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Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations

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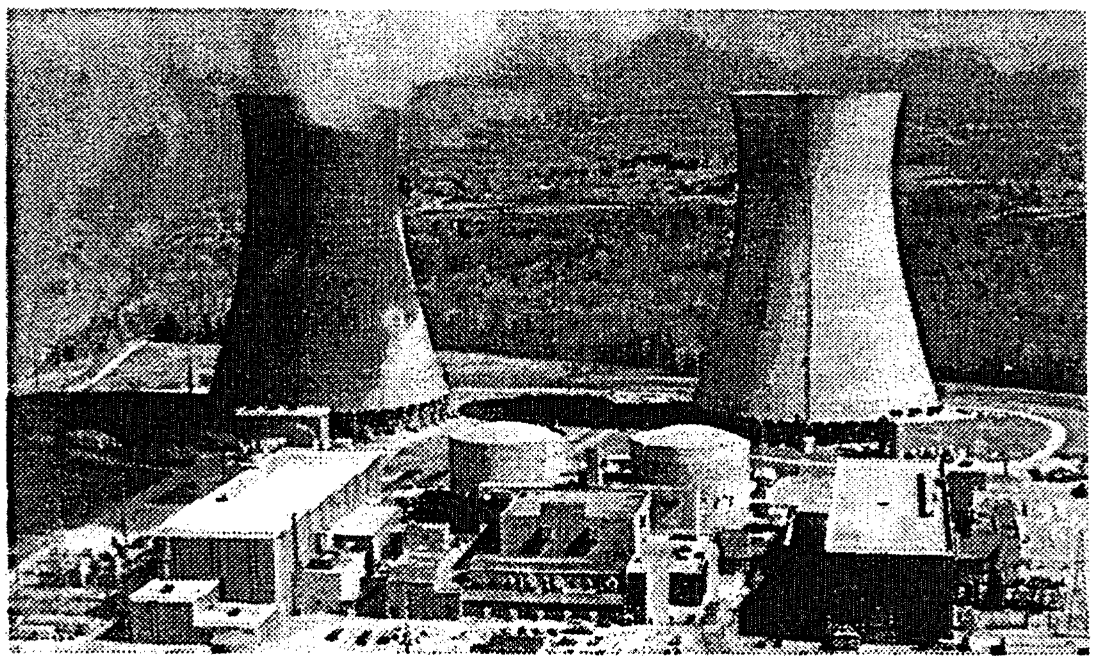

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AGING MANAGEMENT GUIDELINE FOR COMMERCIAL NUCLEAR POWER PLANTS - ELECTRICAL CABLE AND TERMINATIONS

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Abstract

This Aging Management Guideline (AMG) describes recommended methods for effective detection and mitigation of aging mechanisms in commercial nuclear power plant electrical cables and terminations within the scope of license renewal and maintenance rule activities. The intent of this AMG is to assist plant maintenance and operations personnel in maximizing the safe, useful life of these components. It also supports the documentation of aging effects management programs required under the License Renewal Rule 10 CFR 54. This AMG is presented in a manner that allows personnel responsible for performing analysis and maintenance to compare their plant-specific aging effects (expected or already experienced) and aging management program activities to the more generic results and recommendations presented herein.

Acknowledgements

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Electronic Version Availability

A number of Microsoft EXCEL spreadsheets were developed to create the tables and figures in this guideline. The spreadsheets and graphing tools were prepared in a manner that the data evaluated for this guideline can easily be replaced with plant-specific data so utility personnel can easily perform aging assessments of specific polymer formulations. Copies of the computer files, in EXCEL for WINDOWS 5.0 format, can be obtained by contacting DOE's LWR Technology Center @ Sandia at (505) 844-5379.

Likewise, the entire document is available in WordPerfect 5.1 for DOS format. Utility personnel responsible for implementing Maintenance Rule requirements or preparing License Renewal evaluations may find this document useful. Copies of the computer files (one file per section/appendix) can be obtained by contacting DOE's LWR Technology Center @ Sandia at (505) 844-5379.

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1. EXECUTIVE SUMMARY

1.1 Purpose

The continued operation of nuclear power plants for periods that extend beyond their original 40-year license may be a desirable option for many U.S. nuclear plant operators. However, to allow operation of the plant beyond this period, utilities must show that the aging of components important to license renewal is managed. Components must not degrade to the point where they are incapable of performing their safety function(s) during either normal operating or accident conditions. Therefore, to allow operation during a license renewal period, nuclear power plant operators must manage the aging of components to ensure proper function.

This document analyzes potential aging mechanisms and their effects on low- and medium-voltage electrical cable and terminations, and provides guidelines for managing significant degradation mechanisms. Effective management will ensure that these systems continue to perform their safety function(s) during both the current and the license renewal terms. Use of these guidelines will provide utilities with a basis for verifying that effective means for managing age-related degradation of cable systems have been established. The guidelines are also useful for life cycle management purposes to optimize surveillance and maintenance programs and minimize forced outages due to unexpected premature aging. Guidance for performing aging management reviews pursuant to 10CFR54 is also provided.

1.2 Scope

Low- and medium-voltage electrical cable systems consist of cables, terminations, and other associated components (such as cable trays, penetrations, and conduit) used to power, control, and monitor various types of electrical apparatus and instrumentation. The equipment covered by this guideline includes all low- and medium-voltage cables and their terminations.[1] Cable trays, penetrations, conduits, conduit seals, and other ancillary equipment are not addressed in detail. Potential interactions between these components and electrical cables and terminations and potential aging effects are discussed.

Cables and cable systems may be grouped in a number of ways. The groups of cables and terminations described in 10CFR54 as being within the scope of license renewal are as follows:

1. Safety-related

2. Nonsafety-related whose failure could prevent satisfactory accomplishment of a safety-related function

[1] High-voltage systems ($\geq$ 15 kVac) were not included in the scope of this document because: (1) they generally constitute an extremely small fraction of the total amount of cable at a plant, and (2) they are often highly specialized in construction (e.g., oil filled) so they have little in common with the more prevalent low- and medium-voltage systems.

3. Those relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with Nuclear Regulatory Commission (NRC) regulations for

    - Fire protection (10CFR50.48)
    - Environmental qualification (10CFR50.49)
    - Pressurized thermal shock (10CFR50.61)
    - Anticipated transients without scram (10CFR50.62)
    - Station blackout (10CFR50.63).

In addition, cables not included in the above categories but which are important to the continuity of power production or some other aspect of plant operation may, at a utility's option, be included in the scope of a plant's aging management program. Typically, a utility would opt to expand the scope of the aging management program for economic and reliability reasons.

Cable systems may also be grouped according to use or function. These categories include:

- Power cables
- Control cables
- Instrument cables
- Telephone and security cables
- Local and panel wiring
- Thermocouple extension wiring
- Specialty cables[2]
- Lighting cables
- Grounding cables

Further classification of cable systems in terms of their voltage rating is possible:

- Low-voltage ($\leq$ 1000 Vac or $\leq$ 250 Vdc)[3]
- Medium-voltage (2 kVac through 15 kVac)

The majority of plant circuits fall within the low-voltage category.

Included within the scope of terminations in this AMG are the following:

- Plug-in/multi-pin type connectors
- Compression fittings
- Fusion fittings
- Splice insulations (tape and heat-shrinkable tubing)
- Terminal blocks

Appendix A provides definitions of the terminology used in this report and Appendix B provides a detailed description of the components discussed.

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[2] Specialty cable is used in applications that require specific cable attributes, properties, or configuration (e.g., neutron detectors, area radiation monitors, and control rod position indicators).

[3] As in the Low-Voltage, Environmentally-Qualified Cable Industry Report, the upper range of low-voltage is defined as 1000 Vac. Typically, cables are not rated between 1000 and 2000 Vac; however, the results for low-voltage cable are applicable up to 2000 Vac.

1.3 Methodology

This study evaluated the stressors acting on cable and termination components, industry data on aging and failure of these components, and the maintenance activities performed on cable systems. It evaluated the main subsystems within cables, including the conductors, insulation, shielding, tape wraps, jacketing, and drain wires, as well as all subcomponents associated with each type of termination. The principal aging mechanisms and anticipated effects resulting from environmental and operating stresses on these systems were identified, evaluated, and correlated with plant experience to determine whether the predicted effects are consistent with field experience, recognizing that new effects may be identified in the future. Installation stressors were also examined. Then, the maintenance procedures and condition monitoring/testing methodologies used by plant operators were evaluated to determine whether the effects of aging mechanisms are being detected and managed. Other available testing and condition monitoring techniques were also identified. Where an aging mechanism was not fully managed or not considered, additional plant-specific activities to manage the aging mechanism are identified and recommended.

1.4 Conclusions

1.4.1 Historical Performance

The following conclusions were drawn from the historical performance of cables and terminations:

1. The number of cable and termination failures (all voltage classes) that have occurred throughout the industry is extremely low in proportion to the amount of installed cable. However, the data which supports this conclusion is limited in two ways: (1) there is little or no data to quantify performance under accident conditions, and (2) only a few plants have operated for more than twenty years, which is only about one-third of the total expected period of operation for these systems (i.e., 60 years).

2. Thermal embrittlement of insulation is one of the most significant aging mechanisms for low-voltage cable. Mechanical stress (vibration, etc.) was also frequently cited as a cause for failure. These thermal and mechanical aging mechanisms occur predominantly near end devices or connected loads. Thermal aging results largely from localized hot spots; aging due to the ambient environment or ohmic heating may also be present.

3. As evidenced in all of the data sources examined, localized radiolytic degradation (i.e., degradation induced by ionizing radiation) affects low-voltage cables and terminations to a lesser degree than thermal and mechanical degradation. Degradation resulting from exposure to external chemical substances occurs infrequently.

4. Localized thermal, radiolytic, and incidental mechanical damage appear to be the most significant aging mechanisms for cables located near the reactor pressure vessel, especially neutron monitor circuits.

5. Connector failures constitute a large percentage of all failures noted for low-voltage and neutron monitoring systems. A large percentage of these failures can be attributed to oxidized, corroded, or dirty contact surfaces.

6. Failures of hookup or panel wiring constitute a substantial percentage of the total number of low-voltage circuit component failures noted. A large fraction of these failures are not the result of aging influences, but rather stem from design, installation, maintenance, modification, or testing activities.

7. Wetting concurrent with operating voltage stress appears to produce significant aging effects on medium-voltage power cable.

8. Loosening and breaking of lugs are the most significant failures of compression fittings.

9. Damage to cable insulation during or prior to installation may be crucial to the cable's longevity, particularly for medium-voltage systems.

10. Based on the high reliability demonstrated by cable systems and assuming that their reliability remains high, continued reliance on visual inspection techniques for the assessment of low-voltage cable and termination aging appears warranted since these techniques are effective at identifying degraded cables.

1.4.2 Significant Aging Combinations Not Always Managed by Existing Programs

Evaluation of the components of cable systems and terminations, the stressors acting upon the components, and the operational history determined that although several "significant"[4] aging mechanisms exist, few actual subcomponent failures result. Evaluation of the general and specific failure histories for cable systems [as reflected in the Nuclear Plant Reliability Data System (NPRDS) and Licensee Event Report (LER) databases, the available literature, and information provided from host utility plants and surveys] shows that both low- and medium-voltage systems (including neutron monitoring equipment) are highly reliable and experience a generally low failure rate.

All potentially significant aging mechanisms and effects for electrical cable and terminations included in the scope of this AMG are described in Section 4.2 of this report. Examination of the relative importance and likelihood of occurrence of these effects provides a greatly reduced set of significant mechanisms; these were designated as "significant and observed" aging mechanisms for the purposes of this guideline. A comparison of this reduced set of aging mechanisms with common maintenance, surveillance, and condition monitoring techniques employed by operating plants (Table 1-1) indicated that the following combinations may require additional plant-specific aging management activities:

[4] For the purposes of this guideline, a "significant" aging mechanism was defined as one which, if left unmitigated, could potentially affect the functionality of the equipment.

- Localized thermal, radiolytic, or mechanical degradation of low- or medium-voltage cable insulation and jacketing (where jacketing is required for environmental qualification considerations)

- Localized thermal, radiolytic, or mechanical degradation of cables located near the reactor pressure vessel, especially neutron monitor circuits

- Thermal degradation of low- and medium-voltage power cable insulation when the circuit is regularly energized, other than testing, at a significant fraction of the circuit's ampacity

- Degradation of medium-voltage power cable insulation routinely exposed to appreciable wetting or submergence

- Oxidation and/or corrosion of connector contact surfaces associated with low-voltage and neutron detecting circuits (and similar low-current or impedance-sensitive applications)

- Loosening of the bond between a compression fitting and a conductor

The following damage mechanisms, although not aging mechanisms, can limit the useful life of aged cable:

- Damage to medium-voltage cable insulation, jacketing, and shielding during installation

- Damage to low-voltage panel or hookup wire resulting from maintenance activities

- Damage to cable resulting from movement or maintenance activities

- Cracking of bonded jacket/insulation systems on environmentally qualified cable during accident exposure

- Exposure of Kapton® (polyimide) insulation[5] to high humidity (moisture), and/or mechanical damage, specifically, aging degradation of the Teflon® that binds the tape wrap on Kapton® leads

[5] Kapton® insulation is manufactured in thin sheets precoated with a Teflon® adhesive.

Table 1-1 Summary of Stressors, Aging Mechanisms, and Current Maintenance, Surveillance, and Condition Monitoring Techniques

Voltage Category	Component	Sub-component	Applicable Stressors	Aging Mechanisms	Aging Effects	Current Preventive Maintenance Techniques	Available Condition-Related Maintenance Techniques
Low	Cables	Insulation and Jacketing	Heat (environment and ohmic)	Thermoxidative degradation of organics	Embrittlement, cracking	Inspection of accessible portions during routine operations or maintenance	Visual inspection, insulation resistance (IR), polarization index, capacitance; repair or replacement
			Radiation	Radiolysis and photolysis of organics	Hardening, cracking, crazing, swelling	Inspection of accessible portions during routine operations or maintenance	Visual inspection, IR, polarization index, capacitance; repair or replacement
			External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Inspection of accessible portions during routine operations or maintenance	Visual inspection, IR, polarization index, capacitance; repair or replacement
	Connectors	Contact Surfaces	Electro-chemical stresses	Corrosion and oxidation of metals	High resistance	Inspection and, if required, cleaning during maintenance	Visual inspection, time domain reflectometry (TDR), capacitance; repair or replacement
	Compression Fittings	Lugs	Vibration, tensile stress	Deformation and fatigue of metals	High resistance, breakage	Inspection during maintenance	Visual inspection, TDR; repair or replacement
Medium	Cables	Insulation	Moisture and voltage stress	Moisture intrusion; water treeing	Dielectric breakdown and fault to ground	Inspection during maintenance	Visual inspection, IR, polarization index, capacitance, TDR, hi-pot, AC power factor; repair or replacement
Neutron Detecting	Cables	Insulation	Heat (environment)	Thermoxidative degradation of organics	Embrittlement, cracking	Inspection of accessible portions during routine operations or maintenance	Visual inspection, IR, polarization index, capacitance; repair or replacement
			Radiation	Radiolysis of organics	Hardening, cracking, crazing, swelling	Inspection of accessible portions during routine operations or maintenance	Visual inspection, IR, polarization index, capacitance, TDR; repair or replacement
			External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Inspection of accessible portions during routine operations or maintenance	Visual inspection, IR, polarization index, capacitance, TDR; repair or replacement
	Connectors	Contact Surfaces	Electro-chemical stresses	Corrosion and oxidation of metals	High resistance	Inspection and, if required, cleaning during maintenance	Visual inspection, TDR, capacitance; repair or replacement

1.4.3 Nonsignificant Aging Combinations

The following aging effects were considered nonsignificant:

- Embrittlement and cracking of non-bonded jackets, unless the jacket is required to shield the insulation from beta radiation or to seal a cable and prevent moisture intrusion
- Aging degradation of cable filler material
- Short-term (fault) stress on cable and termination components
- Aging of cable tape wrap, other than shielding or semi-conducting tape wrap in medium-voltage cable

1.4.4 Recommendations

Evaluations of maintenance and condition monitoring practices for cable systems (Section 5) led to the conclusion that some of the principal aging mechanisms are not fully managed by existing programs. Accordingly, the following general recommendations for addressing these mechanisms are presented:

1. Aging management activities should focus on aging susceptible applications. This will require periodic evaluations of potentially significant degradation mechanisms for the specific type of cable installed (Section 6 provides a proposed step-by-step methodology). For low-voltage systems, instances of earlier vintage or more aging-susceptible materials used to manufacture cables (such as PVC or Neoprene®) that are used in applications subject to heavy continuous loads or routed through "hot spot" areas should be considered. Particular attention should be paid to components or cable segments located in proximity to an end device. Similarly, medium-voltage power cables routinely subject to wetting or submersion, and connectors used in neutron monitoring circuits should be addressed.

2. Significant aging management efforts are generally not warranted for cable systems located in "benign" areas. Accordingly, aging management activities should be focused more on cable and terminations installed in more environmentally challenging areas, and portions of benign areas which are subject to localized stressors.

3. Accurate characterization of plant environments, especially environmentally challenging areas and areas with localized stressors, is important for effective aging management of certain cable systems. Such characterizations should be conducted to help identify the circuits and components that may undergo premature aging with respect to the rest of the systems.

4. Based on the similarity between many environmentally-qualified (EQ) and non-EQ cables and terminations, existing information and analyses related to the aging of EQ components can be effectively applied to many non-EQ components.

5. Condition monitoring is not currently warranted for all applications of medium-voltage cable. There is no known technique that is capable of effective monitoring of dielectric aging that also has negligible potential for inducing degradation due to the test itself. Preventive measures (such as prevention from wetting) should be considered as means of extending medium-voltage cable longevity.

6. In cases where condition monitoring is deemed appropriate (e.g., those cases where aging effects cannot otherwise be demonstrated to be adequately managed, or as a last resort to replacement), a program to determine baseline aging condition using a nondestructive test or evaluation method should be considered.

7. If cables are replaced, plant cable installation practices and procedures should be reviewed to ensure that the possibility of damaging cables during installation is minimized.

8. Information from continuing qualification and natural aging research programs conducted domestically and abroad should be incorporated into aging evaluations and analyses.

9. Naturally aged cable specimens removed from service should be analyzed and characterized. Data obtained from these analyses should be retained in an industry-wide, readily accessible database.

10. Environmentally-qualified cable using certain bonded jacket/insulation systems should be evaluated if the specific combination of jacket and insulation materials and the bonding process were not qualified as a system.

2. INTRODUCTION

2.1 Background

The Department of Energy (DOE)-sponsored Commercial Light Water Reactor (CLWR) Program [formerly known as the Plant Lifetime Improvement (PLIM) Program], in cooperation with EPRI's 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 these programs was the development of License Renewal Industry Reports (IRs) from 1990 to 1993, which were coordinated by the Nuclear Management and Resource Council (NUMARC; now the Nuclear Energy Institute, NEI). The IRs cover critical classes of long-lived passive components such as reactor pressure vessels, reactor coolant pressure boundary piping, containment structures, and low-voltage, environmentally-qualified cables [2.1]. The DOE-sponsored Aging Management Guidelines (AMGs), supporting continued demonstration of CLWR and LCM concepts, describe and evaluate aging management approaches for groups of equipment not evaluated in the IRs, or expand upon the IRs. To date, eight AMGs have been published, all but two on active components. Topics are:

1. Battery Chargers, Inverters and Uninterruptible Power Supplies [2.2]
2. Batteries, Stationary [2.3]
3. Heat Exchangers [2.4]
4. Motor Control Centers [2.5]
5. Pumps [2.6]
6. Switchgear, Electrical [2.7]
7. Tanks and Pools [2.8]
8. Transformers, Power and Distribution [2.9]

In addition, several AMGs for long-lived passive systems, structures and components are being prepared at this time:

1. Electrical Cablė and Terminations (this AMG)
2. Containment Penetrations
3. Non-Reactor Coolant Pressure Boundary (Non-RCPB) Piping and Tubing

Most AMGs evaluate components determined to be within the scope of both the License Renewal Rule (LRR), 10CFR54.21 [2.10] and [2.11], and the Maintenance Rule (MR), 10CFR50.65 [2.12]. However, this AMG evaluates all low- and medium-voltage cables and terminations, even those not covered by these rules, because the additional scope was small and the techniques are useful for the life cycle management of all cables.

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 obtain a renewed license and to operate a plant during a license renewal period, utilities must show that the detrimental effects of aging of components important to license renewal have been managed so that these components will not degrade to the point where they are incapable of supporting their intended function(s). Therefore, operators of nuclear power plants must manage the detrimental effects of aging of components to ensure that intended function(s) will be performed when required. Electrical cables and terminations are specifically identified in 10CFR54 [2.11] as requiring an aging management review.

From a long-term perspective, it may be desirable to perform aging management activities such as preventive maintenance and refurbishment during the current license period even though some of these activities may not be necessary to satisfy regulatory requirements. These activities may be necessary to ensure that there is no loss of intended function(s), no unacceptable reduction in safety margins, and that higher rates of challenge to plant safety systems do not occur during the license renewal period. Beneficial preventive maintenance and refurbishment activities will typically lead to increased reliability, minimal operating and maintenance costs, and a higher capacity factor during the current license period.

2.2 Purpose

This AMG was prepared for use by plant maintenance and system engineering personnel responsible for design, maintenance, repair/replacement, and aging management evaluations. It provides information and guidance covering each aspect of an aging management program. While this AMG is intended for use by nuclear power plant operators, many of the same methods can be used to plan effective aging management of similar equipment in other facilities. An effective aging management program will ensure that each cable and termination will continue to perform its intended function(s) or will not prevent the performance of intended function(s).

This document contains analyses of potential degradation modes, including the effects of aging, presents guidelines for developing effective aging management programs, and presents a suggested methodology for performing an aging management review in accordance with 10CFR54. Note that methodologies for extending the qualified life of environmentally-qualified (EQ) components are not explicitly considered; additional information on this topic can be found in EPRI TR-100516 [2.14], EPRI TR-104063 [2.13], and other industry documents.

This AMG also provides additional value to nuclear plant operators as follows:

1. It is a well-researched technical document that can be used by maintenance and system engineering personnel to identify, characterize, and manage age-related degradation of electrical cables and terminations. It can also be used as a reference document for plants developing a license renewal application and/or plans for complying with the Maintenance Rule.

2. The information presented is based on an extensive literature search. Therefore, nuclear plant personnel can use this AMG as a substantive reference for relevant information about electrical cables and terminations. Some of the references used include:

    - License Renewal Industry Reports
    - NRC Bulletins, Information Notices, Circulars, Generic Letters, and Reports
    - Code of Federal Regulations (CFR) and the Federal Register

- Vendor Manuals
- Industry Codes and Standards [(e.g., Association of Edison Illuminating Companies (AEIC), American National Standards Institute (ANSI), American Society for Testing and Materials (ASTM), Insulated Cable Engineer's Association (ICEA), Institute of Electrical and Electronics Engineers (IEEE), National Electrical Manufacturer's Association (NEMA)]
- Miscellaneous references and technical papers

3. It consolidates historical maintenance and industry operating information into one source. The plant maintenance and system engineers will find this useful for the identification of age-related degradation (including root causes) and the verification of appropriate corrective action. Issues discussed include:

   - Operating and maintenance history from the Institute for Nuclear Power Operations (INPO) Nuclear Plant Reliability Data System (NPRDS) and NRC Licensee Event Report (LER) databases
   - Additional operating and maintenance history input from host utilities
   - Results of relevant plant surveys
   - Equipment design differences relevant to aging considerations
   - Service environments

4. Aging phenomena are described in detail. This will be useful for maintenance interval and reliability evaluations of electrical cables and terminations. The following topics are discussed:

   - Stressors acting on electrical cables and terminations
   - Identification of aging mechanisms
   - Significance of aging stressors using "if/then" criteria
   - Age-related degradation and potential failure modes
   - Maintenance-induced degradation or failures
   - Effects of aging

5. It can be an effective tool for aging management and personnel training because it:

   - Identifies the need for aging management and can be used as input for Maintenance Rule performance measures and corrective action requirements
   - Discusses both conventional and nonconventional maintenance techniques, and considers how these practices can be used to manage equipment aging effectively
   - Characterizes the initiation and progression of equipment aging for use in training personnel responsible for maintenance and inspection activities
   - Identifies concepts, principles, and methods that may be used to evaluate electrical cables and terminations not within the scope of this AMG.

2.3 Contents

This AMG evaluates low- and medium-voltage electrical cables and their associated terminations. Cable trays, penetrations[1], conduits, conduit seals, and other ancillary equipment are not addressed in detail. Potential interactions between these components and electrical cables and terminations and potential aging effects are discussed.

Section 3 lists the electrical cables and terminations evaluated and component boundaries. Section 3 also includes a detailed study of the operating history of the electrical cables and terminations evaluated from LER and NPRDS data, and from other sources.

Section 4 discusses stressors, aging mechanisms, age-related degradation, failure modes, and, most important, the effects of aging on electrical cables and terminations. Stressors produce aging mechanisms that can cause component degradation (aging effects). An aging mechanism is significant when, if it is allowed to continue without detection or mitigation measures, it will cause the component to lose its ability to perform its intended function(s). Significant and nonsignificant aging mechanisms/effects relevant to electrical cables and terminations 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 and effects determined. Any time-limited aging analyses relevant to electrical cables and terminations are also identified and described. The entire set of aging mechanisms evaluated in this AMG is presented in Section 4.

Section 5 discusses aging management techniques that can be used to mitigate the aging mechanisms and effects determined to be significant (Section 4). Maintenance, inspection, qualification, testing, and surveillance techniques and programs are described. The effectiveness of these techniques or programs in managing significant aging mechanisms is described wherever historical operating data are adequate to support a conclusion. Variations in plant aging management programs or techniques are discussed. "If/then" criteria are presented whenever possible to assist plant personnel in identifying and managing component aging.

Section 6 discusses management options to address the action items identified in Section 5. Appendix A provides a list of definitions for aging terminology used in this AMG. Appendix B provides a description of the components evaluated, including manufacturers' design differences. Appendix C includes a discussion of the design requirements that apply to electrical cables and terminations, including applicable codes, standards, and regulations. Appendix D provides a list of acronyms and abbreviations. Appendix E is a list of trade names for cables and terminations. Appendix F contains a discussion of NPRDS data. Ohmic heating of electrical cable is discussed in Appendix G. Appendix H discusses regulatory requirements related to synergistic effects. Appendix I discusses the EPRI cable aging research program.

[1] Penetrations, including the cable contained therein, will be covered in the Containment Penetrations AMG.

2.4 Generic License Renewal Requirements

The License Renewal Rule [2.11], specifically 10CFR54.21, describes the current requirements for the content of technical information in a license renewal application.[2] Section 54.21 states that an application for license renewal must contain the following:

1. An Integrated Plant Assessment (IPA),
2. A list of current licensing basis (CLB) changes during NRC application review,
3. An evaluation of time-limited aging analyses (TLAA),
4. A Final Safety Analysis Report (FSAR) supplement.

An IPA must:

1. For those systems, structures, and components within the scope, as delineated in Section 54.4, identify and list those structures and components subject to aging management review,

2. Describe and justify the methods used in item 1 (scope determination) of the IPA, and

3. For each structure and component identified in item 1 of the IPA, demonstrate that the effects of aging will be managed so that the intended function(s) will be maintained for the period of extended operation.

An aging management review is intended to demonstrate that plant "programs and procedures will provide reasonable assurance that the functionality of systems, structures and components requiring review will be maintained during the period of extended operation." [2.11] The License Renewal Rule (LRR) focuses on the effects of aging rather than on a detailed review of aging mechanisms. The LRR states there must be a "reasonable assurance" that the intended function(s) of systems, structures, and components (SSCs) will be maintained.

Section 54.21 also requires an evaluation by the licensee for some SSCs which are subject to a TLAA. The TLAAs of concern are those that:

1. Involve the effects of aging,
2. Involve time-limited assumptions defined by the current operating period (40 years),
3. Involve SSCs within the scope of license renewal,
4. Involve bases or conclusions regarding the capability of the SSC to perform its intended function,
5. Were determined to be relevant to a safety determination by the licensee, and
6. Are either contained or incorporated by reference in the current licensing basis.

The requirements of analyses falling under 10CFR50.49 (environmental qualification) are particularly relevant to electrical cable and terminations. Accordingly, an applicant for license renewal will be required to (1) justify that the existing analyses are valid for the period of

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[2] NEI 95-10, "Industry Guideline for Implementing the License Renewal Rule, 10 CFR Part 54," March 1996, is another source of information regarding implementation of the proposed License Renewal Rule.

extended operation, (2) extend the period of analysis to cover the proposed license renewal period, or (3) otherwise demonstrate that the effects of aging will be adequately managed during the extended operating period. Extension of qualified life is not explicitly covered in this document; additional information on this topic can be found in various industry publications such as EPRI TR-100516 [2.14].

This AMG evaluates all potentially significant aging mechanisms and aging management practices that can be used to demonstrate that the effects of aging will be managed so that the intended function(s) will be maintained, even though the LRR does not require this level of detail. It also discusses the link between aging mechanisms and the effects of aging, and supports evaluation of a TLAA under 10CFR50.49.

Exemptions and requests for relief (pursuant to 10CFR50.12 and 10CFR50.55a, respectively) were not considered here because these issues are plant-specific in nature and, therefore, must be considered on a plant-by-plant basis.

2.5 Method Used to Define the Scope of Components to be Evaluated Under the License Renewal Rule and the Maintenance Rule

Although this AMG covers all low- and medium-voltage cables and terminations, plant licensing engineers may wish to limit the scope of their investigations to electrical cables and terminations covered under the LRR and MR. The definitions of SSCs within the scope of the LRR and MR must be evaluated to determine which cable systems are included in the scope. Table 2-1 describes the current definitions. Note that the scope of electrical cables and terminations covered under the Maintenance Rule, 10CFR50.65 [2.12], is almost the same as that covered by the License Renewal Rule, 10CFR54.21 [2.11].

2.6 Method Used to Define the Aging Mechanisms Assessed in This Study

As indicated above, the LRR does not require explicit evaluation of aging mechanisms, but does require the reasonable assurance of preserving intended function(s) that may be degraded by aging. Because the users of this AMG consist of systems engineers and plant maintenance personnel, detailed descriptions of stressors, aging mechanisms, and failure modes, as well as the effects of aging, are included.

To define aging mechanisms assessed in this study, a two-part evaluation was performed. First, the stressors (e.g., mechanical, chemical, electrical, and environmental) on equipment operation were determined. Then, aging mechanisms associated with those stressors were defined. Finally, age-related degradation mechanisms, failure modes, and effects caused by aging were described. This evaluation is contained in Section 4.

Second, industry-wide operating experience (particularly that reported in NRC LERs; Information Notices, Bulletins, and Circulars; and INPO NPRDS data) was examined. A review of the NRC Information Notices, Bulletins, and Circulars was conducted to identify age-related failures. Events described in the NPRDS data and LERs were then analyzed for age-related degradation and to determine the numbers of particular types of failures. The aging mechanisms

Table 2-1 License Renewal Rule and Maintenance Rule Scope Screening Requirements

License Renewal Rule (LRR)	Maintenance Rule (MR)
Safety-related SSCs	
1. Safety-related SSCs, which are those relied upon to remain functional during and following design basis events to ensure:	1. Same as for LRR.
i. The integrity of the reactor coolant pressure boundary,	a. Same as for LRR.
ii. The capability to shut down the reactor and maintain it in a safe shutdown condition, or	b. Same as for LRR.
iii. The capability to prevent or mitigate the consequences of accidents that could result in potential off-site exposure comparable to the 10CFR100 guidelines.	c. Same as for LRR.
Non-safety-related SSCs	
2. All non-safety-related SSCs whose failure could directly prevent satisfactory accomplishment of any of the intended function(s) identified in paragraphs (1) (i), (ii), or (iii) of this definition.	d. Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function,
	e. That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs),
	f. Whose failure could cause a reactor scram or actuation of a safety-related system.
Required by Regulation	
3. All SSCs relied on in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulations for:	
- Fire Protection (10CFR50.48)	
- Environmental Qualification (10CFR50.49)	
- Pressurized Thermal Shock (10CFR50.61)	
- Anticipated Transients without Scram (10CFR50.62)	
- Station Blackout (10CFR50.63)	

associated with these failures were then determined. The review of industry-wide operating experience is contained in Section 3.7.

This multi-source analysis (i.e., using data from NPRDS and NRC documentation) 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 (see Section 4), the significance of each aging mechanism was determined. Those aging mechanisms that would result in a failure having an impact on equipment operation or functionality were designated as significant. Of the significant aging mechanisms identified, those which were observed in the plant operating history or were otherwise likely to occur were considered to be "significant and observed" aging mechanisms. Significant aging mechanisms are discussed in Section 4.2.1; significant and observed aging mechanisms are discussed in Section 4.2.2. Aging mechanisms designated nonsignificant are briefly discussed in Section 4.2.3.

Maintenance, inspection, testing, and surveillance techniques or programs used to manage aging of electrical cables and terminations are discussed in Section 5.2. A discussion of commonly used activities and techniques is provided in Section 5.3. A discussion of current programs that manage aging effects is included in Section 5.4.1. Potentially significant component/aging mechanism combinations not addressed by current programs are discussed in Section 5.4.2.

2.7 References

Note: For conciseness, the references in this report omit the location of major contributors to the literature. They are the Electric Power Research Institute in Palo Alto, CA, the Institute of Electrical and Electronics Engineers in New York, NY, the Nuclear Regulatory Commission in Washington, D.C., and Sandia National Laboratories in Albuquerque, NM.

2.1 EPRI TR-103841, "Low-Voltage Environmentally-Qualified Cable License Renewal Industry Report," prepared by Sandia National Laboratories and Strategic Technologies and Resources, Inc., Revision 1, July 1994.

2.2 SAND93-7046, "Aging Management Guideline for Commercial Nuclear Power Plants - Battery Chargers, Inverters and Uninterruptible Power Supplies," Sandia National Laboratories, February 1994.

2.3 SAND93-7071, "Aging Management Guideline for Commercial Nuclear Power Plants - Stationary Batteries," Sandia National Laboratories, March 1994.

2.4 SAND93-7070, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers," Sandia National Laboratories, June 1994.

2.5 SAND93-7069, "Aging Management Guideline for Commercial Nuclear Power Plants - Motor Control Centers," Sandia National Laboratories, February 1994.

