Electrical cycling	Turn to turn shorts, localized burning	Insulation deteriorates with each electrical cycle until a short circuit occurs
Arc-Chute	Degraded function	Fault current operation	Elevated temperature	Material degradation	Arc-chute material cracking or breakage, dielectric breakdown
Primary Disconnect	Degraded function	High resistivity connection	Racking cycles	Disconnect wear, spring relaxation	Burning of disconnects, loss of continuity

Table 4-2. Identification of Potential Aging Mechanisms for Electrical Switchgear (continued)

Switchgear Component	Potential Failure Mode	Cause	Stressor	Potential Aging Mechanisms	Result
Secondary Disconnect	Degraded function	High resistivity connection	Racking cycles	Spring relaxation	Burning of disconnects, loss of continuity
			Disconnect damage or breakage		
Mechanical Interlock	Loss of function	Friction	Racking cycles	Wear/damage	Possible to remove or insert circuit breaker into compartment with main contacts closed; could jeopardize personnel safety
Auxiliary Switch	Contact failure	Burnt contacts	Mechanical cycling	Contract deterioration	Components that rely on the auxiliary for control will not operate
Current and Potential Transformers	Degraded function	Insulation Deterioration	Temperature, electrical cycling	Shorted windings	Failure of undervoltage, control functions
Undervoltage Trip Attachment	Coil failure	Insulation deterioration	Elevated temperature	Constant coil energization	Breaker trip open upon coil failure
	Failure to trip	Latch failure	Mechanical cycling	Wear of latch	Breaker could fail to trip on undervoltage condition
	Failure to trip	Lack of adequate force	Mechanical cycling	High friction between moving parts	Breaker could fail to trip on undervoltage condition
Control Wiring	Failure to operate	High resistance connection; maintenance; vibration	Elevated temperature; mechanical damage	Loss of electrical and mechanical properties	Insulation will deteriorate and short to ground, will affect associated control devices

Table 4-2. Identification of Potential Aging Mechanisms for Electrical Switchgear (continued)

Switchgear Component	Potential Failure Mode	Cause	Stressor	Potential Aging Mechanisms	Result
Shunt Trip Attachment	Failure to operate	Coil failure	Prolonged energization; temperature	Coil deterioration	Open circuit of coil preventing operation of device
		Loose or misaligned	Cycling; vibration	Loss of tolerances	Device will actuate, yet will not actuate trip mechanism
Overcurrent Trip Device (electro-mechanical)	Improper operation or failure to operate	Metal fatigue	Spring compression	Spring relaxation	Setpoint/time delay drift
		Friction or degraded lubricant	Mechanical cycling/ temperature	Armature mechanical wear	Setpoint/time delay drift; potential loss of overcurrent protection
		Dirt or contaminants	Mechanical cycling	Seal degradation	Dashpot leakage; setpoint/time delay drift
Overcurrent Trip Device (solid state)	Improper operation or failure to operate	Material degradation	Elevated temperature; electrical transients; mechanical shock	Electrical component aging	Erroneous solid-state device output/operation; potential loss of overcurrent protection

[a] Not directly an aging mechanism, but could occur with time.

Loss of mechanical and electrical properties can occur with exposure to ambient temperature, ohmic heating of the conductor, and excessive ohmic heating that accompanies high resistivity connections. Exposure to ambient temperature can cause the bond structure of the insulation to change (a process called carbonization) such that the insulation will harden, embrittle, and eventually crack (i.e., lose its mechanical properties). If the insulation becomes so deteriorated that it can no longer withstand the potential imposed upon it, it will flashover to ground or between phases (i.e., lose its electrical properties). Ohmic heating of the conductor will intensify the deterioration due to ambient temperature so that it may gradually lead to insulation failure and flashover after a long period of time. The excessive ohmic heating that accompanies high resistivity connections could lead to rapid insulation deterioration such that insulation failure and flashover, and possibly burning, occur after a short period of exposure.

The bus, main contact, and primary disconnect insulation could experience a loss of mechanical and electrical properties with exposure to ambient temperature and the ohmic heating that occurs during normal operation. High resistivity connections could develop for each of these components as a result of (1) improper connection of bus bars at the bus joint, (2) poor mating of the main contacts, and (3) poor mating of the primary disconnects.

Because insulating materials are designed to withstand normal operating temperatures for an extended period of operation, deterioration due to ambient temperature and ohmic heating is not highly probable. However, the insulating materials are not designed to withstand excessive ohmic heating due to high resistivity connections. Although the probability of developing high resistivity connections is not high, the catastrophic failure that could occur as a result of a loss of electrical and mechanical properties indicates that this aging mechanism is significant to switchgear operation.

The second aging mechanism for the primary insulation system, surface current tracking, can occur with simultaneous exposure to voltage, humidity, dirt, and contaminants. The presence of these stresses on the surface of insulation can provide a path for current flow such that dry banding will occur and decrease the surface resistance of the insulation. Surface current tracking may eventually lead to flashover of insulation.

Loss of volumetric and surface insulating properties, the third and final aging mechanism for the primary insulation system, could result from the simultaneous exposure of thermally deteriorated insulation to temperature, voltage, humidity, dirt, and contaminants. The cracking that thermal stress can produce could provide a leakage current path through the thickness of the insulation. Humidity, dirt, and contaminants could reduce the surface resistance of the insulation through dry banding such that the leakage current could also travel across the surface of the insulation. The loss of volumetric and surface insulating properties would allow leakage current to flow through and across the surface of the insulation such that flashover to ground or between phases could occur.

The primary insulation system may experience surface current tracking if dirt and contaminants from the environment accumulate on component surfaces and, when exposed to voltage and humidity, provide a path for current flow. The arc-chute insulation is especially susceptible to surface current tracking as it may accumulate additional deposits from the vaporization of arcing contact material during current interruption. The bus insulation is the only primary insulation component that could be affected by a loss of volumetric and surface insulating properties. Ohmic heating could cause volumetric deterioration, and voltage, humidity, dirt, and contaminants could cause surface deterioration.

A review of industry-wide operating experience indicates that a loss of volumetric and surface insulating properties has occurred during normal operation and caused flashover of insulation. NRC Information Notice 89-64, "Electrical Bus Bar Failures,"[4.2] discusses an electrical bus bar failure caused by cracked and brittle Noryl insulation and the presence of moisture and dirt in the bus enclosure. Another failure was caused by cracked Noryl insulation that had been contaminated with bus joint compound (see Section 3.6.1).

The existence of surface current tracking and loss of volumetric and surface insulating properties has been documented. Because the failure that they can produce is catastrophic in nature, both surface current tracking and loss of volumetric insulating properties are considered to be significant aging mechanisms.

Fatigue cracking of various moldings used in insulating applications (such as insulating links and pole unit moldings) was noted in various breakers during overhaul (see Section 3.6.2.3.2). Although apparently not inducing any actual switchgear failures or affecting any critical breaker functions, this type of degradation appears to occur in many classes of switchgear (including General Electric AK, Westinghouse DB, and ABB HK) and should also be considered significant in that it leads to the deterioration of insulating properties.

4.2.1.2 Primary Disconnects

The aging mechanisms for the primary disconnects are disconnect wear and spring relaxation. Both of these aging mechanisms, either separately or in combination, could cause the disconnect connection to become highly resistive such that a loss of continuity or disconnect burning could occur due to excessive ohmic heating. In both cases, the high resistivity connection would be the result of poor contact mating. Disconnect wear could cause poor contact mating by changing the surface dimensions of the disconnects during each racking cycle. As the number of racking cycles increased, the disconnect surfaces would experience incrementally more wear and contact gaps would eventually occur (poor contact mating). Spring relaxation could cause poor contact mating by allowing the disconnect fingers, which normally press against the stab to ensure a tight connection, to move away from the stabs so that a contact gap would be created (poor contact mating). Spring relaxation would increase with an increasing number of racking cycles. Because they could have a large impact on switchgear operation, both disconnect wear and spring relaxation are significant aging mechanisms.

4.2.1.3 Secondary Disconnects

The aging mechanisms for the secondary disconnects are spring relaxation and breakage during maintenance or removal. Spring relaxation could cause the disconnect connection to become highly resistive such that a loss of continuity or disconnect burning could occur. A high resistivity connection would by caused by poor contact mating. Spring relaxation could cause poor contact mating by allowing the disconnects, which normally press against the stab to ensure a tight connection, to move away from the stabs so that a contact gap would be created (poor contact mating). Spring relaxation would increase with an increasing number of racking cycles. Because it could have a large impact on switchgear operation, spring relaxation is a significant aging mechanism.

Although not a direct aging mechanism, disconnect breakage could cause secondary disconnect failure. Breakage of the secondary disconnects could occur during circuit breaker removal or maintenance.

4.2.1.4 Racking Mechanism

The two types of racking mechanisms used to insert circuit breakers into switchgear compartments are the horizontal drawout type and the vertical lift type.

The aging mechanism for the horizontal racking mechanism is wear of the mechanism components, specifically the compartment tracks, levering system, and racking gear. Wear of these parts due to friction could occur with an increasing number of racking cycles. This could eventually lead to binding within the mechanism such that it would be impossible to insert the breaker into the compartment and make up the primary disconnects. Failure to make up the disconnects would render the breaker inoperable. Because operation of the circuit breaker would be hindered by failure of the horizontal racking mechanism, wear of the compartment tracks, levering system, and racking gear is considered to be a significant aging mechanism for electrical switchgear.

The aging mechanism for the vertical racking mechanism is wear of the lifting motor components. Wear of the motor clutch and drive could occur with an increasing number of racking cycles and could eventually lead to motor failure such that the breaker could not be lifted to its connected position. Failure to make up the breaker primary disconnects would render the breaker inoperable. Because operation of the circuit breaker would be impeded by lifting motor failure, wear of the lifting motor clutch and drive is considered to be a significant aging mechanism for electrical switchgear.

4.2.1.5 Arcing and Main Contacts

The aging mechanism associated with the arcing contacts is contact deterioration. Contact deterioration can occur with fault current interruption. The high temperatures that accompany fault current may cause the arcing contact material to vaporize. Loss of arcing contact material will degrade the ability of the arcing contacts to interrupt fault current. If arcing contact pressure is not measured (and contact surfaces inspected) after each fault current interruption, additional electrical cycles can lead to a loss of function. In addition, arcing contact deterioration may lead to main contact deterioration as the main contacts will have to interrupt incrementally more current as the arcing contacts deteriorate. As a result, contact deterioration due to fault current interruption is also an aging mechanism for the main contacts. Degradation of main contact surface with each electrical cycle could cause the main contacts to burn or weld together so that main contact function would be impeded.

The main contacts have one additional aging mechanism: movement of components and loss of tolerances. Movement of main contact parts, caused by the vibration that occurs with operation, could cause contact misalignment and poor contact mating. With each mechanical cycle, the amount of contact mating could decrease to the point where the main contact interface becomes highly resistive and excessive ohmic heating occurs. This heating could eventually lead to contact burning and welding.

Industry-wide operating experience indicates that the main contacts have performed without failure up to the present time. The low occurrence of failures is predominately a result of industry-wide maintenance programs. Most programs include inspection of the arcing and main contacts on a regular basis and immediately after fault current interruption to ensure that the contacts are in good condition. The contacts are replaced as required to prevent significant deterioration of the contact surfaces (see Section 5.2). The inspection and replacement currently performed maintain contact function by preventing contact degradation and, as a result, mitigate the effects of contact deterioration for the arcing and main contacts. Movement of components and loss of tolerances is also prevented by contact inspection because the effect of this aging mechanism, excessive ohmic heating, is observable through visual inspection. Current maintenance practices control these aging mechanisms because the failure of the arcing or main contacts would have a large impact on circuit breaker operation. For this reason, the aging mechanisms for the arcing and main contacts can be considered as significant aging mechanisms. The maintenance practices currently used to maintain arcing and main contact condition should be continued during the license renewal period to preserve contact function.

4.2.1.6 Stored Energy Spring Operated Mechanism

There are five aging mechanisms for the stored energy spring operating mechanism: deterioration of greases, high friction between moving parts, movement of components and loss of tolerances, weld fatigue, and wear of spring charging mechanism components. Aging mechanisms applicable to both stored energy and solenoid operated equipment are discussed in this section.

Deterioration of greases, which could occur due to contamination, aging, evaporation, or separation resulting from time and exposure to ambient temperature, could increase the amount of friction in the latches and mechanism and cause binding. Latch binding would restrict latch movement such that the mechanism would not be activated to open or close. Binding in the operating mechanism would slow or prevent operation completely because of an increase in the amount of torque required to move the mechanism.

The existence of this aging mechanism is documented in IE Bulletin 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Attachment (UVTA) in Use in Safety-Related Applications Other Than the Reactor Protection System."[4.3] The Bulletin states that circuit breaker failure was caused by hardened and contaminated grease in the circuit breaker trip shaft bearings. The hardened grease resulted in an increase in the amount of torque required to operate the mechanism. Because the deterioration of greases has been shown to actually occur in operation and has had a large impact on breaker performance, this aging mechanism is considered to be significant.