2.6 SAND93-7045, "Aging Management Guideline for Commercial Nuclear Power Plants - Pumps," Sandia National Laboratories, March 1994.

2.7 SAND93-7027, "Aging Management Guideline for Commercial Nuclear Power Plants - Switchgear, Electrical," Sandia National Laboratories, July 1993.

2.8 SAND96-0343, "Aging Management Guideline for Commercial Nuclear Power Plants - Tanks and Pools," Sandia National Laboratories, March 1996.

2.9 SAND93-7068, "Aging Management Guideline for Commercial Nuclear Power Plants - Transformers, Power and Distribution," Sandia National Laboratories, May 1994.

2.10 Title 10, U.S. Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," published in the Federal Register, Vol. 56, December 13, 1991 (page 64943).

2.11 Title 10, U.S. Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," published in the Federal Register, Vol. 60, May 8, 1995 (page 22461).

2.12 Title 10, U.S. Code of Federal Regulations, Part 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," published in the Federal Register, Vol. 56, July 10, 1991 (page 31321) and Vol. 58, June 23, 1993 (page 33996).

2.13 EPRI TR-104063, "Evaluation of Environment Qualification Options and Costs for Electrical Equipment for a License Renewal Period for CCNPP," (Calvert Cliffs Nuclear Power Plant), Electric Power Research Institute, October 1994.

2.14 EPRI TR-100516, "Equipment Qualification Reference Manual," Electric Power Research Institute (EPRI), 1992.

3. EQUIPMENT EVALUATED

3.1 General

Electrical cable systems used in nuclear power plants consist of cables, terminations, and other associated components (such as cable trays, penetrations, and conduits) used to power, control, and monitor various types of electrical apparatus and instrumentation. The equipment covered by this guideline includes site low- and medium-voltage cables and their associated terminations. Cable trays, penetrations, conduits, and other ancillary equipment are not directly covered by this guideline; however, potential aging effects or interactions of these components with cables and terminations are discussed.

Specific nuclear plant cable system components[1] covered in this AMG include:

- Cables
- Panel and hookup wires
- Terminal blocks
- Compression and fusion fittings
- Splices
- Multi-pin, single-pin, plug-in, coaxial, and triaxial connectors.

Electrical cables and terminations (and their components) manufactured by numerous companies are installed in U.S. commercial nuclear plants. The cable and termination manufacturers identified during the preparation of this report are listed in Table 3-1. Other manufacturers' equipment may be installed in nuclear plants; however, the amount of such equipment is considered to be small. Aging mechanisms and aging management techniques described here may be applicable to an unlisted manufacturer's equipment because of similarities in cable system component design, construction, and materials.

Substantial consolidation has occurred within the cable industry since the construction of the earliest nuclear plants; consequently, many of the manufacturers listed here may no longer exist or produce cable. In addition, many product lines may have been discontinued or substantially modified; varying configurations of the same general product are common. No attempt was made to analyze specific formulations or product lines; rather, general material categories and component types were examined in this study.

When considering the aging management of cable systems installed at commercial nuclear power plants, several major subsets or categories of circuits can be defined based on factors such as the circuit's function, importance to plant safety or shutdown, or installed location(s). The categories of cables and terminations that must be evaluated to satisfy the requirements of 10CFR54 are as follows:

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[1] Terminal blocks, lugs, splices, seals, and connectors are all included within the designation "termination" for this AMG.

Table 3-1 Cable and Termination Manufacturers

Cables and Wire:

- American Insulated Wire (AIW)
- Anaconda
- Belden
- Bendix
- Boston Insulated Wire & Cable (BIW)
- Brand Rex
- Cerro
- Champlain
- Coleman
- Collyer
- Conax
- Continental (Cablec)
- Cyprus
- Delco-Link
- Eaton
- Ericsson
- Essex
- Galite
- General Cable
- General Electric (GE)
- Harbour Industries
- Hatfield
- ITT Surprenant
- Kerite
- Lewis Engineering
- National
- Okonite
- Omega
- Raychem
- Rockbestos
- Rome
- Samuel Moore
- Simplex

Terminations:

- Alpha
- AMP
- Amphenol
- Bendix
- Bishop
- Buchanan
- Conax
- EGS (Grayboot)
- ERD
- General Electric (GE)
- Kerite
- Kulka
- Litton-VEAM
- Marathon
- Moore
- Namco
- Okonite
- Patel Engineers
- Raychem
- Rosemount
- Scotch (3M)
- Sigmaform
- States
- Thomas and Betts
- Weidmuller
- Westinghouse

1. Safety-related cables and terminations

   Some cables may be used in circuits designated as "safety-related." Safety-related equipment is defined in 10CFR50.49 as those items designed to remain functional during and following design basis events to ensure: (1) the integrity of the reactor coolant boundary, or (2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to regulatory guidelines [per 10CFR50.49 Section (b)(1)]. Safety-related equipment may also require environmental qualification, depending on its location and function.

2. Nonsafety-related cables and terminations, if a failure of the component could prevent satisfactory accomplishment of a safety-related function

   A plant-specific evaluation is required to define this population of cables and terminations.

3. Nonsafety-related cables and terminations required to perform a function in safety analyses or plant evaluations that demonstrate compliance with NRC regulations for:

   - Fire protection (10CFR50.48)

   - Environmental qualification (EQ) (10CFR50.49)

     A significant portion of plant circuits may require environmental qualification in accordance with 10CFR50.49. EQ equipment must be able to perform its required safety function when subjected to harsh environmental conditions resulting from a postulated design basis event (DBE). The cable may be installed in either safety-related, nonsafety-related (that could affect plant safety), and/or post-accident monitoring circuits.

   - Pressurized thermal shock (10CFR50.61)

   - Anticipated transients without scram (ATWS) (10CFR50.62)

   - Station blackout (10CFR50.63).

Plant management may opt to include additional cables and terminations in the scope of an aging management program. Discretionary categories include:

- Cables and terminations important to continued plant operations

  Some circuits may be needed to support continuous, reliable power generation. For example, circuits associated with main turbine systems are neither EQ nor safety-related in most (if not all) plants. However, a failure in the main turbine system may result in a temporary or sustained loss of plant output. From an economic perspective, such cables and terminations are of paramount importance.

- All other cable

  Numerous cables and terminations are not included in the categories listed above. These items are included in circuits and systems whose failure would have little or no appreciable effect on plant safety, operation, or continuity of power. Plant lighting and certain communications systems are common examples of these types of circuits and systems.

3.1.1 Voltage Category

Cable systems contained within the classification of cable important to license renewal may also be categorized by the following voltage ranges:

- Low-voltage (≤1000 Vac, ≤250 Vdc)[2]

- Medium-voltage (2 kVac through 15 kVac)

- High-voltage (>15 kVac)[3]

It should be noted that these voltage ranges reflect cable voltage ratings and not normal operating voltages. The rated voltage of a circuit component represents the maximum voltage at which that component can be continuously operated. Generally speaking, the voltage rating of a nuclear power plant component is much greater than the operating voltage. For example:

Voltage Rating	Normal Operating Voltage
300-V	≤48 Vdc
600-V	≤120 Vac, ≤125Vdc
600-V and 1000-V	480 to 600 Vac
5-kV and 8-kV	4160 Vac
15-kV	13.8 kVac

Circuits falling within a voltage range can be further classified by their function as power, control, instrumentation, specialty, lighting, telephone, or security cable; see Section 3.3 for additional information on these classifications.

[2] As in the Low-Voltage, Environmentally-Qualified Cable Industry Report, the upper range of low-voltage is defined as 1000 Vac. Typically, cables are not rated between 1000 and 2000 Vac; however, the results for low-voltage cable are applicable up to 2000 Vac.

[3] High-voltage systems were not included in the scope of this document because: (1) they generally constitute an extremely small fraction of the total amount of cable at a plant, and (2) they are often highly specialized in construction (e.g., oil filled) so they have little in common with the more prevalent low- and medium-voltage systems.

Specialty applications (such as coaxial- or triaxial-type cables used in nuclear instruments) may use varying voltages, depending on their function. These systems typically operate below 2 kV and will therefore be discussed with the low-voltage systems.

Transient phenomena (such as electrical switching transients or lightning-induced surges) or circuit component testing may produce voltages substantially higher than normal operating voltage for short periods. However, these short duration events are not considered representative of the voltage stress normally applied to plant circuits.

Common nuclear plant operating voltages are 120 Vac, 480 Vac, 4160 Vac, and 13.8 kVac; and 24 Vdc, 48 Vdc, 125 Vdc, and 250 Vdc. These common voltage values will be used in this guideline; however, it should be recognized that other operating voltages (such as 525 Vac) may be used at some plants.

3.1.2 Environmental Qualification (EQ)

Long-term aging has been evaluated for those cables and terminations that have been environmentally qualified (EQ). This special category of equipment has been analyzed for material composition, ambient environmental conditions, and operating parameters so that a "qualified life" could be established. [Note: The term "qualified life" is defined in IEEE Standard 323-1974 [3.1] as "the period of time for which satisfactory performance can be demonstrated for a specific set of conditions." The definition was changed in the 1983 revision of IEEE Standard 323 to be "the period of time, prior to the start of a design basis event, for which equipment was demonstrated to meet the design requirement for the specified service conditions." The 1983 revision is not formally endorsed by the NRC, and the change in definition occurred after most qualifications were established for operating plants. In practical terms, there is little significance to this distinction.]

For most installed EQ cables and terminations, the qualified life is equal to or greater than the 40-year design life of the plant. There is no regulatory requirement for 40 years, or any other specific duration. The qualified life varied depending on whether the equipment was expected to meet the requirements of the DOR Guidelines [3.2], NUREG-0588 [3.3], or 10CFR50.49 [3.4]. The specific requirements of these regulations regarding EQ and aging are described in detail in Appendix C of this AMG.

Because the overall requirements for EQ were different in the three regulations, the specifics regarding aging and aging management also varied. The discussions about them (and several related industry standards and Regulatory Guides) in Appendix C can be summarized as follows:

- For cables qualified to the DOR Guidelines [3.2], the Owner must demonstrate a qualified life if the plant was already constructed and operating and cable materials susceptible to significant degradation due to thermal and radiation aging were used in the plant's construction. Maintenance or replacement schedules were to include consideration of the specific aging characteristics of the material(s), and continuing programs were to be established to review surveillance and maintenance records to ensure that equipment exhibiting age-related degradation was identified and replaced as necessary.

- Cables qualified to the requirements of NUREG-0588, Category II only, had to address aging only to the extent that equipment that is composed, in part, of material susceptible to aging effects should be identified and a schedule for periodically replacing the equipment and/or materials should be established.

- The qualification aging requirements for NUREG-0588, Category I and 10CFR50.49 plants were much more stringent.

Note that with respect to all of the qualification regulations described above, preaging prior to accident testing, material analysis with respect to thermal/radiation aging, qualified life determinations, and ongoing programs which review maintenance and surveillance records all constitute aging management activities that may be considered as part of the 10CFR54 aging management review.

3.2 Results of Methodology Used to Select Components Subject to License Renewal Review

For each plant entering license renewal, a review must be performed to identify electrical cables and terminations that are subject to an aging management review. Per paragraph 1 of Section 54.4 (scope of equipment subject to the license renewal rule) of 10CFR54 [3.5], all cable systems deemed safety-related are included. Paragraph 2 of the definition brings cable systems (such as those nonsafety-related systems that may prevent satisfactory accomplishment of the functions described in paragraph 1) into the scope. Paragraph 3, which addresses environmentally qualified equipment, pressurized thermal shock, and systems necessary to meet ATWS and station blackout requirements, adds additional cable systems to the list. Some circuits in the "important to continued plant operations" and the "all other cable" categories, although not subject to the license renewal rule by definition, may also be included in plant aging management programs if desired by each plant. Accordingly, all of the aforementioned categories of cable are addressed by this AMG.

3.3 Description of Components Evaluated

In addition to the sections that follow, see Appendix B of this guideline.

3.3.1 Electrical Cable and Wire

Nuclear generating stations may have thousands of miles and several hundred different types and sizes of electrical cable/wire. The majority of cables used in nuclear stations can be grouped into the following categories based on their application and design [3.6], [3.7]:

- Low-voltage power cable
- Medium-voltage power cable
- Control cable
- Panel and hookup wire
- Instrumentation cable

- Specialty cable
- Security cable
- Telephone cable
- Lighting cable
- Grounding cable

Low-Voltage Power Cable is used to supply power to low-voltage auxiliary devices such as motors (and motor control centers), heaters, and small distribution or lighting transformers. Single and multiple conductor configurations are used, usually unshielded.

Medium-Voltage Power Cable is used to supply power to larger loads and distribution centers such as reactor recirculation or service water pumps, load centers, transformers, or medium-voltage switchgear. Single and multiple conductor configurations are used, typically shielded at higher voltage ratings (i.e., 8 kV and above).

Control Cable is a type of low-voltage, low-ampacity cable used in control circuits for auxiliary components such as control switches, valve operators, control and protective relays, and contactors. Usually a multiple conductor configuration is used, with shielding for applications in proximity to high-voltage systems.

Panel and Hookup Wire is a type of low-voltage, small-gauge [synthetic thermosetting insulation for switchboard (SIS) or similar] single conductor wire commonly used inside electrical panels, motor control centers (MCCs), switchgear, motor-operated valves (MOVs), solenoid-operated valves (SOVs), or other enclosures.

Instrumentation Cable (Including Thermocouple Extension Wire) is a type of low-ampacity, low-voltage (typically less than 1000 V, with most rated at 300 V) cable used for digital or analog data transmission. Resistance temperature detectors (RTDs), pressure transducer circuits, and thermocouple extension leads usually use a twisted shielded pair configuration. Coaxial and triaxial configurations (shielded) are often used for radiation detection and neutron monitoring, or where other special requirements exist.

Specialty Cable is designed and fabricated for a specific application (e.g., combination instrumentation/power/control cable, mineral-insulated (MI) cable for high temperature applications, special fire-retardant cable).

Telephone Cable is a low-voltage (300 V), multiple-pair, small-gauge (20 to 24 AWG) cable used for connection of telephone or communications circuits. It is typically shielded and jacketed.

Security Cable is a low-voltage multi-conductor cable that is specially armored or encased to prevent cut-through.

Lighting Cable is used to supply low-voltage (120 to 277 V) power to plant lighting systems. A typical configuration includes multiple conductors which may be encased in a metallic sheath.

Grounding Cable is used to connect electrical equipment, including cable raceways and conduits, to the station ground. Size and configuration will vary depending on the application. Grounding cable is generally large gauge and may or may not be insulated.

Low-voltage power, control, and instrumentation cable collectively constitute the bulk of cable installed at a nuclear plant. Medium-voltage power cable is the next most populous type; however, it generally accounts for only a small percentage of the total number of circuits [3.8], [3.9]. The amounts of the remaining categories of cable are each generally very small in relation to the low- and medium-voltage types described above. Specialty cable such as that used for neutron monitoring systems or control rod drive position circuits may be relatively numerous; these are, for the most part, located within primary containment (although segments may be located outside of containment). Panel or SIS wire may exist in large quantities within MCCs, control boards, and switchgear. It is typically of single conductor configuration and unshielded, and used in low-voltage/low ampacity control applications.

Table 3-2 provides an illustration of the relative numbers of various types of circuits found at one nuclear plant (two units).[4]

Table 3-2 Relative Distribution of Circuit Types for One Nuclear Plant (2 Units)

Circuit Type	Approximate Number of Circuits
AC Power	6,580
DC Power	530
Control	31,500
Instrumentation	10,180
Communication	2,560
TOTAL[4]	51,350

Typical low-voltage power applications include valve operator and small pump and fan motors. Typical low-voltage instrumentation applications include thermocouples, RTDs, pressure transmitters, and nuclear instruments. The lengths of these circuits range from tens to thousands of feet, depending on the location of the loads with respect to the power supply. Most cables, however, are less than a thousand feet in total length. Medium-voltage cables are used in nuclear plants in the following applications:

[4] The approximate distribution of circuit types was obtained from a proprietary plant cable and raceway database. Note that not all circuits are necessarily included in this database; however, it is considered to be representative of the cable installed at this site.

- Auxiliary transformer primary and secondary feeders
- Connections between and feeders to medium-voltage buses
- Load center primary feeders
- Medium-voltage motor feeders
- Emergency diesel generator (EDG) power supplies

Safety-related circuits are often lightly loaded or de-energized, as the load supplied by these circuits are only in operation during abnormal plant conditions or surveillance testing. Conversely, nonsafety-related circuits (such as those serving the reactor coolant/recirculation pump or service water pump motors) may be continuously energized and loaded. Note that the safety significance of a circuit is not necessarily related to its importance to plant operation; a nonsafety-related circuit that serves a plant load important to continuous operation would fall into the category of "important to plant operation."

3.3.2 Terminations

Cable terminations may be grouped as follows:

- Compression connectors
- Fusion connectors
- Plug-in connectors
- Splice insulation systems (heat-shrink or tape)
- Terminal blocks.

Compression Connectors are physically crimped or mechanically swaged to conductors.

Fusion Connectors are welded, brazed, or soldered to conductors.

Plug-in Connectors have one or more electrical contacts that plug or screw into a mating receptacle. The junction between the conductor and connector is typically fused; however, any of the methods described in this section can be used. Plug-in connectors are usually used in instrumentation or data transmission applications, some motor-operated valves, control circuits, and limit switches.

Splice Insulation Systems (heat-shrink or tape) are used to environmentally seal cable or splice terminations or junctions. They are generally applied over a compression or fusion connection.

Terminal Blocks consist of an insulating base with fixed points for attaching wiring or terminal (ring) lugs. Terminal blocks are usually located within a device or electrical panel.

Compression fittings (such as ring lugs or barrels) are probably the most common type of termination; these devices are present in one form or another in many types of circuits and electrical components in the plant. Fusion connectors are mostly used on medium-voltage or high ampacity circuits where permanence of connection is desired. They are also commonly used with grounding cables. Splices are most often used to link specific segments of a field cable or to repair a failed section of cable. Connectors are used in applications where ease of separation of the termination is desired, for mating to specific types of equipment, or where multiple simultaneous electrical connections must be made (such as in multi-pin connectors used on instrumentation circuits). Connectors may also be used to seal electrical housings of associated equipment and to complete the seal of the cable jacketing system. Terminal blocks are used as electrical connection points within larger electrical components (such as MCCs, control boards, and motors). Note also that some of the terminations listed above may be used within other terminations [e.g., soldered (fusion) pins used within plug-in type connectors].

A multitude of different types of lugs, splices, and connectors may be in use in the typical nuclear plant. The design and sophistication of a given termination is related to its application, voltage and current rating, and expected environments. For dry environment, low-voltage applications, ring lugs and terminal blocks of simple construction may be used. For wet environments, heat shrinkable insulation or other moisture-retardant systems may be employed to provide protection from short circuits or low insulation resistance. In circuits potentially exposed to steam or water spray environments, splices are often used in place of traditional termination systems to provide protection to the conductors from accident environment conditions. Splices may be used to provide protection from shorting and low insulation-resistance conditions in such environments. For medium-voltage circuits, much more sophisticated terminations and splices must be made to preclude degradation from voltage stress and the formation of tracking paths in the vicinity of the termination due to the higher voltages employed.

3.4 Component Boundaries

Most cable, wire, and termination components, subject to the clarifications and limitations identified below, are included in the scope of this AMG. Cable raceways (including trays, conduits, and duct banks), support or restraint systems, or other ancillary cable system components are not within scope. The following clarifications apply:

1. Bulk wire installed in MCCs or control boards is covered by this AMG.

2. Cables and connectors associated with neutron monitors, radiation detectors, and position indicators for control rod drives are within scope.

Limitations are as follows:

1. Panel or local wire for major equipment is not included in the scope. Wiring internal to (or part of) individual devices, modules, or subcomponents is not within scope because it may have special applications or conditions within the devices.

2. Containment electrical penetration leads are not within scope.

3. Cables and connectors that are internal to or originate in discrete electrical devices (such as ribbon cable used in amplifier drawers, plotters, etc., and circuit card connectors) are not within scope.

4. Motor leads (commonly called pigtails) are not within scope; however, splices or terminations to those leads are within scope.

Figure 3-1 is a schematic representation of medium-voltage cable systems which identifies the boundary between this AMG's included and excluded scope. A similar figure is not needed for low-voltage circuits because all are included in the scope of this AMG, except as noted above.

3.5 Listing of Components Evaluated

Each electrical cable or connection can consist of many different parts or subcomponents.

3.5.1 Cable (Including Wire)

Four (4) cable applications[5] and the associated subcomponents have been evaluated in this guideline:

1. Medium-Voltage Power

   - Conductor
   - Semiconducting or nonconducting shield
   - Electrical insulation or dielectric[6]
   - Filler material
   - Tape wrap
   - Shielding (including drain wire and semiconducting layers)
   - Outer jacketing
   - Armor or sheath

2. Low-Voltage Power or Control

   - Conductor
   - Electrical insulation or dielectric
   - Conductor jacketing
   - Filler material
   - Tape wrap
   - Shielding (including drain wire)
   - Outer jacketing

[5] Note that lighting, security, specialty, communications, and grounding cable use components similar or identical to these four (4) applications.

[6] The terms "insulation" and "dielectric" are often used interchangeably. Some manufacturers routinely use the latter term when referring to cable components that are used for functions other than strict electrical isolation (e.g., signal transmission in a coaxial/triaxial cable).

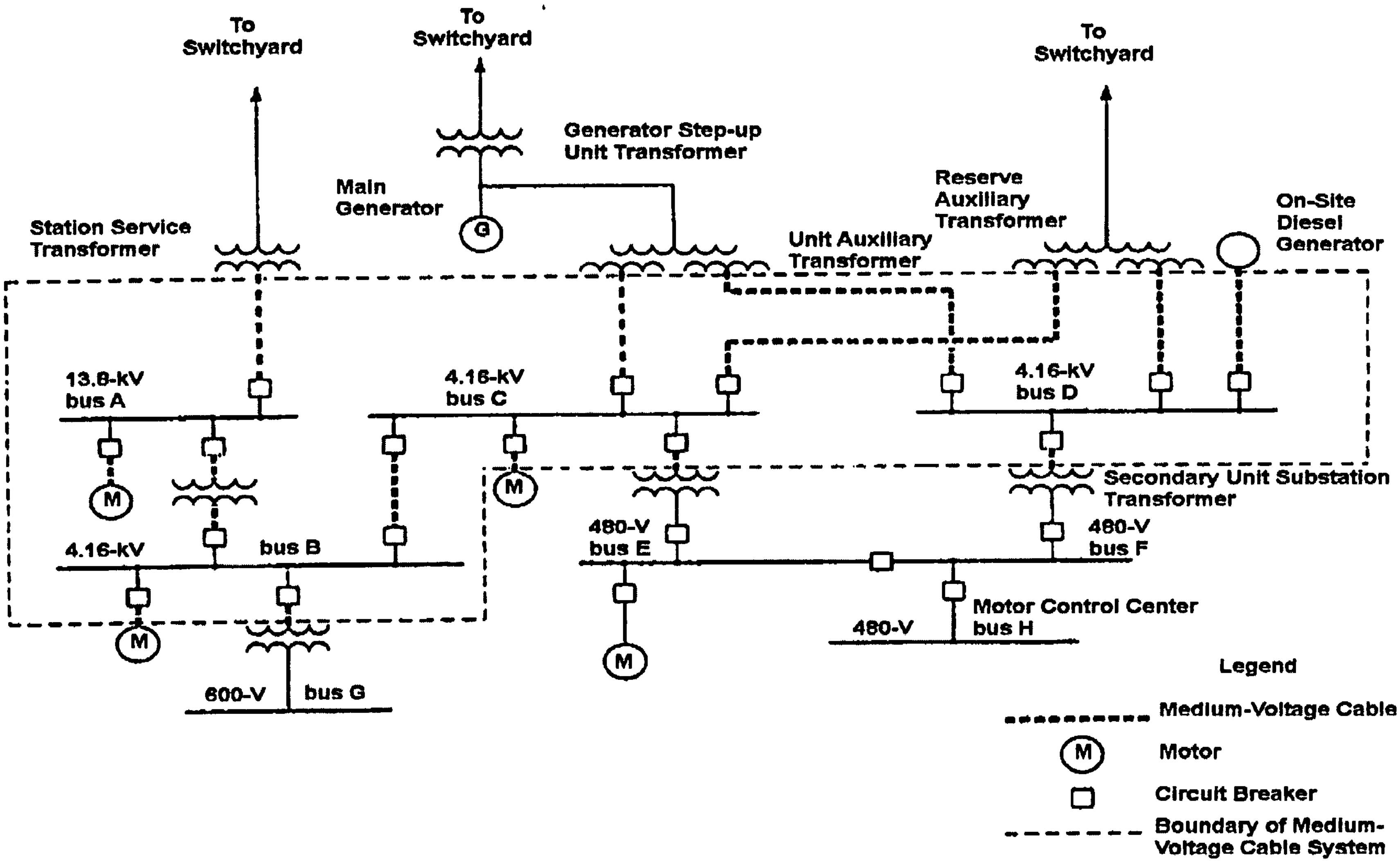

Figure 3-1 Component Boundaries of Medium-Voltage Systems

3. Low-Voltage Instrumentation (Coaxial or Triaxial)

- Conductor
- Insulation
- Dielectric
- Shielding
- Outer jacketing

4. Low-Voltage Instrumentation (Twisted-Shielded)

- Conductor
- Electrical insulation or dielectric
- Conductor jacketing
- Shielding (including drain wire)
- Outer jacketing

3.5.2 Terminations (Including Splices, Connectors, Lugs, and Terminal Blocks)

Subcomponents common to termination devices are listed below. Note that not all subcomponents are necessarily present in each termination device:

1. Compression Fittings

- Crimped lug or barrel
- Mechanical clamp (compression) mechanism

2. Fusion Fittings

- Fusion lug (welded or brazed to conductor)
- Inhibitor compound (aluminum conductors only)

3. Plug-in Connectors

- Electrical contacts (such as blades or pins)
- Electrical terminations (including soldered joints and internal terminations)
- Dielectric
- Backshell housing
- Cable clamp or other fastening mechanism
- O-rings or other environmental seals
- Coupling mechanism (i.e., retaining screws, threaded spool, snap-in housing)
- Thread sealant

4. Splice Insulation Systems

- Heat shrink
- Tape wrap
- Potting compound
- Stress cone or other voltage stress relief mechanism (shielded cable only)

5. Terminal Blocks

   - Terminal block base (dielectric)
   - Terminal hardware (such as posts, nuts, or sliding links)
   - Mounting system
   - Auxiliary components, including covers and fuse holders (optional).

3.6 Analysis of EPRI NUS Cable Database for Environmentally Qualified Cable

The EPRI NUS Cable Database is a computer-based listing of environmentally qualified cables installed in EPRI-member nuclear power plants. The database used for this task, dated April 1993, covers 67 plant sites and 101 units. Currently, there are 6 plant sites (12 units) in operation that are not included in this survey. A few units included in the database have since ceased operations.

Selected information, including plant name, manufacturer, model/type, and references, was extracted from the EPRI NUS Database. Each entry was then categorized as being either a cable, splice and/or termination, or "other" device.[7] Nonrelevant references were deleted from the entries for conciseness, and identical references were retitled to ensure common titling of all reports for sorting purposes. The scheduled commercial date of operation for each plant was added, with the purpose of identifying the range of dates during which cables were purchased and/or installed. The electrical cable listing consisted of 1660 entries; it represents 53 cable manufacturers, along with several cable types of unknown manufacture.

The database seeks to identify and provide relevant information (such as insulation/jacket material and construction) for the various cable configurations installed in EQ applications in participating plants. It may be used to generally characterize industry EQ cable as a whole because (1) most U.S. nuclear units are represented in the database (approximately 89%), and (2) those units participating are considered to have included information on the most numerically predominant types of cable installed in their plants. However, significant variance in the amount of information provided to EPRI from various reporting utilities was noted during the analysis. Examination of the data indicates that not all types of cable used in EQ applications were reported for all participating plants. In addition, the significance of each entry remains somewhat in question, as several instances of seemingly identical entries for the same unit were noted. Hence, no correlation could be made between each entry and a unique cable configuration; the entries can be differentiated by general cable type only.

With one or two exceptions, the analyses of the EPRI NUS Database discussed in the following sections of this AMG are considered generally applicable to both EQ and non-EQ circuits, based on the assumption that the same types and configurations of cable are used in both types of applications at most plants. This assumption is predicated on the fact that most plant operators originally sought to (and continue to) simplify their cable procurement specifications and maintain greater control over their warehouse inventories. Cables suitable for EQ applications were and are routinely used in other types of applications; hence, no advantage

[7] "Other" devices included area radiation monitors, transmitters, thermocouples, and nuclear instruments that are not considered to be within the scope of this AMG.

results from maintaining multiple different types of cable either during construction or for subsequent circuit replacement. Many plant operators now try to avoid the problem by maintaining only a few (or only one) brands or types of cable available for installation in any class of circuit. The most significant exception to this observation is the use of polyvinyl chloride (PVC-) insulated cable and wire. Although PVC-insulated cables were rarely used by the industry in EQ applications, PVC-insulated cable is used widely in non-EQ circuits in many plants.

It should be noted, however, that the various types of cable within a given plant may vary significantly from those listed in the tables below. For example, one pressurized water reactor (PWR) operator contacted as part of the study indicated that a very large fraction (more than half) of its installed cable was insulated with silicone rubber which, per Table 3-4, should account for only about 5% of the cable in the typical plant.

3.6.1 Manufacturer Sort

Electrical cable entries contained in the database were initially sorted by manufacturer to determine the predominant vendors. The results were tabulated in Table 3-3 and identify the number of types of cable in service or purchased from each manufacturer, the number of units where each cable is installed, and a ranking of the 10 most frequently represented cable companies by the number of cable types procured. As shown in the table, entries for Okonite cable were most numerous (359), followed by those for Rockbestos (316)[8] and BIW (150). Rockbestos cables were procured by the most units (78), followed by Okonite (77) and BIW (68). Collectively, these three manufacturers account for approximately 50% of all entries in the database. Also, entries for both Okonite and Rockbestos are more than double those of the third most numerous cable manufacturer (BIW). BIW cables, however, have been procured for nearly as many individual plants as those made by either Okonite or Rockbestos.

3.6.2 Insulation Sort

A third sort of the database was conducted based on the model/type field of the electrical cables. A majority of the entries (1215 of 1660 entries, or approximately 74%) listed the insulation material used on the cable being described. The most numerous insulation materials, trade names, or generic names listed in the database were the following (in alphabetical order): Bostrad, cross-linked polyethylene/polyolefin (XLPE/XLPO), ethylene propylene rubber (EPR), Firewall III, Flamtrol, flame retardant (FR), high-temperature Kerite (HTK), Okonite, polyethylene (PE), silicone rubber (SR), and Tefzel®.

[8] If the entries for Cerro Wire & Cable are added, Rockbestos is the most numerous.

Table 3-3 Manufacturers Listed in EPRI NUS Cable Database

Manufacturer	No. of Database Entries	Rank
Okonite	359	1
Rockbestos	316	2
Boston Insulated Wire & Cable Company (BIW)	150	3
Anaconda Wire and Cable	128	4
Kerite Company	109	5
Brand-Rex	98	6
Samuel Moore	77	7
General Electric (GE)	69	8
Cerro Wire & Cable Company (Rockbestos)	47	9
Raychem	46	10
Continental Wire & Cable Corporation	37	
American Insulated Wire (AIW)	19	
General Cable	18	
Essex Wire Corporation	17	
Rome Cable Corporation	16	
Collyer Insulated Wire & Cable	12	
Cyprus Wire & Cable	11	
Simplex Wire & Cable Company	11	
Eaton	10	
Conax	8	
ITT Surprenant	8	
Champlain Cable	6	
Belden Corporation	5	
Galite	3	
Lewis	3	
Bendix Corporation	2	
Hatfield Electronics	2	
Coleman Industries	1	
National Wire & Cable Corporation	1	
Tensolite	1	
TOTAL	1,590	

Table 3-4 lists both specific materials and manufacturer's trade names or product lines; hence, some additional investigation was required to determine the generic material in many cases (for example, Rockbestos Firewall III insulation can be categorized as a cross-linked polyethylene). Manufacturers' literature, catalogs, and environmental qualification test reports were used as the primary references for determining the generic material categories of insulations identified by trade name/product line. For some entries (such as those for cables insulated with Kerite HTK), even the dominant polymer used in the insulation is proprietary and not readily obtainable. Therefore, these materials could not be included within any of the other existing generic material categories, and were maintained as their own categories.

A total of 17 different types of generic insulation material categories were identified. Table 3-4 shows the various material categories identified in the database.

Table 3-4 Insulation Materials Listed in EPRI NUS Cable Database

Insulation Material	No. of Database Entries	% of Total
BR, butyl rubber	20	1.6
CSPE, chlorosulfonated polyethylene	28	2.3
EPR, ethylene propylene rubber	434	35.5
ETFE, ethylene tetrafluoroethylene	39	3.2
FR, flame retardant	36	2.9
Industrite	2	<1.0
Kerite	61	5.0
Mineral	12	1.0
Neoprene®	2	<1.0
PE, polyethylene	52	4.3
Polyimide	8	<1.0
Polypropylene	3	<1.0
PVC, polyvinyl chloride	12	1.0
SR, silicone rubber	63	5.2
Styrene	1	<1.0
XLN, cross-linked Neoprene®	3	<1.0
XLPE, cross-linked polyethylene	439	35.9
TOTAL	1,215	

3.6.3 Cable Size Sort

It was noted during analysis of the database that some entries contained information regarding the size/configuration of cables installed. With very few exceptions, these entries were limited to those not containing insulation/jacket material information (i.e., either insulation/jacket information or size information was present, but generally not both). All entries listed ranged from one conductor to 27 conductors, from #22 American Wire Gauge (AWG) to 500 thousand circular mils (MCM), and varied in voltage rating between 300 V and 5 kV. As in the insulation materials sort, most of the items in this listing were manufactured by the 10 major cable vendors previously identified. Most of the entries with size/configuration information were derived from a comparatively small number of plants; this appears to be an artifact of the way in which data were recorded by a particular utility and/or entered into the database.[9]

3.6.4 Splice Insulation Database

The only splice-producing manufacturer currently listed in the EPRI NUS Database is Raychem. There were six Conax seals listed and these are all at one nuclear power plant; however, these types of devices are not within the scope of this guideline.[10] The remaining splice-related entries (which number more than 100) all describe Raychem splice insulation. Other common nuclear plant splice manufacturers (such as Okonite, Scotch, and Kerite, which produce tape splice kits) were identified during the preparation of this AMG; however, none of these splices were noted and/or included in the database by the contributing plant(s). Although ostensibly based on a large percentage of the plant population, these results are not considered wholly representative based on information received directly from various plants contacted as part of this study. The other types of tape splices listed above, although not qualified by the manufacturer or maintained as part of a 10CFR50, Appendix B quality program, have nonetheless been tested and qualified by various utilities. These tape splices are known to be in use today. In addition, Conax seals are known to be used in more than the one plant indicated by the database. The reasons for the seeming disparity between the database and actual practice are unknown.