The second aging mechanism for the stored energy spring operating mechanism, high friction between moving parts, could also cause the mechanism to bind. High friction between moving parts can be differentiated from lubricant deterioration (described above) in that deterioration is not necessary for lubricant displacement (i.e., the lubricant is wiped from the mechanism parts by their motion, resulting in high friction between the parts). A lack of operating cycles or a high number of operating cycles could cause this aging mechanism to occur. A lack of cycling would contribute to friction caused by lack of lubricant distribution. A high number of mechanical cycles would increase friction between mechanism parts because of wear resulting from degraded and/or displaced lubrication. Thus, too few or too many operating cycles may produce friction and binding of the latches and mechanism components, specifically the spring release latch device, cam assembly, stop roller and main drive link, such that breaker operation would be slowed or prevented. As a result, the closing coil could burn, and the increase in the amount of torque required to move the mechanism could cause a loss of tolerances.[4.4]

A review of industry-wide operating experience produced four documented occurrences of high friction between moving parts. IE Bulletin 79-09, "Failures of General Electric Type AK-2 Circuit Breakers in Safety-Related Systems,"[4.5] discusses the failure of General Electric AK circuit breakers (solenoid operated) to trip open on demand. The failures were attributed to binding within the circuit breaker trip shaft assembly. The binding was caused by inadequate preventive maintenance programs at the affected plants.

IE Bulletin 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Attachment (UVTA) in Use in Safety-Related Applications Other Than the Reactor Protection System,"[4.3] discusses excessive wear of moving parts in the trip bar latch assembly due to improper and infrequent lubrication. Cleaning and relubrication of the breaker trip shaft assembly corrected the problems with the assembly.

IE Information Notice 87-12, "Potential Problems with Metal-Clad Circuit Breakers, General Electric Type AKF-2-25,"[4.6] examines the failure of General Electric AKF-2-25 circuit breakers (solenoid operated) to open on demand. Mechanical binding of the main mechanism (cam arrangement) was the main cause of the failures. A failure evaluation determined that improper lubricants had been used and the breakers were out of adjustment.

NRC Information Notice 88-44, "Mechanical Binding of Spring Release Device in Westinghouse Type DS-416 Circuit Breakers,"[4.7] examines the failure of two DS-416 tie and feeder circuit breakers to reclose on demand during load sequencing. The breakers failed to reclose due to mechanical binding between the spring release lever and the edge of the breaker casing window. The binding prevented the lever from making contact with the spring release latch that releases the breaker closing springs. Although the root cause of the binding was not determined, the utility replaced the spring release device in the breakers that had signs of binding and verified that the clearances between the lever and the casing were sufficient to preclude further binding.

The Bulletins and Notices above show that high friction between moving parts does exist and that it has a large impact on circuit breaker operation. Therefore, high friction between moving parts is a significant aging mechanism for electrical switchgear.

Movement of components and loss of tolerances, the third aging mechanism for the stored energy spring operating mechanism, could be caused by the vibration that accompanies each operating cycle. The shaking that occurs during operation could cause components and settings to move such that tolerances would be exceeded. Binding and failure to operate could eventually occur after a high number of operating cycles because of friction in misaligned mechanism parts. Because movement of components and loss of tolerances can have a large impact on circuit breaker operation, this aging mechanism is significant for electrical switchgear.

NRC Information Notice 88-42, "Circuit Breaker Failures Due to Loose Charging Spring Motor Mounting Bolts,"[4.8] discusses the failure of an emergency diesel output circuit breaker to close. The failure was attributed to loose charging spring motor mounting bolts. The loose bolts allowed the motor to become detached from the breaker frame. As a result, the motor did not charge the closing spring and the breaker would not close. The utility determined that the charging spring motor mounting bolts had not been sufficiently torqued by the vendor. The bolts were removed, cleaned, coated with Locktite, and torqued to alleviate the problem. Although the root cause of the breaker failure was an installation deficiency, the loosening of the bolts holding the motor to the breaker frame was induced by mechanical stress and vibration occurring cumulatively during the period of installation, and can therefore be considered an age-related failure.

Pole shaft weld fatigue, another aging mechanism for the stored energy spring operating mechanism, has been noted in Westinghouse Model DS breakers, which have poor welds stemming from the manufacturing process. This weld fatigue is more likely to occur as the number of operating cycles increases. Mechanical cycling could stress the pole shaft welds and cause them to fatigue and eventually to crack and break. Cracked or broken pole shaft welds could lead to pole shaft lever misalignment and eventual torque redistribution (the torque transferred by the main drive link would be redistributed nonuniformly among the three poles). Torque redistribution could lead to failure to properly make the main contacts. Pole shaft lever misalignment could also lead to increased force on the main roller. This could cause an increase in trip time and distortion of the mechanism linkages. Distortion of linkages could cause binding and failure to charge.[4.4]

The following documents discuss the existence of weld fatigue. NRC Information Notice 87-35, "Reactor Trip Breaker, Westinghouse Model DS-416, Failed to Open on Manual Initiation From the Control Room," [4.9] discusses breaker failure due to mechanical binding of the operating mechanism. A failure investigation revealed that a broken weld and abnormal wear caused the mechanism to bind.

NRC Information Notice 87-35, Supplement 1, "Reactor Trip Breaker, Westinghouse DS-416, Failed to Open on Manual Initiation From the Control Room,"[4.10] analyzes the mechanical binding reported in Notice 87-35 in greater detail. The broken weld was located on the main drive link between the center pole lever and the pole shaft (the pole shaft connects the poles of all three phases so that they open and close simultaneously). The weld failure allowed the main linkage to move laterally and jam at or near full closure. A large number of operating cycles (3000 or more) caused wear that allowed sufficient rotation of the main roller axis such that wedging occurred and the breaker failed to open.

NRC Bulletin 88-01, "Defects in Westinghouse Circuit Breakers,"[4.11] discusses one additional weld failure that caused mechanism binding and the detection of broken welds during routine maintenance in response to Notice 87-35, Supplement 1. The center pole lever weld failure reported in Bulletin 88-01 freed the center moving contact assembly such that it could move independently of the pole shaft that drives the other two moving contact assemblies. The failure caused electrical single phasing problems, so that only two out of the three poles closed properly, and resulted in erratic operation of the connected equipment. An engineering analysis of the failed weld concluded that the failure occurred because of excessive porosity. The broken center pole lever welds identified during routine maintenance, which had not yet caused breaker failure, were caused by an extensive lack of fusion of the weld to lever as a result of improper weld technique.

The Bulletins and Notices above indicate that weld fatigue in Westinghouse Model DS breakers does exist and that it may have a large impact on circuit breaker operation. Therefore, weld fatigue is considered a significant aging mechanism for electrical switchgear. It should be noted, however, that if suspected faulty pole shafts (or other welded components susceptible to this type of failure) have been previously evaluated and/or replaced, this failure mechanism is no longer applicable to the affected equipment. In cases where no such evaluation has been performed, consideration of weld fatigue as an aging mechanism is warranted.

Wear, an aging mechanism for the spring charging mechanism components, could occur with mechanical cycling. The friction that occurs with each cycle can wear ratchet teeth, pawls, and drive plates. In addition, grooving on the oscillator surface and wear of the charging motor crank and handle assembly and carbon brushes can cause irregular motion of the crank shaft. Wear and failure of any of these components, in the form of motor failure, binding, failure to hold the ratchet wheel, and failure to rotate the cam assembly, could render the spring charging mechanism inoperable and the breaker unable to close.[4.4] Because wear of the spring charging mechanism components can have a large impact on circuit breaker operation, this aging mechanism is significant for electrical switchgear.

NRC Information Notice 90-41, "Potential Failure of General Electric Magne-Blast and AK Circuit Breakers,"[4.12] discusses operating problems with prop springs. (This discrepancy, although not specifically an aging mechanism, is included for completeness.) A prop spring holds the prop in position when the breaker is closed such that it prevents the operating mechanism from tripping the breaker. This Notice also discusses problems with snap rings and lubricants used in refurbished breakers. A broken prop reset spring caused failure in three different types of General Electric circuit breakers: an AM-4.16 kV, an AM-4.16-350-1H, and an AMH-4.76. In each case, the broken prop reset spring rendered the circuit breaker unable to remain closed. In the AM-4.16-kV circuit breaker, the spring failed as a result of a metal fatigue crack that initiated at a surface lap in the wire. The utility decided to prevent this type of failure by replacing prop springs every 2000 cycles. In the General Electric AM-4.16-350-1H circuit breaker, the spring failed as a result of a fatigue crack that had occurred at the end of the coil, where the wire was bent at 90° to form the hook. The circuit breaker had operated for 1400 cycles before failure. The spring was replaced and the breaker was returned to service. The cause of prop spring failure for the General Electric AMH-4.76 circuit breaker was not given, but the circuit breaker had operated for 1625 cycles before failure. The utility replaced the prop reset springs on all safety-related circuit breakers with more than 900 cycles of operation.

4.2.1.7 Solenoid Operated Mechanism

There are several aging mechanisms for the solenoid operated mechanism. Two of the aging mechanisms, prolonged energization of the solenoid coil and turn-to-turn shorts/localized burning, could inhibit closing operations. The remaining aging mechanisms for the solenoid operated mechanism, deterioration of greases, high friction between moving parts, movement of components and loss of tolerances, weld fatigue, and prolonged energization of the trip coil, could prevent opening operations.

Prolonged energization of the solenoid coil could occur with jamming of the moving core due to dirt accumulation. Jamming would not allow the core to complete its closing operation; as a result, the solenoid coil would not be able to de-energize. Because the solenoid coil is not designed for long periods of energization, the elevated temperatures that occur with prolonged energization could cause the coil to heat up and burn out. Solenoid coil burnout could also be caused by auxiliary switch failure. If the auxiliary switch did not send the appropriate signal when the breaker closed, the solenoid coil would remain energized and could burn out.

Turn-to-turn shorts and localized burning could occur with electrical cycling. During each closing operation, the temperature of the solenoid coil during energization could cause a small amount of insulation deterioration. As the number of electrical cycles increased, the insulation deterioration could increase and lead to turn-to-turn shorts and localized burning. The solenoid coil insulation would deteriorate further because of this aging mechanism and could eventually fail and cause a short circuit. At this point, closing operations would not be possible.

Because prolonged energization of the solenoid coil and turn-to-turn shorts/localized burning could cause failure that would have a large impact on circuit breaker operation (would not allow closure), these two aging mechanisms are considered to be significant for solenoid operated electrical switchgear.

The remaining aging mechanisms for the solenoid operated equipment (deterioration of greases, high friction between moving parts, movement of components, and loss of tolerances) are also applicable to the stored energy spring operating mechanism. See Section 4.2.1.4 for a discussion of these effects.

4.2.1.8 Arc-Chute

The aging mechanism for the arc-chute, material degradation, could occur with the elevated temperature that accompanies fault current operation. Elevated temperature could cause the arc-chute material to erode and embrittle, eventually resulting in the loss of electrical properties. Arc-chute material degradation would increase with an increasing number of fault current operations. Cracking and breaking of the arc-chute plates or ceramic stack could eventually occur and lead to failure to extinguish current or flashover between phases, respectively, during the next interruption. Because it could have a large impact on current interruption, arc-chute material degradation is a significant aging mechanism for electrical switchgear.

In addition to material degradation, loss of surface and volumetric insulating properties is a potentially significant aging mechanism for arc-chutes. Exposure to thermal stress, dirt, moisture, and other contaminants could lead to the loss of electrical insulating properties, thereby resulting in surface tracking, current propagation directly through the volume of the material, or both. Several plants operating General Electric Magne-Blast medium-voltage switchgear (with arc-chutes manufactured from asbestos) have reported instances of moisture permeation of the arc-chute resulting in low insulation resistance or Doble test readings. This appears to occur primarily in areas of relatively high humidity or moisture (e.g., outdoors or near bodies of water). Techniques used to manage the aging of asbestos arc-chutes are discussed in detail in Section 5.2 of this guideline.

4.2.1.9 Mechanical Interlock

The aging mechanisms for the mechanical interlock are friction and/or inadequate lubrication. Friction could result in wear or damage such that the mechanical interlock would not open the breaker contacts during insertion into or removal from the breaker compartment. Mechanical interlock wear due to friction would increase with an increasing number of racking cycles. Failure of the mechanical interlock could be dangerous to personnel as it would be possible to insert or remove the circuit breaker into and from the compartment with the main contact closed. Additionally, binding and/or wear of the interlock mechanism could prevent the breaker from closing and thus performing its required function(s). Because failure of the interlock mechanism due to inadequate lubrication, friction, or loss of tolerances could have a large impact on circuit breaker operations, this aging mechanism is considered significant.

4.2.1.10 Auxiliary Switch

Aging mechanisms for auxiliary switches include contact wear due to switch rotation/actuation as well as bent or out-of-adjustment operating linkages. Contact wear would increase with the number of switch cycles, potentially resulting in high resistance or incomplete contact(s) and resultant loss of circuit continuity or function. Similarly, wear of operating linkages would increase with the number of cycles of the switch, resulting in failure of contacts to make or break as appropriate. Bending of the linkage could occur from mishandling during maintenance. Because these switches can affect breaker functions, the impact of these aging mechanisms will vary with the function provided by the switch; therefore, these aging mechanisms are considered significant.

4.2.1.11 Current and Potential Transformers

The primary aging mechanism for current and potential transformers is winding insulation breakdown. Winding insulation breakdown is caused by elevated insulation temperature (due to ohmic heating and breaker internal ambient conditions) and electrical cycling. Degraded winding insulation can produce shorted transformer windings (turn to turn), resulting in faulty voltage/current transformation, spurious undervoltage trips, and erroneous overcurrent trip settings. Current and potential transformers provide a variety of breaker functions, including undervoltage, overcurrent, and differential current sensing, and are therefore important to overall breaker operation; hence, winding insulation breakdown can be considered a significant aging mechanism.

4.2.1.12 Undervoltage Trip Device

There are three aging mechanisms for undervoltage trip devices: constant coil energization, latch wear, and high friction between moving parts. Because the latch-type undervoltage trip attachment is a de-energize to operate device, the coil is constantly energized. The heating that accompanies constant coil energization can cause the coil insulation to deteriorate. Coil insulation deterioration could eventually lead to burning and coil failure. Because the circuit breaker would automatically trip open upon coil failure, constant coil energization could have a large impact on circuit breaker operation and is a significant aging mechanism.

Latch wear, the second aging mechanism for the latch-type undervoltage trip attachment, would occur with mechanical cycling. The latch that pushes the trip bar could become worn with an increasing number of mechanical cycles to the point where the latch would no longer make contact with the trip bar. As a result, the breaker could fail to trip on an undervoltage condition.

The existence of latch wear is documented in IE Bulletin 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Feature in Use in Safety-Related Applications Other Than the Reactor Trip System."[4.3] IE Bulletin 83-08 discusses the failure of a Westinghouse breaker to close on demand. This failure occurred during life cycle demonstration tests conducted by Westinghouse and was directly related to the UVTA latching mechanism. The failure occurred on a new UVTA that was initially lubricated in accordance with the latest Westinghouse recommendation but which, for test purposes, was not subsequently lubricated. This failure to close occurred after 571 trip and reclose operations, and was attributed to normal latch wear. The latch wear placed the breaker mechanism in a trip-free condition such that the breaker could not be closed electrically or mechanically. This failure does not represent a safety concern in reactor trip breaker applications, but there is a concern that such failures could, in other applications, prevent the performance of a safety-related function. Because the existence of latch wear has been documented and latch wear could have a large impact on circuit breaker operation, it is a significant aging mechanism for electrical switchgear.

High friction between moving parts, the final aging mechanism for undervoltage trip devices, would occur with mechanical cycling. A lack of cycling would contribute to friction due to lack of lubricant distribution. A high number of mechanical cycles would increase friction between mechanism parts due to wear. Thus, too few or too many operating cycles would produce friction and binding in the mechanism such that the mechanism would not trip the circuit breaker on an undervoltage condition.

The existence of high friction between moving parts has been recorded in the following documents. IE Bulletin 79-09, "Failures of General Electric Type AK-2 Circuit Breakers in Safety Related Systems,"[4.5] addresses failures of General Electric AK-2 circuit breaker undervoltage trip (UV) devices. The failures were attributed to binding and out-of-adjustment conditions in the UV device linkage mechanism. A failure investigation determined that the binding and out-of-adjustment conditions resulted from inadequate preventive maintenance programs.

IE Circular 81-12, "Inadequate Periodic Test Procedure of PWR Protection System," [4.13] also addresses UV device failure due to binding. In this case, the binding was caused by an out-of-adjustment condition. This failure was attributed to an inadequacy in the periodic test procedure. The procedure did not verify the trip function of the UV coil trip independent of shunt trip coil.

IE Bulletin 83-01, "Failure of Reactor Trip Breakers (Westinghouse DB-50) to Open on Automatic Trip Signal,"[4.14] discusses the failure of the Westinghouse DB-50 UVTA to open its associated reactor trip breaker on demand. The failure was attributed to sticking of the UVTA.

IE Bulletin 83-04, "Failure of the Undervoltage Trip Function of Reactor Trip Breakers," [4.15] discusses the failure of General Electric AK-2 type UV devices to trip their associated reactor trip breakers during testing. The failures were also attributed to either binding or out-of-adjustment conditions within the linkage mechanism of the UV device and were not detected during previous testing because the shunt trip and UV device trip functions were not verified independently.

IE Bulletin 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Feature in Use in Safety-Related Applications Other Than the Reactor Trip System,"[4.3] addresses the failures of both the Westinghouse DB-50 UVTAs and the General Electric AK-2-25 UV devices reported in Bulletins 83-01 and 83-04, respectively. The problems with alignment and lubrication that were identified as causes for failure to trip included (1) improper lubrication of linkages and other moving parts within the UVTA or UV device, (2) inadequate adjustment of spring tension of the UVTA or UV device, and (3) excessive wear of moving parts within the UVTA or UV device because of infrequent lubrication of the moving parts or improper adjustment of the spring tension.

Further investigation revealed that some PWRs and BWRs also employ similar undervoltage features in other safety-related applications. These applications may include the engineered safety features systems and the 120-Vac uninterruptible power source from the motor-generator sets in BWR plants. Circuit breakers supplied by manufacturers other than Westinghouse or General Electric may be used in some plants for these non-reactor trip breaker applications.

In addition to failure to trip, Bulletin 83-08 discusses failure of a Westinghouse breaker to close on demand. This failure occurred during life cycle demonstration tests conducted by Westinghouse and was directly related to the UVTA latching mechanism. The failure occurred on a new UVTA that was initially lubricated in accordance with the latest Westinghouse recommendation but which, for test purposes, was not subsequently lubricated. This failure to close occurred after 571 trip and reclose operations, and was attributed to normal latch wear. The latch wear placed the breaker mechanism in a trip-free condition such that the breaker could not be closed electrically or mechanically. This failure does not represent a safety concern in reactor trip breaker applications, but there is a concern that such failures could, in other applications, prevent the performance of a safety-related function.

IE Information Notice 85-58, Supplement 1, "Failure of a General Electric Type AK-2-25 Reactor Trip Breaker,"[4.16] discusses a defect in the General Electric AK-2-25 UV device that caused the UV devices to fail to meet their required response times.* A failure analysis revealed that several laminated sections had slipped down and effectively eliminated the air gap between the movable armature and the pole face. The physical contact between the laminations and pole face allowed the armature to be held down by residual magnetism after dc power was removed. The residual magnetism caused the UV devices to exceed their required response time. Corrective action involved replacing the UV trip devices and instituting a program to measure the air gap between the laminations and pole face on a yearly basis (there were no previous instructions in General Electric literature pertaining to the air gap between the laminations and pole face).

Because the occurrence of high friction between moving parts has been shown to exist in reactor trip applications, could exist in other applications, and can have a large impact on circuit breaker operation, it is a significant aging mechanism for the undervoltage trip attachment.

4.2.1.13 Overcurrent Trip Device (OCTD)

As discussed in Section 3.4.2.5, overcurrent trip devices can be divided into two major classifications: (1) electromechanical devices and (2) solid-state devices. Aging mechanisms for the electromechanical devices include spring relaxation, armature mechanism wear and friction, and damping mechanism failure due to seal degradation or leakage. Aging mechanisms for solid-state units include failure/drift of electronic components, winding insulation breakdown of the current transformer, and deterioration associated with the aging of the solenoid actuator.

The electromechanical overcurrent device is susceptible to setpoint and time delay drift caused by either relaxation of the force limiting and/or calibration springs, wear of the mechanical linkage which controls the device, or failure of the dashpot assembly that acts as the damping mechanism. Dirt and degradation of the lubrication used on this armature could create increased friction (and resulting wear). Dirt and atmospheric contaminants may also produce damage to the dashpot seals (leaking dashpots have accounted for numerous OCTD failures as discussed in Section 3.6.2). Vibration ("hum") may, over extended periods, induce slight eccentricities or misalignments in the various armature components such that the force necessary to actuate these components is increased and their wear accelerated.

Aging of the solid-state devices would primarily be due to aging of the electronic components used in the unit itself (e.g., variations in the capacitance of a capacitor or failure of a diode). Generally speaking, variations in the properties of electronic components occur at slow and predictable rates. A given percentage of components will fail when new; the

* Although not an age-related condition, this is a potential problem that should be covered by good maintenance.

probability of subsequent failures decreases dramatically until late in the component's life, at which point the probability again increases (this behavior is known as the "bathtub curve"). Hence, assuming that adequate pre-aging and quality control is used with these components, the vast majority of solid-state units should perform with minimal parametric variation until late in their design lifetime. However, elevated temperature, electrical transients, and power supply voltage fluctuations, as well as mechanical vibration (and other agitation), can be assumed to shorten this period.

Aging mechanisms applicable to the current sensor (transformer) and solenoid actuator are discussed in Sections 4.2.1.11 and 4.2.1.7, respectively.

4.2.1.14 Control Wiring

Three aging mechanisms exist for control wiring: chafing and cutting of the insulation, ohmic/ambient heating of the insulation, and contact/connection degradation. Movement of the surrounding mechanisms (during racking evolutions, breaker operation, or normal component vibration) could potentially chafe or cut control wiring insulation and even the underlying conductor in severe cases. Failure of control wiring insulation (and/or the underlying conductor) can lead to shorts and loss of circuit continuity, and can ultimately affect the operation of breaker control devices and functions. Ohmic and ambient heating of the conductor and insulation can result in a loss of the mechanical and electrical properties of the wiring (i.e., insulation resistance, conductor flexibility, etc.). Connection degradation can result from low connection contact area (loose or dirty connections), corrosion or oxidization of contact surfaces, and ohmic heating. High resistance control wiring connections can affect breaker control functions via loss of circuit continuity. Because control functions are essential to the breaker safety function, these mechanisms are considered significant.

4.2.1.15 Shunt Trip Attachment

Aging mechanisms for the shunt trip attachment are coil deterioration and loss of tolerances. Prolonged energization of the shunt trip attachment coil or exposure to elevated temperatures from other sources could result in deterioration of the coil insulation, thereby leading to shorting and coil failure. This would effectively preclude the shunt trip device from operating. Loss of tolerances could occur as a result of loosening or movement of the device on its mounting, improper adjustment, or wear of the mechanical components used to actuate the trip bar. Cycling of the breaker and other sources of vibration or shock can loosen the device; wear may occur over time due to friction. Since the failure of the shunt trip attachment can affect the plant operator's ability to control the breaker, these aging mechanisms are considered significant.

4.2.2 Non-significant Aging Mechanisms

4.2.2.1 Metal Housing System

The potential failure mode for the switchgear housing structure is a loss of structural integrity, i.e., a loss of structural alignment or a loss of seismic withstand capability. Loss of structural integrity could be caused by one of three aging mechanisms: material fatigue, material degradation, or loss of components. Material fatigue, resulting from mechanical stress, could cause housing welds to crack and circuit breaker rails to deform (in the horizontal racking type). Material degradation, resulting from exposure to contaminants and moisture, could cause the structural members and fasteners to rust, pit, and corrode.

Although not a direct aging mechanism, loss of components could cause a loss of anchoring and structural strength. Loss of components could occur due to poor maintenance practices. Maintenance of the housing structure may involve removal of housing enclosure parts for cleaning and visual inspection. When the housing enclosure parts are replaced, fasteners and/or hardware may be inadvertently left out. If a fastener or piece of hardware is left out each time that the switchgear is serviced, the number of missing fasteners will increase with time and could eventually result in a loss of structural integrity. Thus, although not a direct aging mechanism, loss of components could occur with time.

Loss of structural integrity is a concern for the switchgear housing because the housing protects and supports the internal components. However, industry-wide operating experience with the metal housing systems (see Section 3.6) indicates that they have performed without failure up to the present time. In addition, Reference 4.1 states that the metal housing system does not have a tendency to age significantly with time. Therefore, unless the switchgear (and housing) are located in high moisture/corrosive environments (such as being outside in salty ocean air), structural deterioration of the metal housing is not a significant aging mechanism. In general, the switchgear under consideration in this study is located indoors in non-corrosive environments; moisture or contaminants at the levels necessary to induce degradation of the structural integrity of the housing would likely be detected in other equipment/components first. In those cases where the equipment is located in such a corrosive environment, aging of the housing may be significant, and must be addressed by appropriate maintenance practices.

4.2.2.2 Stored Energy Spring Operated Mechanism

Another consideration related to the stored energy spring operating mechanism is prolonged energization of the control coils. Prolonged energization of the closing and trip coils could occur with slowing and jamming of the operating mechanism. Prolonged energization could cause the coils to heat up and burn out. Prolonged energization of the trip coil could also be caused by auxiliary switch failure (the auxiliary switch failed to move to the open position when the breaker was tripped). Either coil may burn out if energized for a period longer than its design period. Coil failure would result in failure to close, failure to open, or failure to operate if both coils were burned out.

A review of industry-wide operating experience produced three documented occurrences of prolonged energization. IE Information Notice 87-12, "Potential Problems with Metal-Clad Circuit Breakers, General Electric Type AKF-2-25,"[4.6] examines the failure of General Electric AKF-2-25 circuit breakers to open on demand. Shunt trip coil burnout due to prolonged energization, which occurred with binding in the main mechanism (cam arrangement), resulted in the failure to open.

NRC Information Notice 87-35, "Reactor Trip Breaker, Westinghouse Model DS-416, Failed to Open on Manual Initiation From the Control Room,"[4.9] discusses breaker failure because of mechanical binding of the operating mechanism. The binding caused shunt trip coil failure because it did not allow the shunt trip coil to de-energize. The shunt trip coil eventually burned and opened.

NRC Information Notice 88-44, "Mechanical Binding of Spring Release Device in Westinghouse Type DS-416 Circuit Breakers,"[4.7] examines the failure of two DS-416 tie and feeder circuit breakers to reclose on demand during load sequencing. The breakers failed to reclose due to mechanical binding between the spring release lever and the edge of the breaker casing window. The binding prevented the lever from making contact with the spring release latch that releases the breaker closing springs. Thus, the closing coil, which becomes energized and moves the lever, could not de-energize; it overheated and burned out.