3.6.5 Conclusions Regarding EPRI NUS Database

Analyses of the data in the EPRI NUS Database indicate the following about cable used in nuclear plants:

1. **Insulation Types.** Approximately 36% (by number of entries) of all EQ insulations are XLPE/XLPO and 36% are EPR [including EP and ethylene propylene diene monomer (EPDM)]. The third largest category, silicone rubber, is only 5% of the

[9] As an alternative, the cable database for one nuclear plant was examined in an attempt to obtain more information on the typical cable size distribution. Unfortunately, this database did not identify the size of each cable separately, making the task of determining the relative amounts of each size/configuration of cable infeasible for this study.

[10] "Seals" of the type listed in the database are a distinct category of device not considered to fall within the definition of a cable, termination, or splice.

entries listed. Therefore, the remaining 23% of entries with identified insulation materials are distributed among 17 different generic insulation compounds, revealing that EQ cables are predominantly insulated with either XLPE or EPR. Because these results are assumed to be generally applicable to non-EQ cable, it can be inferred that a significant amount of the non-PVC, non-EQ cable installed in U.S. nuclear plants uses either XLPE or EPR insulation.

2. **Manufacturer.** Okonite appears to be the most commonly installed EQ cable, followed by that made by Rockbestos and BIW.

3.7 Operating and Service History

U.S. Nuclear Regulatory Commission Information Notices, Circulars, Generic Letters, and Bulletins were reviewed to determine the industry-wide operating experience with cable and terminations. Each applicable Information Notice, Circular, Letter, Bulletin, and safety evaluation report (SER) is discussed in Section 3.7.1. Some documents that pertained to cable and terminations were not considered applicable to this report (for example, failures resulting from improper design).

Cable and termination data derived from the Institute for Nuclear Power Operation (INPO) Nuclear Plant Reliability Data System (NPRDS) and NRC Licensee Event Reports (LERs) were also reviewed. Component failures described in these sources were analyzed to identify significant cable system failure mechanisms and their relative likelihood of occurrence. These analyses are discussed in Sections 3.7.2 and 3.7.3, respectively.

Finally, industry studies and literature were searched for applicable documents relating to cable and termination operating history and failures. Materials identified during this search are discussed in Section 3.7.5.

3.7.1 Industry-Wide Operating Experience with Components; NRC Documentation

The following subsections discuss various NRC documents applicable to the failure or aging of electrical cable and terminations. Note that several other NRC documents relating to cable and terminations were located; however, these were not considered relevant to component aging and are therefore not discussed further.

The following NRC documents are discussed:

- Information Notices 93-33 and 92-81
- Information Notice 92-01
- Information Notice 89-30
- Information Notice 87-52
- Information Notice 86-71
- Information Notice 86-49
- Information Notice 82-03
- Information Notice 80-08
- Circular 77-06

NRC Information Notices 93-33, "Potential Deficiency of Certain Class 1E Instrumentation and Control Cables" [3.10] and 92-81, "Potential Deficiency of Electrical Cables with Bonded Hypalon Jackets" [3.11]

IN 92-81 [3.11] describes failures of cables containing ethylene propylene rubber (EPR) insulation and bonded Hypalon® (CSPE) jackets, which occurred in qualification research testing reported in NUREG/CR-5772, "Aging, Condition Monitoring, and Loss-of-Coolant Accident (LOCA) Tests of Class 1E Electrical Cables" [3.12], and NUREG/CR-6095, "Aging, Loss-of-Coolant Accident (LOCA), and High Potential Testing of Damaged Cables" [3.13]. IN 93-33 [3.10] reported additional functional failures and low insulation-resistance values for cables in the NUREG/CR-5772 test program.

The program reported in NUREG/CR-5772 had two objectives: (1) determination of the long-term degradation behavior of typical instrumentation and control cables used in nuclear power plant applications, and (2) determination of the potential for assessment of residual cable life using condition monitoring (CM) techniques. Accelerated thermal and radiation aging was performed simultaneously at low rates (~100°C and ~100 Gy/hr [10 krad/hr]) during 3-, 6-, and 9-month periods to achieve an equivalency to 55°C for 20, 40, and 60 years, respectively (based on an activation energy of 1.15 eV). Radiation doses were 200, 400, and 600 kGy [20, 40, and 60 Mrad], respectively. The cables were then exposed to accident radiation (1.1 MGy [110 Mrad] at 6 kGy/hr [600 krad/hr]) and LOCA testing.

The objectives of the test program described in NUREG/CR-6095 [3.13] were to determine the effects of dielectric withstand voltage testing on cables and to assess functionality and survivability under LOCA conditions of radiation aged and thermally aged cables with simulated maintenance/installation damage. Testing for this program consisted of the evaluation of unaged and undamaged cable specimens to identify any damaging effects associated with high-potential (hi-pot) testing, and the aging and accident testing of damaged[11] cable specimens; a determination of the hi-pot voltage necessary to indicate impending cable failure was also included as part of this phase. The testing involved irradiation to a total integrated dose (TID) of 1.3 MGy [130 Mrad] at 3 kGy/hr [300 krad/hr], followed by thermal aging at 158°C for 336 hr[12] and LOCA steam simulation.

Bonded Jacket Failures

In the NUREG/CR-5772 test program [3.12], five cable types in the test had insulation and jackets on individual conductors. Of these, the individual jackets on two of the cable types were thought to be not bonded or very lightly bonded (probably not coextruded). Three of the cable types had bonded jackets. During the tests, some of the bonded jacket cables failed. The tested Okonite cable (1/C #12 AWG, 15 mils Okolon over 30 mils EPR) had one failure noted for a specimen aged to 60-years equivalent. Three failures also

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[11] "Damaged" specimens were those with their insulation/jacket intentionally reduced in thickness to simulate the effects of damage during maintenance or installation.

[12] 158°C was chosen to provide the equivalent of 60 years at 65°C for a material with an activation energy of 1.00 eV, based on an aging time of 2 weeks (336 hr).

occurred in the Sandia test program for Samuel Moore Dekoron Dekorad cable with composite EPR/CSPE insulation/jacket.

The other failures listed in NUREG/CR-5772, and described in IN 93-33 [3.10], were of a Rockbestos Firewall III irradiation crosslinked polyethylene (XLPE) insulated conductor aged to a 60-year equivalent, and three Kapton®-insulated wires aged to 20-, 40-, and 60-years equivalent, respectively. There is no indication that the Rockbestos XLPE failure was a jacket-insulation interaction (only a 45-mil Neoprene® overall jacket was present), and *may* be considered a "random" failure.[13] Sandia noted that the most probable cause of failures for the Kapton®-insulated wires was handling damage for two of the specimens, and damage in the vicinity of the chamber penetration for another specimen (which also may have been from handling or installation). As evidenced by the EPRI NUS Database, very little Kapton® insulation exists in bulk cable runs; however, this type of wire is used in various other plant components such as penetrations and seals. EPRI Report NP-7189 [3.14] and NRC IN 88-89 [3.15] provide additional information on Kapton®-insulated wire.

Three cable types were included in the NUREG/CR-6095 tests [3.13]: (1) Okonite Okolon #12 AWG (30-mil EPR/15-mil CSPE bonded jacket); (2) Rockbestos silicone rubber (30 mils) #16 AWG; and (3) Brand Rex XLPE (30 mils) #12 AWG. Results of this testing indicated some jacket (and, in certain cases, insulation) circumferential cracking of the Okonite specimens after aging and irradiation. After the LOCA simulation, all of the Okonite specimens displayed severe damage (including splitting and longitudinal cracking and exposed conductors). All ten Okonite specimens failed the LOCA testing. It is unclear whether the circumferential cracking experienced after aging participated in any way in the longitudinal splitting observed after the LOCA testing.

The Sandia tests indicate a possibility of interactions between the individual conductor jacket and insulation. The failures of one type of specimen indicate that a failure mode exists at some given aging level for this cable that results in longitudinal splitting of the conductor jacket/insulation system after exposure to accident steam conditions. The longitudinal splitting observed may be precipitated by swelling of the EPR under irradiation/high temperature thermal exposure, which produces a rupture of the bonded jacket. This failure mode seems to be just beginning on the 60-year (equivalent) aged Okonite specimens under the test conditions of NUREG/CR-5772, yet has progressed completely under the NUREG/CR-6095 test conditions. Note that the differences in the test conditions include a different aging temperature (100°C versus 158°C), a different aging sequence (simultaneous thermal and radiation aging followed by accident radiation exposure versus total accident plus aging dose followed by thermal aging), and dose rates (100 Gy/hr [10 krad/hr] versus 3,000 Gy/hr [300 krad/hr]). The disparity in results between the two programs can be attributed to one or more of these differences.

Bonding of the individual conductor jacket to the insulation may tend to localize tensile stress on the surface of the insulation. As the tensile stress on the jacket reaches a value sufficient to induce rupture of the jacket, the failure of the jacket may produce tearing on

[13] Only one failure was noted for six Firewall III specimens tested.

the surface of the insulation to which it is bonded because the tensile stress is now applied primarily to the surface of the insulation, and is focused in the area of the jacket rupture. One implication of the Sandia results is that a jacket composed of less aging-resistant material that is bonded to the underlying insulation may fail due to cracking before an unbonded or even unjacketed conductor. No qualification testing of this size and configuration of bonded EPR/CSPE low-voltage cable was performed by Okonite; hence, the existence of bonded jacket interactive mechanisms cannot be directly refuted.

Conclusions

Although the results of the testing described in NUREG/CR-6095 initially indicated potentially severe problems with aged, bonded jacket/insulation systems under accident conditions, further examination of the aging and test conditions shows that the failures of the cables tested can be attributed to the severity of the test regimen. The aging temperature of 158°C and aging dose of 1.3 MGy [130 Mrad] are comparatively high, and the aging sequence used during the NUREG/CR-6095 testing was one that is known to produce rapid degradation of EPR compounds. This adds further support to the proposition that the aging regimen applied by Sandia may have induced physical phenomena within the materials which would not otherwise occur under actual plant aging/accident conditions (i.e., exposure to full aging and accident doses followed by thermal aging and subsequent LOCA is not a situation that could realistically occur in any plant). Although the aging temperature and total dose of the NUREG/CR-5772 program were substantially lower (100°C and 0.6 MGy [60 Mrad] maximum, respectively), the lower dose rate used (approximately 100 Gy/hr [10 krad/hr]) is one at which significant dose rate phenomena have been observed for EPR [3.16], [3.17]. In addition, the 0.6 MGy [60 Mrad] aging dose applied to the 60-year specimens (the group in which the only bonded jacket conductor failure occurred) is somewhat higher than that which would be experienced at most plants, even inside primary containment. However, the NUREG/CR-5772 results may be conservatively interpreted to indicate that some effect due to interaction of the bonded jacket and insulation may occur at levels of aging anticipated to occur beyond the original 40-year operating period. Current data suggest that additional research and evaluations may be warranted for use of bonded-jacket cables that are exposed to aging conditions that may promote jacket cracking. This is particularly important if the cable test specimens were not representative of the installed bonded-jacket cables.

<u>NRC Information Notice 92-01, "Cable Damage Caused by Inadequate Cable Installation Procedures and Controls" [3.18]</u>

IN 92-01 describes cable damage caused by improper cable installation techniques at one Tennessee Valley Authority (TVA) nuclear plant. Specifically, cable was removed from conduit to inspect for damage thought to have occurred as a result of welding in the area. Inspection of the removed cable revealed damage (some of the cable had exposed conductors) that was not attributable to the welding activities. Further analysis of the cable indicated that this damage was the result of cable pull-bys, an installation practice by which cable is installed in conduit over the top or beside existing cable.

This Information Notice is significant because damage to cables occurring as a result of the installation process may ultimately produce failure of the cable under either normal or accident service environments. Installation damage, although not an aging mechanism, can dramatically affect the longevity of a cable.

NRC Information Notice 89-30, "Excessive Drywell Temperatures" [3.19]

IN 89-30 discusses the effects of localized high temperatures on safety systems and related equipment that may have an impact on the service temperature basis used to establish the thermal aging life of installed EQ equipment. The Information Notice describes events at various boiling water reactor (BWR) plants which resulted in elevated drywell temperatures and degradation of various components including electrical cable. Relevant conclusions of the Information Notice state that (1) BWRs routinely operate at or near their drywell EQ temperature limit, (2) substantial temperature gradients may exist in these drywells, and (3) the drywell head region (i.e., upper elevations) is most susceptible to high temperature. These conclusions are applicable to drywell cable and termination aging in that high general area temperatures within the drywell will age organic insulation materials at an accelerated rate.

NRC Information Notice 87-52, "Insulation Breakdown of Silicone Rubber-Insulated Single Conductor Cables During High Potential Testing" [3.8]

IN 87-52 discusses the high-potential testing of low-voltage No. 14 AWG silicone rubber-insulated cable at one nuclear plant. This testing was initiated in response to concerns raised regarding the installation of the cables (specifically, that some may have been damaged during receipt, storage, or installation, and that this damage may have reduced the dielectric strength of the insulation) and a lack of vertical support. Silicone rubber cables from three separate manufacturers (including AIW and Rockbestos) were installed in the plant. Six silicone cables (16 conductors, normally energized at 125 Vdc) were tested at 10,800 V to address the vertical support issue. Three of the six cables experienced breakdown (the lowest at 7500 V) and one had a low polarization index. Additional cables were then hi-pot tested; a total of 9 failures occurred out of 91 conductors tested.

Subsequent investigation of the first six silicone-insulated cables tested showed no evidence of external damage to the cable outer braid. However, laboratory analysis showed that the insulation for each cable was cut (presumably by the conductor) at localized points on the inside of the insulation surface; these points tended to coincide with one another along the length of the cable. The lowest remaining insulation thickness found in these locations was 8 mils. This indicated a lateral or side impact to the cable prior to installation, such as having a heavy object dropped on or rolled over the cables while they were laid out, rather than pulling damage or lack of vertical support. The AIW cable was found to be particularly soft and had a low impact strength, and six of the nine cables which failed testing were made by AIW. All of the AIW cables were eventually replaced.

The utility also performed subsequent qualification (LOCA) testing on specimens with intentionally reduced insulation thickness. Specimens with as little as 4 mils of remaining insulation were shown to pass mandrel bend and hi-pot testing following the aging and LOCA exposure.

NRC Information Notice 86-71, "Recent Identified Problems with Limitorque Motor Operators" [3.9]

IN 86-71 discusses the aging of electrical wiring inside Limitorque motor operators caused by localized high temperatures. This aging resulted from improper energization of space heaters inside the limit switch compartments; these heaters were intended for energization during storage only to prevent the accumulation of moisture.

NRC Information Notice 86-49, "Age/Environment Induced Electrical Cable Failure" [3.20]

IN 86-49 discusses age/environmentally induced failure of electrical cables caused by localized high temperatures. The Information Notice describes the importance of periodic inspection and walkdowns of cable systems to identify environmental conditions that may adversely affect their longevity or function. In addition, the need for a comprehensive maintenance and surveillance program for medium-voltage cable is identified.

NRC Information Notice 82-03, "Environmental Tests of Electrical Terminal Blocks" [3.21]

This Information Notice published the results of a test conducted to investigate the deterioration of terminal blocks' insulators under accident conditions. The Information Notice describes the importance of clean terminations and terminal blocks in safety-related circuits and discusses regulations for establishing appropriate procedures to ensure cleanliness and installation integrity of these devices. Licensees are reminded that the plant preventive maintenance program in use at their facilities should ensure that (1) proper operation of all essential components is achieved throughout the life of the plant and that (2) terminations and terminal blocks are periodically inspected for cleanliness and installation integrity following any maintenance activity affecting them.

NRC Information Notice 80-08, "The States Company Sliding Link Electrical Terminal Block" [3.22]

This Information Notice discusses defects with States Company sliding-link terminal blocks relating to cracking between the threaded screw hole and the side of the U-shaped link. This crack widens when the screw is tightened, resulting in a poor or intermittent electrical connection. The defective link is impossible to cinch tightly and may be difficult to detect by visual inspection. This defective mechanical connection can ultimately result in an electrical circuit malfunction.

NRC IE Circular 77-06, "Effects of Hydraulic Fluid on Electrical Cables" [3.23]

This Circular documents the effects of exposing various low-voltage power, instrumentation, and control cables to phosphate-ester electro-hydraulic control (EHC) fluid at one nuclear plant. The fluid, which had been leaking from a piece of plant equipment, had migrated into nearby cable pans and resulted in swelling and plasticization of the outer jacket of the cable. All cables were jacketed with PVC (a material that is highly susceptible to degradation by esters), and were insulated with either polyethylene or butyl rubber. An inspection of the cables revealed that only the PVC jacket was plasticized.

Although not considered a common occurrence, exposure of cables and terminations to chemical substances and foreign materials has been documented at several plants, and can result in degradation of the component's performance and functionality. These effects are generally localized.

3.7.2 Evaluation of NPRDS Data

To substantiate the postulated stressors and aging mechanisms for electrical cable and terminations, plant component failure data were reviewed. One of the primary sources of this type of failure data is the INPO NPRDS. Failure records contained in the NPRDS include such information as the voltage rating, type of equipment, date of discovery, cause category, and a brief narrative describing the event.[14] NPRDS data are not focused directly on component aging, as NPRDS does not necessarily address the root cause or mechanism of component degradation. In addition, 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. Furthermore, cables and terminations are not uniquely classified or categorized within the database. As a result of these limitations, the database is not well suited to providing probabilistic information about the reliability of a specific population of cable and/or termination components with respect to age-related degradation. However, the data can be used to identify those cable and termination components that have a high incidence of degradation or failure relative to other components, as well as types of applications and environments which are conducive to degradation or failure.

The NPRDS database was searched by using keywords in the narratives. This method was chosen because, as previously stated, no separate classification or descriptive category for "cable" or "terminations" was included in the NPRDS system, and many cable or termination failures are reflected in reports regarding the connected load or intervening device (such as motors or electrical switchgear) rather than the circuit component itself. Hence, extremely broad limits were set on the search to ensure that as many pertinent reports as possible were identified. Keywords used in the narrative search included "wir(e)", "cabl(e)," "term(ination)," "conn(ector)", and "splic(e)."[15] This search generated 5260 potentially applicable reports, whose event dates ranged from November 1975 through mid-1994. Data pertinent to cable and termination component failures were identified; those pertaining to equipment not within scope (such as wiring failures at the component or subcomponent level) were deleted. The remaining reports were then individually evaluated to determine their applicability to aging and aging mechanisms.

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[14] The cable or termination manufacturer was identified in only a few instances.

[15] The more general forms of these words were used as database search keywords to avoid excluding related reports. For example, if the word "wire" were used as a keyword, reports containing the word "wiring" (as opposed to wire) would be excluded.

Based on analysis of the NPRDS data, a total of 1458 reports applicable to low- and medium-voltage cable and termination failure were identified. Table 3-5 presents a summary of the NPRDS failure data, and shows the distribution of failure reports within each voltage category. Components related to "high voltage" neutron monitoring systems were included in a separate category due to their significant differences from other cable types and applications.

Table 3-5 Summary of NPRDS Failure Data

Voltage Range	Component	Number of Failures[1]	Percentage of Total[2]
Low (Max. 1000 Vac)	Cable	150	14.5
	Connector	314	30.3
	Compression/Fusion Fitting	132	12.8
	Hookup and Panel Wire	377	36.4
	Terminal Block	36	3.5
	Splice/Insulation	26	2.5
	Total	1,035	100.0
Medium (Max. 15 kVac)	Cable	24	68.6
	Connector	4	11.4
	Splice/Insulation	6	17.1
	Compression/Fusion Fitting	1	2.9
	Total	35	100.0
Medium (Neutron Monitor; 1 kV to 5 kV)	Connector	321	82.7
	Cable	67	17.3
	Total	388	100.0
	TOTAL	1,458	

Notes: 1. Number of failures does not include those attributed to maintenance or other personnel error.
2. Percentages shown are rounded to nearest tenth of 1 percent.

Many of the reports reviewed in this analysis required a substantial degree of interpretation; incomplete and even contradictory descriptions of the circumstances surrounding the failure were sometimes noted. Such reports were estimated to comprise roughly 20% of the total number. In cases where the ambiguity could not be resolved with any degree of certainty, the report in question was not used. Due to the uncertainty inherent in some of the data, the relative proportions of various types of failures may differ somewhat from the "actual" values; this potential error was assumed to be evenly distributed (that is, reports erroneously attributed were assumed not to affect one component, failure mode, or failure cause grouping disproportionately in relation to another).

As previously discussed, one type or category of termination may be included as a subcomponent of another type of termination; for example, a compression fitting may be used inside a multi-pin connector, and so forth. In such cases, the failure report was classified based on the subcomponent level unless information on the component was included. Accordingly, a report describing only a failed compression fitting would be categorized as a compression fitting failure, whereas a report describing the same fitting within a multi-pin connector would be classified as a connector failure. In the case of splices, only splice insulation failures were categorized as splice failures; degradation of the underlying compression/fusion fitting was classified as a compression/fusion fitting failure. Failed compression fittings attached to terminal blocks were included as compression fitting failures because these components are not part of the block itself.

Several additional difficulties were encountered in analyzing the NPRDS data. These considerations are discussed further in Appendix F of this guideline.

Those NPRDS reports resulting from prior equipment installation, maintenance, modification, or surveillance testing (as differentiated from events detected during these activities) were classified as "maintenance-induced." Maintenance-induced events, although not an aging mechanism, do constitute a mechanism for degradation of cable and termination components over time. Failures resulting from maintenance-induced causes are identified in each of the discussions presented below, and treated as a separate category of failure.

The operating voltage for each failed component was also noted. Failure reports were categorized as describing either low- or medium-voltage systems or those relating to nuclear instruments (low current, high-sensitivity neutron detector applications). The latter distinction was based on the large number of reports applicable to neutron monitoring systems and the significant differences between these systems and other medium-voltage applications. By far, the largest percentage of the total number of reports described low-voltage systems, with a substantially smaller percentage relating to nuclear instrument systems, and a very small percentage to medium-voltage systems. Reports relating to higher voltage systems (>15 kV) were excluded; however, these constituted an extremely small number of reports (<1%).

The "voltage rating" field of the NPRDS report was not always a reliable indicator of the voltage to which the component was exposed; for example, some reports describing failures of auxiliary components on large electrical devices (such as power transformers) were often coded with the voltage rating of the transformer rather than that of the failed component. Hence, careful interpretation of many reports was required. In general, the greater part of circuits in the typical nuclear plant are low-voltage; therefore, it was expected that the failures would occur in rough proportion.

3.7.2.1 Low-Voltage Systems

3.7.2.1.1 Low-Voltage Component Failure Analysis

A total of 1342 events from more than 50 different nuclear units were recorded for low-voltage cable and terminations of the type considered by this guideline. Of these 1342 events, 307 were considered maintenance-induced and were deleted from further analysis. Table 3-5 shows the failure data compiled for the remaining 1035 reports. Hookup and panel wire failures constituted the highest single percentage of low-voltage failures (377 reports/36.4%), followed by connector components (30.3%). The next most prevalent component to fail was field cable (14.5%), followed by compression/fusion fittings (12.8%), terminal blocks (3.5%), and splices (2.5%). Figure 3-2 is a graphical representation of these data.

Note that the failure data presented in this guideline was collected during normal plant operation. Failure data for design basis event (DBE) conditions are not available.

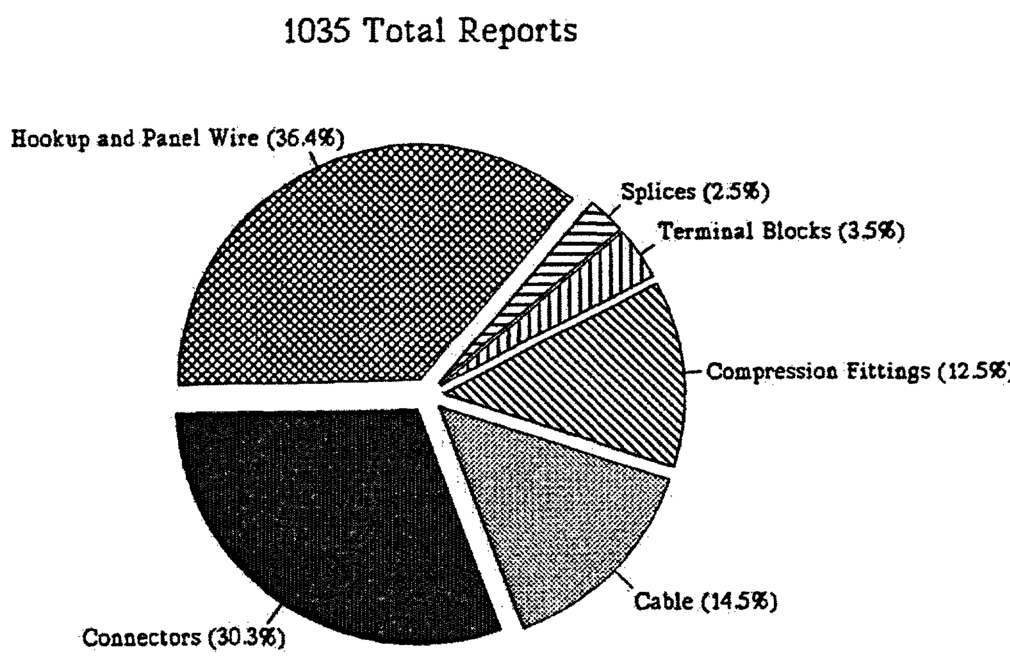

Figure 3-2 NPRDS Failure Data for Low-Voltage Components

3.7.2.1.2 Hookup and Panel Wire

Of the 545 failure reports covering hookup and panel wire, 168 were considered maintenance-induced and subsequently excluded. It should be noted, however, that although no numerical data were gathered, a large percentage (estimated at a third or more) of these "maintenance-induced" reports were the result of pinching or shorting of wires in doors or covers (such as control board panel doors or MOV access covers).

Failed subcomponents included insulation (56%) and conductors (39%). The single most common failure mode for hookup and panel wire was a short circuit to ground (45% of all reports), followed by high resistance/open circuit (including broken conductors) (44%). Only 2% listed an unidentified failure mode.

Significant failure causes included mechanical stresses (17%) and heat damage (11%); 59% of the reports could not be attributed to any specific cause.

The majority of failures noted in the reports (64%) were detected during operation; 16% and 10% of the total number of reports were detected during surveillance testing and maintenance, respectively. Of the 64% of the failures detected during operation, 62% affected the required function of the equipment; the remaining 2% had no effect on the circuit's required function. See Figure 3-3.

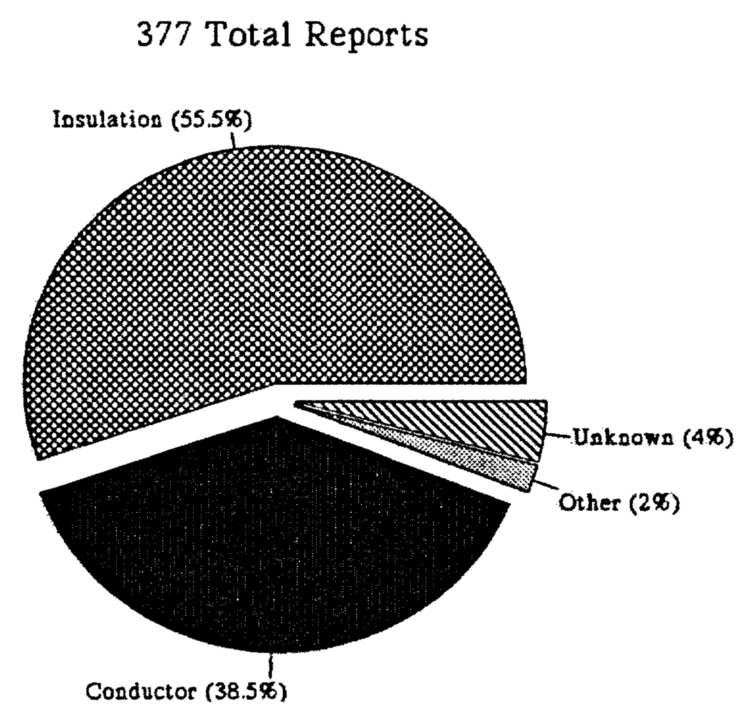

Figure 3-3 NPRDS Failure Data for Low-Voltage Hookup and Panel Wire

3.7.2.1.3 Low-Voltage Connectors

Of the 335 failure reports covering electrical connectors, 21 were considered maintenance-induced and therefore excluded. The most prevalent failed subcomponents included contacts/pins (31%) and miscellaneous hardware (5%). Fifty-eight percent of all reports related to connectors did not identify the affected subcomponent(s).

The single most common failure mode for connectors was high resistance/open circuit (48% of all reports), followed by bent or deformed components (24%), and shorts to ground (12%). Thirteen percent of the 314 reports did not identify a failure mode.

The most significant failure cause was oxidation/corrosion/dirt (44%); 39% of the reports did not list any specific cause. The remaining 22% noted failures caused by normal aging (5%), wear (3%), moisture intrusion (3%), unrelated work in the immediate area (3%), mechanical stress (2%), and heat (1%).

The majority of failures noted in the reports (68%) were detected during operation of the connector; 16% and 6% of the total number of reports were detected during surveillance testing and maintenance, respectively. Of the failures detected during operation (68%), 67% affected the required function of the equipment. See Figure 3-4.

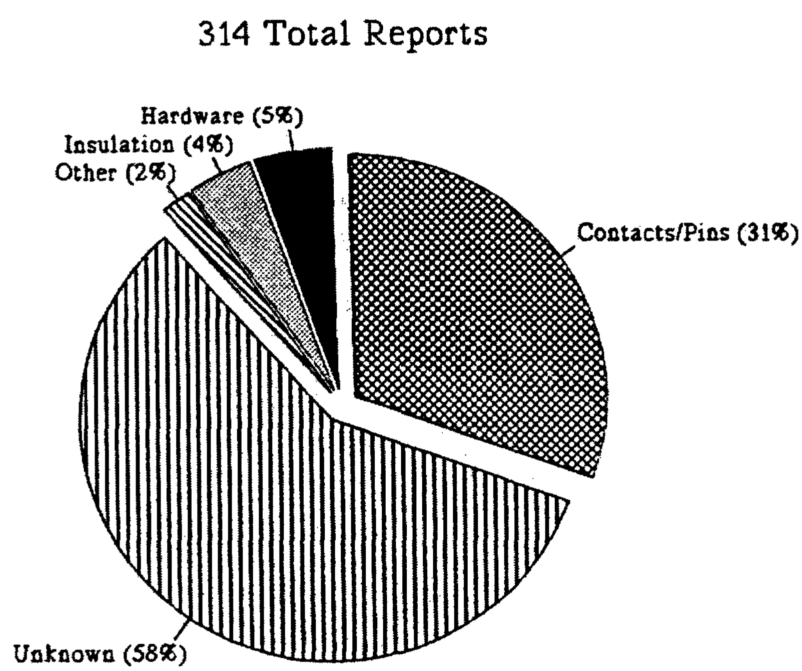

Figure 3-4 NPRDS Failure Data for Low-Voltage Connectors

3.7.2.1.4 Low-Voltage Cables

Of the 173 failure reports covering field cable, 23 were considered maintenance-induced and excluded from further consideration. The most prevalent failed subcomponents included insulation (65%) and conductors (19%); 12% of the reports had unidentified failed subcomponents.

The single most common failure mode for cables was a short to ground (54% of all reports), followed by open circuit/high resistance (23%). Eleven percent of the reports did not list a failure mode.

Significant failure causes included heat or high temperature (18%) and mechanical stress such as vibration or tensile stress (15%); 49% of the reports could not be attributed to any specific cause.

The majority of failures noted in the reports (51%) were detected during operation of the cable; 12% and 10% of the total number of reports were detected during surveillance testing and maintenance, respectively. Of the failures detected during operation (51%), all affected the required function of the circuit. See Figure 3-5.

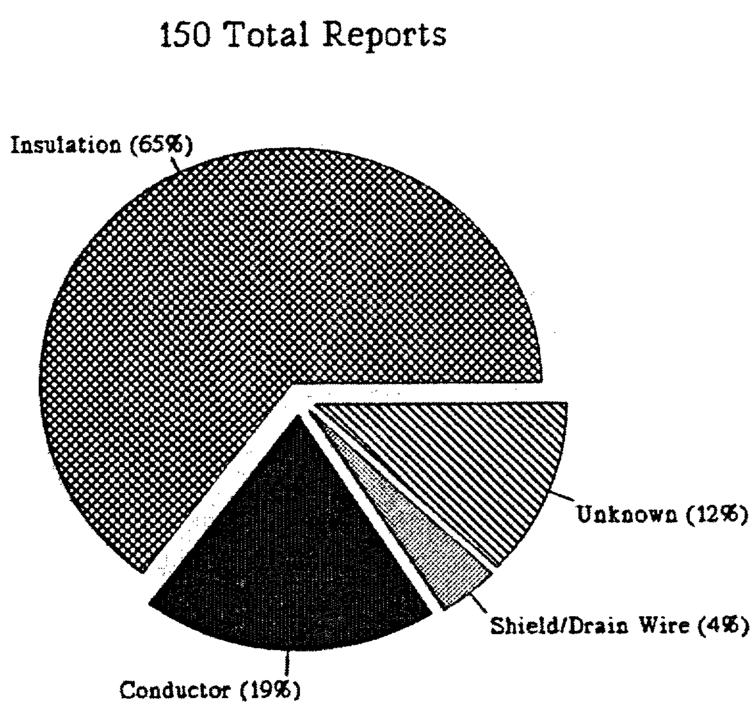

Figure 3-5 NPRDS Failure Data for Low-Voltage Cables

3.7.2.1.5 Low-Voltage Compression and Fusion Fittings

Of the 165 failure reports covering low-voltage compression and fusion fittings, 33 were considered maintenance-induced and excluded from further consideration. The most prevalent failed subcomponents included the lug itself (83%) and associated hardware such as compression bolts (15%).