It should be noted that prolonged energization was not the root cause of the failures cited above; other deficiencies (such as lack of lubrication) precluded the components from operating as designed, and ultimately induced the coil failure(s). However, when investigated, only the root cause of the failure to operate may be addressed, and other failed or degraded secondary components (such as the closing coil) may not be identified. Similarly, failure of the closing coil (if detected first) may be deemed to be the result of random component failure or "end of life", and the root cause may go unidentified, possibly resulting in further problems. For these reasons, prolonged energization of components is not considered a significant aging mechanism in itself, but rather should be viewed as an additional consideration when investigating and repairing failures related to the functions of the energized component.

4.3 References

4.1 NUREG/CR-4715, BNL-NUREG-52017, "An Aging Assessment of Relays and Circuit Breakers and System Interactions," prepared by Franklin Research Center, Philadelphia, PA, pages 98, 99, and 100, June 1987.

4.2 NRC Information Notice 89-64, "Electrical Bus Bar Failures," September 7, 1989.

4.3 IE Bulletin 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Feature in Use in Safety-Related Applications Other Than the Reactor Trip System," December 28, 1983.

4.4 NUREG/CR-5280, "Age-Related Degradation of Westinghouse 480-Volt Circuit Breakers, Volume 2: Mechanical Cycling of a DS-416 Breaker - Test Results," prepared by M. Subudhi, E. MacDougall, S. Kochis, W. Wilhelm, and B. S. Lee at Brookhaven National Laboratory, pages 5-2, 5-5, June 1990.

4.5 IE Bulletin 79-09, "Failures of General Electric Type AK-2 Circuit Breakers in Safety-Related Systems," April 17, 1979.

4.6 IE Information Notice 87-12, "Potential Problems with Metal-Clad Circuit Breakers, General Electric Type AKF-2-25," February 13, 1987.

4.7 NRC Information Notice 88-44, "Mechanical Binding of Spring Release Device in Westinghouse Type DS-416 Circuit Breakers," June 24, 1988.

4.8 NRC Information Notice 88-42, "Circuit Breaker Failures Due to Loose Charging Spring Motor Mounting Bolts," June 23, 1988.

4.9 NRC Information Notice 87-35, "Reactor Trip Breaker, Westinghouse Model DS-416, Failed to Open on Manual Initiation From the Control Room," July 30, 1987.

4.10 NRC Information Notice 87-35, Supplement 1, "Reactor Trip Breaker Westinghouse Model DS-416, Failed to Open on Manual Initiation From the Control Room," December 16, 1987.

4.11 NRC Bulletin 88-01, "Defects in Westinghouse Circuit Breakers," February 5, 1988.

4.12 NRC Information Notice 90-41, "Potential Failure of General Electric Magne-Blast Circuit Breakers and AK Circuit Breakers," June 12, 1990.

4.13 IE Circular 81-12, "Inadequate Periodic Test Procedure of PWR Protection System," July 22, 1981.

4.14 IE Bulletin 83-01, "Failure of Reactor Trip Breakers (Westinghouse DB-50) to Open on Automatic Trip Signal," February 25, 1983.

4.15 IE Bulletin 83-04, "Failure of the Undervoltage Trip Function of Reactor Trip Breakers," March 11, 1983.

4.16 IE Information Notice 85-58, Supplement 1, "Failure of a General Electric Type AK-2-25 Reactor Trip Breaker," November 19, 1985.

5. EFFECTIVE MANAGEMENT OF AGING MECHANISMS

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

Criteria 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 Part 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.

These 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 aging (see Section 5.4). Further guidance on the specific methodology for performing the maintenance techniques discussed in the following sections can be obtained from the applicable EPRI NMAC circuit breaker maintenance guide.[5.2, 5.3, 5.4, 5.5]

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

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

- Visual inspection
- Measurement of component properties
- Cleaning
- Adjustments
- Lubrication
- Operability checks.

A sample of U.S. nuclear plants* indicates that the periodicity of maintenance and surveillance generally coincides with the periodic refueling outage so that it can be performed while the plant is shut down. Usually only a portion, approximately one-fifth to one-third, of the switchgear is examined during the refueling outage. This results in a 5- to 8-year maintenance interval for most switchgear. Some plants chose to maintain safety-related switchgear each refueling period. Most plants employ time-based refurbishment schedules, primarily because of the simplicity of administering such schedules, as well as the lack of component degradation/failure information necessary to justify condition-based programs (see Section 6.1 below). In most cases, the preventive maintenance activities coincide with the refueling outages, when switchgear components can be removed from service with less effect on the plant. Similarly, the calibration of protective devices internal to the breaker (which are installed primarily on low voltage systems) is normally accomplished coincident with maintenance/overhaul periods, unless the results of periodic testing or other conditions dictate a higher frequency.

At a number of plants, breaker subcomponents that have been identified as being prone to failure (such as prop springs and microswitches) are replaced during each maintenance period; this is a precautionary measure designed to reduce the likelihood of in-service failure of the subcomponent, which may ultimately affect the breaker's ability to carry out its required function. These replacements are generally based on plant-specific operating history and experience with failures of specific switchgear components.

In addition to preventive maintenance, functional surveillance tests require safety-related circuit breakers to be verified periodically as being operable. Offsite power supplies must be verified as being operable by manually or automatically transferring load from the primary source to the alternate source at least once per 18 months.[5.6] This transfer causes the associated circuit breakers to be exercised. Similarly, when each safety system is exercised under the surveillance program, the associated circuit breaker is exercised. These circuit breaker surveillance operations are too infrequent to cause excessive cyclic wear by themselves.

To more comprehensively describe the maintenance and surveillance techniques commonly used to maintain medium- and low-voltage switchgear, vendor and utility maintenance procedures were reviewed. The results of the review follow. Common maintenance and surveillance techniques are discussed for each component. Note that certain subsections and discussions apply to specific breakers. For example, stored energy operating mechanism discussions would not apply to solenoid operated circuit breakers, and vertical-lift racking mechanisms discussions would not apply to circuit breakers with horizontal levering mechanisms.

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* Several plants were chosen at random and individually surveyed to determine such items as breaker overhaul frequency, maintenance practices and techniques, sources of information used in the determination of component replacement and maintenance periodicity, and scope of maintenance efforts.

5.2.1 Metal Housing System

The common maintenance practices currently used to maintain the metal housing system are visual inspection, cleaning, lubrication, replacement, and verification of the tightness of components. The strength of the structure and visual inspection that is performed completely control one of the housing system aging mechanisms: material fatigue that could lead to structural failure of the housing. Visual inspection for loose or broken parts, corrosion, rust, and cracked welds assures the structural integrity of the housing system by identifying fatigue before it significantly weakens the metal housing members. Visual inspection, when combined with cleaning, painting, and occasional component replacement, controls another aging mechanism for the metal housing system: material degradation. Material degradation is controlled by visual inspection for paint damage, indications of corrosion or rusting, and obstruction of vents, and cleaning of the switchgear structure and compartments (including the shutter mechanism and heater, if applicable). The final aging mechanism for the metal housing system, loss of fasteners, is controlled by verification of the tightness of anchoring and housing fasteners and replacement of lost or loose fasteners. Verification of the tightness of components and replacement as required ensure that the metal housing system will remain securely fixed to the building structure and that the housing parts will remain tightly fastened to one another, assuring structural integrity.[5.7-5.27]

5.2.2 Primary Insulating System

Primary insulation systems associated with electrical switchgear typically consist of two distinct parts: (1) the insulation located on the breaker power stabs and other electrical connection points and (2) the insulation between the breaker operating mechanism linkage and the movable (main) contacts. The common maintenance practices currently used to maintain these systems are visual inspection, cleaning, insulation resistance testing, high potential* testing, and inspection of the connections. The combination of visual inspection, insulation resistance and high potential testing, and inspection of the connections completely controls two key primary insulating system aging mechanisms: loss of electrical and mechanical properties. Visual inspection for embrittlement and cracking prevents insulation failure due to a loss of mechanical properties. Insulation resistance and high potential testing prevent in-service failure due to a reduction in insulating properties. Inspection of the connections for tightness, signs of overheating, damage, and deterioration allows identification of connection insulation degradation and prevents failure.

Visual inspection, cleaning of insulating surfaces, and insulation resistance testing help control two primary insulating system aging mechanisms: surface current tracking and loss of volumetric insulating properties. Visual inspection of the insulation for tracking paths, evidence of overheating, surface contamination, surface irregularities, and discoloration allows identification of the presence of surface current tracking. Visual inspection also helps in the identification of embrittlement and cracking from thermally induced deterioration that causes a

* High potential testing is not recommended for all applications, and may cause damage to switchgear components. The manufacturer's maintenance recommendations should be consulted prior to conducting any high potential testing.

loss of volumetric insulating properties. Cleaning of the primary insulation prevents the accumulation of dirt and contaminants that, particularly in the presence of moisture, could provide tracking paths to ground. Cleaning also prevents the deterioration of volumetric insulating properties by removing contaminants that could cause chemical deterioration of the insulation. Insulation resistance and high potential testing provide a means of monitoring the volumetric and surface insulating capability of the insulation.[5.6-5.9, 5.11-5.23, 5.26-5.35]

5.2.3 Primary and Secondary Disconnects

The primary and secondary disconnects and support insulation are cleaned to remove any dirt or contamination that may have accumulated on the disconnect or insulating surfaces. The primary and secondary disconnects are visually inspected for evidence of overheating, wear, contamination, dried out lubricants, and misalignment, and to verify that they are securely mounted. If contamination or significant wear is identified, the disconnects are replaced or refinished as appropriate. Tolerances can be checked and adjusted if necessary. Lubrication of primary and secondary disconnect surfaces is performed as required. The support insulation for the disconnects is visually inspected for surface contamination, signs of overheating, brittleness, breaks, cracks, warping, flaking, damage, and secure mounting. The primary and secondary disconnect insulation resistance is measured for each phase. High potential tests are also performed.* The tightness of connections is inspected to prevent the formation of high resistance connections.[5.1, 5.7-5.11, 5.14-5.17, 5.19-5.22, 5.24-5.27, 5.29-5.32, 5.35-5.39]

5.2.4 Racking Mechanism

The current maintenance practices used to maintain horizontal racking mechanisms are cleaning, visual inspection, lubrication, and operational testing. Together, these maintenance practices control the aging mechanism for the horizontal racking mechanism: wear of the tracks, levering system, and racking gear. Cleaning of the horizontal racking mechanism parts prevents the accumulation of dirt and contaminants that could cause wear and damage. A visual inspection of the racking mechanism, accessories, and mounting hardware detects wear (particularly of the circuit breaker rails, rollers, levering device, and gear assembly), damage, and loose hardware. Lubrication of the mechanism parts, as necessary, prevents wear of mating surfaces. Operational testing ensures that there is no binding within the mechanism and that the circuit breaker functions appropriately in each racking mechanism position.

The current maintenance practices used to maintain the vertical racking mechanism are also cleaning, visual inspection, lubrication, and operational testing. Together, these maintenance practices control the aging mechanism for the vertical lift racking mechanism: wear of the motor clutch and drive. Cleaning of the racking motor clutch and drive prevents the accumulation of dirt and contaminants that could cause wear and damage. A visual inspection of the motor clutch and drive allows identification and correction of wear. Lubrication of the mechanism parts as required prevents wear of mating surfaces. An operational test is performed

* High potential testing is not recommended for all applications, and may cause damage to switchgear components. The manufacturer's maintenance recommendations should be consulted prior to conducting any high potential testing.

to verify that there is no binding within the mechanism and that the mechanism latches and the circuit breaker function properly in each position.[5.7-5.10, 5.16, 5.19, 5.22-5.26, 5.35]

5.2.5 Main Contacts

The current maintenance practices that are used to maintain the main contacts are cleaning, visual inspection, refinishing, verification of tolerances, resistance measurement, and verification of the freedom of motion of the contact assembly. Lubrication of the contact pivot areas, although desirable, is not generally feasible during routine maintenance because of the inaccessibility of these areas (i.e., old lubricant cannot be readily removed, nor can new lubricant be properly applied without more complete disassembly generally associated with breaker overhaul/refurbishment). Cleaning, visual inspection, and refinishing, when combined, control contact deterioration, one of the two aging mechanisms for the main contacts. Resistance measurements of the primary current-carrying circuit, coupled with visual inspection of the main contacts for cracking, burning, pitting, wear, and corrosion, particularly after fault current interruption, ensure good contact condition. The main contacts are cleaned to remove any dirt or contaminants that may have accumulated on the contact surfaces. Refinishing or replacement is performed if contact surface deterioration exceeds a predetermined limit. Verification of tolerances and verification of the freedom of motion of the contact assembly control the other aging mechanism for the main contacts: movement of components and settings and loss of tolerances. Tolerances, including contact gap, contact wipe, and contact thickness, are checked and adjusted to ensure proper contact mating. Main contact spring pressure may also be measured. Verification of the freedom of motion of the moving contact assembly ensures that the contact assembly as a whole is operating properly and will promote good contact mating. [5.10, 5.12, 5.15-5.17, 5.19, 5.22, 5.24-5.31, 5.34-5.44]

5.2.6 Arcing Contacts

The current maintenance practices that are used to maintain the arcing contacts are cleaning, visual inspection, and verification of tolerances. These maintenance practices, when performed together, control contact deterioration, the aging mechanism for the arcing contacts. The arcing contacts are visually inspected for cracks, pitting, burns, uneven wear, and corrosion, particularly after fault current interruption, to ensure good contact condition. The arcing contacts are cleaned to remove any deposits produced during arc interruption. Tolerances, including arcing contact thickness and arcing contact wipe, are also checked and adjustments are made if necessary. Arcing contact spring pressure may also be measured. Replacement is performed if the tolerances exceed a predetermined limit. Performance of these maintenance practices maintains arcing contact condition, assuring that arc interruption during breaking and making of current are via the sacrificial arcing contacts rather than the main contacts.[5.10, 5.15-5.17, 5.19, 5.21, 5.22, 5.24-5.26, 5.28-5.31, 5.34, 5.35, 5.37-5.40, 5.42-5.45]

5.2.7 Stored Energy Operating Mechanism

The operating mechanism is cleaned to remove dirt that may have accumulated on mechanism parts. If an excessive amount of dirt accumulates on mechanism parts or contaminates the lubrication, it will create friction between moving surfaces and cause the mechanism to wear and its operation to slow. The condition of the operating mechanism is assessed through visual inspection for loose, missing, or broken parts; loose connections; dried, contaminated, or gummy lubricants; damage; wear; and cracked welds. The spring charging motor is inspected for damage, evidence of overheating, misalignment, loose mounting bolts, and insulation breakdown. The closing release latch assembly is inspected for damage, missing or loose screws and bolts, and deteriorated or damaged coil insulating material. The spring release lever is inspected for cracks or fractures and tightness of mounting hardware. Tolerances, such as trip and release latch wipe and trip armature travel, are checked and adjusted. Because of the inaccessibility of many areas of the operating mechanism, complete visual inspection and proper lubrication (i.e., removal of old lubricant and installation of new) are not possible during routine maintenance evolutions. Hence, periodic overhaul/refurbishment of the breaker is required to ensure that all critical areas of the mechanism are adequately inspected and lubricated.

Operating mechanism integrity is verified by checking the position of the contacts while performing manual and electrical open and close operations, checking the freedom of motion of the mechanism during operation for sticking or binding, observing the contacts during trip-free operation to make sure that the breaker contacts do not close (design-dependent criteria), and measuring the closing and opening time of the main contacts. In addition, the spring charging motor limit switch is checked for continuity. The freedom of motion of the spring release armature is inspected for binding. The force required to move the trip latch is measured to verify it has not increased such that a tripping operation would be prevented. The pickup voltages and currents for the trip and spring release coils are measured and trended by some nuclear plant operators to evaluate proper operation; others disassemble and relubricate the latches and associated mechanisms to assure operation. Lubrication of the operating mechanism is performed as required to prevent wear of mating surfaces.[5.9, 5.11, 5.14-5.18, 5.20, 5.21, 5.23-5.26, 5.29-5.33, 5.35, 5.36, 5.38, 5.39, 5.41, 5.45-5.47]

5.2.8 Solenoid Operated Mechanism

The solenoid operated mechanism is cleaned to remove dirt that may have accumulated on mechanism parts. If an excessive amount of dirt accumulates on mechanism parts or contaminates the lubricant, it will create friction between moving surfaces and cause the mechanism to wear and bind. The condition of the solenoid coil is monitored by inspection for signs of overheating, including excessive varnish on the underside, discoloration, or unusual bulging. Tolerances and mounting are checked and adjustments made as needed. The integrity of the solenoid operated mechanism is verified by checking the freedom of motion of the mechanism for sticking or binding. Lubrication of the solenoid armature and mechanism is performed as required. In general, complete visual inspection and proper lubrication (e.g., removal of old lubricant and installation of new) are not possible during routine maintenance evolutions. Hence, periodic overhaul/refurbishment of the breaker is necessary to ensure that all critical areas of the mechanism are adequately inspected and lubricated. Consult the applicable EPRI NMAC Maintenance Guide for more detailed information concerning breaker overhaul and refurbishment.[5.2-5.5, 5.20, 5.23, 5.27, 5.32, 5.34, 5.39, 5.43]

5.2.9 Arc-Chute

The current maintenance practices that are used to maintain the arc-chute are cleaning, visual inspection, and insulation resistance testing. Cleaning, visual inspection, and insulation resistance testing control the aging mechanisms for the arc-chute: material degradation, and loss of surface or volumetric insulating properties. Visual inspection for damage, burns, moisture, wear, breakage, contamination, and plate erosion identifies material degradation. (Note: In general, minor cracks in or damage to arc-chute insulating components will not adversely affect their performance as an insulator). The arc-chute and insulating parts are cleaned to remove any dirt or soot that may accumulate on the arc-chute plates or in the stacks. Insulation resistance testing (conducted with the arc-chutes in place on the breaker) indicates the loss of surface and/or volumetric insulating capabilities due to contamination, physical damage, or moisture intrusion. In cases of moisture intrusion (such as in arc-chutes manufactured from asbestos or other semi-porous materials), placement of the component in a warm, low humidity environment may effectively drive off the moisture from the material, thereby rendering it suitable for continued use (contingent upon successful follow-up testing and inspection). Replacement of the arc-chute is performed if the degradation could prevent the arc-chute from performing its function during current interruption (e.g., if persistent low insulation resistance readings, insulation cracking, or significant non-correctable surface contamination are observed). It should be noted that for certain switchgear (i.e., General Electric Magne-Blast medium-voltage equipment), replacement of the arc-chute may be made more difficult because spare parts may have been discontinued or are not otherwise readily available. See Section 5.3.5 for further discussion of replacement alternatives.[5.10, 5.12, 5.15, 5.17-5.19, 5.21, 5.22, 5.24-5.31, 5.34, 5.35, 5.38, 5.40, 5.42, 5.44]

5.2.10 Cubicle Mechanical Interlocks

The mechanical interlocks are evaluated by inspecting the closing spring, contact, and shutter positions at the remove, disconnect, test, and connected positions. Verification of automatic breaker trip as the breaker is moved between the disconnect, test, and connected positions is also performed. Adjustment is made as needed.[5.8, 5.10, 5.11, 5.20]

5.2.11 Auxiliary Switch

The fixed and movable contact surfaces and cover are cleaned to remove dirt or contaminant accumulation. The contacts are inspected for wear, pitting, burning, and misalignment, and the cover is inspected for cracks or breaks. Lubrication is performed as required. Switch integrity is verified during breaker operation; switch contact position is evaluated to ensure that the contacts are properly oriented when the breaker contacts are closed and open. Two additional tests, contact resistance across closed contacts and continuity, are performed to check switch integrity. The auxiliary switch connections are checked for tightness to eliminate high resistance connections and open circuits.[5.11, 5.16, 5.20, 5.21, 5.24, 5.26, 5.27, 5.38, 5.43]

5.2.12 Current and Potential Transformers

The current and potential transformers are cleaned to remove dirt and contaminants. Transformer mounting hardware is checked to ensure that the transformers are securely fixed to the switchgear housing, and transformer connections are inspected for tightness. A current transformer operational test is performed to ensure that the output current is at the correct proportion to the input current. Insulation resistance testing is performed to verify the integrity of the insulation between the primary and secondary elements. Additionally, ratio testing of potential transformers can be used to determine the voltage transformation ratio.[5.8, 5.10, 5.16]

5.2.13 Control Wiring

The control wire insulation is cleaned to remove dirt and contaminants and visually inspected for cracks, fraying, gaps, or other damage. Control wiring is replaced if necessary. The wiring harness is visually inspected for proper routing (no sharp bends and adequate clearance from potential hazards such as sharp metal edges, hot components, or moving mechanisms) and support. Insulation integrity is checked by taking insulation resistance measurements for each phase. The tightness and condition of mating surfaces of the connections are checked to eliminate any highly resistive connections, and terminations are inspected for adequate conductor engagement.[5.1, 5.8-5.11, 5.15, 5.17, 5.20-5.22, 5.24-5.27, 5.29-5.32, 5.35-5.38]

5.2.14 Shunt Trip Attachment/Trip Solenoid

The shunt trip attachment/trip solenoid is inspected for coil condition and tightness of screws and bolts. Shunt trip/trip solenoid integrity is verified by checking normal operation and checking freedom of motion of the core and trip lever for sticking and binding. The freedom of motion check is performed by pushing the moving core against the stationary core. Adjustments and lubrication are performed as required.[5.17, 5.20, 5.33, 5.37, 5.43]

5.2.15 Overcurrent Trip Device

The overcurrent trip device is cleaned to remove dirt and contaminants. The tightness of the mounting hardware and connections is checked. Inspection of the clearance between the actuator trip lever and trip bar is also inspected. Adjustments are performed as required. The following tests are performed to verify overcurrent trip device function: long time delay for each phase, short time delay for each phase, instantaneous pick-up, and circuit breaker clearing time.[5.16, 5.21, 5.23, 5.33, 5.43, 5.46]

5.2.16 Undervoltage Trip Attachment

The undervoltage trip attachment is inspected for loose mounting hardware and coil deterioration. The clearance between the trip lever and the trip bar is inspected. An operational test is performed to verify functional capability. Tolerances between the output lever of the undervoltage trip attachment and the trip bar are verified. Note: Undervoltage trip attachments on reactor trip breakers are subject to detailed inspections and functional verifications.[5.23, 5.27, 5.33, 5.43]

5.3 Other Maintenance and Surveillance Techniques and Programs

Other maintenance and surveillance techniques and programs either in current use or proposed include infrared thermography, vibration signature measurement, acoustic testing, contact printing, refurbishment, and replacement. Each technique is discussed below.

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 of $\pm 0.1\,^{\circ}C$ with rapid response times.[5.48] 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. The advantage of infrared thermography for use on switchgear is that hot spots can be observed while the equipment is energized. Thermographic inspection requires doors to switchgear compartments to be open and bus housing covers to be removed to allow useful information to be taken.

For switchgear, spot measuring devices would be of limited use in that 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 a hot spot can be readily compared to surrounding components and sections of the system to determine what is causing the hot spot. If thermographic scans were performed previously, comparisons can be made and variations in thermal images can be evaluated to determine if hot spots are developing or changing. In switchgear, hot spots at disconnects and in the vicinity of main contacts could indicate high resistance connections that would cause overheating and subsequent insulation damage. Identifying such conditions could allow correction of the condition before significant insulation damage occurred. At 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 condition of components, it is not a panacea and should be used with other techniques. Certain aging mechanisms do not produce significant amounts of heat and may not be easily identified from thermal scans. For example, surface tracking of insulators may not be observable by thermography; however, it may be observable by visual inspection. Likewise, chaffing of insulation from rubbing against a bracket or support would not cause heating, but could be observed by visual inspection. 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 and can grossly affect results. Therefore, interpretation of results may require considerable skill or the operator may have to modify the target by covering it with a black tape. Also, the operating status of the switchgear will affect results. If thermography is performed while a bus 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 bus and its loads need 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 switchgear condition.

5.3.2 Vibration Signature

Still under development, vibration signature analysis of switchgear can be used to detect loose, worn, or otherwise improperly operating mechanisms. The vibration signature of a particular device is measured by accelerometers that are mounted on the device and its mounting surfaces. The vibration signature resulting from a change of state (operation) of the device is captured on tape and transferred to a computer database for storage, analysis, and trending. [5.48]

The primary advantage of vibration signature measurement is that a more significant amount of information is potentially available about the condition of individual subsystems than can be obtained from normal maintenance practices, particularly circuit breaker timing tests. The primary disadvantage of using this technique is related to signature interpretation. Previous knowledge of the signature for the specific unit under test is required to be able to determine if there have been any changes in the equipment; a signature for each piece of equipment must be stored for comparison to later measurements. In addition, interpretation and understanding of the signature for each circuit breaker under test is required. Finally, the signature of a particular component may be masked by that of other components during testing so that the ability of this method to detect failures of individual components is limited.[5.49]

5.3.3 Acoustic Testing

Also in the developmental stages, acoustic testing is a maintenance and surveillance technique that can be used with vibration signature analysis to detect loose, worn, or otherwise improperly operating mechanisms. The acoustic signature of a device is recorded by a microphone mounted near the device.[5.48] The signature is recorded on tape and transferred to a computer database for storage, analysis, and trending. Just as the acoustic test is similar to vibration analysis in that it relies on the interpretation of a recorded signature, the advantages and disadvantages associated with vibration analysis are also applicable to the acoustic test. Acoustic monitoring techniques are currently used in various other nuclear plant applications, including fluidic systems and check valves.

5.3.4 Contact Printing

Contact printing is a maintenance and surveillance technique used to measure the amount of main contact mating. A carbon sheet is placed between the main contacts. Inspection of the print left on the carbon after the contacts close and open and comparison to an earlier print will indicate if mating is decreasing. The amount of contact mating is measured as a percent of total original contact surface. Each print is kept for trending.[5.38]

The primary advantage associated with this technique is the early detection of contact surface deterioration. Monitoring contact mating, and thus the deterioration of contact material, will allow timely replacement of the contacts before failure occurs. Early detection of contact deterioration will also reduce the number of failures experienced.

5.3.5 Refurbishment/Replacement

Refurbishment and replacement are two methods that may be used to control switchgear aging. Most times, refurbishment and replacement are applied to the drawout circuit breakers rather than to the generally longer lived housing and bus system.