The single most common failure mode for compression/fusion fittings was loosening or breakage (71% of all reports), followed by high electrical resistance (17%). Only 2% of the 132 reports listed an unidentified failure mode.

Significant failure causes included mechanical stress (16%) and oxidation/corrosion/dirt contamination (17%); 61% of the reports could not be attributed to any specific cause.

The majority of failures noted in the reports (51%) were detected during operation; 33% and 9% of the total number of reports were detected during surveillance testing and maintenance, respectively. Of the failures detected during operation, all affected the required function of the circuit. See Figure 3-6.

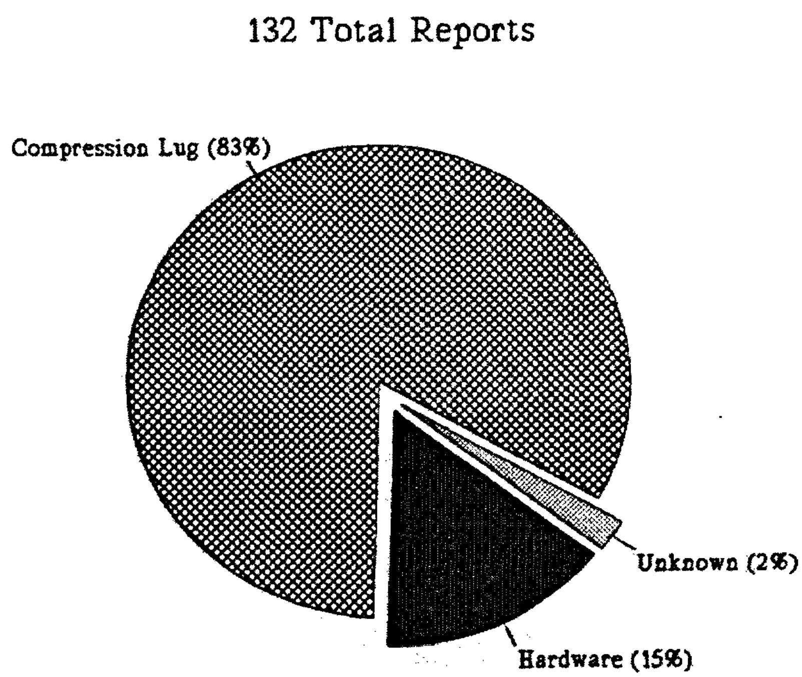

Figure 3-6 NPRDS Failure Data for Low-Voltage Compression and Fusion Fittings

3.7.2.1.6 Low-Voltage Terminal Blocks

Of the 38 failure reports covering terminal blocks, 2 were considered maintenance-induced and excluded from further consideration. The most prevalent failed subcomponents included terminal posts/hardware (54%) and insulating blocks (29%). The single most common failure mode was broken or loose components (67% of all reports), followed by short circuit to ground (21%).

The only significant failure cause identified was mechanical stresses (13%); 67% of all reports were the result of unknown causes. Half of the failures noted were detected during operation (all affected functionality); 25% and 13% of the total number of reports were detected during surveillance testing and maintenance, respectively. See Figure 3-7.

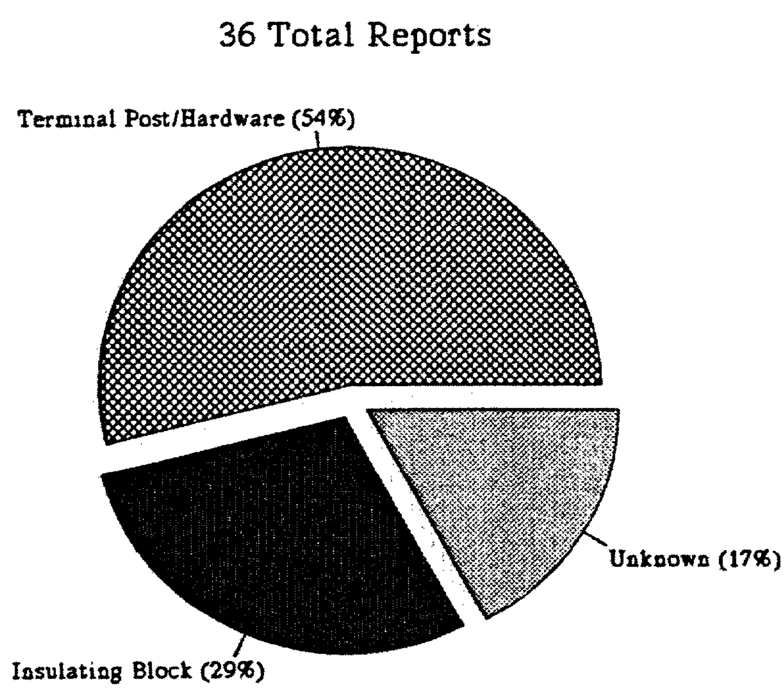

Figure 3-7 NPRDS Failure Data for Low-Voltage Terminal Blocks

3.7.2.1.7 Low-Voltage Splices

Of the 32 failure reports covering low-voltage cable splices, 6 were considered maintenance-induced and excluded from further consideration. The most common failed subcomponents were insulation (18%) and conductors (18%); 53% of the applicable reports listed no failed subcomponent. The most common failure modes for splices were a short circuit to ground and high electrical resistance/open circuit (29% each). Six of the 26 reports (24%) listed an unidentified failure mode. See Figure 3-8.

The only significant failure cause noted was mechanical stress (24%); 47% of the reports could not be attributed to any specific cause. A total of 47% of failures noted in the reports were detected during operation of the cable (all affected operation); 35% were detected during surveillance testing.

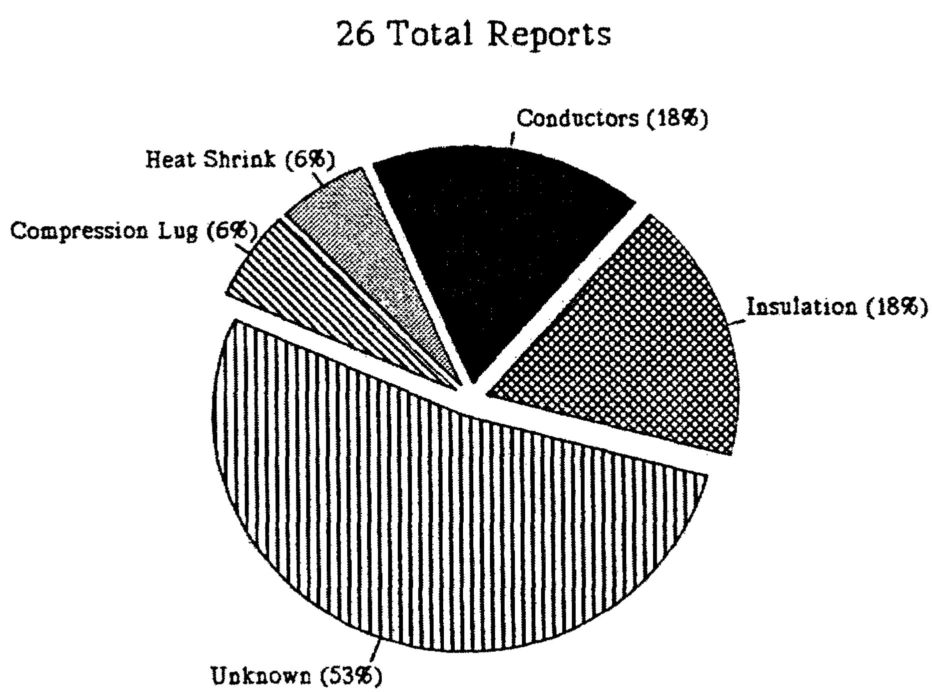

Figure 3-8 NPRDS Failure Data for Low-Voltage Splice Insulation

3.7.2.2 Medium-Voltage Systems

3.7.2.2.1 Medium-Voltage Component Failure Analysis

A total of 41 events from 12 different nuclear units were recorded for medium-voltage cable and terminations. Of these 41 events, 6 were considered maintenance-induced and were discounted from further analysis. Figure 3-9 presents a graphic representation of the failure data compiled for the remaining 35 reports, and shows that cable failures constituted the highest single percentage (24 reports/69%), followed by splices (17%), and connectors (11%). The low number of total reports is consistent with the relatively small fraction of plant cable systems operating at medium-voltage levels. Due to the small amount of data, no inferences regarding medium-voltage component reliability can be drawn.

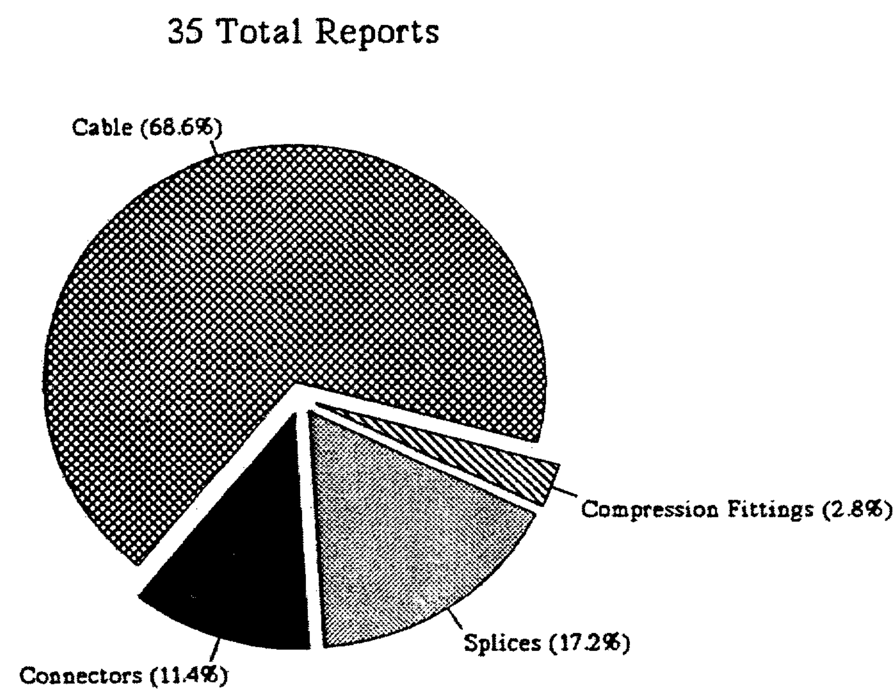

Figure 3-9 NPRDS Failure Data for Medium-Voltage Components

3.7.2.2.2 Medium-Voltage Cables

Of the 26 failure reports covering medium-voltage field cable, 2 were considered maintenance-induced and were discounted from further analysis. The most prevalent failed subcomponent was insulation (92%). The single most common failure mode for cable was a short circuit or grounding (62% of the 24 applicable reports), followed by cutting, breaking, or cracking of the insulation (21%); 54% of the failure reports could not be attributed to any specific cause.

The majority of failures noted in the reports (70%) were detected during operation of the cable. Two failures were detected during maintenance, and none during surveillance. Of the failures detected during operation, 79% affected the required function of the equipment; the remaining 21% had no effect on the circuit's required function.

3.7.2.2.3 Medium-Voltage Splices

Six failure reports were applicable to cable splices. Insulation failure accounted for all six reports. All six reports included shorting to ground as the failure mode. The failure cause and method of detection showed no significant trend.

3.7.2.2.4 Medium-Voltage Compression and Fusion Fittings

Five failure reports were applicable to medium-voltage compression and fusion fittings, four of which were maintenance-induced. The remaining failure resulted from breakage of the fitting due to mechanical stress, and was detected during operation.

3.7.2.2.5 Medium-Voltage Connectors

Four failure reports were applicable to medium-voltage connectors, which appear to be rarely used in nuclear plant applications. None was considered maintenance-induced. No subcomponent failure was prevalent. Broken or loose subcomponents accounted for three of the four failures, which were each detected during operation.

3.7.2.3 Neutron Monitoring Systems

Neutron monitoring systems (including source, intermediate, and power range monitors) were separated into their own category based on (1) their substantial differences with typical low- and medium-voltage power, control, and instrumentation circuits, and (2) the relatively large number of reports related to these devices and identified in the database.

Neutron detectors are frequently energized at what is commonly referred to as "high" voltage, usually between 1 kV and 5 kV. This is not high voltage in the sense of power transmission voltage, but rather elevated with respect to other portions of the detecting circuit. The non-detector portions of typical neutron monitoring equipment operate at lower voltages and reports relating to these devices were included with the low-voltage equipment described in previous sections. Failure reports relating to the 1 kV to 5 kV neutron detectors are described in the following paragraphs.

3.7.2.3.1 Component Failure Analysis

A total of 443 events from more than 30 different nuclear units were recorded for cable and terminations associated with neutron detectors. Of these 443 events, 55 were considered maintenance-induced and were excluded from further consideration. Of the remaining 388 reports, connector failures constituted the highest single percentage of failures (321 reports/83%), followed by cable (67 reports/17%).

3.7.2.3.2 Neutron Monitor Connectors

Of the 374 failure reports covering neutron monitor circuit connectors, 53 were considered maintenance-induced and excluded from further consideration. The most prevalent failed subcomponents include contacts/pins (19%) and hardware associated with the connector (8%); 66% of the failures did not identify the failed subcomponent.

The single most common failure mode for connectors was high resistance/open circuit (47% of all reports), followed by bent or deformed components (17%) and shorting to ground (15%). Ten percent of the reports listed no failure mode.

Significant failure causes included oxidation/corrosion/contamination (34%), unrelated work in the immediate area (15%), and moisture intrusion (13%); 24% of the reports could not be attributed to any specific cause. It should be noted that an apparently large percentage[16] of the reports associated with connectors involved those located under or in proximity to the reactor pressure vessel; this is consistent with the characteristically severe thermal and radiation environment, relatively high level of moisture, and limited space available in these areas.

The majority of failures noted (63%) were detected during operation; all of these failures affected circuit or equipment functionality; 14% and 15% of the total number of reports were detected during surveillance testing and maintenance, respectively. See Figure 3-10.

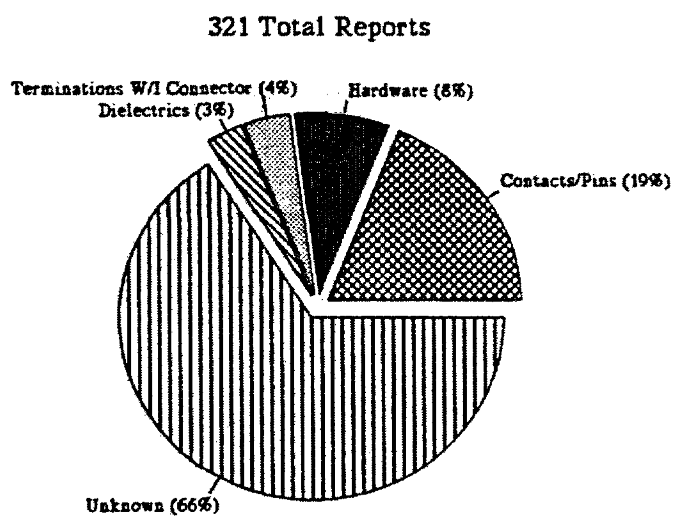

Figure 3-10 NPRDS Failure Data for Neutron Monitor Connectors

[16] No numerical data regarding locations of failed connectors were recorded during this study.

3.7.2.3.3 Neutron Monitor Cables

Of the 69 failure reports covering neutron monitor cables, 2 were considered maintenance-induced and were excluded from further consideration. The most prevalent failed subcomponents included insulation (83%) and conductors (9%).

The single most common failure mode for cable was a short to ground (61%), followed by damaged or overheated insulation (18%). Six of the 67 reports (9%) listed an unidentified failure mode. The most significant cause of failure was exposure to high temperature (18%); 55% of the reports could not be attributed to any specific cause. Thirty percent of the failures noted in the reports were detected during operation of the cable; all affected the required function of the equipment. The method of detection could not be ascertained for 45% of the reports. See Figure 3-11.

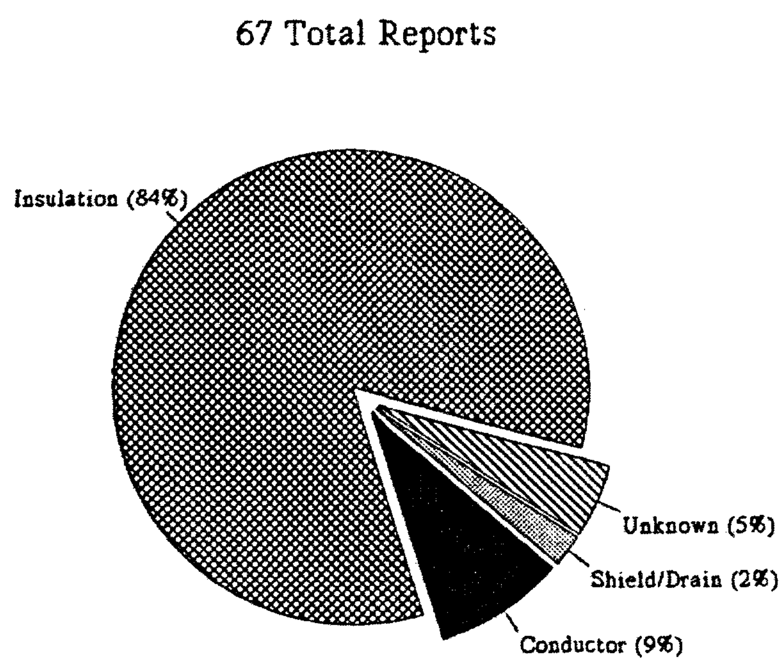

Figure 3-11 NPRDS Failure Data for Neutron Monitor Cables

3.7.2.4 Conclusions from NPRDS Review

Low-Voltage Systems

1. Hookup and panel wire and electrical connectors constituted the highest percentage of the total failures noted (each roughly one-third of all low-voltage reports). In contrast, splices and terminal blocks each constituted a very small percentage of the total failures noted, indicating a comparatively low failure and/or use rate. Cable and compression/fusion fittings fell roughly between the two groups.

2. The most significant failure mode for cable and wire collectively was a short to ground (approximately half of all cable and wire failures). It can be inferred that these failures are the result of failure of the dielectric (insulation). Open circuiting/high resistance was the second most common mode (roughly one-third of all cable and wire reports), indicating degradation or breakage of the conductor(s). High temperature aging and mechanical stresses (such as vibration or tensile stress) were cited most often as the primary causes for both cable and wire failures.

3. The most common failure mode for low-voltage electrical connectors (approximately half of the connector-related reports) was high electrical resistance/open-circuiting. Oxidation, corrosion, and dirt buildup on contact surfaces were the most common causes of failure (44%).

4. The most common failure mode for low-voltage compression/fusion fittings was loosening or breakage (71%), and was most often caused by mechanical stress or oxidation/corrosion.

5. Roughly two-thirds of all low-voltage cable and termination failures noted were detected during operation, and affected the functionality of the circuit/connected load. Percentages of such failures ranged from 47% for splices to 68% for connectors, thereby indicating some degree of consistency between components. Surveillance testing and maintenance were the next most common methods of detection, respectively, accounting for roughly 20% of all reports collectively. Hence, surveillance testing and maintenance activities may identify only a fraction of incipient low-voltage cable system component failures or instances of degradation. However, the significance of this conclusion must be considered in light of the overall failure rate of these systems; see Section 5.4.2 for additional information.

6. Hookup and panel wire failures had the highest incidence of maintenance-induced failure (31% of all reports noted); hence, roughly one-third of all wiring failures are the result of causes that are not related to aging. This was significantly higher than that for any other component in any voltage range (next highest was low-voltage compression fittings at 20%).

Medium-Voltage Systems

1. Cable failures constituted the highest percentage of the total failures noted for medium-voltage systems, roughly two-thirds of all reports. Splices and connectors each constituted substantially smaller percentages. (Note: The overall number of reports applicable to medium-voltage systems was very low, 35 in total.) Insulation was the most common failed subcomponent (92%), with the most significant failure mode being shorting to ground (approximately two-thirds of all medium-voltage cable failures).

2. Insulation failure resulting in shorting to ground was noted for all six reports pertaining to medium-voltage splices. Therefore, although the failure rate of these devices appears comparatively low, there is seeming commonality in their mode of failure.

Neutron Monitoring Systems

1. Connectors were by far the most problematic component, comprising more than four-fifths of all failures in this category. The most common failed subcomponent was contacts/pins, and the most common failure mode was high electrical resistance/open circuiting. Oxidation, corrosion, and dirt buildup were the most common cause of failure.

2. Although not as significant as that for connectors, failure of the cabling associated with detectors was noted. Shorting of the cable from damaged insulation resulting from exposure to heat and possibly radiation or mechanical stress was most common. This result is consistent with the type of environment in which these systems typically operate (i.e., within the drywell near the reactor pressure vessel, and subject to periodic motion during operation).

3.7.3 Evaluation of LER Data

NRC Licensee Event Reports (LERs) are another source of cable and termination failure and degradation data. LERs are issued by nuclear plant operators when equipment failures and plant operating events meet the reporting requirements specified in 10CFR50.73. As with NPRDS data, LERs do not directly record data related to component aging. In addition, the criteria for issuance of an LER do not encompass all component failures (especially those of little or no consequence to plant safety). Hence, evaluation of LER data provides only a partial picture of failure information; accordingly, the data may or may not be representative of general equipment failure behavior. LER data can be used, however, as support for the findings derived from other data sources (such as NPRDS and industry studies), as well as for verification of postulated aging mechanisms.

The LERs used in this analysis covered the period from early 1980 through April 1994. The abstracts of 2536 LERs were identified through a keyword search of the LER database maintained by Oak Ridge National Laboratory. The reports generated by this search were individually reviewed; in cases where the applicability of a given report to a topic could not be reliably determined, the report was discarded. Of the 2536 reports reviewed, 640 (25.2%) were ultimately retained as being applicable to electrical cable and terminations of the type considered by this AMG; 16 of the reports were considered maintenance-induced and not analyzed further. The remaining 624 reports were then categorized by voltage range (low, medium, or neutron monitoring, to be consistent with the NPRDS data), component, subcomponent, failure mode, failure cause, and method of detection. Categorization by manufacturer was not practical due to the nearly complete lack of information on component manufacturer.

Of the total 624 applicable reports, 344 (55.1%) were related to connector failures, 136 (21.8%) were related to cable failures, and 88 (14.1%) were related to failures of wire. The remaining 9% were distributed among terminal blocks, splices, and compression/fusion fittings. For all components and voltage ranges, the great majority of failures noted were detected during operation of the component, and affected its functionality. This result is somewhat expected, in that the criteria specified in 10CFR50.73 are primarily concerned with reporting of operational failures.

3.7.3.1 Low-Voltage Systems

3.7.3.1.1 Component Failure Analysis

The data contained in the LER database described 566 events related to low-voltage systems. Of these reports, 13 were maintenance-induced. The distribution of the remaining reports was: connector failures (58%), cable failures (19%), wire failures (14%), terminal blocks (4%), compression/fusion fittings (3%), and splices (2%). See Figure 3-12.

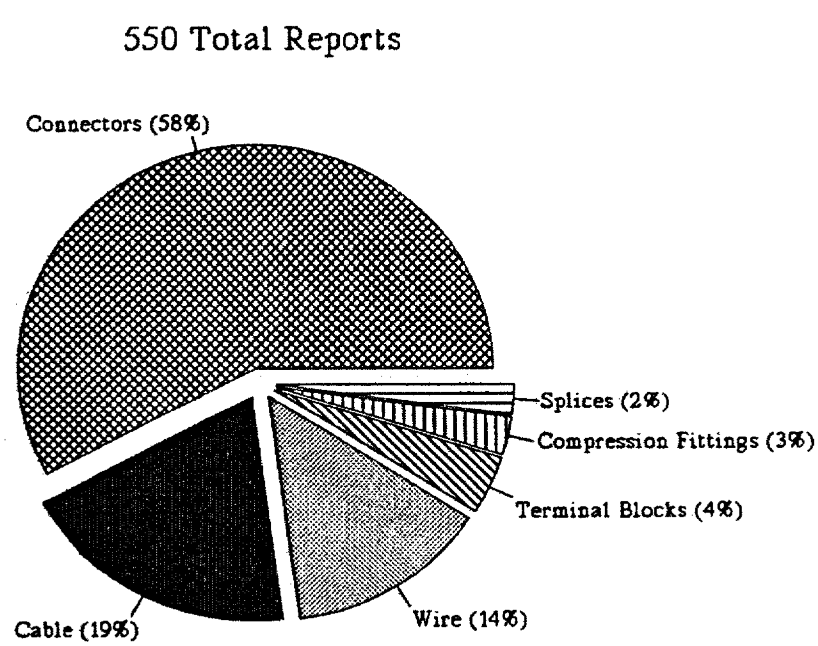

Figure 3-12 LER Failure Data for Low-Voltage Components

3.7.3.1.2 Low-Voltage Connectors

Of the 323 failure reports covering electrical connectors, 7 were considered maintenance-induced and were excluded from further consideration. Most (86%) reports related to connectors did not specifically identify a failed subcomponent, and the remaining reports indicated no particular pattern. The single most common failure mode for connectors was loose or broken subcomponents (59% of all reports). Thirty percent of the 319 reports did not list a failure mode. The most significant failure cause was oxidation/corrosion/dirt (13%); 75% of the reports did not list any specific cause. The remaining failures (12%) were caused by normal aging, moisture intrusion, and mechanical stress, in roughly equal proportions.

3.7.3.1.3 Low-Voltage Cables

Of the 102 failure reports covering low-voltage cables, 1 was considered maintenance-induced. The most prevalent failed subcomponents included insulation (20%) and conductors (8%). A total of 66% of the reports had unidentified failed subcomponents. The most common failure mode for cable was a short to ground (16% of all reports), followed by loose or broken components (10%). Fifty-five percent of the reports did not list a failure mode. The most significant failure causes included moisture intrusion (10%) and corrosion of conductors (6%); 62% of the reports could not be attributed to any specific cause.

3.7.3.1.4 Hookup and Panel Wire

Eighty failure reports covered hookup and panel wire; none of the failure reports were considered maintenance-induced. Failed subcomponents included insulation (34%) and conductors (41%). A total of 18% of the reports did not identify the failed subcomponent. The single most common failure mode for hookup and panel wire was breakage (42% of all reports), followed by short circuits (40%). A total of 18% of the reports listed an unidentified failure mode. No significant failure causes could be identified; 90% of the reports could not be attributed to any specific cause.

3.7.3.1.5 Low-Voltage Compression and Fusion Fittings

Twenty-two failure reports covered low-voltage compression fittings; none of the failure reports were considered maintenance-induced. The most prevalent failed subcomponent was the lug itself (89%). The single most common failure mode for compression fittings was loosening or breakage (68% of all reports). A total of 10% of the reports listed an unidentified failure mode. No significant failure causes were evident; 74% of the reports could not be attributed to any cause.

3.7.3.1.6 Low-Voltage Terminal Blocks

Of the 25 failure reports covering terminal blocks, 4 were considered maintenance-induced and were excluded from further consideration. The most prevalent failed subcomponents included insulating blocks (38%) and terminal posts/hardware (24%). The most common failure mode was broken or loose components (24% of all reports); the remaining reports (16) were distributed among several other failure causes such that their numbers were insignificant. No significant causes of failure were identified (40% were unidentified).

3.7.3.1.7 Low-Voltage Splices

Of the 11 failure reports applicable to low-voltage cable splices, 1 was considered maintenance-induced. Conductors were cited as the failed subcomponent in 5 of the 10 reports, yet no trend in failure mode or cause of failure was detected.

3.7.3.2 Medium-Voltage Systems

The LER database contained 50 reports related to medium-voltage circuits. A total of 52% of these reports were related to cable, 40% to connectors, and the remainder to compression/fusion fittings and splices. See Figure 3-13.

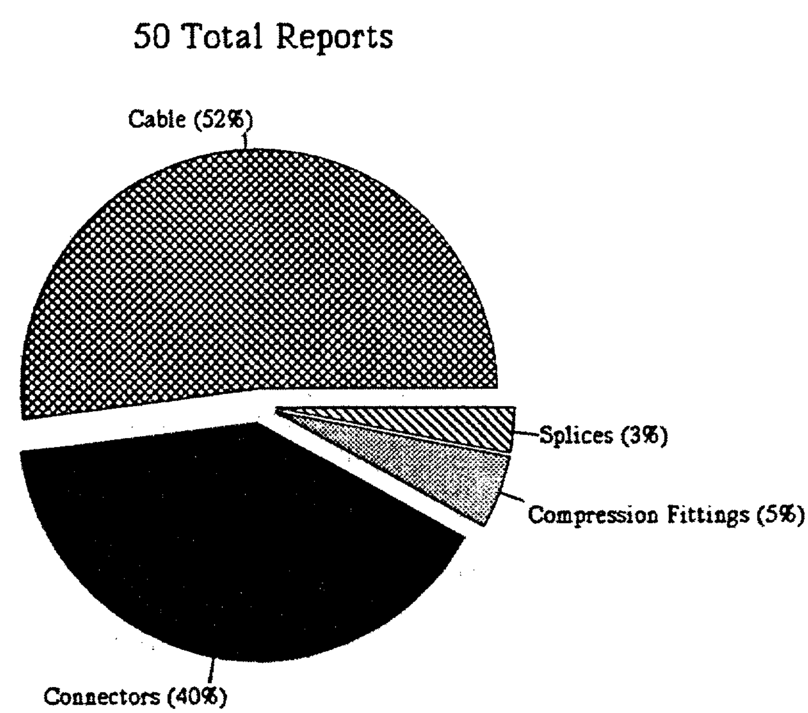

Figure 3-13 LER Failure Data for Medium-Voltage Components

3.7.3.2.1 Medium-Voltage Cables

Twenty-six failure reports covered medium-voltage cables; none of the failure reports were maintenance-induced. The most prevalent failed subcomponents were insulation (27%) and conductors (19%); 54% were unidentified. The single most common failure mode for cable was a short circuit or grounding (27% of the 26 applicable reports); 54% of the failure reports could not be attributed to any specific cause.

3.7.3.2.2 Medium-Voltage Connectors

Twenty failure reports covered medium-voltage connectors; none of the failure reports were considered maintenance-induced. Significant failed subcomponents included hardware (70%) and contacts/pins (30%). Broken or loose subcomponents accounted for 55% of the failures. The majority of medium-voltage connector reports (95%) did not identify a cause.

3.7.3.2.3 Medium-Voltage Compression and Fusion Fittings

Three failure reports covered medium-voltage compression and fusion fittings; none of the failure reports were considered maintenance-induced. These three failures resulted from loosening or breakage of the fitting due to mechanical stress.

3.7.3.2.4 Medium-Voltage Splices

Two failure reports covered medium-voltage cable splices; one of which was maintenance-induced. Insulation failure accounted for the remaining failure, which was caused by moisture intrusion.

3.7.3.3 Neutron Monitoring Systems

Of the 23 LERs covering neutron monitoring system cable and terminations, 2 were maintenance-induced. Of the remaining 21 LERs, 76% involved cables and 24% connectors. No significant failed subcomponents, failure modes, or failure causes could be identified because the majority of reports did not provide any of this information.

3.7.3.4 Conclusions from LER Review

General observations regarding cable and termination failures as described by the LER database are summarized in the following paragraphs. It should be noted that the LER data, in comparison with the NPRDS data, had less information regarding failed subcomponents, failure modes, and causes. Very high percentages of each category were listed as "unknown," thereby making meaningful observations or inferences difficult.

Low-Voltage Systems

1. Connector failures were the most prominent, accounting for more than half of the low-voltage reports. The next highest were cables, which were related to 19% of all low-

voltage failures. The most common failure mode for the connectors was loose or broken subcomponents.

2. Conductor breakage and insulation degradation (resulting in short circuit) are the most likely aging-related failures to occur in hookup and panel wiring.

3. Loosening or breakage of the lug was the most common failure for compression and fusion fittings.

Medium-Voltage Systems

1. Medium-voltage cable and connector failures were most common. Due to the comparatively low number of reports for both components (26 and 20, respectively) and the lack of detailed information, no real inferences regarding subcomponent, mode, or cause can be postulated.

Neutron Monitoring

1. Cables (as opposed to the connectors reflected in the NPRDS data) appeared to result in the most failures associated with neutron monitoring systems (roughly three-fourths).

3.7.4 Studies Providing Industry-Wide Operating Experience for Low- and Medium-Voltage Electrical Cable and Terminations

The following industry reports were reviewed for relevant operating history and other insights related to cable and termination aging:

- EPRI TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables" [3.24]
- EPRI NP-5002, "LWR Plant Life Extension" [3.25]
- NUREG/CR-3122, "Potentially Damaging Failure Modes of High- and Medium-Voltage Electrical Equipment" [3.26]
- EPRI TR-103841, "Low-Voltage Environmentally-Qualified Cable License Renewal Industry Report" [3.27]
- NUREG/CR-5461, SAND89-2369, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants" [3.28]
- EPRI EL-3501, "Characterization of Failed Solid-Dielectric Cables: Phase I" [3.29] and EPRI EL-5387, "Characterization of Failed Solid-Dielectric Cables: Phase II" [3.30]
- EPRI NMAC NP-7485, "Power Plant Practices to Ensure Cable Operability" [3.7]

The reports are discussed individually in the following paragraphs.

EPRI TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables" [3.24]

Concerns have been expressed that medium- and low-voltage cables may degrade more rapidly when exposed to water. Two studies were performed by EPRI. One evaluated the types of failures occurring in medium-voltage cables used in power plants to determine the types of failures and the need for a condition evaluation technique that would predict residual life. The second evaluated the available data concerning the effects of wetting and submergence of low-voltage cable to determine if further research is necessary.

Medium-Voltage Cable

Fossil and nuclear power plant operators were surveyed to determine the number and types of medium-voltage (4 to 15 kV) cable failures that have occurred and the causes of failure. Utility personnel were also asked if there is a need to develop a test for evaluating the condition and estimating the continued service life of medium-voltage in-plant cables. The types of condition evaluation techniques currently in use were also identified.