During refurbishment, the circuit breaker is completely disassembled, worn parts are replaced, and the entire mechanism is lubricated. There are two approaches to refurbishment: refurbishment at a fixed time interval and refurbishment based on equipment condition. The use of either approach is at the discretion of the plant operator and may be related to the degree of in-house circuit breaker repair expertise and capability. Some plants choose to perform limited overhauls of their circuit breakers and send the breakers out to the manufacturer's service shop for refurbishment on a fixed periodicity of approximately 10 years. Others choose to do more detailed in-house overhauls and inspections, and send circuit breakers for refurbishment by a service shop only when the condition of the circuit breaker is such that in-plant work cannot restore the breaker to an acceptable condition (e.g., tolerances can no longer be maintained, or parts are significantly worn). Based on information gathered during the analysis of failure reports and overhaul records (as presented in previous sections of this study and the EPRI NMAC maintenance guides), refurbishment of the circuit breaker is necessary to comprehensively address breaker aging mechanisms and degradations not addressed during routine maintenance. Hence, refurbishment is an essential element of an effective switchgear aging management program.

In some cases, circuit breakers are replaced rather than refurbished. If severe damage was caused by interruption of fault current or if the circuit breaker sustained an internal phase-to-ground or phase-to-phase fault, replacement of the breaker may be necessary. Generally, replacement parts for switchgear can be divided into two classifications: (1) commodity items (e.g., bolts and screws, which are not switchgear specific) and (2) items unique to switchgear applications (e.g., arc-chutes, trip devices). Because of the relative importance of the circuit breaker with respect to the performance of required system functions, and the complexity of the circuit breaker itself, the original equipment manufacturer should be used (where possible) as the primary source for both commodity and switchgear unique parts.

Another factor warranting consideration in the procurement of replacement parts is obsolescence. If the manufacturer no longer produces the switchgear line, and/or no longer manufactures parts (e.g., General Electric Magne-Blast asbestos arc-chutes), an alternate parts source must be used. In some cases, companies specializing in aftermarket components may supply the needed components (or substitute). However, use of these components and circuit breakers is problematic for nuclear plant operators in that commercial grade dedication must be performed on the circuit breakers to allow their use in safety-related applications. Special analysis and testing of the components are then necessary before the devices can be placed in service.

Other alternatives for dealing with component or switchgear obsolescence include the use of equipment stocked for non-safety switchgear of similar type and fabrication. As with aftermarket-supplied parts, unqualified parts must be upgraded using the commercial dedication process described above. In extreme cases (or instances where the component in question is of extremely simple design), the nuclear plant operator (or third party) may fabricate the part from existing design information provided from such documents as specifications and technical manuals.

Switchgear obsolescence is likely to become an increasingly important issue as time passes, simply because older product lines of switchgear installed in nuclear plants during construction will eventually be discontinued and replaced by their more modern counterparts. One strategy employed by nuclear plant operators is the substitution of failed or aged safety-related circuit breakers (or components) with those taken from non-safety applications; this, in effect, provides the plant operators with a limited supply of breakers (and parts) that have already been qualified for use in safety-related applications by virtue of their similarity to the original equipment. Newer, unqualified models are then substituted into the non-safety applications from which the replacements were drawn. This strategy is limited, however, by the fact that the supply of qualified replacements used in non-safety applications will eventually run out, thereby forcing the plant operators to upgrade their safety-related equipment with new units.

Another consideration during replacement of circuit breakers is the possibility of counterfeit parts; a variety of electrical components (ranging from relays to entire metal-clad circuit breakers) have been discovered to be counterfeit and/or not in conformance with applicable industry and manufacturers' standards for such components. This is of particular concern in those applications where component performance is essential to the fulfillment (or non-preclusion) of a required plant function. Hence, an effective program for the management of switchgear aging (which uses component replacement) must necessarily ensure both (1) the authenticity of the components used as replacement parts and (2) their adherence to applicable performance and material standards. These requirements can be met using a variety of techniques, including examination of the equipment upon receipt (specifically, examination of the nameplate data, appearance/condition of the component as compared to known authentic units, comparison of the shipping documentation with the component data, etc.), verification of equipment origin (i.e., contacting the manufacturer to ensure that the equipment was in fact procured from their facility), and performance testing prior to installation.

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 received for review, indicating that switchgear maintenance programs are documented. These procedures also indicate that the programs are implemented under plant onsite review committees, and controlled by plant administrative procedures.

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 inspection and maintenance activities to 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 switchgear. Conditions requiring plant-specific confirmation of effectiveness are contained in Section 5.4.2.

Table 5-1. Common Maintenance and Surveillance Techniques

Switchgear Component	Aging Mechanism(s)	Maintenance and Surveillance Techniques That Mitigate Effects of Aging Mechanisms	Required Acceptance Criteria
Metal Housing System	Material fatigue	Visual inspection of the switchgear structure for loose or broken parts, corrosion, rust, and cracked welds	
	Material degradation	Cleaning of the switchgear structure and inside all compartments (including shutter mechanism and heater if applicable); visual inspection for paint damage, signs of rodent infestation, obstruction of vents; lubrication and replacement of components as required	
	Loss of components	Verification of tightness of all fasteners and hardware; replacement as required	Anchor/housing bolt and fastener torque specifications
Primary Insulation	Loss of electrical and mechanical properties	Visual inspection of insulation and connections for embrittlement and cracking; insulation resistance and high potential testing; inspection of connections for tightness, signs of overheating, damage, and deterioration	Insulation resistance, withstand voltage
	Surface current tracking	Cleaning of insulating surfaces; visual inspection for tracking paths, evidence of overheating, surface contamination, surface irregularities, discoloration, warping, and distortion; insulation resistance and high potential testing	Insulation resistance, withstand voltage

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

Switchgear Component	Aging Mechanism(s)	Maintenance and Surveillance Techniques That Mitigate Effects of Aging Mechanisms	Required Acceptance Criteria
Primary Insulation (continued)	Loss of volumetric insulating properties	Cleaning of insulating surfaces; visual inspection for tracking paths, evidence of overheating, surface contamination, surface irregularities, discoloration, warping, distortion, and cracking; insulation resistance and high potential testing	Insulation resistance, withstand voltage
Horizontal Racking Mechanism	Wear of tracks, levering system and racking gear	Cleaning of mechanism parts; visual inspection of mechanism and hardware; lubrication; operational testing	
Vertical Racking Mechanism	Wear of motor clutch and drive	Cleaning of motor parts; visual inspection of clutch and drive; lubrication; operational testing	
Arcing Contacts	Contact deterioration	Cleaning of arcing contact surfaces; visual inspection of the arcing contacts for cracks, pitting, burns, uneven wear, and corrosion, particularly after fault current interruption; pressure and tolerance check and adjustment if necessary	Arcing contact tolerance, pressure
Main Contacts	Contact deterioration	Cleaning of main contact surfaces; visual inspection of the main contact for cracking, burning, pitting, wear, and corrosion, particularly after fault current interruption; refinishing or replacement if necessary	
	Movement of components and loss of tolerances (poor contact mating)	Tolerance check and adjustment if necessary; verification of the freedom of motion of the main contact assembly; pressure check; lubrication as required	Main contact tolerance, pressure
Stored Energy Spring and Solenoid Operated Mechanism	Deterioration of greases	Visual inspection for condition of greases; verification of the freedom of motion of the mechanism during operation; measurement of the main contact open and close times; verification of contact position during opening, closing, and trip-free operations	Main contact open/close times

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

Switchgear Component	Aging Mechanism(s)	Maintenance and Surveillance Techniques That Mitigate Effects of Aging Mechanisms	Required Acceptance Criteria
Stored Energy Spring and Solenoid Operated Mechanism (continued)	High friction between moving parts	Cleaning of operating mechanism parts; visual inspection of the operating mechanism for damage and wear; measurement of main contact open and close times; measurement of force required to move the mechanism; verification of freedom of motion of mechanism during operation; verification of latch operation; verification of contact position during opening, closing, and trip-free operations; tolerance check and adjustment if necessary; lubrication as required	Main contact open/ close times; operating force; main contact tolerance
	Movement of components and loss of tolerances	Visual inspection for loose, missing, or broken parts; measurement of main contact open and close times; pressure check; freedom of motion of mechanism during operation; verification of contact position during opening, closing, and trip-free operations; tolerance check and adjustment if necessary	Main contact open/ close times; main contact tolerance, pressure
	Pole shaft weld fatigue	Visual inspection of weld condition; measurement of main contact open and close times; verification of freedom of motion of mechanism during operation; verification of contact position during opening, closing, and trip-free operations	Main contact open/ close times
	Wear of spring charging mechanism components	Cleaning of spring charging mechanism components; visual inspection of the spring charging mechanism components for damage and deterioration; continuity check of spring charging motor limit switch contacts; verification of freedom of motion of spring release armature	
	Prolonged energization of the control coils	Visual inspection of the coils for damage and deterioration; measurement of the pickup voltages and currents for the trip and spring release coils	
Solenoid Operated Mechanism Only	Prolonged energization of solenoid coil	Visual inspection of the coil for damage and deterioration; verification of the freedom of motion of the armature	
	Turn to turn shorts, localized burning	Visual inspection of the coil insulation for signs of overheating	

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

Switchgear Component	Aging Mechanism(s)	Maintenance and Surveillance Techniques That Mitigate Effects of Aging Mechanisms	Required Acceptance Criteria
Arc-Chute	Material degradation dielectric breakdown	Cleaning of the entire arc-chute assembly; visual inspection of the arc-chute assembly for damage, burns, contamination, plate erosion, and breakage; insulation resistance testing; replacement if necessary	Insulation resistance
Primary Disconnect	Disconnect wear and spring relaxation	Cleaning of primary disconnects; visual inspection for wear, misalignment, secure mounting, and evidence of overheating; refinishing or replacement if necessary; tolerance check and adjustment if necessary; lubrication as required	Primary disconnect tolerance
Secondary Disconnect	Spring relaxation, contact wear, disconnect damage	Cleaning of secondary disconnects; visual inspection for wear, misalignment, secure mounting, and evidence of overheating; tolerance check and adjustment if necessary; lubrication as required	Secondary disconnect tolerance
Mechanical Interlocks	Wear, physical damage	Visual inspection of the contacts and shutter position (if applicable) at each breaker position during inspection of the circuit breaker into the switchgear compartment; verification of appropriate mechanism tolerances	
Auxiliary Switch	Contact deterioration	Cleaning of contact surfaces; visual inspection of contacts for wear, pitting, burning, and misalignment; verification of contact position during breaker operation; measurement of contact resistance; check of switch continuity	Contact resistance
Current and Potential Transformers	Insulation failure and overheating; conductor failure	Cleaning, inspection of mounting hardware, inspection of connections for tightness, inspection for overheating, operational test, ratio testing, insulation resistance testing	Voltage/current ratio, insulation resistance
Internal Control Wiring	Loss of electrical and mechanical properties, chaffing	Cleaning of control wire insulation; visual inspection of insulation for cracks, fraying, and damage; replacement if required; visual inspection of wiring harness for proper routing and support; measurement of insulation resistance; inspection of connections for tightness; continuity check	Insulation resistance, continuity
Shunt Trip Attachment	Coil deterioration, improper tolerance with trip bar	Inspection of coil and tightness of hardware; operational testing; verification of freedom of motion during operation; adjustment and lubrication as required	Trip bar to shunt trip interface tolerance

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

Switchgear Component	Aging Mechanism(s)	Maintenance and Surveillance Techniques That Mitigate Effects of Aging Mechanisms	Required Acceptance Criteria
Overcurrent Trip Device (electro-mechanical)	Loss of calibration, leaking dashpot	Calibration; cleaning of the overcurrent trip device; inspection of the tightness of the mounting hardware and connections; verification of clearance between trip lever and the trip bar; adjustment as required; operational requirements testing; lubrication (where specified by manufacturer)	Trip bar/lever clearance, over-current calibration
Undervoltage Trip	Constant coil energization	Visual inspection of coil for deterioration, overheating	
	Latch wear	Verification of clearance between trip lever and trip bar; operational testing	Trip bar/lever clearance
	High friction between moving parts	Operational testing	

Each maintenance procedure was also reviewed for compliance with criterion 3. 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 developed 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, with a limited number of specific cases, very few repetitive failures associated with any one specific circuit breaker component for a given manufacturer's model line.

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

Comparison of the aging mechanisms identified in Sections 3.6 and 4.2 with circuit breaker maintenance methodology verified that nearly all component/aging mechanism combinations are addressed by current programs. The following section discusses the limitations and exceptions to this statement.

5.4.2.1 Conditions for a Fully Acceptable Program

If the circuit breakers are located in a mild environment area (not subject to an elevated temperature/steam condition or elevated radiation field under accident conditions), are in areas where temperatures do not exceed 104°F for significant periods, and are not subjected to a high number of operating cycles, 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 possible exceptions as follows:

General Exceptions

Electrical Device Management. Electrical devices (including motors, relays and switches) appear to constitute the largest number of the failures noted; routine maintenance does not appear wholly effective at identifying degraded components prior to failure. Based on plant-specific historical information, component installed age, and breaker cyclic loading, selective replacement of these components prior to failure may be warranted, especially in applications where a high rate of individual electrical component failures has been noted.

Breaker Refurbishment. There is strong indication that inadequate lubrication and wear of the main operating mechanism is responsible for numerous instances of switchgear failure to operate on demand. The effects of lubrication degradation and wear on certain components can only be mitigated by periodic or condition-based overhaul of the breaker. Recommended refurbishment/overhaul intervals for each specific class and application of breaker are contained in the applicable volume of the EPRI NMAC maintenance guide series; these intervals generally fall in the range of 6 to 12 years.[5.2-5.5]

Overcurrent Trip Devices. Electromechanical overcurrent trip devices appear to be susceptible to loss of calibration; these devices should be checked at intervals frequent enough to assure their continued proper performance. In general, little maintenance of the device (other than calibration) is recommended by the manufacturer.