Information representing 50 plants was compiled from telephone interviews with 35 persons from 25 utilities. The surveys indicated that the bulk of the failures were related to wetting in conjunction with manufacturing defects, damage during installation, or deterioration of terminations. The survey identified only 27 failures in almost 1000 plant-years of experience. Only one plant continues to use dc high-potential testing for condition monitoring purposes, but is looking at alternative means of cable evaluation. Some plants use insulation resistance testing; some do not perform condition monitoring testing. The consensus from the survey was that there is currently insufficient interest to support development of a condition evaluation test method for medium-voltage cable used in power plants.

Low-Voltage Cable

A review of the literature and surveys of utility personnel were used to evaluate the effects of moisture on the operability and aging of low-voltage cable. The feedback from operations indicated that moisture-related failures of low-voltage cable are not occurring at any appreciable rate (see Section 3.7.3.1.2 of this guideline, which indicates approximately 10 moisture-related failures of low-voltage cable in the LER database). Only two isolated types of failure were identified. The first involved very low insulation resistance values for old natural rubber cables immersed for a long period in water-filled conduits in fossil fuel power plants. The second related to degraded noise immunity in certain instrumentation and closed circuit television circuits that resulted from periodic immersion in water at nuclear power plants. The second problem related to moisture tolerance of the jacketing system rather than to insulation capabilities.

The evaluation determined that current electrical test methods could identify the presence of moisture in insulation systems; however, the tests cannot assess the effects of moisture on cable longevity. Therefore, while water can be detected to allow it to be removed from conduit systems, its effect is not readily assessable. The overall conclusion of the study was that moisture-related degradation is not a significant concern for general applications.

EPRI NP-5002, "LWR Plant Life Extension" [3.25]

EPRI NP-5002 provided interim results from the pilot plant life extension studies conducted at Surry Unit 1 (PWR) and Monticello (BWR). These pilot studies were initiated in 1984 to identify specific research and development needs related to plant life extension and to serve as a basis for power system aging and life extension guidelines for the nuclear industry. The study considered many different plant components, including electrical cable located inside primary containment. The evaluation of the Surry containment cable assessed the impact of (1) low-voltage power, control, and instrumentation cable; (2) medium-voltage power cable; and (3) thermocouple extension cable on the possibility of extended life operation for Surry Unit 1. The cable insulation materials evaluated included EPR, XLPE, and silicone rubber. The findings and conclusions of the study are as follows:

- Based on Arrhenius analysis of organic materials used in the insulation of these cables, a 60- to 80-year life is achievable with an insulation operating temperature of 50 to 75°C (122 to 167°F).

- EQ instrument cable was originally qualified for 40 years based on an ambient temperature of 55°C (131°F); requalification would be required for life extension.

- Where accessible, cables inside containment should be visually inspected at regular intervals to (1) identify signs of bulk insulation degradation and (2) to help ensure that localized high temperature degradation is not occurring.

- Termination and connector capability should be further evaluated.

- The effects of jacket aging on instrument cable shield and connected load performance should be further evaluated.

- A more detailed evaluation of cable for life extension should be made.

The study identified several aging mechanisms for cable insulation and conductors, including thermal and radiation aging, voltage stress of medium-voltage power cables, moisture intrusion, and long-term mechanical (tensile) stress. In addition, the study recommended the following monitoring requirements:

- Comparison of the performance capability of the cables with the actual in-plant environments over the entire cable length

- Regular measurement and recording of ambient air temperatures within various portions of the containment

- Performance of radiation surveys for background radiation levels

- Development of current loading history for power cables
- Consideration of replacement of cables that have a history of being moved or flexed

NUREG/CR-3122, "Potentially Damaging Failure Modes of High- and Medium-Voltage Electrical Equipment" [3.26]

NUREG/CR-3122 considers the effects and circumstances surrounding electrical faults of cables, connectors, and other electrical components used in both nuclear and nonnuclear facilities. The scope was limited to equipment with voltage ratings of 4100 Vac and above. As part of the study, several sources of failure information were consulted. The Nuclear Safety Information Center (NSIC) database was searched for applicable reports, and the study also examined proceedings from the Doble Clients Annual Conference (an industry forum for issues and technology related to electrical components) for pertinent data. Plant visits and interviews were also used.[17]

The study concludes that cables and connectors will have a predictably long service life if properly installed and not subject to mechanical forces, moisture, or excessive temperatures. This lifetime is generally dictated by the aging of the insulation; failures of cable appear random and generally affect only segments of a cable run. Cables located in open trays may affect other cables through movement or heating.

EPRI TR-103841, "Low-Voltage Environmentally-Qualified Cable License Renewal Industry Report" [3.27]

This report (commonly referred to as "the Cable Industry Report") assessed the viability of low-voltage (i.e., less than 1000 V) environmentally qualified cable for license renewal. Splices to loads, panel or switchboard wire, connectors, terminal blocks, and component leads were not included in the scope; digital circuit cables, Kapton® leads, and butyl rubber-insulated cable were also not included due to their unique design attributes or specialized applications. Specifically excluded from consideration were degradations due to (1) design nonconformances, (2) unintended long-term submergence, (3) unintended chemical exposure, and (4) improper maintenance. The report indicates that plant-specific evaluations are required to assess the relevance of the devices, their degradations, and other aspects of the report.

The general methodology of this report was similar to that of this AMG, in that relevant components and their service/operating history were described, significant aging mechanisms were identified, and in cases where current acceptable programs could not be shown to effectively manage these mechanisms, options for managing component aging were discussed. An aging mechanism was considered significant if, when allowed to continue without any additional preventive measures, the continued functionality of the component could not be demonstrated. To determine relevant operating history, both LERs and NRC documentation (Information Notices) were examined. LERs affecting cable both

[17] Doble Clients information is a proprietary source of information, and was therefore not available for use in this guideline.

inside and outside of containment were examined for the period 1968 to 1992. After screening out nonapplicable reports, only 87 LERs were identified. It was concluded through review of the time to detection that a large fraction of the failures occurred within the first few years of cable operation, many of which resulted from mechanical damage. The number of failures decreased significantly after 10 years, with no indications of significant long-term degradation or age-related failure. The report provided the following overall conclusions:

- Changes in insulation electrical properties, conductor/shield corrosion, loss of fire retardants, corona breakdown, and water treeing were not significant aging mechanisms for low-voltage cable.
- Embrittlement of jacket materials was not significant under certain circumstances.[18]
- Embrittlement of insulation is a significant aging mechanism for low-voltage EQ cable.
- All significant component/aging mechanism combinations were addressed by current programs (e.g., EQ and maintenance programs).

<u>NUREG/CR-5461, SAND89-2369, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants" [3.28]</u>

This Sandia report examined the aging of cables and terminations; specifically, equipment design and materials were characterized, aging mechanisms and stressors identified, and current industry maintenance and testing practices were described. This study also analyzed LERs from mid-1980 through 1988 related to the aging or accident survivability of cables. Cables installed both inside and outside containment were included. The study demonstrated that the number of LERs for cable and connections is very small considering the number of plants and the number of circuits/connections in the typical plant.

The LER search located a total of 151 reports applicable to "cable" and 196 events related to "connections." These tallies are assumed to include cable and connections from all voltage ranges. More than half of the cable-related reports involved electrical faults (shorting or grounding), whereas 13% were the result of open circuits. One quarter of the reports (38 of the 151 total) were attributed to design errors. Forty-two percent involved cable located inside containment, whereas 58% involved cables located outside containment.

For connections, 32% were attributed to loose connections, 28% to "bad" connections (the term "bad" being used when the type of connection failure was not specified), and 8% to shorted connections. Twenty-two percent were design related. Almost two-thirds of the failures were outside containment.

[18] These circumstances include (1) instances where the jacket is not bonded to the insulation (see Section 3.7.1 of this guideline), (2) instances where the jacket is not required to provide beta radiation shielding to demonstrate environmental qualification in accordance with 10CFR50.49, (3) electrical shield isolation is not important, and (4) the jacket's physical integrity is not necessary for qualification of cable connectors or splices.

The NUREG/CR-5461 cable failure rates covering a period of 8 years compare very favorably with 14 years of LER results summarized in Section 3.7.3 of this AMG. The results for connections show somewhat more disparity, which can be attributed to some differences in scope, as well as differences in method of categorization (i.e., many reports attributed to "loose connections" in NUREG/CR-5461 would be attributed to wiring, cable, or connector components in this AMG). Overall, however, both results indicate a very low rate of failure relative to the number of devices in operation during the period(s) of coverage. (See also Reference [3.31], which summarizes the findings of NUREG/CR-5461.)

EPRI EL-3501, "Characterization of Failed Solid-Dielectric Cables: Phase I" [3.29] and EPRI EL-5387, "Characterization of Failed Solid-Dielectric Cables: Phase II" [3.30]

The principal objective of this program was to identify and verify factors that affect the longevity of XLPE- and high molecular weight polyethylene (HMWPE-) insulated underground medium-voltage cables. This objective was accomplished in two discrete phases. Phase I consisted of the collection of data and relevant information on medium-voltage cable insulation failures from a group of 15 individual plant operators. This information was loaded into a database to facilitate statistical analysis of potential "predictor" variables for insulation failure. Findings of this analysis indicated that some statistically significant predictors were identified (namely, operating voltage stress, volatiles, and the presence of halos [microvoid-containing volatiles]), with a higher level of statistical significance for HMWPE than for XLPE. Phase II used actual service-aged HMWPE- and XLPE-insulated cable samples provided by various U.S. utilities to test the hypotheses formulated in Phase I. Results of this phase showed some consistency with the Phase I findings; perhaps the most significant finding is that the combination of greater age and thinner insulation walls would produce a higher failure rate. Also, the presence of peroxides and peroxide decomposition products was found to have some correlation with the electrical integrity of the insulation.

EPRI NMAC NP-7485, "Power Plant Practices to Ensure Cable Operability" [3.7]

This report evaluated the operability criteria for nuclear plant cables, as well as cable maintenance, surveillance, and installation practices. As part of this evaluation (Section 7.0), data from the NRC's Nuclear Plant Aging Research (NPAR) program (LERs through February 1984) were examined. The study concluded that failures during operation of cable are rare, and that most failures are the result of physical damage during or after installation, or poorly made terminations. The study also cites a search conducted by Duke Power of the NPRDS database which indicated that the cable failures noted were related primarily to installation errors, termination problems, or misapplication.

In addition, a number of experts (including cable manufacturers, utility personnel, and government/university researchers) were interviewed in order to identify aging mechanisms of low-voltage cable. The consistent result from these interviews was that low-voltage cable as a whole has experienced a very low failure rate, and that failures are primarily the result of external environments outside design limits. Medium-voltage cables are subjected to elevated electrical stress by virtue of their operating voltage, and small imperfections in the insulation may result in cable failures; however, the overall failure rate of medium-voltage cable has been low as well.

3.7.5 Host Utility Operating Experience and Plant Surveys

As part of the development of this AMG, information relating to cable systems was obtained from "host" utilities through interviews with plant maintenance and supervisory personnel and review of plant documents and records. There were three host utilities for this study, whose units included mid-1970s PWRs, mid-1980s PWRs, and mid-1980s BWRs. Some of the more notable instances of cable and termination degradation occurring at these host facilities are discussed in the following paragraphs. These discussions are not intended to comprehensively recount all cable-related degradation or failures occurring at the host plant; to the contrary, no effort was made to determine the total numbers of failures of each type. Rather, the intent was to validate observations noted in the analysis of the NPRDS and LER data,[19] as well as the aging mechanisms and effects discussed in Section 4.

In general, the plants interviewed indicated that the single most common type of aging observed was thermal embrittlement of organic cable and termination materials, especially near hot end devices and/or in high ambient temperature spaces.[20] Some primarily radiation-induced effects (such as embrittlement and/or swelling of neutron detector cables in close proximity to the reactor pressure vessel) were noted at some plants; however, comparatively few effects attributable to radiation were identified. These observations appear to be in agreement with the NPRDS and LER data discussed above, which cite shorting to ground due to insulation degradation as the most common low-voltage failure mode (NPRDS and LERS), and high temperature exposure and mechanical stress as the most frequently listed failure causes (NPRDS). Note also that instances of low-voltage cable and wire shorting to ground induced by moisture (as indicated by the LERs) may, in fact, be due to moisture intrusion through preexisting cracking, an effect of thermal and/or radiation exposure. In some regard, more confidence can be placed in the host plant observations for identifying relevant root causes because a very large percentage of both NPRDS reports and LERs describe no failure cause and/or mode.

Host Utility No. 1 (Mid-1980s BWRs)

Thermal Aging of Low-Voltage Steam Tunnel Cable

Cable runs located at various elevations in steam tunnel spaces were thermally aged according to (1) their elevation in the space and (2) their proximity to steam piping. Some thermal stratification within the space was evident for cables not located near steam piping; cables at low elevations showed less aging than similar runs at high elevations. Cables located in trays in proximity to steam piping showed degradation and embrittlement according to radiant energy patterns (i.e., some cables were partially shielded by the trays and other cables). In

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[19] Very few of the NPRDS reports or LERs discussed the mode and cause of a given failure with sufficient specificity to validate the existence of some of the aging mechanisms hypothesized in Section 4. For example, no instances of UV radiation degradation of nuclear plant cables were found in the data.

[20] Few instances of observed degradation on high-ampacity circuits were noted.

some cases, two cables in the same tray showed dramatically different levels of aging (based on visual and physical inspection), depending on their position in the tray. No failures of the affected cable have occurred to date. This type of aging represents a significant exception to the general observation that localized thermal aging occurs primarily at the end device.

Ultraviolet Degradation of Polyethylene-Insulated Cable

Instrumentation cables located in close proximity to fluorescent indoor lighting have developed spontaneous circumferential cracks in exposed portions of the insulation. These cables are insulated with polyethylene and have a light-colored (white) appearance. The cracking is believed to be due to the emission of ultraviolet (UV) radiation from the lighting, which is known to degrade materials that are not UV-stabilized. Similar cables with insulation of different colors exposed to the same environment showed no signs of such cracking. For some of the affected cables, the cracking was severe enough to expose the underlying conductor. However, no operational failures were documented as a result of this degradation.

Host Utility No. 2 (Mid-1980s PWRs)

Failure of 12-kV Circulating Water Pump Cable

Two failures of cables used to supply power to a circulating water pump have occurred. The cables supplying the motor were EPR insulated, Neoprene® jacketed with two extruded semiconducting layers, one taped semiconducting layer, and a copper tape shield. The Neoprene® jackets of some of the affected cables had softened and completely dissolved due to (1) the operating temperature of the cable, (2) foreign chemical substances (fatty acids and ethyl ester compounds) in a nearby sump that inadvertently drained into the cable ducting, and (3) the presence of salt (chlorides) from ocean water spray in the sump. Once the integrity of the jackets was lost, the salt/chemical solution rapidly corroded the copper tape shield; the cables eventually suffered a single-point failure of the EPR insulation. The exact cause of the EPR failure was unknown; subsequent investigation yielded no indication of cable damage during installation.

Host Utility No. 3 (Mid-1970s PWRs)

Aluminum Termination Failures

Cracking of the tang to barrel connections on Thomas and Betts aluminum terminal lugs used on 10 AWG and larger cables has been observed. This cracking appears to have occurred primarily on large machines where frequent maintenance involving the termination occurred. Very few actual circuit failures have occurred as a result of this problem. At present, only copper lugs are being used by the plant, with the aluminum lugs being replaced as a standard maintenance activity.

Tape Splice Failures

Several splice failures also occurred at this host plant as a result of use of a specific tape product in fabrication of 480-V and 4-kV tape splices. These failures were the result of creeping and loss of overlap of the tape, thereby reducing the dielectric strength of the insulation systems and resulting in shorting. Once the problematic tape was identified, its use was discontinued and the failures ceased.

Plant Surveys

A limited number of mail surveys were received from operating plants (other than host utilities) as part of the study; these surveys requested information on the types of cables/terminations installed, common maintenance activities, and types/relative quantities of aging degradation being experienced. No effort was made to determine the number of a given type of failure for each plant, as this was felt to be more accurately characterized by the other failure data (such as NPRDS and LERs).

In general, the surveys showed results which were consistent with the information obtained from NPRDS, LERs, EPRI NUS database, and the host utilities. Thermal damage appeared to be the most significant aging effect; several instances of heat damage [to source range monitor (SRM)/intermediate range monitor (IRM) cables on BWRs, as well as localized degradation of main steam isolation valves (MSIV) and safety/relief (SRV)] were noted. Loosening and breakage of low-voltage compression fitting lugs were also listed in several cases. One plant reported overheating and failure of residual heat removal (RHR) motor lead lugs due to improper crimping/filling of the oversized lugs. One plant noted two failures of circulating water pump motor cables resulting from improper manufacturing (insulation compounding); no operational failures of medium-voltage cable due to water treeing were identified.

3.7.6 Overall Conclusions Regarding Historical Performance of Equipment

Six primary sources of information were used in this AMG to characterize the historical performance of electrical cables and terminations, namely,

- NRC Information Notices, Bulletins, Circulars, and Generic Letters
- NPRDS data
- LER data
- Industry information provided by previous analyses and reports
- Information obtained from operating nuclear plants acting as host utilities
- Plant surveys

These sources each provide a somewhat different perspective on aging of cables and terminations. Several limitations are inherent in any comparison of these results, stemming primarily from the variations in equipment types within the population, the differing scope of equipment included, classification of failures, and criteria used in the analysis. Accordingly, no statistical inferences (such as mean-time-between-failure) can be drawn concerning component failure probability or rate. Despite these limitations, the following generic observations were made:

1. The number of cable and termination failures during normal operating conditions (all voltage classes) that have occurred throughout the industry is extremely low in proportion to the amount of cables and terminations (see Section 5.4.2 for analysis of cable and termination failure rates by class based on NPRDS data).

2. Thermal aging and embrittlement of insulation is one of the most significant aging mechanisms for low-voltage cable, based on (a) the large percentage of low-voltage cable reports (both NPRDS and LER) that are attributable to insulation degradation and shorting,[21] (b) the conclusions of other industry studies, and (c) information obtained from host utilities/surveys. Mechanical stress (including vibration, bending of wire and manipulation, etc.) was also frequently cited as a cause for failure. As evidenced from discussions with host utilities (and, to some degree, the empirical data, for which no formal analysis of failure location was conducted), these aging mechanisms occur predominantly near the end devices or connected loads. Thermal aging results largely from localized hotspots; aging due to ambient environment or ohmic heating may also be present.

3. As evidenced in all of the data sources examined, localized radiolytic degradation affects low-voltage cables and terminations (as a whole) to a lesser degree. This is consistent with (a) the comparatively low percentage of the total circuit population that is installed in high-dose spaces and (b) the high radiation damage thresholds of most component materials in comparison to typical plant TIDs (see Section 4.1). Degradation resulting from exposure to external chemical substances appears to occur very infrequently.

4. Localized thermal, radiolytic, and incidental mechanical damage appear to be the most significant aging mechanisms for cables located near the reactor pressure vessel, especially neutron monitor circuits.

5. Connector failures constitute a large percentage of all failures noted for low-voltage (30% for NPRDS, 58% for LERs) and neutron monitoring systems (83% for NPRDS, 24% for LERs). A large percentage of these failures can be attributed to oxidized, corroded, or dirty contact surfaces.

6. Failures of hookup or panel wire constitute a substantial percentage (36% for NPRDS, and 14% for LERs) of the total number of low-voltage circuit component failures. A large fraction of these failures are not the result of aging influences, but rather stem from design, installation, maintenance, modification, or testing activities.

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[21] Only 18% of the NPRDS reports for low-voltage cable were attributable to thermal stress; however, this was the single most significant cause, and nearly half (49%) of the total number of reports did not identify a cause. Assuming that the same proportion (18/51) of these unidentified failures is due to thermal stressors, about 36% of all NPRDS low-voltage cable failure reports can be attributed to thermal degradation. In addition, even severely embrittled and cracked low-voltage cable may operate without failure in certain environments; introduction of other stressors after such degradation has occurred (such as moisture during operations or LOCA) may ultimately induce the failure.

7. Wetting concurrent with operating voltage stress appears to produce significant aging effects on medium-voltage power cable.

8. Loosening and breakage of lugs are the most significant compression fitting failures by a wide margin, based on both NPRDS and LER data.

9. Damage to cable insulation during or prior to installation may be crucial to a cable's longevity, particularly for medium-voltage systems.

3.8 References

3.1 IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," The Institute of Electrical and Electronics Engineers, Inc., corrected copy June 1976.

3.2 NRC IE Bulletin 79-01B, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," Enclosure 4 to "Environmental Qualification of Class 1E Equipment," Nuclear Regulatory Commission, January 14, 1980 (in practice, referred to as the DOR Guidelines).

3.3 NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Equipment Including Staff Responses of Public Comments, Resolution of Generic Technical Activity A-24," Nuclear Regulatory Commission, Rev. 1, July 1981.

3.4 Title 10, U.S. Code of Federal Regulations, Part 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," (10CFR50.49), published in the Federal Register, Vol. 48, No. 15, January 21, 1983 (pages 2730 to 2734).

3.5 Title 10, U.S. Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," published in the Federal Register, Vol. 60, May 8, 1995 (page 22461).

3.6 EPRI EL-5036, "Wire and Cable," Power Plant Electrical Reference Series, Vol. 4, Electric Power Research Institute, 1987.

3.7 EPRI NP-7485, "Power Plant Practices to Ensure Cable Operability," Nuclear Maintenance Applications Center, Electric Power Research Institute, July 1992.

3.8 NRC Information Notice 87-52, "Insulation Breakdown of Silicone Rubber-Insulated Single Conductor Cables During High Potential Testing," Nuclear Regulatory Commission, October 1987.

3.9 NRC Information Notice 86-71, "Recent Identified Problems with Limitorque Motor Operators," Nuclear Regulatory Commission, August 1986.

3.10 NRC Information Notice 93-33, "Potential Deficiency of Certain Class 1E Instrumentation and Control Cables," Nuclear Regulatory Commission, April 28, 1993.

3.11 NRC Information Notice 92-81, "Potential Deficiency of Electrical Cables with Bonded Hypalon Jackets," Nuclear Regulatory Commission, December 11, 1992.

3.12 NUREG/CR-5772, "Aging, Condition Monitoring, and Loss-of Coolant Accident (LOCA) Tests of Class 1E Electrical Cables" (in three volumes: Vol. 1, "Crosslinked Polyolefin Cables;" Vol. 2, "Ethylene Propylene Rubber Cables;" Vol. 3, "Miscellaneous Cable Types"), Sandia National Laboratories, August 1992, November 1992, and November 1992.

3.13 NUREG/CR-6095, SAND93-1803, "Aging, Loss-of-Coolant Accident

(LOCA), and High Potential Testing of Damaged Cables," prepared by SEA Inc., and Sandia National Laboratories, April 1994.

3.14 EPRI NP-7189, "Review of Polyimide Insulated Wire in Nuclear Power Plants," Electric Power Research Institute, February 1991.

3.15 NRC Information Notice 88-89, "Degradation of Kapton Electrical Insulation," Nuclear Regulatory Commission, November 1988.

3.16 NUREG/CR-2157, "Occurrence and Implications of Radiation Dose-Rate Effects for Material Aging Studies," prepared by Sandia National Laboratories, June 1981.

3.17 NUREG/CR-4301, SAND85-1309, "Status Report on Equipment Qualification Issues Research and Resolution," prepared by Sandia National Laboratories, November 1986.

3.18 NRC Information Notice 92-01, "Cable Damage Caused by Inadequate Cable Installation Procedures and Controls," Nuclear Regulatory Commission, January 1992.

3.19 NRC Information Notice 89-30, "Excessive Drywell Temperatures," Nuclear Regulatory Commission, March 1989.

3.20 NRC Information Notice 86-49, "Age/Environment Induced Electrical Cable Failure," Nuclear Regulatory Commission, June 1986.

3.21 NRC Information Notice 82-03, "Environmental Tests of Electrical Terminal Blocks," Nuclear Regulatory Commission, March 4, 1982.

3.22 NRC Information Notice 80-08, "The States Company Sliding Link Electrical Terminal Block," Nuclear Regulatory Commission, March 7, 1980.

3.23 NRC IE Circular 77-06, "Effects of Hydraulic Fluid on Electrical Cables," Nuclear Regulatory Commission, April 1977.

3.24 EPRI TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables," Electric Power Research Institute, August 1994.

3.25 EPRI NP-5002, "LWR Plant Life Extension," Interim Report, Electric Power Research Institute, January 1987.

3.26 NUREG/CR-3122, ORNL/NSIC-213, "Potentially Damaging Failure Modes of High- and Medium-Voltage Electrical Equipment," prepared by Oak Ridge National Laboratory, August 1983.

3.27 EPRI TR-103841, "Low-Voltage Environmentally-Qualified Cable License Renewal Industry Report," prepared by Sandia National Laboratories and Strategic Technologies and Resources, Inc., Revision 1, July 1994.

3.28 NUREG/CR-5461, SAND89-2369, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants," prepared by Sandia National Laboratories, July 1990.

3.29 EPRI EL-3501, "Characterization of Failed Solid-Dielectric Cables: Phase I," Electric Power Research Institute, August 1984.

3.30 EPRI EL-5387, "Characterization of Failed Solid-Dielectric Cables: Phase II," Electric Power Research Institute, September 1987.

3.31 NUREG/CR-5643, "Insights Gained from Aging Research," prepared by Brookhaven National Laboratory, March 1992.

4. STRESSORS AND AGING MECHANISMS

This section describes applicable stressors and aging mechanisms, and assesses the potential significance of these mechanisms for low- and medium-voltage cables and terminations. These stressors and aging mechanisms were determined by considering the design, applications, and operating experience of the cables, along with relevant industry research, information, and reports. Guidelines or criteria are also developed to aid plant personnel in evaluating the severity of a given stressor or aging mechanism and its effects on aging of cables and termination components. If the relevant criteria are met (or, in the case of a quantitative threshold, exceeded), then the effects of the associated aging mechanism may be substantial for that component; these are referred to as "if-then" criteria. Note that the development of these criteria is separate from the determination of the significance of a given aging mechanism (Section 4.2 below); "if-then" criteria merely assist a plant operator in determining whether the environmental and operational stressors present at his/her plant are of a sufficient type and/or magnitude to result in substantial aging effects on the plant's cable systems. As discussed in Section 4.2, the significance of an aging mechanism (for the purposes of this document) centers more around whether loss of component functionality may result, and whether the loss of functionality has been observed to occur at a comparatively high frequency in relation to other aging mechanisms.

4.1 Stressors Acting on Cables and Terminations

A stressor is an "agent or stimulus that stems from pre-service and service conditions and can produce immediate or aging degradation of a system, structure, or component" [4.1]. Stressors result in aging mechanisms, which are "specific processes that gradually change the characteristics of a system or component with time or use" [4.1]. Stressors caused by normal operation and environmental conditions have a direct effect on the existence and progression of aging mechanisms. It is therefore important to understand the behavior of materials when subject to these various stressors in order to design and operate the component satisfactorily and to develop methods for detecting and mitigating component degradation.

The stressors that are relevant to cables, splices, connectors, compression/fusion fittings, and terminal blocks, either individually or in combination, include the following:

- Thermal
- Electrical
- Mechanical
- Radiation
- Chemical and electrochemical[1]
    - Oxygen
    - Ozone
    - Moisture/humidity
- Dirt, dust, and other contaminants

[1] Oxygen, ozone and moisture/humidity are all chemical stressors. They are listed individually because they are the most significant chemical stressors for polymers.

Although not directly producing stress, oxygen, humidity, dust, dirt, and other types of contamination may intensify the effects of other stressors acting on cable systems and related components and may result in more rapid deterioration.

It should also be noted that certain types of degradation may result only from the combination of two or more stressors. For example, voltage stress and moisture may combine to produce degradation of dielectric materials that would otherwise not occur in the presence of one stressor alone. Similarly, some stressors act to accelerate the degradation that would otherwise be experienced from another stressor; the effect of oxygen on thermal- or radiation-induced degradation is such a case. Hence, both individual stressors and their potential interactions with other stressors must be considered when evaluating the degradation potential of cable system components.

Cables are unique compared with other plant equipment in that they are distributed components, and traverse multiple plant locations and environments. Accordingly, individual sections of a given cable may age or degrade at different rates based primarily on the severity of their respective environments.

The following sections discuss the effects on cables and terminations of each stressor listed above and provide insight into the aging mechanisms applicable to each of the cable and termination components listed in Section 3 of this AMG.

4.1.1 Thermal Stressors and Aging Mechanisms

Thermal stress results from exposure of cable system components to normal and abnormal environments. Environmental influences that may induce thermal stress on a cable or associated termination may result from general area ambient temperatures, localized high temperatures (hot spots), or electrical heating resulting from current flow within the components. Elevated temperature produces some degree of aging in most organic materials. The effects of thermally induced degradation of organics may include embrittlement, cracking or crazing, discoloration, melting, and a change in the mechanical and electrical properties of the material(s) that are essential for the cable or connection to perform its design function. Thermoxidative reactions (i.e., those occurring in the presence of oxygen) are considered in Section 4.1.5.5.

4.1.1.1 Thermal Degradation of Organic Materials

Thermal energy absorbed by polymers initiates various types of chemical reactions within a polymer. Direct effects of this energy absorption include increased molecular excitation. Because organic materials are characteristically covalently bonded (electron sharing), damage to these bonds readily results from such excitation. In solid polymers, free radicals may be formed which help induce other chemical reactions, the predominant types which have important effects on mechanical properties are crosslinking and chain scission. Crosslinking refers to that process where long chain molecules typically present in polymers are covalently bonded together. Chain scission, on the contrary, is the breaking of these chains into smaller pieces. In fact, both scission and crosslinking usually occur during polymer degradation.

Each of these processes will result in some sort of effect on the macroscopic properties of the material, depending on their relative importance and the degree of reaction. Crosslinking will generally result in increased tensile strength and hardening of the material, with some loss of flexibility and eventual decrease in elongation-at-break. Note that crosslinking may be induced during the manufacturing process (chemically or via irradiation) to produce desired properties in certain materials. Scission generally produces reduced tensile strength; however, elongation may increase, decrease, or remain essentially constant, depending on the type of polymer and the level of degradation.

Other effects that may occur in polymers include crystallization and chain depolymerization, where molecules "unzip" in sequential fashion due to the free radicals at the ends of the scissioned molecule. Crystallization is often the result of exposure to high temperature or rapid heating/cooling of a material and therefore is generally not considered an aging phenomenon, although in some instances scission processes can result in enhanced crystallinity. Chain depolymerization is basically a subset of the chain scission process that occurs during normal aging to varying degrees based on the material type and aging influences.

Thermal degradation effects on cable system materials can be divided into two categories based on the longevity of exposure and the dominant physical processes: short-term and long-term. Short-term effects will typically result from relative extremes of temperature and can occur over a very brief period of exposure. Long-term effects, on the other hand, occur over a more protracted period and are commonly associated with the concept of component "aging." Each of these types of degradation is discussed in the following sections.

4.1.1.1.1 Short-Term Thermal Degradation

Exposures of organic materials to comparatively high temperatures (e.g., those well in excess of normal ambient aging temperatures or cable service ratings) may produce other types of physical or chemical processes and degradation not normally associated with low-temperature aging. For example, exposure of thermoplastics to high temperatures can result in reduced viscosity or melting, thereby allowing material deformation (flow) under mechanical stress. This situation can ultimately affect the mechanical and electrical properties of the material (including reduced thickness, electrical resistance, etc.) and produce shorts, leakage, or other undesirable effects.[2] For other materials, crystallization resulting from thermal exposure can produce substantial and irreversible changes in physical properties such as tensile strength, compression set, elongation, and viscosity as well as electrical performance [4.2]. In addition, differential thermal expansion of materials at low temperature can create substantial mechanical stress and result in cracking of certain cable or termination components. At high temperatures, thermal expansion of organic components can place significant stress on nearby components.[3]

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[2] Overcurrent testing observed by the authors on small-gauge Tefzel® (ETFE) insulated wire caused the insulation to melt and dissociate from its conductor due to the sustained high conductor temperatures during the test.

[3] For example, thermal expansion of a polymer grommet constrained inside the connector assembly of a D. G. O'Brien electrical penetration assembly caused damage to nearby components, thereby necessitating redesign. The thermal expansion was attributed to the comparatively large temperature swings experienced by the containment-side connector as primary containment temperature changed. See NRC Information Notice 81-20 for additional information.

Note that the susceptibility of each component or material to such short-term effects may depend on several factors, including the type of material, the peak temperature to which it is exposed, the duration of exposure, ambient environmental conditions (humidity, oxygen concentration, etc.), and the rate of heat input/component temperature change. A precise temperature or other criterion that differentiates long-term aging from short-term degradation may be impractical or impossible to determine for many materials. Rather, knowledge of the differences in effects of such exposures (if any) can be useful in identifying short- versus long-term degradation mechanisms. Furthermore, modeling of short-term thermal degradation by use of the Arrhenius equation (described below) is generally not valid, because the fundamental chemical and physical processes induced by the higher temperatures may be significantly different from those which occur under more typical low-temperature thermal aging. Hence, it is often difficult or impossible to assess how much of a material's lifetime has been "lost" as a result of a brief exposure to high temperature.

4.1.1.1.2 Long-Term Thermal Degradation

Long-term thermal degradation of cable system materials is controlled by the mechanisms described in Section 4.1.1.1. Multiple models describing long-term thermal degradation of organic materials have been developed, such as the Arrhenius, Eyring, and inverse power models, which are described in detail in EPRI NP-1558 [4.3]. The Arrhenius model, which provides a relationship between material lifetime and thermal stress (that is, temperature), is by far the most commonly used and recognized, and is described below.

Arrhenius Model

The Arrhenius model relates the rate of degradation (reaction) to temperature through the following exponential function [4.3]:

$$R = Ae^{(-\phi/kT)}$$

where:

R	=	rate at which the degradation reaction proceeds
A	=	frequency factor (constant for the material under evaluation)
ϕ	=	activation energy (eV)
k	=	Boltzmann's constant (8.617×10^{-5} eV/K)
T	=	absolute temperature (K)

The activation energy, ϕ, is a measure of the energy required to produce a given type of endothermic reaction within the material. This parameter can be correlated to the rate of degradation; that is, materials with higher activation energies will thermally degrade at a slower rate than those with lower activation energies.