Additionally, switchgear that is (or has been) located in the following environments will require further plant-specific activities, which are described in Section 6:

- Exposure to the effects of desert dust storms, which could cause contamination of insulating surfaces and operating mechanism lubricants.
- Exposures to normal temperatures in excess of 104°F for significant periods.
- Exposure to' accident temperature/steam or radiation conditions that require environmental qualification and definition of qualified lives for subcomponents.
- Service conditions requiring a high number of operating cycles. Note that high cycle operation for a 4.16- or 13.8-kV circuit breaker has a threshold in the tens of cycles per year, and 480-V circuit breaker has a threshold in the hundreds of cycles per year.

Model-Specific Exceptions

The following model-specific exceptions (in addition to the general exceptions described in the preceding paragraph) were noted, and may warrant additional scrutiny:

- General Electric 480-V circuit breakers with electromechanical overcurrent trip devices. Per the NPRDS data discussed in Section 3.6.2.1.1, these trip devices appear to experience calibration problems and dashpot failures that cause premature or lack of tripping on overcurrent conditions. Replacement of electromechanical overcurrent trip device seals (and recalibration) at 10- to 12-year intervals is recommended for those devices with time delay dashpots.

- General Electric 4.16- and 13.8-kV circuit breakers. Per the NPRDS data discussed in Section 3.6.2.1.4, the closing spring charging mechanisms are experiencing a significant number of failures proportional to other subcomponents. These failures are associated with both electrical (motor failures, limit switches for charging motor control, etc.) and mechanical (ratcheting mechanism, gears, etc.) failures.

- ITE/Brown Boveri/Gould (ABB) 4.16- and 13.8-kV circuit breakers. Per the NPRDS data discussed in Section 3.6.2.1.6, the electrical components of the closing spring charging mechanism appear to be experiencing a significant number of failures proportional to other subcomponents.

It should be noted that the above listed conditions do not indicate that current surveillance/maintenance programs are ineffective. Rather, they indicate that plant-specific review of the procedures and overall programs requires additional consideration, as described in Section 6, to assure that the programs are effective.

5.5 References

5.1 10 CFR 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, page 64978.

5.2 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Asea Brown Boveri/Halliburton NUS Corporation, Volume 1, Part 1, Draft Report, August 1992.

5.3 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 2, Final Report, July 1992.

5.4 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 3, Final Report, December 1992.

5.5 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 4, Draft Report, September 1992.

5.6 Proprietary Plant Procedure 21, "High Potential (Hypot) Insulation Testing of Electrical Cables," Revision 00, September 25, 1989.

5.7 I.B. 32-100-1A, "Westinghouse Instructions for Low-Voltage Metal-Enclosed Switchgear," December 1952.

5.8 Proprietary Plant Procedure 1, "Maintenance of General Electric 4.16 kV Metal-Clad Switchgear, Type M-26," Revision 1, November 27, 1989.

5.9 Proprietary Plant Procedure 2, "Maintenance of General Electric 4.16 kV Circuit Breakers, Type AM-4.16-350 Magne-Blast Breakers," Revision 0, November 30, 1988.

5.10 Proprietary Plant Procedure 3, "Maintenance of Siemens-Allis 4.16 kV Metal-Clad Switchgear," Revision 2, January 8, 1991.

5.11 Proprietary Plant Procedure 4, "Maintenance of Westinghouse DS-206 & DS-416 Circuit Breakers," Revision 3, October 5, 1990.

5.12 Proprietary Plant Procedure 5, Section 8.10, "Examination and Meggering of 480 V Bus 1G," Revision 1, March 1992.

5.13 Proprietary Plant Procedure 6, Section 8.1, "Examination and Meggering of 4160 V Bus 1A," Revision 1, March 1992.

5.14 "Allis-Chalmers Instructions for Types MA-75C, MA-250C, and MA-350C, 5 kV Air Magnetic Circuit Breakers with Solenoid or Stored Energy Operators," December 1973.

5.15 Proprietary Plant Procedure 12, "Maintenance of GE AK-2A Circuit Breakers," Revision 3, October 31, 1989.

5.16 Proprietary Plant Procedure 13, "Circuit Breaker Inspection and Testing (Refueling Interval)," Revision 8, March 18, 1992.

5.17 Proprietary Plant Procedure 15, "ITE K-600S Circuit Breaker Maintenance," Revision 0.

5.18 Proprietary Plant Procedure 16, "ITE 4160 Volt Breaker Rework," Revision 0, July 30, 1991.

5.19 Proprietary Plant Procedure 18, "ITE 4160 V Switchgear Cubicle Rework," Revision 0, May 9, 1991.

5.20 Proprietary Plant Procedure 19, "Westinghouse Type DB Circuit Breakers and Associated Switchgear (Other Than Reactor Trip Breakers) Refueling Interval Maintenance," Revision 0, April 30, 1991.

5.21 Proprietary Plant Procedure 20, "ITE 480 Volt Breaker Rework," Revision 0, April 23, 1991.

5.22 I.B. 32-150-4A, "Westinghouse Instructions for Metal-Clad Switchgear with Type "DH" Air Circuit Breakers," April 1955.

5.23 I.B. 33-850-1 & 2E, "Westinghouse Instructions for De-ion Air Circuit Breakers, Types DB-15, DB-25, DB-F & DBL-25, 600 Volts A-C, 250 Volts D-C," May 1965.

5.24 Proprietary Plant Procedure 23, "480 Volt G.E. (AK25) Breaker Maintenance," Revision 00, July 7, 1988.

5.25 Proprietary Plant Procedure 24, "480 Volt G.E. (AK50) Breaker Maintenance," Revision 00, October 31, 1989.

5.26 Proprietary Plant Procedure 25, "480 Volt G.E. (AKF) Breaker Maintenance," Revision 00, June 10, 1988.

5.27 Proprietary Plant Procedure 27, "Reactor Trip Breaker Maintenance and Testing," Revision 0, June 23, 1989.

5.28 NUREG/CR-4715, BNL-NUREG-52017, "An Aging Assessment of Relays and Circuit Breakers and System Interactions," prepared by Franklin Research Center, Philadelphia, PA, June 1987, pages 99 and 100.

5.29 GEK-41902B, "Instructions and Recommended Parts for Maintenance of Magne Blast Circuit Breakers, Types AM-4.16-250-9, 1200 and 2000 Amperes," undated.

5.30 GEK-7347C, "Instructions and Recommended Parts for Maintenance of Magne Blast Circuit Breakers, Type AM-13.8-1000-4H," undated.
5.31 Proprietary Plant Procedure 7, "Maintenance of Medium-Voltage Circuit Breakers, Type AM-13.8-1000," Revision 1, August 24, 1989.
5.32 Proprietary Plant Procedure 11, "Maintenance of Siemens-Allis 4.16 kV Circuit Breakers, Types FA-350 and MA-350," Revision 3, March 3, 1990.
5.33 I.B. 33-850-3-E, "Westinghouse Instructions for Types DB-50, DBF-16, and DBL-50 Air Circuit Breakers," September 1976.
5.34 I.B. 32-253-1, "Westinghouse Instructions for Porcel-Line Metal Clad Switchgear, Type DH-P, Circuit Breakers," May 1964.
5.35 Proprietary Plant Procedure 22, "13.8 kV and 4.16 kV Westinghouse DHP Breakers," Revision 00, November 30, 1988.
5.36 GEK-7320, "Instructions and Recommended Parts for Maintenance of Magnet Blast Circuit Breakers, Types AM-4.16-350-2C and AM-4.16-350-2H," undated.
5.37 Proprietary Plant Procedure 14, "ITE K-1600 & K-1600S Circuit Breaker Maintenance," Revision 0 (initial issue), undated.
5.38 Proprietary Plant Procedure 17, "18 Month Interval 4160 Volt Breakers and Associated Switchgear Maintenance," Revision 1, February 20, 1992.
5.39 I.B. 32-251-4, "Westinghouse Instructions for De-ion Air Circuit Breakers, Type 50DH350," November 1958.
5.40 Proprietary Plant Procedure 8, "Response Time Testing of 4.16 kV Breakers for STP-633.2," Revision 0, March 15, 1989.
5.41 Proprietary Plant Procedure 9, "Testing Close and Trip Coils of Siemens-Allis 4.16 kV Circuit Breakers, Type MA-350," Revision 0, November 5, 1990.
5.42 Proprietary Plant Procedure 10, "Inspection and Meggering of Non-Segregated Buses and Associated Equipment," Revision 0, April 11, 1990.
5.43 I.B. 33-850-4 & 5E, "Westinghouse Instructions for Types DB-75, DB-100, and DBF-40 Air Circuit Breakers," September 1976.
5.44 EPRI Report NP-6973, Infrared Thermography Guide, Electric Power Research Nuclear Maintenance Applications Center, 1990.
5.45 I.B. 6.1.2.7-1G, "ASEA Brown Boveri Installation/Maintenance Instructions for Type K-225 Thru K-2000 and K-600S Thru 2000S Low-Voltage Power Circuit Breakers," updated.
5.46 I.B. 33-790-1E, "Westinghouse Instructions for Low-Voltage Power Circuit Breakers, Types DS and DSL," September 1979.
5.47 Proprietary Plant Procedure 26, "Reactor Trip Breaker Response Time Test," Revision 00, October 18, 1988.
5.48 NUREG/CR-5762, "Comprehensive Aging Assessment of Circuit Breakers and Relays for Nuclear Plant Aging Research (NPAR) Program, Phase II," Wyle Laboratories for U.S. Nuclear Regulatory Commission, Draft Version, undated.
5.49 NUREG/CR-4715, "An Aging Assessment of Relays and Circuit Breakers and System Interactions," Franklin Research Center for Brookhaven National Laboratory and U.S. Nuclear Regulatory Commission, June 1987.

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, several service-related and model-specific conditions may require plant-specific activities to establish an effective aging management program for certain switchgear. These activities are described in the following subsections.

6.1.1 Management of Electrical/Control Devices

Electrical/control devices (spring charging motors, control relays, undervoltage and shunt trip devices, secondary disconnects, auxiliary contacts, and switches) are responsible for a substantial percentage of the failures noted in the NPRDS and LER data. Based on these findings, additional attention to these components may be warranted. Plant operators should first determine whether a significant number of electrical device failures or deficiencies are evidenced for their equipment; this may be indicated by frequent corrective maintenance or replacement of these components. If such evidence is present, an evaluation of existing maintenance/testing procedures and practices should be undertaken to determine their adequacy with respect to the components experiencing problems. In addition, determination of the root cause of the failures may help to identify an unrelated condition that induces failure of the electrical components (e.g., binding of the operating mechanism resulting in prolonged energization and eventual failure of the closing coil). Selective replacement of certain electrical devices, improved testing and monitoring of the components, or adjustment of the maintenance interval are other potential alternatives for dealing with these types of failures (assuming no other underlying cause can be found).

6.1.2 Breaker Refurbishment

All circuit breakers will require refurbishment at some time during the life of the plant. As evidenced by the analysis of historical data presented in Section 3.6, refurbishment is an important element in any switchgear aging management program. To assure the effectiveness of such a program, the specific criteria for breaker refurbishment must be defined. There are two primary alternatives: time-based refurbishment and condition-based refurbishment. For those plants using condition-based refurbishment, criteria for initiating refurbishment should be defined for use by equipment maintainers. Section 6.2 provides additional information regarding equipment maintenance periodicities. References 6.1 through 6.4 provide additional guidance for refurbishment programs.

6.1.3 Calibration of Overcurrent Trip Devices

Examination of the NPRDS, LER, and overhaul data presented in Section 3.6.2 indicates that electromechanical overcurrent trip devices are susceptible to setpoint drift. Plant-specific data gathered during maintenance or testing of these devices (such as the "as-found" setpoint) may be evaluated to determine if the current frequency of calibration is adequate. For example, if the device as-found readings are consistently out of specification, consideration should be given to shortening the interval on which calibration of the units is conducted. Alternatively, electromechanical overcurrent devices can be replaced with more stable solid-state units using manufacturers' retrofit kits specifically designed for this purpose.

6.1.4 Switchgear Exposed to Effects of Dust Storms

A limited number of switchgear units in a limited number of plants are located in areas where the effects of desert dust storms can contaminate switchgear internals. Some of these units are contained in outdoor switchgear housings having filtered air inlets. Others are located inside the plant, but may be affected by significant amounts of dust that enter the building. At plants having switchgear exposed to such conditions, plant operators must review procedures to determine if filters that protect the switchgear are changed as appropriate following a dust storm, and if maintenance and surveillance procedures are adequate to identify and control the effects of dust contamination on primary insulation systems and in the mechanism of the switchgear.

6.1.5 Switchgear Exposed to Temperatures in Excess of 104°F

Switchgear in a limited number of plants can be exposed to temperatures well in excess of 104°F for significant periods of the day for long periods during the year. The periodicity of the maintenance and surveillance procedures for this switchgear should be frequent enough to assure that lubricants in the trip and close latches, close spring charging motor, and main operating mechanisms have not degraded (i.e., separated, evaporated, or hardened) because of exposure to the operating temperatures.