A common form of the Arrhenius equation relates the degradation time for a material at one temperature to that at another temperature as follows:

$$t_1 = t_2 \, e^{[\phi/k \, (1/T_1 - 1/T_2)]}$$

where:

t_1 = time at temperature T_1
t_2 = time at temperature T_2

According to this form of the equation, exposure of a material of activation energy ϕ to temperature T_2 for a period of t_2 produces degradation equivalent to exposure at T_1 for period t_1. Implicit in this relationship is the idea that exposure of a material at higher temperature for shorter duration will result in degradation equivalent to that resulting from longer exposure at lower temperature.

This relationship is useful in that:

- the longevity of a given material at a different temperature may be estimated;
- long-term, low-temperature aging (similar to that which generally occurs in nuclear power plant environments) can be approximated through the use of higher temperatures for shorter durations (i.e., accelerated aging);
- the model can be used to compare basic properties of one material with those of another during the development of a new cable product.

The Arrhenius model does have several theoretical and practical limitations; for example, (1) reactions and aging mechanisms at high temperature and normal service temperatures may be different (i.e., activation energy (ϕ) may be a function of temperature, rather than constant); (2) the potential for problems when extrapolation through a material phase transition region (e.g., crystalline melting point region) is necessary; (3) use of regressed statistical data, which may generate varying results for activation energy based on the endpoint criterion selected; and (4) unavailability, in some instances, of activation energy information for specific material formulations (i.e., generally, activation energies are available for a given class of material) [4.3], [4.4], [4.5], [4.6]. These limitations stem largely from the relatively simplistic kinetic model used as the basis for the relationship, and the use of empirical data for the determination of activation energy. In addition, highly accelerated aging may produce heterogeneous aging effects within the material, due mostly to the limited opportunity for oxygen diffusion into all but the surface layers of the material [4.7], [4.8]. Thus, artificial aging may produce effects on the material (such as changes in macroscopic physical properties) that are largely an artifact of the accelerated aging process. The Arrhenius relationship should be used with caution. Although it may be used to provide a generalized description of the correlation between thermal exposure and degradation, it may produce results that are not representative of the actual behavior of the material under actual long-term aging conditions. EPRI NP-1588 [4.3], EPRI TR-100516 [4.4], a book chapter on accelerated aging methods [4.5], and SAND88-0754 [4.6] discuss the Arrhenius model, its uses, and limitations in greater detail.

Practical Implications of Arrhenius Model

Arrhenius calculations are commonly used as a part of the basis for the environmental qualification of equipment. The general approach is to use this relationship, empirical data from controlled tests (activation energy and life at test temperature), and enveloping assumptions regarding the equipment's operating environment to determine a theoretical or "qualified" life for a material. This qualified life is essentially the allowable in-service time for the material given the assumption that the component must be able to function under accident environments, even at the end of its qualified life. Even for non-environmentally qualified equipment, the relationship may be used to estimate the effects of environments on material longevity.

As a result of the exponential Arrhenius relationship, a small change in a material's aging temperature produces a substantial change in its longevity. As an example, the extrapolated time for a Neoprene® rubber cable jacket to reach an endpoint of 50% absolute elongation at 40°C (104°F) is roughly 130 years.[4] The time to reach the same endpoint at 50°C (122°F) is approximately 44 years. Hence, reducing the aging temperature from 50 to 40°C increases the estimated longevity of the material by nearly a factor of three (a difference of 86 years). The practical outgrowth of this relationship is that reducing an organic material's service temperature a small amount can result in significant gains in longevity (discounting other potentially life-limiting influences).

Figure 4-1 illustrates the general relationship between aging temperature and longevity for various common cable and termination materials. This graph is derived from experimental aging data obtained from several sources, including manufacturer's aging studies and qualification testing for general applications [4.9], [4.10], [4.11], [4.12], CSPE and Neoprene® [4.13], ethylene propylene diene monomer (EPDM) [4.14], EPR [4.15], ETFE [4.16], PVC [4.17], Silicone [4.18], Viton [4.19], and XLPE [4.20]. *Note that these data are not applicable to all material formulations and plant-specific evaluations are required.* Based on the Arrhenius equation, a linear regression of 1/T versus log(t) can be performed on thermal aging test data to calculate the activation energy resulting from the "best fit" line for the data. Such aging tests are often conducted at elevated temperature (on the order of 140°C or above) to permit more rapid completion of the tests; hence, the resulting curves must be extrapolated to lower temperatures. As previously discussed, such extrapolation of the linear regression curve may or may not be representative of the actual behavior of the material in the lower temperature region. A common aging endpoint was specified for all of the data[5] (50% retention of absolute elongation); hence, the results are comparable in this regard. This endpoint is considered conservative in that bending and manipulation without cracking has been demonstrated for absolute elongation values below 50%. Note that the curve shown for each material is specific to one manufacturer's formulation; thus, the results obtained for a specimen of the same generic class of material yet produced by a different manufacturer may vary substantially. However, the results shown in the figure may be considered representative of the relative thermal aging characteristics of the generic classes of material.

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[4] Based on data contained in "Comparative Heat Resistance of Hypalon and Neoprene" [4.13].

[5] With the exception of the EPDM, PVC, Silicone and PVC data, for which $e_{absolute}$ = 50% data were not available. See Table G-1.

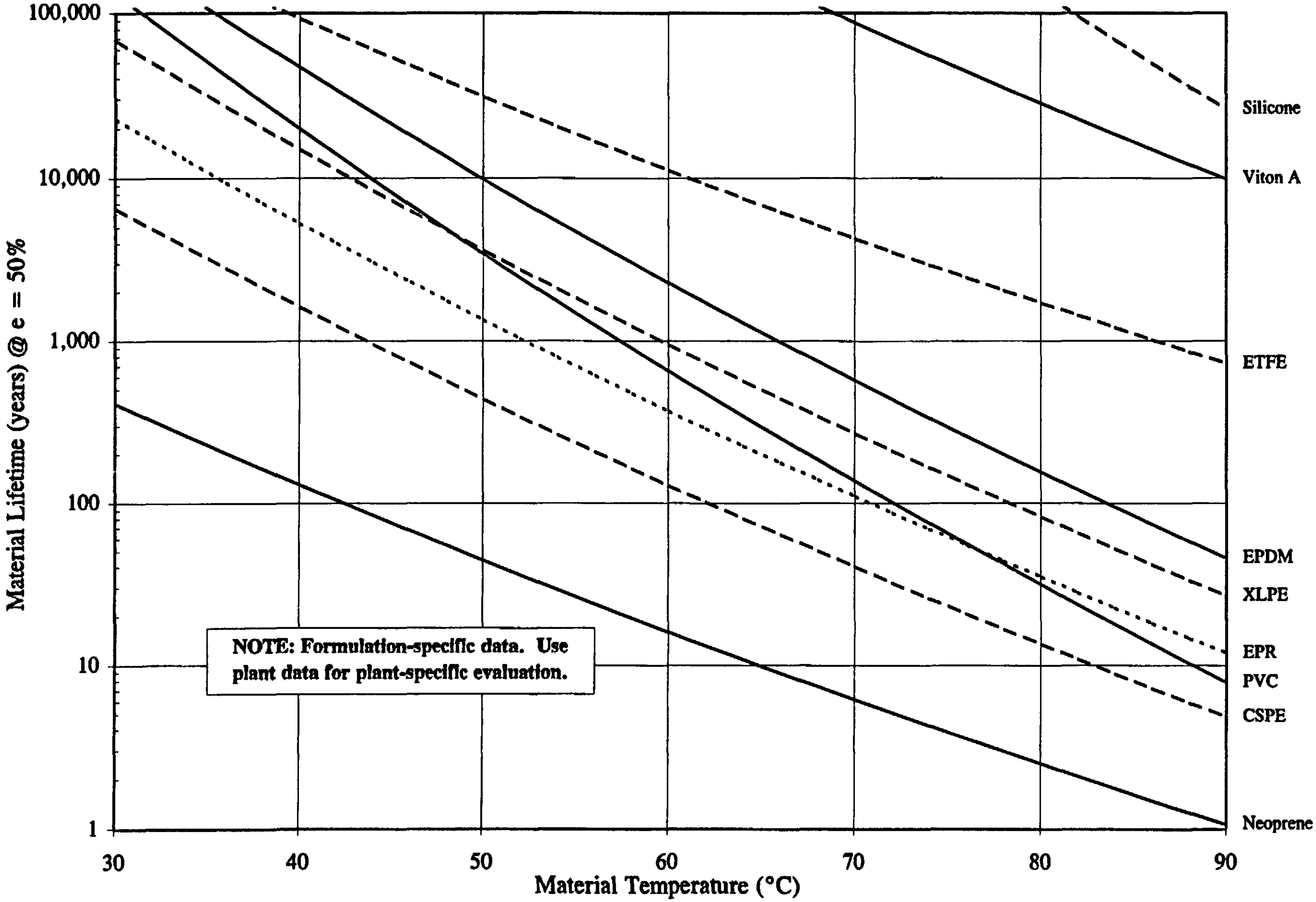

Figure 4-1 Extrapolated Time to Retention of 50% Absolute Elongation for Various Cable and Termination Materials

As shown in the figure, the thermally superior material is silicone rubber, where the extrapolated time to 50% absolute elongation is in excess of 10^4 years at 90°C. Clearly, the common insulation materials [including EPR, EPDM, XLPE, silicone, and ETFE (Tefzel®)] have far superior thermal performance than the common jacket materials (CSPE, PVC, and Neoprene®)[6]. Viton (a common seal material) also shows exceptional thermal capability.

4.1.1.2 Sources of Thermal Stress

For most plant areas, normal (i.e., non-accident) general area temperatures result in slow degradation of cable materials over the entire length of cable exposed to that environment (i.e., bulk aging). Localized heat sources, however, may produce comparatively severe damage in a small section of the cable within a short period of exposure. Elevated temperatures caused by thermal stratification in the ambient air volume can age large sections of cable located at higher elevations within an enclosed space. Aging may also result from ohmic and eddy current heating of cable conductors and associated components. Each of these mechanisms is described in the following paragraphs.

Ambient Effects

Normal general area temperatures within various plant spaces result from the interaction of various influences, such as the types and number of heat-producing equipment in operation in that space; the number and lineup of heating, ventilating, and air conditioning (HVAC) systems in operation; the thermal conductivity of the bounding surfaces such as walls and floors; external (outdoor) temperature; and the temperature of adjacent spaces. These general area temperatures are controlled to remain within technical specifications or other established design limits for that space. Normal general area aging temperatures can be estimated through (1) examination of the plant's environmental study, which estimates a maximum value for each plant zone, or (2) use of installed temperature monitoring equipment. The maximum temperature values obtained from the plant environmental study are considered conservative (i.e., bounding) with regard to actual general area temperatures; hence, estimates of bulk cable aging based on these values may also be conservative. Temperature monitoring equipment (if installed) provides direct data for the representative general area temperature of a given space, assuming the detectors are installed in representative locations that are free from localized effects such as a direct heat source or ventilation air flow.

Localized Heating

Hot spots are a major concern to cable longevity because severe localized aging resulting in embrittlement and cracking of the jacket and insulation may occur. Hot spots affect portions of a given cable run, and the rate of material degradation due to hot spot exposure is generally significantly higher than that experienced in bulk aging. The rate is dependent on the nature of the cable materials (some are more heat resistant than others), the intensity of the heat source and the cable's proximity to it, and the existence of any mitigating factors such as shielding or

[6] Note that the thermal lifetime of polyimide (Kapton®) is estimated to be nearly 10^4 years at 90°C and 0% relative humidity; however, its estimated lifetime at 100% relative humidity (or submerged) is only in the hundreds of hours [4.25].

ventilation. Localized aging caused by hot spots is of more immediate concern due to the potential rapid aging; degradation and possible loss of functionality may occur relatively rapidly for cables exposed to hot spot conditions. Furthermore, as described above, short-term degradation effects (such as melting and flowing, crystallization, and thermally induced mechanical stresses) may result from severe localized heating. It should be noted that most localized aging or degradation will occur at or near the connected end device, because this represents the most significant heat source for most circuits. Typical locations where cables/terminations may be exposed to hot spot conditions include main steam isolation valves (MSIVs), safety/relief valves (SRVs), pressurizer cubicles (in PWRs only), in the vicinity of steam piping (radiant heating) or steam leaks, and areas with degraded HVAC.

Ohmic Heating

Another source of thermal stress on cable materials is ohmic (I^2R) heating resulting from electrical current. This phenomenon generally affects the entire cable run, although localized effects may occur.[7] As current flows through a conductor, heat is generated by the resistance of the conductor. I^2R losses and the rate of heat generation in cable conductors are related to a number of factors, including the resistance (or conductance) of the constituent conductor materials, the current being carried, and the presence of magnetic field interactions determined by the geometry and physical arrangement of the conductor(s) [4.21]. For a given conductor size, increased current will increase the heat generated by the conductor. The radial thermal gradient (ΔT) between the conductor and outer cable surface depends on several factors, including the thermal conductivity of the insulation and jacket (and any other components in between), their thicknesses, and the ambient temperature. Accordingly, ampacity limits (e.g., the design current carrying capability) for a given cable will vary based on the conductor size and resistance, cable materials, installation geometry, and ambient temperature in which the cable operates. Base ampacities are developed to ensure that the maximum temperature rating of the insulation material is not exceeded under the installed and operating conditions of the cable (including the use of 10CFR50 Appendix R fire wrap materials). Power cables are selected such that their base ampacity equals the rated full load current of the connected load multiplied by a "safety" factor (typically 1.15 or 1.25). This safety factor is included to address potential operation of the load above its rating or during periods of peak distribution system demand when voltage is reduced [current increases during low voltage conditions (brown out) since the same power is still required to operate a device (e.g., a motor)].

Relevant ICEA standards assume that all cables located in trays operate at their rated ampacity. Conduit ampacities are based on the use of the smallest possible conduit in which the cable(s) will fit; as conduit size is increased, heat transfer is improved and cable operating temperature lowered. Duct bank ampacities are based on the worst-case seasonal ground temperatures.

Under most conditions, therefore, the cables can be expected to operate at temperatures well below the thermal rating of the insulation. Other factors that may contribute to this general

[7] A second type of ohmic heating may occur due to the presence of leakage currents. In degraded insulation, leakage current through the dielectric may produce direct ohmic heating of the insulation. In severe cases, this heating may result in localized degradation of the insulation and eventual breakdown.

observation include (1) use of over-sized cable due to voltage drop and short circuit considerations, (2) cables to motors requiring less than their rated horsepower, and (3) margins applied for future load growth considerations. Exceptions to this general rule may include electrical faults (the cable may operate at temperatures above the insulation's continuous thermal rating but below its short circuit thermal rating) and accident conditions [such as loss-of-coolant accident (LOCA)] where the ambient temperature exceeds that considered in formulating the base ampacity.

Thermal aging resulting from conductor ohmic heating is potentially significant in power cable applications where the connected load is operated for a significant percentage of its installed lifetime and the current during such operation is a substantial percentage of the ampacity of the cable. Note that ampacity is a function of ambient temperature; therefore, the ambient environments through which the cable passes must be identified to calculate the cable operating temperature and associated aging effect. Intermittently operated, low duty factor loads at high current may result in substantial aging of the associated cable. Loads run continuously at operating currents that are small relative to the ampacity of the cable will result in little cable aging. Instrumentation and control circuits characteristically operate at such low currents that no appreciable ohmic heating occurs. Based on the conservatisms and factors accounted for in the determination of cable, tray, conduit, and duct bank ampacities, and the large number of nonpower applications, very few plant circuits are expected to experience any appreciable amount of ohmic heating-induced aging. Note also that, because the conductor is in direct physical contact with the insulation, the aging resulting from conductor ohmic heating occurs "inside-out" and that this aging may be limited by poor oxygen diffusion to the interior portions of the insulation. Appendix G and IEEE S-135 [4.22] provide additional guidance on estimating conductor temperature for a given type of cable under prevailing environmental and load conditions.

Other circuits in direct proximity to the loaded circuit (e.g., located in the same raceway) may also be affected by the ohmic heating of the loaded circuit. This effect results from heating of the nonloaded cable insulation through direct contact and heating of the surrounding airspace within the conduit. Therefore, the thermal aging of all conductors (loaded or unloaded) in the same raceway as the suspect cable must also be considered. Section 4.1.1.3 and Appendix G provide additional information and guidance regarding the evaluation of individual circuits for potential ohmic heating-induced aging.

In addition to the conductor, ohmic heating of other conductor and termination components may occur due to a variety of phenomena. Corrosion, oxidation, insufficient contact pressure, and improper swaging or crimping may result in poor electrical contact (high resistance connections/joints) between the cable conductor(s) and terminations, or between individual components within a termination conducting path. Organic components in the vicinity of this high resistance (such as cable or splice insulation) will undergo premature thermal aging compared with the rest of the circuit. If the rate of heating/temperature is extreme, more severe damage to the component(s) may occur.

Circulating Currents

Circulating currents may be induced in metallic components by virtue of varying magnetic fields in their vicinity. Magnetic fields are created by current flowing through a conductor; alternating current circuits will accordingly produce alternating magnetic fields. As the magnetic flux permeating the component varies, an electromotive force (emf) is established, which creates circulating current flow within the component. This circulating current may generate heat through ohmic losses in the shield [4.21]. For example, shielding installed in cable that is grounded at both ends may carry significant circulating currents and therefore be subject to appreciable heat. Cable ampacity tables [such as those in Insulated Power Cable Engineers Association (IPCEA) P-53-426/NEMA WC50-1976 [4.23]] are often corrected for the effects of such circulating current losses.

Seasonal Temperature Effects

Another factor that can affect cable system thermal aging is the variation in ambient temperature due to daily, seasonal, or operational effects. Throughout a given day, outside air (and water) temperature may vary significantly; also, solar radiant heat transfer may account for additional temperature rise in exposed components during daylight hours. Much larger ambient temperature variations may occur over the course of a given year; differences in air temperature of more than 50°C [90°F] are not uncommon for some portions of the country [4.21]. Operational temperature effects stem from significant changes in plant operating status, such as maintenance or refueling outages.

Minimum and maximum allowable temperatures are usually specified for most major plant spaces, and HVAC systems are operated so as to maintain these temperatures. However, in some cases, these temperature bands are not or cannot always be maintained. Hence, seasonal or daily variations in temperature within these spaces may be fairly large. Figure 4-2 illustrates seasonal temperature variations for various elevations in the primary containment of a typical U.S. nuclear plant. Note that the magnitude of the change from summer to winter for the plant shown is on the order of 14 to 17°C [25 to 30°F]. Figure 4-3 shows the variations for one elevation in a plant reactor building; similar yet smaller changes are evident. Seasonal temperature changes in other plant areas (such as service water pump houses or other structures separate from the reactor/turbine buildings) may have larger variations in ambient temperature due to daily or seasonal effects because these spaces may have wider allowable temperature bands or no HVAC equipment. However, the effects of these latter variations are not considered of great importance from a cable system aging management perspective because (1) the relative fraction of the total plant cable population installed at these locations is usually quite low, (2) few if any EQ or safety-related circuits are located in such spaces, and (3) the maximum aging temperature to which these circuits would be exposed is generally well below that experienced in hotter areas of the plant (such as inside primary containment or steam piping tunnels).

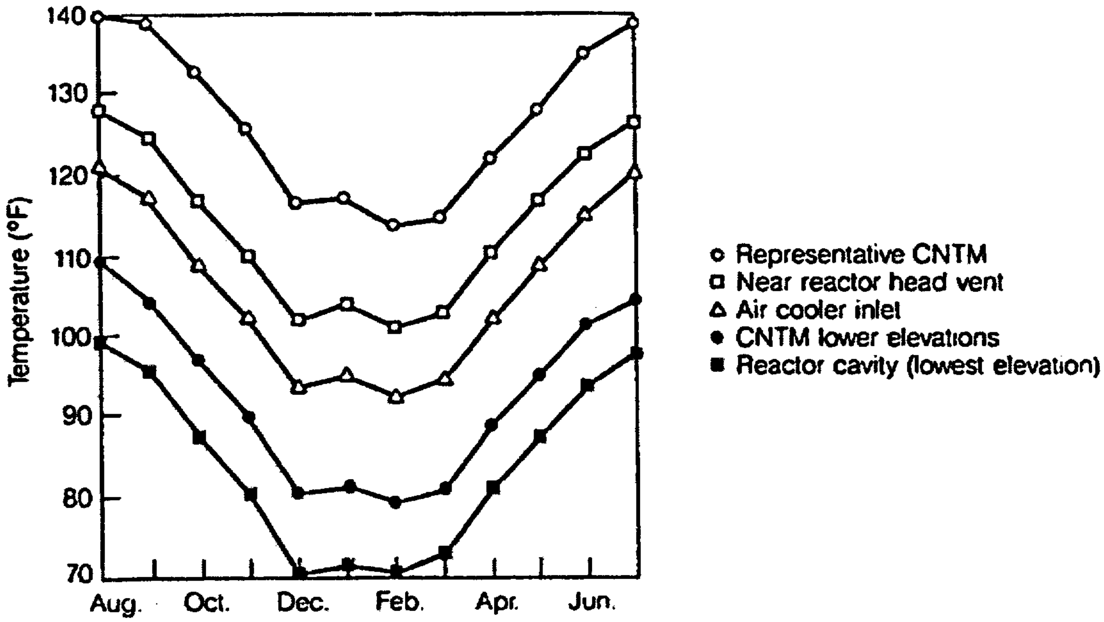

Figure 4-2 Seasonal Temperature Variations Within the Primary Containment of a Typical U.S. Nuclear Plant [4.24]
(Note: In the legend, CNTM is an abbreviation for containment)

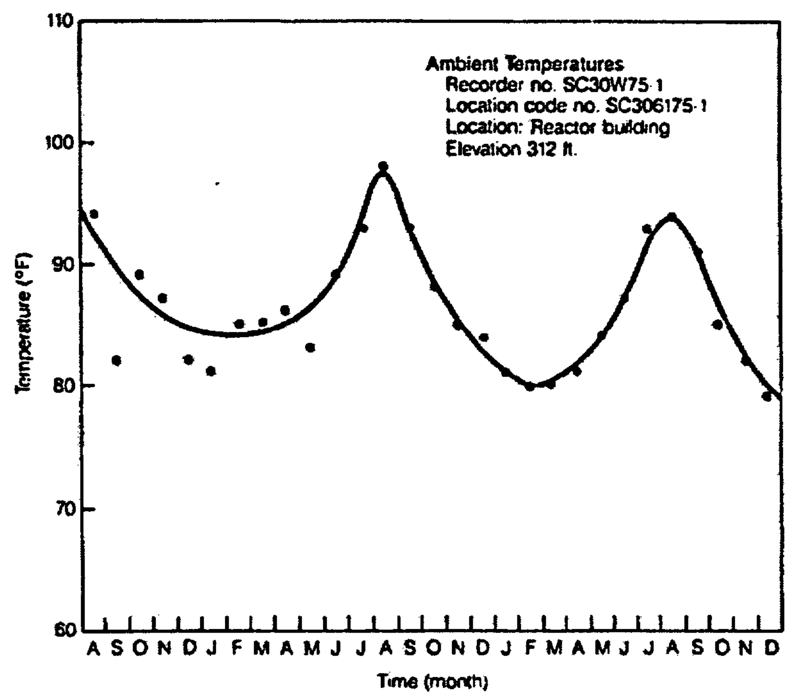

Figure 4-3 Seasonal Temperature Variations for a Single Elevation of Reactor Building of a Typical U.S. Nuclear Plant [4.24]

Changes in the ambient temperature in plant spaces are also largely a function of the operational status of the plant. Figure 4-4 shows variations in one plant's reactor building temperature as a function of time (and outages). Looking at the figure, a significant fraction of the lifetime of a given organic cable or termination component installed at this location will be spent at temperatures below 38°C [100°F]; the thermal aging occurring during these periods will be minimal, and the longevity of the component extended accordingly.

Thermally induced mechanical stress on cable and termination components may occur due to variations in component temperature with time. These variations may result from seasonal, daily, or operational changes in the ambient environment or current loading of an individual circuit. As the temperature of the cable/termination changes, various stresses can be produced by the interaction of components with each other or with surrounding equipment or structures. These stresses are considered mechanical in nature, and are discussed in subsequent sections of this AMG.

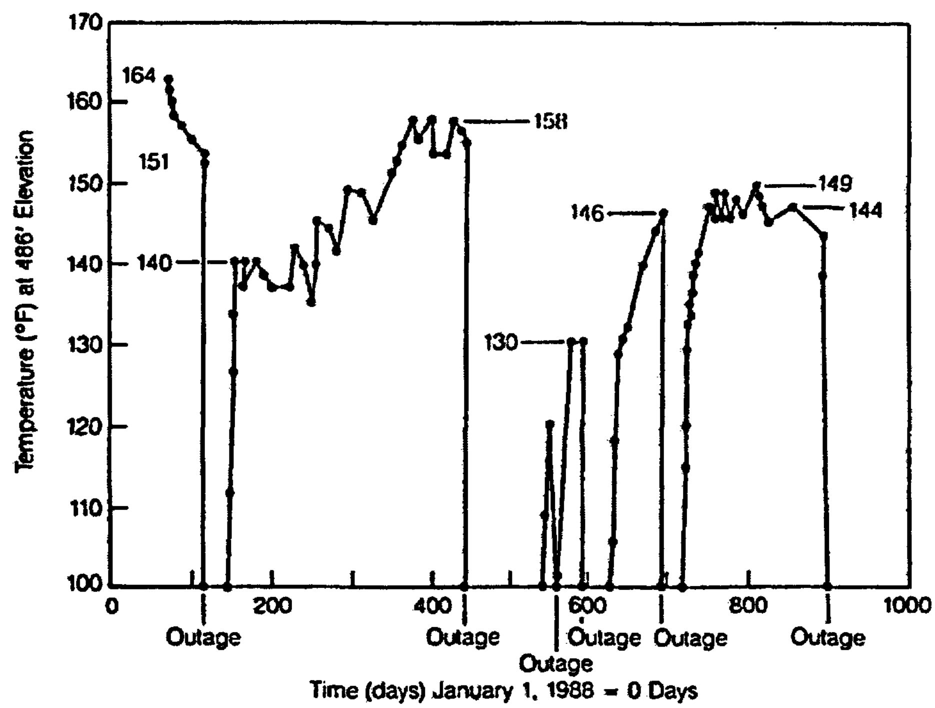

Figure 4-4 Operational Temperature Variations for a Single Elevation of a Reactor Building of Typical U.S. Nuclear Plant [4.24]

4.1.1.3 "If-Then" Criteria for Thermal Stressors and Aging Mechanisms

Table 4-1 lists the "if-then" criteria applicable to thermal stressors and aging mechanisms. Similar tables are presented for other stressors and aging mechanisms in subsequent sections of the AMG. For some of these stressors/aging mechanisms, no specific quantitative guidelines can reasonably be formulated; therefore, qualitative criteria are included in these instances. As a general rule, any quantitative criteria are set with sufficient conservatism that the functionality of the component will not be affected (based on an assumed 60-year period) if the criteria are not exceeded. For example, the recommended maximum ambient temperatures for each generic material type (Table 4-2 and Appendix G of this document) are derived based on an endpoint of 50% retention of absolute elongation, which is conservative with respect to continued cable insulation and/or jacket functionality during a design basis event.

It should be emphasized that the thermal aging criteria of Table 4-2 are meant only as a general guideline, and are not a replacement for more substantive evaluation based on the underlying stressors applicable to a given plant location and the specific types of materials in use. The model used to develop these guidelines (e.g., Arrhenius) may not explicitly consider the effects of radiation, long-term oxygen diffusion, or combined aging environments.[8] Therefore, caution must be exercised in their application. Accordingly, these criteria should only be applied in low dose-rate environments (less than about 0.02 Gy/hr [2 rad/hr], or roughly 10 kGy [1 Mrad] over 60 years) where thermal aging predominates[9] [4.6].

Note that Table 4-1 and similar tables which follow, where applicable, identify other coincident stressors or environmental conditions that may either be necessary for certain types of degradations to occur or may accelerate their effects. In this manner, significant combinations of stressors may be identified. At the end of this section, Tables 4-14 through 4-18 identify aging mechanisms and effects that are considered significant (i.e., that potentially affect functionality) for each cable and termination subcomponent in Section 3.5.

Table 4-2 differentiates between the maximum recommended temperature for the material based on a 60-year lifetime and the maximum recommended ambient (general area) temperature for power cable applications where the material is used as conductor insulation. The difference between the two stems from the additional temperature rise of the enclosed conductor due to ohmic heating. As discussed in Appendix G, the latter value assumes a continuous and high relative loading (80% of ampacity), and is therefore somewhat conservative. Ratings for each insulation material were chosen based on ICEA standard requirements and/or manufacturer's product data. Note that these ratings may vary for cables of the same insulation material (e.g., three different types of silicone-insulated cables may have continuous ratings of 90°C, 120°C, and 150°C, respectively). Furthermore, the effects of ohmic heating are only significant for power cables; therefore, for instrumentation or control cables, the maximum recommended material temperature will be more applicable in evaluating circuit longevity.

[8] Section 4.1.6 provides additional information on combined thermal and radiation aging environments.

[9] As discussed in Section 4.1.4, the radiation damage threshold for most cable/termination materials is on the order of 10 kGy [1 Mrad]. Furthermore, the analyses described in Section 4.1.6 predict that the time to reach elongation endpoint (TED) is relatively invariant at this dose rate for most materials [4.6].

Table 4-1 Thermal Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Ambient heating (in oxygen environment[1]) (4.1.1.2)	Thermal and thermoxidative degradation	Embrittlement / reduced elongation[2]; variations in tensile strength; loss of antioxidant; loss of plasticizer	- Hard or brittle jackets, insulation, or other organic components - Spontaneous/bending-induced cracking of outer jacket or insulation - Material discoloration or crazing - Conductor discoloration - Shrink-back at joints - Increased compression set	All cable and termination organic materials (Note: Butyl rubber may soften with increased thermal exposure)	See Table 4-2[3]	Continuous (60 years)	Thermal aging of each material is a function of the applicable activation energy. Activation energy will vary somewhat within a generic class of material based on differences in formulation. Other factors (including oxygen concentration, aging temperature, etc.) also affect rate of thermal degradation.
Ohmic heating (in oxygen environment) (4.1.1.2)					See Figure 4-1	Assumes continuous energization	Curves may be adjusted for less than continuous energization; see Appendix G
Localized heating (in oxygen environment) (4.1.1.1.1; 4.1.1.2)					See Appendix G	See Appendix G	Measured at cable/component surface; reduces maximum potential thermal lifetime

Notes:

1. The term "oxygen environment" refers to normal prevailing atmospheric conditions (such as those found outside of primary containment) where the relative oxygen concentration is approximately 20%. As discussed in Section 4.1.5, as oxygen concentration is reduced, the rate of thermal or radiation-induced oxidative degradation is reduced accordingly for most materials.

2. Note that for certain materials, chain scission effects dominate, and increases in elongation may occur with increased thermal aging.

3. Maximum temperature may vary. See Figures 4-2, 4-3, and 4-4.

As an example of the application of the guidelines contained in Table 4-2 and the Arrhenius data in Figure 4-1, consider a 90°C rated, Neoprene®-jacketed, XLPE-insulated power cable installed at a location where the ambient temperature is 45°C (113°F). After 60 years, the insulation will reach 50% absolute elongation; however, the jacket will have degraded beyond the 50% absolute elongation threshold well before 60 years of operation. If the integrity of the jacket is required throughout the 60-year operating period, the lower temperature (14°C [57°F]) associated with Neoprene® must be considered. If jacket integrity is not required, then the less limiting insulation temperature may be used.

From a plant spaces approach (see Section 6), circuits contained in spaces whose degradation-weighted average ambient temperature is below the applicable value from Table 4-2 (e.g., 45°C [113°F] for the XLPE-insulated, power cable described above, assuming jacket longevity is not critical) can be eliminated from further consideration. Note that the application of the Table 4-2 guidelines will be somewhat over-inclusive. That is, all power cables that operate in ambient environments greater than or equal to those in the table will not reach the stated endpoint criterion before the expiration of 60 years, because the assumptions made in the derivation of these values (i.e., continuous operation at 80% of rated load) may be conservative. Few if any cables are expected to actually operate near this loading, especially when considering the effects of plant outages and other interruptions in operation.

However, by knowing the maximum allowable temperature for a given material that equates to a 60-year estimated thermal lifetime, the allowable fraction of rated ampacity for a given ambient temperature can be estimated (see Appendix G). This information can then be used to identify those circuits that are potentially at risk for reaching the endpoint criterion (50% absolute elongation) before the end of 60 years. Figure 4-5 illustrates how constant ambient temperature and constant electrical loading affects cable thermal life for the cable insulation materials listed in Table 4-1. Because the maximum allowable material temperature for a 60-life is fixed, the allowable electrical loading for any given material (and thus the I^2R heating of the cable) decreases as the ambient temperature is increased. In the figure, Neoprene® has the least thermal endurance and silicone rubber and Viton A have the most thermal endurance.[10] See Appendix G for more information on the effect of cable loading on thermal life, including an analysis of cables that are subject to variable service conditions during their life. The effects of fire wrap material or other cable configuration effects are not directly considered in this analysis; however, derated ampacities due to these factors may be substituted into the appropriate equation in Appendix G to analyze how the curves would change.

[10] The silicone rubber actually has greater thermal endurance than the Viton A even though Figure 4-5 appears to show the opposite. This is because the cable thermal ratings of the two materials are different; the silicone rubber cable operates at 120°C when at 100% of its rated ampacity, whereas the Viton A is only at 90°C.