6.1.6 Switchgear Requiring Qualification for Accident Environments

Switchgear that may be exposed to accident environments must be qualified for the accident environment. Environmental qualification programs generally require qualified lives to be established for components based on aging analyses or aging tests. For such switchgear, plant-unique replacement schedules for switchgear subcomponents based on the environmental qualification results must be followed. Therefore, the plant programs for these switchgear should incorporate the maintenance concepts described in Section 5.2 and Table 5-1, coupled with the replacement schedule dictated by the qualification program.

6.1.7 Switchgear with High Cycle Operation

Certain circuit breakers within a switchgear unit may accumulate much higher numbers of operating cycles than other circuit breakers because of their use in the electrical system. As the voltage level and interrupting capacity of switchgear increases, the number of cycles considered to be high decreases. The values of operation endurance capability described in References 6.5 and 6.6 (for high- and low-voltage switchgear, respectively) can be used as guidelines for the evaluation of specific plant switchgear applications; breakers whose number of operating cycles approaches these values should be identified as being potentially "high cycle," and further evaluation of the breaker should be made to determine if more frequent maintenance is appropriate. If no corrective maintenance has been necessary between scheduled maintenances for the higher cycle breaker applications, use of the standard maintenance periodicity for the circuit breakers is appropriate. It should be noted that very few breakers are expected to be in "high cycle" applications.

6.1.8 Model-Specific Conditions

Section 5.4.2 identifies the following concerns for specific circuit breaker types:

- General Electric 480-V circuit breakers with electromechanical overcurrent trip devices may experience calibration problems and dashpot failures that may cause premature or lack of tripping on overcurrent conditions. Replacement of overcurrent trip device dashpot seals (and recalibration) at 10- to 12-year intervals is recommended.

- For General Electric 4.16- and 13.8-kV circuit breakers, the closing spring charging mechanisms may experience a significant number of failures associated with both electrical and mechanical components.

- For ITE/Brown Boveri/Gould (ABB) 4.16- and 13.8-kV circuit breakers, the electrical components of the closing spring charging mechanism (such as limit switches and charging motor brushes) may experience a proportionately high number of failures.

Operators of nuclear plants having these switchgear should perform the following activities:

- Review the plant failure records for the switchgear to determine if such failures are occurring at the plant.

- If failures are identified, review the maintenance/surveillance procedures for the equipment to determine if the maintenance/surveillance activities for the circuit breaker subsystems are sufficiently detailed and frequent to identify and correct problems with the subcomponents. Upgrade the procedures as appropriate.

Even if no failures are identified with these subcomponents, it may be appropriate to review the procedures to assure that maintenance of these subcomponents is adequately described to preclude problems.

6.2 Additional Considerations for Switchgear Maintenance

Because of the substantial cost and effort associated with maintaining nuclear plant electrical switchgear, extension of the interval between periodic maintenance and overhaul 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 and overhaul 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.

It is difficult to develop reliability data and a meaningful mean time between failure for electrical switchgear. Therefore, development of a statistically justifiable periodicity for switchgear maintenance is also problematic. However, evaluation of several types of information related to switchgear aging and failure, when taken collectively, may provide a suitable basis for the judicious extension of equipment maintenance, overhaul, 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 efficacy of existing maintenance practices is the use of component condition information derived from maintenance activities. Because of their comprehensive scope, breaker maintenance and overhaul represent important opportunities for collecting information on the actual physical condition of breaker subcomponents. 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 breaker subcomponent detected during overhaul may indicate that the current interval specified should not be lengthened (at least with respect to this subcomponent). Conversely, little or no evidence of wear or other degradation may indicate that an extension of the interval is permitted. "As-found" condition data may also be useful in the determination of periodic component replacement. Information concerning the as-found condition of the switchgear subcomponents can be readily gathered during scheduled maintenance/overhaul periods (for example, using prepared data sheets listing each significant subcomponent and the possible range of observed conditions), and can be compared to 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

The environment to which the switchgear is exposed (both prior to and during operation) has been demonstrated to be an important determinant in the rate of degradation of various components. The specific environment in which the equipment operates should be characterized in terms of such factors as temperature, humidity, and contaminants. The environment should then be accordingly factored into the determination of the appropriate maintenance intervals if it is determined to present significant opportunity for component degradation. Benign environments would indicate the potential for lengthening periods. High temperature, 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 or overhaul. Although much of the relevant history of a given piece of switchgear 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 data bases or other documentation. Unless explicit descriptions of subcomponent 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 switchgear 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 because the effects of environment, maintenance practices, operations, and any other external influences are present in the failure data. To use these data effectively, it is necessary to separate those events that have caused a failure of the switchgear to fulfill its required function (or would have caused the switchgear 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 switchgear subcomponents and to identify potentially problematic devices. The absence of a significant number of subcomponent failures would 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 because of the small population size and other limitations inherent in the data.

6.2.5 Conclusions

Although no 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 switchgear components can be described and understood, the more confidently maintenance planners will be able to determine the appropriate overhaul and component 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

6.1 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Asea Brown Boveri/Halliburton NUS Corporation, Volume 1, Part 1, Draft Report, August 1992.

6.2 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 2, Final Report, July 1992.

6.3 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 3, Final Report, December 1992.

6.4 NP-7410, "Circuit Breaker Maintenance," prepared for Nuclear Maintenance Applications Center (NMAC) by Grove Engineering, Volume 1, Part 4, Draft Report, September 1992.

6.5 C37.06-1979, "Preferred Ratings and Related Capabilities for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," April 24, 1979.

6.6 C37.16-1980, "Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage Power Circuit Breakers and AC Power Circuit Protectors," February 6, 1980.

APPENDIX A
DEFINITIONS

Aging mechanism: the physical or chemical processes that result in degradation;[1] specific process that gradually changes characteristics of a system, structure, or component with time or use.[2]

Relevant aging mechanism: an aging mechanism that is likely to occur to a structure or component with certain characteristics and that is exposed to one or a few specific normal operating conditions.

Significant aging mechanism: an aging mechanism is potentially significant when, if allowed to continue without additional detection or mitigation measures, it will cause the component or structure to lose its ability to perform its required function during the license renewal term.

Age-related degradation: a change in a system's, structure's, or component's performance or physical or chemical properties, resulting in whole or in part from one or more aging mechanisms;[1] aging effects that could impair the ability of a system, structure, or component to perform a design function (synonymous with aging degradation).[2]

Failure mechanism: physical process that results in failure.[2]

Failure mode: the manner or state to which a system, structure, or component fails.[2]

Failure cause: circumstances during design, manufacture, or use that have led to failure.[2]

Stressor: agent or stimulus that stems from fabrication or pre-service and service conditions and can cause aging mechanisms or immediate degradation to a system, structure, or component (synonymous with stress).[2]

Relationship of Aging Terms

A **stressor**, produced by such conditions as temperature, radiation, or voltage, acts on a component. If the component (or its materials) is sensitive to the stressor, an **aging mechanism** will occur.

The **aging mechanism** may lead to **age-related degradation** if the effects of the aging mechanisms that result in age-related degradation are not accounted for through such actions as maintenance.

Eventually, an aging mechanism may lead to a **failure mechanism**. The result of the failure mechanism is the **failure mode** of the component.

Review of the failure mode, failure and aging mechanisms, age-related degradation, and stressors will provide the **failure cause** for age-related failures.

References:

1. Federal Register, Vol. 56, No. 240, Nuclear Plant License Renewal Supplementary Information Section VI e(ii), page 64954.

2. Electric Power Research Institute Project 2927-7, "Draft of Nuclear Power Plant Common Aging Terminology," Prepared by MPR Associates, Inc., April 1992.

APPENDIX B
DOCUMENTS NOT RELATED TO EQUIPMENT AGING

Table B-1 lists those Information Bulletins, Circulars, and Information Notices published by NRC Inspection and Enforcement (IE) that were determined to be unrelated to aging degradation of electrical switchgear. A justification for designating these Bulletins, Circulars, and Notices as unrelated to switchgear aging degradation is provided.

Table B-1. Bulletins, Circulars, and Notices Not Related to Electrical Switchgear Aging Degradation

Document/Title/Date	Justification
IE Bulletin 73-01, "Faulty Overcurrent Trip Relay Device in Circuit Breakers For Engineered Safety Systems"	Manufacturing defect in dashpot endcaps of 480-V Westinghouse DB series circuit breakers
IE Bulletin 74-09, "Deficiency in General Electric Model 4 kV Magne-Blast Breakers"	Faulty roller bars and clearance problems; auxiliary switch installation deficiency
IE Bulletin 79-11, "Faulty Overcurrent Trip Device in Circuit Breakers For Engineered Safety Systems"	Related to cracked dashpot endcap problem identified in Bulletin 73-01; manufacturing problem related to raw materials
IE Circular 79-17, "Contact Problem in SB12 Switches on General Electric Metalclad Circuit Breakers"	Manufacturing defect; worn die formed elongated holes in contact arms
IE Information Notice 80-31, "Maloperation of Gould Brown Boveri 480V Type K-600S and K-DON 600S Circuit Breakers"	Undersized bushings used in secondary close latches
IE Information Notice 81-06, "Failure of ITE Model K-600 Circuit Breaker"	Incorrect tripping coil wire size
IE Information Notice 83-76, "Reactor Trip Breaker Malfunctions (Undervoltage Trip Devices on GE Type AK-2-25 Breakers)"	Undervoltage armature remains in midposition after operation due to interference between the armature and a copper shading ring; design problem
IE Information Notice 84-29, "General Electric Magne Blast Circuit Breaker Problems"	Sleeve bearing material has short life; manufacturing defect; replacement recommended

Table B-1. Bulletins, Circulars, and Notices Not Related to Electrical Switchgear Aging Degradation

Document/Title/Date	Justification
IE Bulletin 85-02, "Undervoltage Trip Attachments of Westinghouse DB-50 Type Reactor Trip Breakers"	Manufacturing defect; undervoltage trip attachment did not provide enough lifting force to the breaker trip bar
IE Notice 85-58, "Failure of a General Electric Type AK-2-25 Reactor Trip Breaker"	Failure due to lack of verification of critical parameters of refurbished reactor trip breaker before installation
IE Notice 85-64, "BBC Brown Boveri Low Voltage K-Line Circuit Breakers With Deficient Overcurrent Trip Devices, Models OD 4 and 5"	Manufactured with incorrect short time delay band lever
IE Information Notice 85-93, "Westinghouse Type DS Circuit Breakers, Potential Failure of Electric Closing Feature Because of Broken Spring Release Latch Lever"	Failures due to defective spring release latch levers
IE Information Notice 87-41, "Failures of Certain Brown Boveri Electric Circuit Breakers"	Failure to close due to insufficient torquing of the charging motor mounting bolts by the vendor; repeated closing and opening of the breaker due to defect, need to add a light spring to the close latch of the operating mechanism
IE Information Notice 88-38, "Failure of Undervoltage Trip Attachment on General Electric Circuit Breakers"	Mechanical binding of the undervoltage trip linkage was caused by a manufacturing anomaly and improper welds
IE Information Notice 88-54, "Failure of Circuit Breaker Following Installation of Amptector Direct Trip Attachment"	Failure caused by improper installation of the Amptector unit
IE Information Notice 88-75, "Disabling of Diesel Generator Output Circuit Breakers by Anti-pump Circuitry"	Anti-pump circuit design deficiency
IE Information Notice 91-15, "Incorrect Configuration of Breaker Operating Springs in GE AK-Series Metal Clad Reactor Trip Breakers"	Failures caused by improper assembly during manufacturing or refurbishment

APPENDIX C: ACRONYMS

A	Ampere
AK	Model designator for a General Electric 480-V circuit breaker
AM	Model designator for a Siemens-Allis medium-voltage circuit breaker
AMG	Aging Management Guideline
ANSI	American National Standards Institute
AWS	American Welding Society
BTP	Branch Technical Position (NRC)
BWR	Boiling water reactor
CFR	Code of Federal Regulations
Class 1E	Class 1 electrical equipment (IEEE designation for safety-related)
DB	Model designator for a Westinghouse 480-V circuit breaker
DG	Diesel Generator
DH	Model designator for a Westinghouse medium-voltage circuit breaker
DHP	Model designator for a Westinghouse medium-voltage circuit breaker
DS	Model designator for a Westinghouse 480-V circuit breaker
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
GE	General Electric
ICEA	Insulated Cable Engineers Association
IE	Inspection and Enforcement (former NRC Division)
IEEE	Institute of Electronic and Electrical Engineers
INPO	Institute for Nuclear Plant Operation
IPA	Integrated Plant Assessment
IR	Industry Report
GDC	General Design Criteria
kVac	Kilovolts alternating current
LCM	Life Cycle Management
LCO	Limiting Condition for Operation
LWR	Light Water Reactor
MA	Model designator for a General Electric medium voltage circuit breaker
MTBF	Mean time between failure
MVA	Megavolt amperes
NEMA	National Electrical Manufacturer's Association
NPRDS	Nuclear Plant Reliability Data System
NRC	Nuclear Regulatory Commission
NUMARC	Nuclear Management and Resources Council
OCTD	Overcurrent trip device
PLIM	Plant Lifetime Improvement
PWR	Pressurized Water Reactor
rd	Rad (unit of radiation)
RG	Regulatory Guide
RMS	Root mean square
SCs	Structures and components
SQUG	Seismic Qualification Utility Group
SRP	Standard Review Plan (NRC)

SSCs	Systems, structures, and components
Std	Standard
UL	Underwriter's Laboratories
UV	Undervoltage
UVTA	Undervoltage trip attachment
Vac	Volts alternating current
Vdc	Volts direct current

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