Table 4-2 Recommended Maximum Ambient Temperature for a 60-Year Life Under Purely Thermal Aging Conditions

Generic Material Type[1]	Instrumentation and Control[2] Cable Recommended Maximum Ambient Temperature[3]		Power Cable[4] - Recommended Maximum Ambient Temperature @ 80% of its 30°C Ampacity[3]		Assumed Cable Thermal Rating - Dry
CSPE (Hypalon®)	66°C	152°F	31°C	88°F	90°C
EPDM[5]	88°C	190°F	50°C	121°F	90°C
EPR	75°C	167°F	39°C	101°F	90°C
ETFE (Tefzel®)	122°C	252°F	57°C	135°F	90°C
Neoprene®	47°C	117°F	14°C	57°F	90°C
PVC[5]	76°C	168°F	39°C	102°F	90°C
Silicone Rubber[5]	133°C	271°F	66°C	150°F	120°C
Viton A	147°C	297°F	77°C	171°F	N/A
XLPE/XLPO[5]	83°C	181°F	45°C	113°F	90°C

Notes:

1. Data are formulation specific. Use plant data for plant-specific evaluations.
2. For cables that have no ohmic heating, tabulated ambient temperatures are equal to the maximum recommended material temperature.
3. Based on 50% retention of absolute elongation (see Figure 4-1).
4. See Appendix G for derivation of maximum recommended temperatures for cable applications. Tabulated temperatures are for copper conductors.
5. See Table G-1 for end-of-life conditions for EPDM, PVC, silicone rubber, and XLPE.
6. The longevity of polyimide-insulated (Kapton®) wire varies greatly with temperature and humidity. Applying the methodology of Appendix G to the data contained in Table 4-3 of EPRI NP-7189 [4.25] yields a maximum 60-year equivalent temperature of greater than 100°C for dry cable applications [0% relative humidity (RH)]. However, for 100% RH conditions, Kapton®-insulated wire may fail well before 60 years at 20°C.
7. If the material is used as a jacket, then the maximum ambient temperature can be exceeded unless jacket integrity is required (e.g., for beta radiation shielding, to protect the cable insulation from moisture). Generally, the cable jacket is only required for physical protection of the insulation during cable installation and the insulation's properties would be used to determine the cable's lifetime.

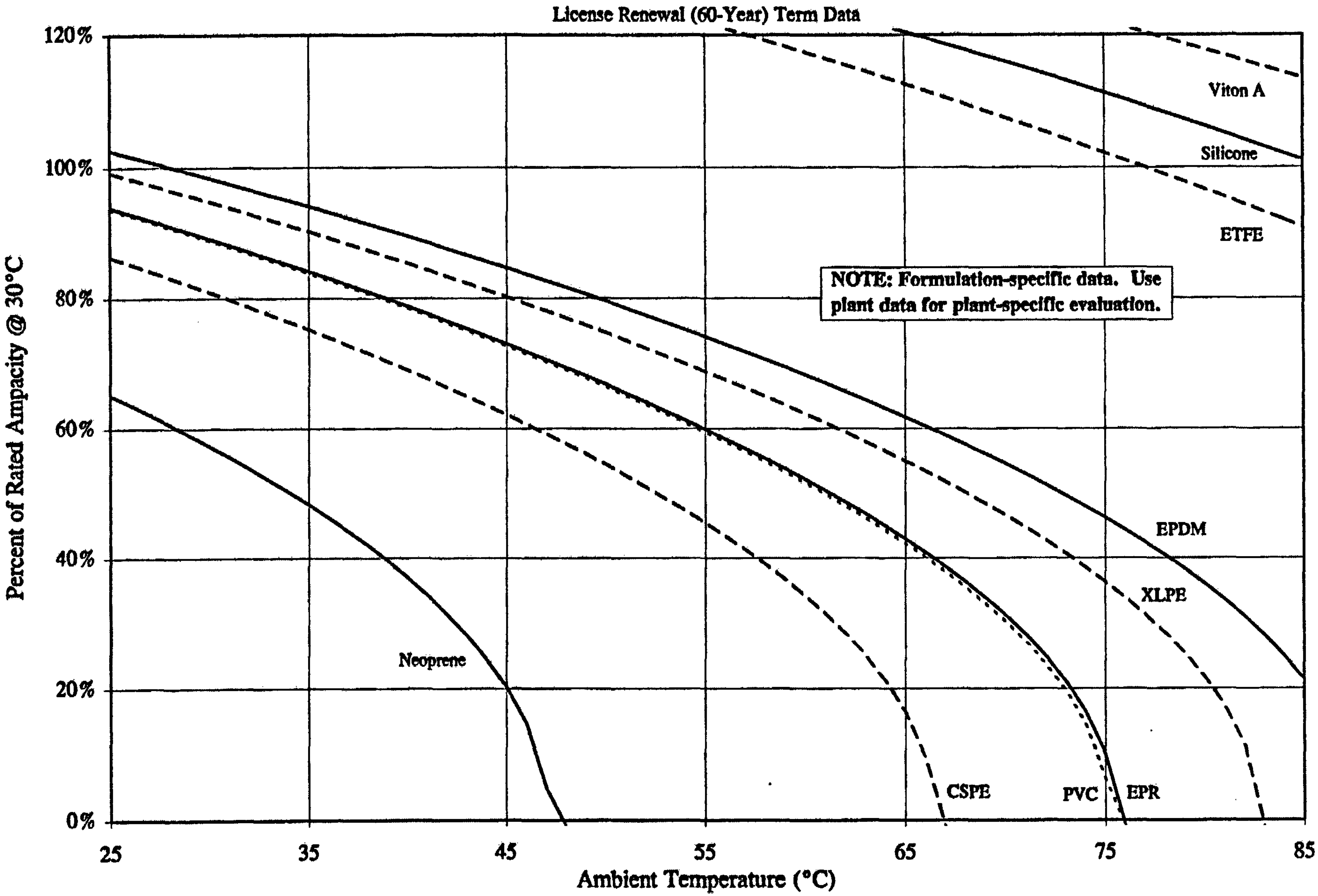

Figure 4-5 Fraction of Rated Ampacity versus Ambient Temperature for Various Cable Insulation; 60-Year Lifetime

As an example of this methodology, consider an XLPE-insulated power cable located in a 60°C [140°F] ambient environment. Per Table 4-2, 60°C would exceed the maximum recommended ambient temperature for a 60-year lifetime (45°C at 80% of its 30°C ampacity), thereby making this cable a candidate for further evaluation. From Figure 4-5, the cable could be operated continuously at up to ~60% ampacity over a 60-year period and the XLPE insulation would still exceed the 50% retained absolute elongation criteria. Therefore, if the circuit is determined to operate below approximately 60% of its 30°C ampacity, the insulation may be eliminated from further consideration.

For cable or termination components that are not exposed to appreciable ohmic heating (e.g., seals used in instrumentation circuit connectors), the I&C cable maximum recommended ambient temperature value from Table 4-2 can be used to determine whether the component is a candidate for further evaluation. Note that for seals and similar components, the compression set of the material is another useful measure of remaining life. Compression set data (such as that contained in Du Pont Report E-46315 [4.26]) can be used in place of the elongation endpoint data described above to generate an analogous estimate of the maximum recommended temperature for the compression set endpoint chosen.

4.1.2 Electrical Stressors and Aging Mechanisms

Stressors associated with the electrical functions of cable and termination components may also lead to age-related degradation. Electrical stresses on cable system components are caused by continuous energization at normal voltage and current levels, and by extreme voltage gradients from over-voltage transients, spikes, and fault interruption. The following topics associated with electrical stresses and aging are discussed in the succeeding paragraphs:

- Energization at normal voltage levels
- Transient conditions
- Partial discharge
- Effects of moisture and contaminants
- Water treeing
- Indications of electrical degradation
- Effects of high potential testing on XLPE-insulated cables

4.1.2.1 Energization at Normal Voltage Levels

Energization at normal design voltage levels can electrically stress cable insulation over the long term; the amount and severity of this stress is determined primarily by the dielectric strength and thickness of the insulating material used, and the operating voltage and frequency.[11] In general, an inverse relationship between the time to failure (breakdown) of an insulating system and the voltage (stress) has been observed. Two mathematical models commonly used to express this relationship are the exponential and inverse power models [4.27].

[11] Cables are designed to specific voltage ratings that always exceed the cable operating voltage (e.g., cables used in 4160-V systems are rated at 5 or 8 kV).

The exponential model is described by the equation:

$$L = C\, e^{-(V - V_t)},\ V > V_t$$

where:

L	=	lifetime, time to failure at voltage V.
V_t	=	threshold voltage, a constant
V	=	operating voltage, a constant
C	=	time to failure at an operating voltage equal to V_t, a constant

Note that a threshold voltage (V_t) is used such that breakdown may only occur when the applied voltage is greater than the threshold.

The inverse power model is described by the equation:

$$L = kV^{-N}$$

where, L is the time to breakdown at constant voltage V, and N and k are constants. A threshold voltage may also be incorporated in the inverse power model.

As with the Arrhenius thermal aging model described previously, several limitations are inherent in the application of the exponential and inverse power models. Constants used in each model are experimentally determined and material specific, and extrapolation beyond the experimental conditions may produce non-representative results (e.g., if a discontinuity in the relationship exists due to the effects of another physical process). Furthermore, the time to breakdown at a specific voltage stress level may vary significantly for several seemingly identical samples; this relationship often may be represented by a probability distribution (such as Gaussian or Weibull). Hence, caution must be exercised in attempting to estimate the longevity of a given application based solely on voltage stress. The literature [4.27] and [4.28] provides additional information on accelerated testing and the evaluation of electrical aging effects on various insulation systems. Additionally, the data [4.27] would tend to indicate that insulation breakdown due to energization at normal operating voltages is of much less concern for low-voltage cable, based on the comparatively low applied voltage stress[12].

Another consideration relates to the presence of impurities in the insulation. For a potential gradient across a stack of equal thickness layers of differing materials, the voltage drop across each of the layers varies inversely with the material's dielectric constant; the highest fraction of voltage drop will occur across the material of lowest dielectric constant. Thus, materials with

[12] For example, Figure B3 of IEC Report 727-1, Part 2 [4.27] shows an estimated voltage endurance in excess of 100 years at a voltage stress of approximately 5 kV/mm (roughly 127 V/mil), which is well in excess of typical operating voltage stress levels for low-voltage cable.

lower dielectric constants will usually be limiting in terms of the overall effective dielectric strength of the insulation system. The dielectric constant of gas or other impurities entrained in the insulation may be low in relation to the surrounding insulation; hence, a larger voltage drop occurs across the impurity, causing a large stress. This can cause localized ionization and breakdown at the inclusion site, which may rapidly degrade the insulating material [4.21], [4.29], [4.30], [4.31]. This effect is generally significant only for medium-voltage cable insulation due to the higher voltage stress present at normal operating voltages.

4.1.2.2 Transient Conditions

Voltage and current surges are characterized by rapid magnetic field generation and collapse and the production of large potentials in the insulation, which can place substantial stress on the dielectrics of the cable and associated terminations. Inductive surges and other electrical transients resulting in high potentials can cause stressors that contribute to breakdown of insulation and other dielectric materials. When an electrical pulse or surge is applied to a cable, the voltage does not distribute uniformly throughout the length of the cable instantaneously and some portions of the insulation may be stressed more severely than others. These stressors can ultimately result in localized degradation or breakdown of the insulation, causing shorts or flashover to ground [4.21].

Voltage or inductive surges may affect both low- and medium-voltage systems. Loads such as dc motors and large solenoids can produce significant inductive voltages on low-voltage systems. If preexisting degradation or defects in the insulation are present, these defects may be significantly exacerbated by exposure to large voltage spikes or surges, so that failure of the cable occurs much earlier than would otherwise be the case [4.32], [4.33]. This is particularly true of medium-voltage systems, which are exposed to a higher normal operating voltage level.

Voltage and current surges occurring in electrical cable systems and their connected loads may be produced through a variety of mechanisms, including electrical switching (bus transfers), fault interruption, blowing of current-limiting fuses, or lightning [4.31]. In such cases, higher dielectric stress is imposed on insulating materials, and greater ohmic heating of the conductor, surrounding insulation, and associated terminations can result. Bus transfers may be either manual or automatic; automatic bus transfers are fast or slow. Manual or operator-induced bus transfers occur on a regular basis for various circuits. This switching is usually conducted in a controlled manner; loads (current) are minimized and phases synchronized so that the severity of the resulting electrical transient is minimized. Similarly, slow automatic bus transfers do not generally create large voltage surges. Fast automatic bus transfers, on the other hand, can create significant voltages because the bus and source voltage may be out of phase. Bus transfers are normally accomplished via medium-voltage circuits and switchgear, thereby "insulating" low-voltage systems from the surge. In addition, transients experienced in low-voltage systems (such as those resulting from load starting/stopping, etc.) are less severe and small in comparison with the rating of the cable and associated termination. However, medium-voltage systems may be directly exposed to comparatively high voltages created by bus transfers or other voltage transients. Furthermore, some medium-voltage switchgear (such as vacuum breakers) have the potential to produce significant transient voltages.

Transient voltages are also influenced by the grounding scheme (if any) on a particular distribution system. Systems that are ungrounded or grounded via high-impedance pathways can experience higher transient voltages.

Electrical faults may produce extremely high currents in both low- and medium-voltage cable systems. These transients are considered in the design and selection of electrical system components (such as electrical cable, terminations, and switchgear); nonetheless, aging of cable insulation occurs through voltage stress[13] [4.21]. Voltage stress results from the near-instantaneous interruption of current flow through the conductor upon termination or clearance of the fault, and can peak at levels well in excess of normal operating voltages. Repeated exposure to fault current or electrical surges may reduce the longevity of the insulation (as well as other cable and termination components) due to cumulative voltage stress.

Lightning strikes may create severe overvoltage conditions; voltages in excess of 500,000 volts and currents greater than 200,000 amperes are possible. In addition, the current may build up at rates as high as 10,000 amperes per microsecond [4.31]. Lightning-induced surges have steep wave fronts that travel along the conductors away from the strike location in both directions. Lightning or surge arresters are typically installed so that they mitigate the effects of the voltage/current surge (see, for example, ANSI/IEEE Standard 142-1982 [4.34]). Most power plant cable is not subject to lightning-induced surges; however, most cables are designed with sufficient basic impulse insulation level (BIL) capability to withstand the voltage stress resulting from most of these events. This capability is typically expressed in terms of voltage withstand capability (i.e., 110-kV BIL for a 15-kV power cable) and is somewhat higher for cable than that of other electrical distribution equipment. Terminations are generally matched to the performance of the cable system (see, for example, IEEE Standard 48-1975 [4.35]).

4.1.2.3 Partial Discharge

Another phenomenon that can degrade electrical cable insulation is internal partial discharge. Also known as *corona*, this effect results from large potential gradients between materials separated by air or similar media. A high voltage gradient results in ionization of the air between the materials, which permits the air to act as an electrical conductor. If the gradient is sufficiently large and the separation sufficiently small, complete dielectric breakdown may occur. Partial discharge can occur between conducting components internal to the cable structure or between insulators separated by a gaseous medium. Partial discharges are usually extinguished when the large voltage difference inducing its formation is reduced; however, the dielectric quality of organic materials may be reduced during each subsequent discharge. As a result, subsequent discharges will occur at progressively lower voltage levels. This process can continue until the discharge extinction voltage level is less than the normal operating level, in which case the discharge will not extinguish and faulting will ultimately occur. If a conductive inclusion is in the insulation wall, the wall thickness will effectively be reduced and the localized stress increased, causing higher voltages across the remaining insulation.

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[13] No significant thermal aging caused by ohmic heating is generally experienced due to the extremely short clearing times for most faults.

Partial discharge effect is generally of little concern for low-voltage electrical cables because the requisite voltage gradient necessary to ionize the interposing medium is not present. However, in medium-voltage applications, it may result in degradation of the cable material due to the higher voltage gradient [4.21], [4.30], [4.36], [4.37]. Medium-voltage cable insulation removed from service that has inclusions and voids often identifies the possibility of long-term partial discharge breakdown. The damage patterns identified in the insulation look like trees, thus the term "electrical treeing."

4.1.2.4 Effects of Moisture and Contaminants

In some cable applications, the combination of voltage and moisture can affect insulation that is dirty or deteriorated, resulting in surface tracking paths between conductor and ground, or conductor to conductor. Moisture allows leakage currents to flow across the insulation surface when a potential gradient exists. The leakage current flow will cause some of the moisture in portions of the tracking path to evaporate; however, the leakage current will tend to remain constant which increases the current density in the remaining tracking path. This can result in localized burning of the insulation and carbonization at the ends of the tracking paths and ultimately in insulation failure.

Water penetration into electrical cable insulation may also result in decreased dielectric strength. As water[14] permeates the insulation, the conductivity of the dielectric is increased due to the increased ion mobility and concentration. Increased conductivity results in an increased leakage current flowing either through or on the surface of the insulation; this current flow eventually produces insulation with a permanently degraded dielectric strength. Some insulation and jacket materials have extremely limited water absorption and permeation, and are therefore relatively unaffected. PVC is an example of a jacketing material commonly used in high moisture applications to help prevent radial ingress of moisture to the underlying insulation. Similarly, Tefzel® (ETFE), Hypalon®, and some other forms of polyethylene are highly resistant to moisture. Note, however, that water may penetrate the cable in a longitudinal fashion (such as at terminations) and propagate along the conductor, thereby rendering the moisture resistance of the outer jacket or insulation materials of little consequence.

As used in this guideline, the term "wetting" refers to a significant amount of moisture in contact with the cable/termination components, such as would be produced by repeated instances of standing water, system leakage/spray, or flooding. Note, however, that even minor and/or intermittent surface condensation, in conjunction with voltage stress and contaminants, may create an environment where surface tracking may occur. Furthermore, some evidence exists to indicate that the rate of diffusion of water through a polymer is relatively independent of form [4.38]. Therefore, the water diffusion rate for a "dry" material in a 100% RH atmosphere may not be much different than that for the same material completely submerged in water. Also, as temperature increases, the diffusion rate generally increases as well [4.38]. Hence, water diffusion through a material would seem to be worst in a hot, wet (or humid) environment.

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[14] Pure water is a good insulator. However, most water sources contain sufficient impurities to be conductive.

Table 4-3 shows the results of ICEA EM-60 water resistance testing of various cable and termination materials as specified in applicable ICEA cable standards such as ICEA S-66-524 [4.39]. This test involves the submergence of an insulated conductor in high temperature (75°C or 90°C) water for several days while the capacitance and power factor of the insulation are measured. Although these results may not be useful in directly predicting the longevity of a given insulation material in wet environments, they do provide some indication of relative performance. Data for other materials (such as CSPE, PVC, and Neoprene®) are contained in EPRI TR-103834-P1-2 [4.38].

Table 4-3 Insulation Life at 90°C During ICEA EM-60 Testing [4.38]

Material	Time to Failure
Natural Rubber	<24 hours
Silicone Rubber	3-4 months
Butyl Rubber	9 months
EPR	47 months
XLPE	35 months
ETFE (Tefzel®)	>24 months

Moisture may also result in corrosion or oxidation of cable or termination components. The effects of moisture on metallic cable/termination materials are analyzed in Section 4.1.5.3.

Contamination of the cable/termination may also occur during the manufacturing process. This is particularly critical for cable insulation, especially that used on medium-voltage power cable, due to the comparatively high voltage stress that this insulation experiences. Inclusions or voids within the insulation tend to increase the dielectric stress across the void or inclusion, so that the insulation immediately surrounding the problem area is more rapidly degraded via the effects of partial discharge. Failures of medium-voltage cable have occurred at some utilities, and have been traced to manufacturing defects and/or insulation contamination exacerbated by moisture intrusion [4.38], [4.40], [4.41], [4.42].

4.1.2.5 Water Treeing

Water treeing is a degradation and long-term failure phenomenon that has been documented for medium-voltage electrical cable with certain extruded polyethylene insulations and EPR insulations. Water trees occur in hydrophobic polymers used as insulating materials when the materials are exposed to electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. Water trees are a degradation mechanism distinct from electrical treeing, which requires no water to proceed (see partial discharge discussion in Section 4.1.2.3). Despite the distinction, electrical trees are mistaken by many to constitute the final stage of water treeing.

Water treeing may occur in several insulation materials; however, it appears to be associated most often with XLPE or HMWPE insulation. The growth and propagation of water trees in medium-voltage cable insulation is somewhat unpredictable and erratic; hence, the longevity of affected cables is often indeterminate. Water treeing has historically been more prevalent in higher voltage cables; proportionately few occurrences have been noted for cables operated below 15 kV. This is likely due to the comparatively high electric field density and voltage gradient required for significant treeing to occur. However, water treeing in medium-voltage cable operated below 15 kV has been documented [4.38] and investigations are under way regarding EPR (e.g., [4.43]) and tree-retardant XLPE.

Chemical reactions induced by an electrical field cause water treeing. Electrochemical reactions are initiated at the surface of voids or inclusions where the polymer exhibits hydrophilic behavior (i.e., the moisture is condensed out of the polymer matrix). Initiation sites are located in certain regions of the polymer that result from inclusions/impurities, oxidation during compounding, or cable manufacturing. Ionic contaminants attract water to the region; an applied electric field stimulates reduction-oxidation reactions that deteriorate the polymer, thereby creating more polar sites near the polymer/water boundary. Some studies indicate that the purity of the water in the tree region is very high, thereby indicating a high dielectric strength [4.44].

Oxidation theories of water treeing hypothesize that water tree growth results from the electrical oxidation of the insulation polymer in polar amorphous regions and in the direction of the local electric field. As the oxidation occurs, polymer chain scission occurs and a "tree" is formed. As the process progresses, the polymer in the tree region is made hydrophilic, so that water is condensed from the polymer matrix. This water promotes the transport of ions to the tip of the tree, which further promotes oxidation in this region; hence, the water tree is self-propagating. Due to the relatively slow rate of propagation for this process, the effects of exposure to moisture may take several years to manifest themselves; by this time, the cable has usually degraded to the point of requiring replacement [4.45], [4.46], [4.47], and [4.48]. Figure 4-6 shows a medium-voltage power cable cross section with a typical water tree formation.

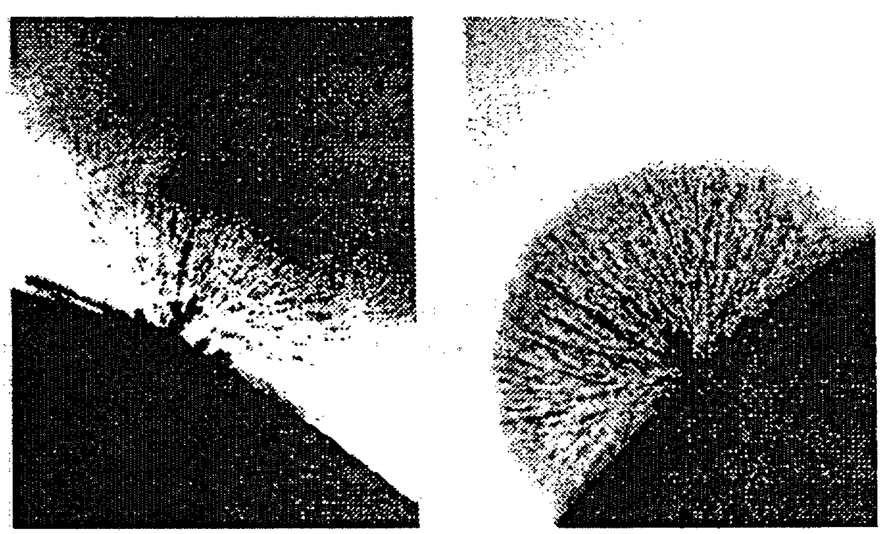

Figure 4-6 Water Tree Formation in Medium-Voltage Cable Insulation

In general, the following observations may be made regarding the growth and prevention of water trees:

- The formation and growth of trees varies directly with operating voltage; treeing is much less severe in 4-kV cables than those operated at 13 or 33 kV. Due to the low dielectric stress, water trees do not occur in low-voltage cables.

- Tree formation and growth is often related to both the void and impurity content of the insulation.

- Drying field-aged cables with inert gas and subsequent conductor impregnation with insulating liquids (such as Dodecanol or Acetophenone) may significantly extend cable life [4.47].

- No evidence that continued operation results in drying of the insulation/tree site, or that operation reduces the rate of treeing, was located in the literature. However, substantial evidence indicates that the operation of a submerged cable may create a "thermal barrier" and actually force water out of the insulation [4.38]. Recall, however, that increased temperature may also accelerate diffusion of water through various media (such as the outer jacket).

- Tree growth appears to be more prevalent in insulation materials that are subject to mechanical tension (as opposed to compression).

- Improved surge protection may extend the life of in-service cable [4.47].

- Water tree formation is generally negligible in low-moisture environments (i.e., it requires ingress of moisture/ions to the insulation). Accordingly, wetting or submergence of insulation that is susceptible to water trees for a sustained period should be avoided.

- Several water-tree retardant polymers [such as tree-retardant XLPE (TR-XLPE)] are currently available. In addition, longitudinally and radially water-blocked constructions are available to combat the ingress of water in the insulation material [4.49].

- The effects of temperature and oxygen concentration on tree initiation and formation are not well understood [4.47].

- Jackets and semiconducting shields may substantially reduce the ingress of moisture and ion migration, thereby reducing the rate of tree formation and propagation. New materials using ion scavengers may be effective at further reducing water tree growth.

4.1.2.6 Indications of Electrical Degradation

Evidence of electrical damage or continuing degradation due to the stressor/aging mechanism combinations described in Sections 4.1.2.1 to 4.1.2.5 may include one or more of the following [4.50]:

- Indications of tracking on surfaces near terminations
- Noise (ionization of air due to partial discharge; medium-voltage only)
- Thermal damage to insulation, jacketing, or other organic components in the vicinity of conductors or terminations
- Corroded, tarnished, or discolored inorganic (metallic) components such as cable conductors or terminations.

4.1.2.7 Effects of High-Potential Testing on XLPE-Insulated Cables

EPRI TR-101245 [4.33] documents EPRI research to determine the effects of dc high-potential (hi-pot) testing on the longevity of extruded XLPE-insulated medium-voltage cables. Direct current hi-pot testing is commonly performed on cables subsequent to manufacturing, for proof or acceptance testing after installation, or for maintenance/troubleshooting during service.

The results of this study indicate that dc hi-pot testing did not adversely influence the ac breakdown strength of unaged or artificially aged XLPE-insulated cables. The study did indicate, however, that hi-pot testing of artificially aged cables with reduced dielectric strength resulted in more rapid degradation than in similar cables not subjected to this testing. The study indicated that the effects of dc testing were most apparent on specimens that contained a new section of cable, a splice, and an aged section of cable. Also observed was an increased failure rate with multiple hi-pot test applications. Water treeing was also identified in most of the failure sites (note that the testing was performed with the cables submerged in water).

Thus, the report indicates that satisfactory ac breakdown strength is not necessarily indicative of the integrity of an aged cable's XLPE insulation. Furthermore, because the results indicate that dc hi-pot testing reduces the longevity of aged XLPE-insulated cables in wet environments, dc maintenance testing of such cables should be discontinued where feasible. However, acceptance testing of new or unaged cables may be performed without adverse effects.

Alternating current hi-pot exposes the dielectric medium to an alternating current at voltage levels that are substantially reduced over those used in dc hi-pot testing for a given duration (typically 5 min). This type of testing more closely approximates the stresses applied to the dielectric during normal operation. Cable insulation can sustain application of dc potentials at basic impulse insulation level (BIL) for extended periods without damage [4.31]; however, most insulating materials will sustain damage from ac overvoltage testing as a function of the overvoltage, time, and frequency of the ac signal. Accordingly, ac hi-pot is generally considered to be more likely to damage cable insulation and exacerbate existing defects than dc hi-pot testing [4.31]. Direct current hi-pot is therefore recommended for any repetitive post-factory testing application.

4.1.2.8 "If-Then" Criteria for Electrical Stressors and Aging Mechanisms

Table 4-4 summarizes the electrical stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components. Note that for many electrical aging mechanisms and effects, no quantitative or specific criteria can readily be developed. For example, the initiation and propagation of water trees in cable insulation depends on many factors, including water and ion concentration, voltage stress, temperature, electrical surges/transients, etc.; no "formula" for water treeing exists. Therefore, only the general environments or conditions that have historically produced this type of degradation are highlighted to alert the plant operator to the *potential* for treeing.

4.1.3 Mechanical Stressors and Aging Mechanisms

Mechanical stressors and aging mechanisms can be caused by a variety of conditions that occur during cable operation and installation. These stressors include vibration (including fatigue stress), thermal/gravity-induced mechanical stress, installation stresses, and external mechanical influences (such as incidental bending, cutting, or abrasion during maintenance or normal equipment operation).

4.1.3.1 Vibration

Vibration may result in fatigue of connection components, as well as cutting, wear, and abrasion of components. Vibration is generally induced by operation of external equipment, which can affect the cable connection, the equipment (such as a power lead connected to a running motor), or components or structures otherwise mechanically connected to the cable (such as cable trays or conduits that are vibrated by an external source). Vibration resulting from the direct connection of a cable/termination to the operating load may produce fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Vibration may also loosen the connection between the termination and cable conductor, resulting in high electrical resistance or separation of the termination from the conductor. Abrasion or cutting of the cable jacket and insulation (e.g., on sharp edges) by the motion of the connected load, nearby structures or components may occur over time, eventually reducing the mechanical (and electrical) integrity of the material and ultimately resulting in short circuits or moisture intrusion.

4.1.3.2 Gravity-Induced Cable "Creep" and Tensile Stress

Mechanical stress on cable and termination components may also result from the installed physical arrangement of these components and the effects of temperature variation and gravity. Due to the weight per unit length of electrical cable (often several pounds per foot for high ampacity cables) and various environmental influences, adequate support for the cable must exist in order to reduce the effects of tensile stress and elongation over time.

Table 4-4 Electrical Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Moisture (wetting); voltage (4.1.2.4, 4.1.2.5)	Water treeing	Tree formation; reduced dielectric strength and eventual breakdown	- Few if any apparent indications; may ultimately result in cable failure	Susceptible materials including nontree retardant XLPE and HMWPE	Medium-voltage cable subject to (1) regular submergence/wetting/ high humidity, and (2) operational voltage stress; jacketed cables at lower risk	Generally a long-term phenomenon	Treeing in aged XLPE cables may be aggravated by dc hi-pot testing
	Moisture intrusion	Reduced dielectric strength	- Reduced insulation resistance; flashover	Moisture-permeable materials[1]	Moisture-permeable materials located in wet/humid environments and exposed to voltage stress	Long- or short-term	Generally of little concern for low-voltage cable
Voltage (no moisture) (4.1.2.1, 4.1.2.3)	Partial discharge leading to dielectric breakdown; electrical treeing	Increased leakage currents; reduced dielectric strength	- Reduced insulation resistance - Visible or audible ionization - Flashover	All organic insulating materials	Medium-voltage applications with voids or air gaps in areas of high voltage stress (such as insulation/shield voids, between adjacent termination components, etc.)	Continuous discharges may rapidly create local degradation in insulating materials	Periodic discharges may gradually degrade insulating properties of material
Voltage stress, moisture, contaminants (4.1.2.4)	Surface tracking	Localized damage to insulation surface; reduced dielectric strength	- Formation of visible tracking paths or carbonization - Localized material discoloration	All organic insulating materials	Areas of high voltage stress with alternating wet/dry or continually wet conditions and substantial dust or dirt contamination; near terminations or electrical stress risers	May result in rapid degradation	

Table 4-4 Electrical Aging Summary for Cable and Termination Components (cont'd)

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Transient voltage stress (4.1.2.2)	Dielectric breakdown	Reduced dielectric strength	- Reduced insulation resistance; flashover to ground	All organic insulating materials	Circuits exposed to faults, repeated switching transients, lightning strikes	May result from one or numerous transients	Switching transients generally small in relation to lightning or electrical faults

Notes:

1. Moisture-permeable or absorptive materials may include acetals, polyimide (Kapton®), some acrylic resins, polyacrylic rubber, and some butyl and natural rubbers. Typical formulations of EPR/EPDM, SR, PE, XLPE, CSPE, and PVC all absorb very little water by weight, yet may be water permeable (see Section 4.1.2).

In vertical runs of power cable, the cable may "creep" with time as a result of the combined effects of the weight of the unsupported vertical cable run (gravity), thermal cycles resulting in expansion/contraction of the cable materials, and routing over a hard or sharp edge at the top of the run. Changes in cable operating temperature are the result of ambient temperature and loading changes. During periods of comparatively high cable temperature, the cable will elongate, permitting the cable to creep over the edge of the vertical drop (i.e., the upper horizontal portion of the cable will thermally expand, thereby permitting the weight of the vertical section to drag the additional length over the edge). During periods of relatively low temperature, the horizontal (and vertical) portions of the cable will contract, thereby attempting to drag the cable back over the edge; however, due to the weight of the vertical portion of the cable and the friction created by the edge over which the cable passes, the cable will not return completely to its original position. Accordingly, increased stress is placed on the portion of the cable at the top of the vertical drop as it contracts, as well as any terminations or splices in that segment of the cable. Repetitive thermal cycles may result in increasing creep and stress at the top of the cable segments/terminations. Ultimately, this stress can result in significant cable wall damage at the top of the run or tensile failure of the upper termination. Indications of this phenomenon include cutting and chafing of the cable jacket/insulation in the vicinity of overhang edge, increased tension on the terminations associated with the horizontal cable run, and pile-up of cable in the bottom of the vertical run. Figure 4-7 is a pictorial representation of this process.

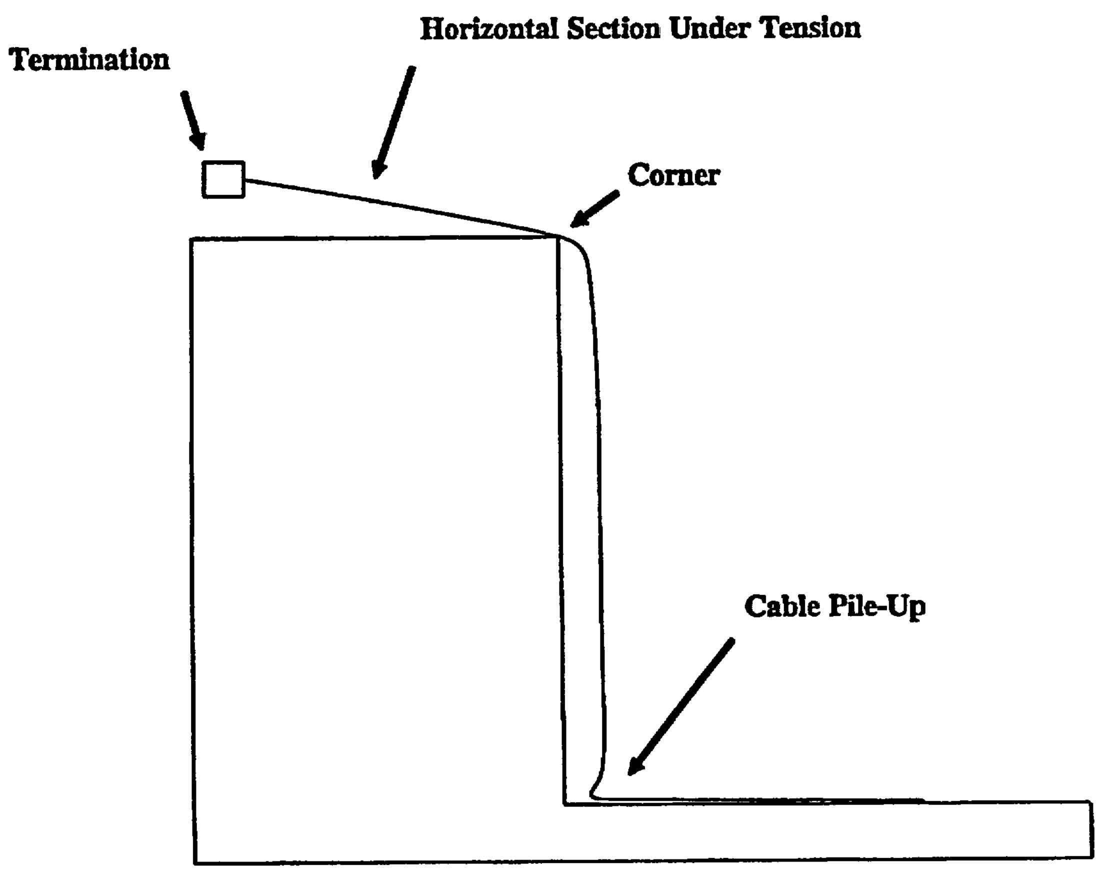

Figure 4-7 Cable Creep in Horizontal/Vertical Runs

A related aging mechanism occurs in right-angled conduit fittings (condulets) interfacing between a horizontal and vertical cable run. The weight of the vertical cable run combined with thermal expansion/contraction tends to pull the cable outer surface across the metallic inner edge of the condulet, thereby resulting in chafing and/or cutting of the cable. In addition, high tensile stress is placed on the horizontal sections of the cable inside the conduit.

To preclude this type of damage, an appropriate system to support the vertical segments and minimize the movement of the cable under thermal expansion/contraction may be used.

4.1.3.3 Compression

Organic materials placed in compression for extended periods may exhibit an effect known as compression set; this is based on the amount that a material fails to return to its original dimension or shape after compressive load is removed[15] [4.51]. This quantity is of primary interest for O-rings, seals, gaskets, and grommets (such as those used in sealed electrical connectors), because it can be related to the ability of the O-ring/seal to perform its design function, especially under situations where the device is disassembled and subsequently reassembled using the same O-ring. Exposure to heat, radiation, chemicals, oxygen, ozone, etc. can produce significant changes in the compression set of a given material. For most elastomers, compression set increases (indicating a loss of resiliency) with increased thermal and radiation exposure. It should be noted, however, that most plants replace such components each time maintenance or testing is performed, thereby obviating the need for further consideration of aging management. Specific information regarding the compression set of a particular material can be obtained from the component manufacturer; compression set properties for a typical seal material (Viton) are shown below [4.26].

Compression set is defined as:

$$set = \frac{t_0 - t}{t_0 - t_c}$$

where:

t_0	=	original, uncompressed thickness
t_c	=	compressed thickness
t	=	thickness after material recovery
0% set	=	total recovery
100% set	=	no recovery

[15] Compression set is defined in ASTM test D 395 as the residual decrease in thickness of a test specimen which is observed 30 minutes after the removal of a specified compressive load applied under established time and temperature conditions.

Percent Compression Set of Viton at Various Temperatures [4.26]

Time (hours)	At Room Temperature	At 300°F (149°C)	At 392°F (200°C)
1000	--	12%	50%
2000	--	16%	65%
4000	21%	22%	79%
8000	21%	32%	98%

4.1.3.4 Installation-Related Degradation

4.1.3.4.1 Cables

Degradation during cable installation is not an aging mechanism, but it can adversely affect the longevity of both low- and medium-voltage cable systems. Installation degradation is normally controlled or prevented through use of approved procedures, controls, and standards during cable installation. EPRI EL-5036 [4.29], Cablec's Cable Installation Manual [4.52], EPRI EL-3333 [4.53], and applicable IEEE standards provide guidance on the proper installation of cables in various applications. Installation damage usually occurs as a result of failure to use or properly implement such guidance.

Installation Damage Mechanisms

The pulling or bending of cables exerts either a tensile or compressive stress on many cable components; such bending or pulling normally occurs during the installation of the cable. Damage to the cable insulation resulting from cutting, chafing, or excessive stress during pulling cuts or tears the dielectric so that increased voltage stress occurs at the location of the damage; over time high stress accelerates the breakdown of the dielectric and may eventually result in cable failure (electrical fault). This effect may be aggravated by the presence of wetting, where water can permeate the damaged area in the dielectric and increase its conductivity. Indications of installation damage include elongation or twisting, cuts, rips, tears, abrasions, or "shrink back" (i.e., apparent shrinkage of the jacket near its terminations so that portions of the underlying components are exposed). Although visual indications will occur primarily on the jacket, they may also affect any underlying components such as shielding, wraps, or insulation. Note that installation-related degradation may exist with no external indications.

Sidewall Bearing Pressure

Sidewall bearing pressure is that compressive force applied to the side of the cable at the point of contact with the conduit or bend through which the cable is being pulled. Excessive sidewall bearing pressure may result in over-compression of, or damage to, the insulation/jacketing by the conductor or conduit. This is significant in that the primary source of sidewall bearing pressure is pulling tension during installation. The longer the cable and the more tortuous the pulling path, the greater the likelihood for cable damage due to excessive sidewall bearing pressure. To avoid damage, cable installation procedures must establish controls for pulling tension. Two tension calculations are generally used: maximum allowable tension and the estimated pulling tension. Difficult pulls should be controlled by means of a tension-limiting device such as a dynamometer.

The minimum bend radius of the cable must also be considered during routing and installation. The larger the radius, the less tensile stress on components in the outer radius of the bend, and the less compressive stress on those in the inner portion. Shielded power cable generally requires special conduit due to its large minimum bend radius [4.29], [4.52], [4.53].

Pull-Bys

A pull-by is the installation of a cable in a conduit or duct where other cables are already installed. This process is potentially damaging to the existing cable in the conduit by virtue of the pulling mechanisms employed for the new cable being installed (such as ropes and swivels). Although pull-bys may be performed successfully by following strict guidelines, incorrectly performed pull-bys can result in damage to either the cable being installed or the existing cable in the conduit. Pull-by damage most frequently occurs at bends in the conduit system where a surface of an installed cable must bear the loading of the pulled cable. The resulting friction and cutting, generally by the pull rope, cuts through the installed cable. Also, the pull rope or cable being pulled can wrap around installed cables, resulting in a knot that will tear the installed cable's insulation if the pulling continues [4.29], [4.52], [4.53].

Jamming

Jamming is a condition under which three similarly sized cables pulled into a conduit experience a dramatic increase in the pulling tension required. The increase is the result of friction or binding between the outer surfaces of two of the cables with the conduit; this friction results from the third cable being forced between the other two so that the total diameter of the three cables is roughly equivalent to that of the conduit interior. Jamming may tear or crush the cable insulation due to the increased pulling tension. Jamming is of greater concern for larger power cables [4.29], [4.52], [4.53].

Incidental Cable Damage

In addition to the mechanisms described above, incidental damage to the cable may occur during, but not as a direct result of, the installation process. For example, cable may be degraded by abrasion, cutting, or similar mechanisms before actually being installed. This is especially true for softer insulations, such as silicone rubber, or those which are unjacketed. One utility contacted as part of this study indicated that it had experienced damage to braided silicone-insulated cable after the cable was removed from the reel (but before installation) due to an apparent mechanical trauma (such as having a heavy object dropped on top of it while it was laid out).[16]

Effects of Installation Damage

Low-Voltage Cables

The effects of installation damage are generally less severe for low-voltage cable than for medium-voltage cable. Low-voltage cables experiencing almost complete insulation cut-through may not have a significantly reduced life (even in the presence of moisture) due to the low-voltage stress in relation to the dielectric strength (volt per mil) of their insulation. Even a few mils of insulation on a 600-V system are sufficient to provide the necessary dielectric strength to prevent significant leakage current through the dielectric (see, for example, the testing described in NUREG/CR-6095 [4.54]). In addition, the electric field strength intensity at any given point is not sufficient to create partial discharge across areas of locally high stress (such as voids or inclusions) in the insulation.

Medium-Voltage Cables

The stressor combination of installation damage and moisture appears to have a far greater impact on medium-voltage cables [4.38]. Failure data [4.38] indicate that a substantially higher rate of failure results in medium-voltage cables that have been damaged by being pulled through a raceway during installation and which operate in high moisture environments. Medium-voltage cable has voltage stress one or more orders of magnitude higher than that for low-voltage cable. Installation damage sites, voids, or inclusions may experience sufficient dielectric stress to create ionization (and its resulting degradation) within that area. Moisture present in this region will only increase the conductivity of the surrounding insulation, and eventually produce a failure at this site [4.55].

Damage to the cable jacketing, although not directly affecting the dielectric strength of the medium-voltage cable, may nonetheless affect its longevity. Once the integrity of the jacket has been violated, any moisture present on the jacket may permeate into the insulation via absorption or damage created coincident with the jacket damage [4.29], [4.52], [4.53], [4.56].

4.1.3.4.2 Terminations

As with cables, termination components may be degraded or damaged during installation. This degradation may result from improper assembly or installation practices and/or incidental damage. Types of degradation or damage potentially occurring during installation of terminations include (but are not limited to):

- Galling or stripping of connector threads

[16] The damage mechanism was determined by subsequent analysis of the insulation, which indicated that the interior surface of the insulation on several cables in a common conduit had been damaged by their conductors at nearly the same point along each cable's length (Section 3.7.1).

- Bending and/or pushback of connector pins/contacts
- Improper crimping pressure and/or tool (compression fittings)
- Heat damage to conductor or surrounding insulation (fusion fittings)
- Improper solder joints
- Improper tape splice or stress cone fabrication
- Improper heat shrink insulation (over- or underheated during curing with heat gun)
- Abrasion, cutting, or chafing of organic seals or gaskets
- Overtightening of terminal block hardware (and cracking of the insulating base)
- Cold flow (creep) of conductors due to tensile stress

A number of sources ([4.29], [4.31], [4.51], and [4.57]) provide additional guidance on the proper selection and installation of various types of terminations. Manufacturer's guidance should also be consulted, because the configurations of terminations and materials used may vary widely, and standardized installation practices may not be available for certain termination types.

4.1.3.5 Maintenance/Operation-Related Degradation

Component Manipulation

Degradation of cable system components results largely from manipulation of the component during maintenance or testing. Because the greater part of cable is not disturbed or moved subsequent to its installation, little or no degradation of cable components (such as abrasion of exposed jacketing/insulation resulting from movement of the cable[17]) is expected. Manipulation of cables can result in cracking and possibly exposure of bare conductors in those cables with embrittled insulation or jacketing. Generally, the cable insulation and/or jacketing must be sufficiently aged and embrittled so that its elongation-at-break is very low. As the cable is bent, the outer radius of the jacket/insulation is placed in tension; if the bend is of sufficiently small radius, the elongation capability of the aged material can be exceeded and cracking can occur. For jacketed cables, the jacket will often age more rapidly than the underlying insulation, thereby cracking much more readily under sufficient bending stress. This is usually of little concern for the insulation, because cracking of the jacket will tend to release the stress on the insulation. However, in some bonded jacket/insulation systems, cracking of the jacket may localize the stress at the site of the insulation/jacket interface (within the newly formed crack) and precipitate a rupture of the underlying insulation. Section 3.7 discusses potential issues

[17] This type of wear is to be distinguished from incidental mechanical damage (such as that resulting from work in the immediate vicinity or personnel traffic).

related to bonded jacket/insulation interactions. Thermal criteria set forth in Tables 4-1 and 4-2 help limit the reduction in elongation so that cracking during manipulation is avoided.

For some terminations such as multi-pin or threaded connectors, wear may represent a significant aging mechanism. As a result of maintenance, inspection, or periodic surveillance testing activities, these connectors may be disconnected and reconnected at an appreciable frequency, so that their hardware or mating components may eventually wear out from friction or fatigue. The same may be true of terminal block hardware or any other termination component that is both moveable and manipulated frequently.

Work Hardening

In extreme cases, work hardening of the cable conductor or metallic termination components may occur due to manipulation and bending, thereby resulting in embrittlement and possible breakage. Work hardening (or cold working) occurs in metals that are worked at low temperatures. As the yield strength of the metal is exceeded, progressively higher amounts of stress are required to continue plastic deformation (strain) of the material. This increase in stress correlates to an increase in hardness and a corresponding loss in ductility. This process is illustrated through the bending of a new conductor; the first bend occurs with relative ease, whereas subsequent bends at the same location require more and more stress until finally embrittlement and breakage occur. Work hardening may occur in components that are frequently moved or manipulated (such as a wire that is routinely bent or moved out of the way during maintenance, or a contact pin in a multi-pin connector that is bent during engagement/disengagement of the connector) [4.58], [4.59]. The severity of the work hardening effect depends primarily on the frequency of manipulation, the range of motion/stress applied, and the type of material being stressed. In most power plant applications, the frequency of manipulation is sufficiently low that work hardening is of minimal concern.

Physical Damage

Cables outside of raceways are also susceptible to physical damage from incidental contact during maintenance, and from personnel traffic. This is especially true where cables are routed at or near ground level, across passageways, or in space-restricted locations where contact or abrasion is likely. Armored cables may be afforded more protection, but these cables are not immune from such damage. Furthermore, cables in open trays, flexible conduits, and even rigid conduits are susceptible to physical damage when used in a manner inconsistent with their design (e.g., as hand- or footholds). Damaged raceways and cables are usually identified promptly and repaired as necessary.

Terminations are also subject to a variety of different types of physical damage. As with cables/conduit, connectors may also be improperly used as hand- or footholds by plant personnel. Connectors and similar plug-in type terminations are especially susceptible to incidental impact, tension, or shear stresses because the connector is often rigidly mounted to some structure, thereby reducing its ability to move when stressed. In addition, stress may be focused on a termination when a connected cable run is moved, pulled, or allowed to hang freely without support.

Electrical Faults

Mechanical stress on cable system components may also be induced by fault currents. Due to the large electric and magnetic fields generated by cable conductors during fault conditions, substantial mechanical forces may result which can move or stress the cable. This is especially true where the cable is unrestrained or not fully supported. Although the duration of the fault conditions is usually very short, the currents and resulting forces may be sufficient to cause the unrestrained portions of the cable to thrash so that large stresses are imposed on restrained portions or nearby terminations. These forces are usually only of concern in larger sizes of cables because of their higher current and greater weight. In general, cable and raceway installation practices and standards account for fault-induced stress through proper support and restraint of susceptible circuits.

Thermal Cycling

Circuits exposed to appreciable ohmic or ambient heating during operation may experience loosening related to the repeated cycling of connected loads or of the ambient temperature environment. Differing materials used in various cable system components can produce situations where stresses existing between these components change with repeated thermal cycling. For example, under loaded conditions, appreciable ohmic heating may raise the temperature of a compression termination and cable conductor well above the ambient temperature, thereby causing thermal expansion of both components. Differing thermal expansion coefficients may alter mechanical stresses between the components so that the termination may tighten on the conductor. When the load or current is reduced, the affected components cool and contract. Repeated cycling in this fashion can produce loosening of the termination under ambient conditions, and may lead to high electrical resistance joints or eventual separation of the termination from the conductor. Note that this effect is not necessarily limited to compression-type terminations; threaded connectors, splices, and terminal blocks may loosen if subjected to significant thermally induced stress and cycling.

Because most plant environments do not routinely experience the magnitude of temperature changes necessary to induce these effects, heavily loaded power circuits (i.e., those loaded to a high enough fraction of their rated ampacity to produce significant ohmic heating) that are routinely cycled are the most likely to experience such effects. Despite consideration of such stresses during component design, selection, and installation, instances of terminations loosening were identified by several plants contacted during preparation of this guideline, and are evidenced in the empirical data presented in Section 3.

4.1.3.6 "If-Then" Criteria for Mechanical Stressors and Aging Mechanisms

Table 4-5 summarizes the mechanical stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components.

Table 4-5 Mechanical Aging Summary for Cable and Termination Components[1]

Stressor	Aging Mechanisms	Material Changes	Aging Effects/Indications	Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Vibration; external mechanical influences (4.1.3.1; 4.1.3.5)	Cutting/ chafing of organic materials	Reduced dielectric strength; exposed conductors	- Visible cuts, chafing, or other damage to insulation - Exposed conductors, shielding, etc.	All insulation and jacketing materials	Cables or terminations attached to vibrating component and in contact with nearby equipment; routed across sharp edges, in high traffic areas, etc.	Rate of degradation depends on type of material and stressor	
	Metal fatigue (see also Work Hardening)	Reduced ductility; embrittlement	- Broken conductors or other metal components - Significant force required to bend conductors - Discoloration	Metals	Conductors/metallic components subject to vibration by nearby equipment or end device	Generally long-term; however, may occur rapidly (based on frequency/amplitude of vibration, etc.)	Restraint and/or rerouting of cable can significantly reduce effects
Bending during maintenance (4.1.3.5)	Work-hardening/ fatigue of metallic components	Reduced ductility; embrittlement	- Broken conductors or other metal components - Significant force required to bend conductors - Discoloration	Metals	Conductors or metallic termination components that are routinely terminated/ determinated or otherwise bent	Generally long-term	Severity depends on maintenance frequency, material, and stress applied
	Cracking of embrittled insulation/ jacketing	Reduced dielectric strength; exposed conductors	- Surface or through-cracking of insulation - Shattered or flaking jacket	All organic insulating/ jacketing materials	Heat or radiation-damaged cables with embrittled organic components bent so that residual elongation is exceeded	Occurs during maintenance or movement of cable in tray or conduit	Absolute elongation greater than 50% generally allows sufficient flexibility for all typical maintenance activities.[2] As a rule of thumb, avoid bending insulation of noticeably hardened cable more than a few degrees.

Table 4-5 Mechanical Aging Summary for Cable and Termination Components[1] (cont'd)

Stressor	Aging Mechanisms	Material Changes	Aging Effects/Indications	Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Gravity; temperature variations (ambient or ohmic) (4.1.3.2)	Cable creep; tensile stress on components	Elongation, deformation, tearing	- Tearing of jackets and/or insulation - Deformed or high-resistance terminations - Exposed conductors near terminations - Stretched or twisted appearance of cable outer jacket (including labels)	Organic and inorganic materials	Cables with significant unsupported vertical hangs	Generally long-term phenomenon	May be accompanied by cutting or chafing of cable jacket or insulation at overhang point
Compressive load (4.1.3.3)	Material deformation/ relaxation	Compression set	- Reduced seal thickness or other dimensional changes - Seal leakage - Hardening/loss of flexibility	All organic materials	Organics seals placed in compressive stress (such as in assembled electrical connectors)	Percent compression set increases as a function of time; depends on material	Routine replacement should be considered as measurement or trending of compression set not practical for small seals

Notes:

1. Installation stressors are not considered an aging mechanism, and are not included in this table.
2. This is only a guideline, and may not be true for certain cable configurations (such as those with bonded jacket/insulation systems).

4.1.4 Radiation Stressors and Aging Mechanisms

The types of radiation that may be expected in nuclear power plants may be classified as either a particle or electromagnetic wave. Four primary types of radiation exist: alpha, beta, gamma, and neutron [4.60], [4.61]. Although all four types are present in the typical nuclear power plant, the significance of each varies greatly with respect to cable and termination aging. Other types of radiation to be considered include Bremsstrahlung (a by-product of beta radiation interaction) and ultraviolet radiation (electromagnetic radiation of energy or frequency lower than that of gamma or X-rays).

In most plant areas, normal radiation dose rates (all sources) are roughly commensurate with natural background levels (i.e., <0.01 mGy/hr [<1 mrad/hr]). In some spaces, however, the dose rate during normal operation is significantly higher; this is especially true of the primary reactor containment, in which normal radiation dose rates may range from about 0.1 to 1000 Gy/hr [0.01 to 100 rad/hr], depending on plant type [4.62]. Because electrical cable and terminations are routed through these higher-dose spaces, the aging of these components resulting from exposure to radiation must be considered.

Alpha

Alpha (α) radiation is helium atom nuclei emitted at high speed during the disintegration of unstable nuclei. Alpha radiation is highly damaging to some organic materials; however, due to its electric charge and relatively large mass, alpha radiation is easily shielded. Alpha emitters have short half-lives, and the range of alpha particles in free air is extremely limited [4.60], [4.61], [4.63]. No appreciable alpha dose is anticipated for any cable or connection in the plant under normal conditions, and any alpha dose incident upon cable system components would be attenuated within the first few mils of material; thus, no degradation of the underlying material would result. Alpha radiation is not considered further in this AMG.

Beta

Beta (β) radiation is an electron emitted from a nucleus when a proton changes to a neutron, or vice versa; it can be produced from a number of sources and varies in its energy level (expressed in million electron volts, or MeV). Beta penetration is proportional to the density of the absorbing material, and is more penetrating than alpha particles [4.60], [4.63]. Under certain accident scenarios, significant beta radiation may be produced from sources liberated during the accident (i.e., leaking reactor coolant/steam). This dose must be considered in the environmental qualification of the cables and terminations; however, under normal conditions, beta-emitting sources are not present in the ambient environment.

Gamma

Gamma (γ) radiation is electromagnetic in nature, and is emitted from a broad variety of nuclear species. Gamma energy varies in relation to its frequency and wavelength, so that higher frequency radiation is more energetic [4.60], [4.63]. Gamma sources exist in the reactor core and are created as a result of the fission process. Gamma radiation is highly penetrating in comparison with alpha and beta radiation. The gamma dose rate attributable to natural sources is extremely low (<<0.01 mGy/hr [<<1 mrad/hr]) and for the most part, invariant with time. The gamma dose rate attributable to reactor plant operation varies widely as a function of location within the plant and reactor power level, and may range up to 2 Gy/hr [200 rad/hr] inside primary containment. Therefore, gamma dose must be considered in the aging of some cables and termination insulations and jacket materials. Because individual electrical circuits may span multiple plant locations, a single cable may be exposed to varying dose rates and, therefore, different radiation aging effects along the length of its run.

Bremsstrahlung

A related form of radiation known as Bremsstrahlung (braking radiation) results from the interaction of a beta particle with an inorganic material. Photon (gamma or X-ray) radiation is produced from the deceleration of an incident beta particle upon striking the absorber. Accordingly, the dose rate arising from Bremsstrahlung interaction is related to the incident beta dose rate. As a general rule, the Bremsstrahlung dose is conservatively estimated at about 3% to 5% of the incident beta dose [4.60], [4.63]. Because Bremsstrahlung is electromagnetic radiation, its effect on organic cable materials is comparable to that of gamma rays. Bremsstrahlung radiation of an intensity sufficient to result in significant degradation of organic materials in cables or terminations is created only during accident conditions (i.e., when high concentrations of beta-producing nuclides are released to the atmosphere)[18]; accordingly, Bremsstrahlung radiation is not significant with respect to cable aging, but rather is considered only in the context of equipment qualification during accident conditions.

Ultraviolet

Ultraviolet (UV) radiation is a form of electromagnetic energy with a lower frequency than that of gamma or X-rays [4.63]. Due to its reduced energy, it is far less penetrating; however, UV may affect certain organic materials through an interactive process known as photolysis.[19] Photolysis operates through the excitation of electrons within specific molecular functional groups in a polymer. Some polymers, including polyester, PVC, and polyurethane, contain these functional groups as part of their basic molecular structure. Hydrocarbon polymers (such as polyethylene/polyolefin, polypropylene, and EPR), although ideally not containing the functional groups necessary for photolysis, may exhibit some degree of photolytic behavior due to aging or because the polymer formulation includes photosensitive materials (fillers or impurities containing ketones or hydroperoxide groups) [4.64].

For photolysis to occur, a quantity of energy at a particular wavelength must be absorbed so as to initiate the dissociation of the molecules into their constituent radicals, thereby

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[18] The only beta radiation sources with potential aging effects on cable and termination systems (during normal operation) identified as part of this study were those associated with refueling and spent fuel storage systems. However, these were not considered significant because (1) the resulting Bremsstrahlung dose is estimated at approximately 3% to 5% of the incident beta dose, and (2) the fuel pool water has a shielding effect. Note also that as indicated in a typical FSAR for a late 1980s BWR, the typical design basis criteria for spent fuel storage facilities is to maintain radiation levels at or below those for continuous occupational exposure during normal operations.

[19] UV radiation may also interact with free oxygen to produce ozone (Section 4.1.5).

ultimately affecting the overall physical properties of the polymer. Indications of UV photolysis include embrittlement, discoloration, and spontaneous cracking.

UV stabilization is generally accomplished through the use of UV absorbers, quenchers, and hindered amines. More than one of the UV stabilization methods may be employed in a single material; synergistic effects have often been noted when stabilizers are used in this manner [4.65].

Many polymers commonly used in cables can exhibit photolytic behavior if they are not stabilized. Polyethylene and polypropylene are subject to rapid embrittlement and crazing under exposure to UV, whereas PVC is subject to darkening, cracking, and embrittlement. Fluorocarbons (such as Teflon® and Tefzel®) are extremely resistant to UV radiation. Polyimide (Kapton®) may undergo some minor loss of tensile strength after prolonged UV exposure. Thermosets (such as epoxies and phenolics) exhibit generally good UV resistance, with some discoloration and minor cracking often occurring with long-term exposure. Elastomers such as Hypalon®, EPR/EPDM, Neoprene®, butyl, and silicone rubber are all generally resistant to the effects of UV radiation, with some minor effects noted. Table 4-6 generally describes the effects of UV radiation on various materials, when there is no photolytic stabilization.

Table 4-6 Effect of Ultraviolet Radiation on Polymer Stability (No Photolytic Stabilization) [4.66]

Polymer	Effect of Ultraviolet Energy
Plastics	
Mylar	Decreases tensile strength and elongation
Polyamide (nylon)	No significant effect
Polymethyl methacrylate	Surface discoloration and crazing
Polyethylene	Embrittlement
Polypropylene	Embrittlement
Polyimide	No significant effect
Polystyrene	Yellows
Plasticized polyvinyl chloride	Develops tacky and discolored surface
Teflon®	No significant effect
Elastomers	
Butyl	Increases tensile strength and elongation
Hypalon® (chlorosulfonated polyethylene)	No significant effect
Neoprene®	Increases tensile strength, decreases elongation
Nitrile	Decreases tensile strength and elongation
Styrene-butadiene (SBR)	Decreases tensile strength and elongation
Silicone	Surface crazing
Viton A	No significant effect

Note: Results are for relative comparison only; spectral distribution or dose not specified.

It should be noted that most commercially available cables using polymers susceptible to UV damage have stabilizers added to preclude this effect. For example, carbon black is a typical additive to cable polymer formulations; even a few percent of this material greatly enhances UV stabilization in polyolefins through absorption [4.65]. One notable exception that has been identified is PVC insulation containing less than 3% carbon black; at least one nuclear plant has experienced degradation of this material in cables located in close proximity to overhead fluorescent lights. Although not a definitive test, UV-sensitive polymers may sometimes be identified by a white or very light color, which results from the lack of any carbon black or similar stabilizer.

UV radiation sources at nuclear plants include solar radiation and ultraviolet or fluorescent lamps [4.21]. UV radiation is readily shielded by even a thin layer of opaque material; hence, only materials directly exposed to these sources may be degraded. Electrical cables and terminations may be routed outdoors above-grade (primarily medium-voltage cable) or in proximity to fluorescent sources indoors so that comparatively intense UV exposure results. Cable used in certain plant applications (such as closed-circuit television, meteorological, or telephone circuits) may be routed almost completely outdoors.

Degradation of cable installed outdoors will vary with a number of factors such as the duration of exposure, ambient and cable temperature, annual solar intensity, and the type of material used on the exposed surfaces of the cable. Most cables suitable for outdoor use are purposely formulated to resist degradation caused by solar UV exposure. An additional consideration relates to nonstabilized cable stored on reels in outdoor locations. Cable stored in this fashion may sit undisturbed for several years; in areas of significant solar exposure, susceptible cable materials may degrade rapidly under such conditions if left uncovered. Some of the cable stored outdoors may not be intended for outdoor use; hence, its UV resistance may be comparatively low.

Indoor cable may be exposed to UV radiation from fluorescent lamps installed in the plant. A significant fraction (roughly 20%) of the total energy emitted from a fluorescent lamp can be UV radiation of varying wavelengths [4.21]. Although this radiation is not known to be particularly harmful to humans, it may nonetheless degrade certain polymeric cable and termination components. Factors affecting the rate of degradation include the type of material used, the proximity of the cable/component to the fluorescent source, the presence of any attenuating media (such as plastic lenses or coverings), and the duration of exposure. Symptoms of UV cracking in such applications are similar to those for outdoor cable, and may include discoloration and cracking, especially in the immediate vicinity of the fluorescent source (such as cables run near overhead fluorescent lamps in a plant control rooms) [4.64], [4.65].

In addition to the aging mechanisms already described, UV radiation may produce ozone through interaction with diatomic oxygen. Section 4.1.5 discusses potential effects of ozone on cable and termination materials.

Neutron

Neutron (*n*) radiation emanates from the reactor core during operation (and to a greatly reduced degree during shutdown). Neutrons are relatively massive subatomic particles that vary in energy level (fast/thermal) and penetration capability. Energetic neutrons may be destructive to both inorganic and organic materials [4.60]; however, the neutron reflectors, moderators, and radial shielding installed around the reactor core and vessel ensure that the net neutron flux (and hence dose rate) out of the vessel shielding is extremely low in comparison to that of gamma radiation. Thus, virtually no cable within primary containment is exposed to significant neutron dose, with the possible exception of any cables located inside the neutron shielding or directly adjacent to the reactor pressure vessel in areas of high relative neutron flux. Cables used in such applications generally contain inorganic or metallic materials with a high damage threshold for neutron radiation.

Effects of Radiation Exposure

Radiation interacts with matter in two principal ways: ionization/excitation of atoms in the material (radiolysis), and displacement of atoms or subatomic particles, thereby altering the molecular structure of the material. Both processes are applicable to radiation-induced degradation; however, displacement effects are usually not significant for organics because of their less rigid structure and covalent bonding. Similarly, ionization effects are of little significance to inorganic materials because of their ionic bonding and rigid structure. In general, radiation effects are much more severe on organic than on inorganic materials [4.60], [4.61].

Ionization and excitation within organic materials result in accelerated chemical reactions; the type of reaction is determined by the material. Their magnitude or extent is determined by the total energy deposited into the material. In most cases, the effects of radiation type and energy spectrum on the total energy deposited are minimal; thus, equal doses of various types of radiation will produce roughly equal damage in an organic material. This relationship does not generally hold for inorganic materials. Accordingly, the specific type of radiation dose applied to an inorganic as well as the type of material irradiated must be carefully considered. Of the types of radiation produced by a nuclear reactor, neutron radiation is clearly of most concern to inorganics and metals for the reasons stated above [4.66].

Radiation incident on cable and termination organic components produces aging/degradation through scission, oxidation, or crosslinking of polymer chains; this process is generally known as radiolysis [4.64]. (Note that radiation-induced oxidation is considered separately in Section 4.1.5.5 of this AMG.) As with thermal exposure, the tolerance of an individual material to various types of radiation will vary according to the general type of material (i.e., elastomer, fluoropolymer, etc.) and its individual chemical structure and formulation. Organic materials commonly used in nuclear plant cable and termination applications vary widely in their susceptibility to radiation. Changes in the material's overall mechanical properties (such as elongation-at-break, tensile strength, and hardness) and electrical properties (such as dielectric strength and conductivity) may result from exposure to radiation. As a general rule, cable system organic materials exposed to total gamma doses less than about 1 kGy [100 krad] (corresponding to a dose rate of ~2 mGy/hr [~0.2 rad/hr] over 60 years) will experience little or no aging from radiation exposure [4.60]. Above this level, however, progressive changes in physical properties begin to occur as dose is increased. The threshold[20] is unique for each

[20] Defined by EPRI NP-2129 [4.60] as "... the first detectable change in a property of a material due to the effect of radiation."

material, and can be affected by environmental conditions such as temperature [4.67]. For a given dose[21], radiation-induced damage to polymers in oxygen environments may depend on the dose rate of the exposure [4.5], [4.6], [4.9], [4.68], [4.69], and [4.70]. Table 4-7 lists approximate radiation threshold values for generic cable and termination materials. For many of the polymers used in fabricating cables and terminations, the radiation threshold is roughly 10 kGy [1 Mrad]. References [4.60] and [4.61] provide additional information on the degradation of specific materials with radiation and other environmental influences. Section 4.1.5 discusses the effects of radiation exposure on the loss of fire retardants within cable materials.

Macroscopic effects of radiation-induced degradation of organics may include embrittlement, cracking or crazing, swelling, discoloration, and melting, as well as a change in the mechanical or electrical properties of the affected material (such as reduction in elongation-at-break, insulation resistance, or change in tensile strength). Radiation damage to cable jacketing and insulation may make them difficult to handle or terminate due to brittleness. In addition, severe radiation exposure may induce swelling (due to increased moisture absorption) for certain materials [4.71]. This effect generally occurs at high radiation levels where corresponding mechanical properties of the material are significantly degraded [4.60]. One plant contacted during the preparation of this guideline indicated that some swelling of jacket material had been experienced in cables located in immediate proximity to the reactor vessel and subject to high humidity. Similarly, other organic cable and termination components (such as O-rings or seals) may swell, thereby producing increased tension or pressure on other components in direct proximity.

For inorganic materials, a rough estimate of the threshold level of concern can be made. Figure C-6 of Reference [4.3] (reproduced here as Figure 4-8) shows approximate levels of radiation damage for various inorganic insulating materials based upon changes in their physical properties. Note that a neutron fluence of roughly 1×10^{18} n/cm^2 (equivalent to a gamma dose of about 3×10^7 Gy [3×10^9 rad]) results in no significant damage or change in material properties for the materials listed (with the exception of glass). Metals generally have comparable or higher damage thresholds, on the order of 1×10^{19} n/cm^2 (approximately 2.5×10^8 Gy [2.5×10^{10} rad]) [4.66]. The predominant effects on metals are increased hardness and reduced creep rate. Fatigue properties and electrical resistance are among the least affected [4.66]. Accordingly, a conservative threshold dose of 1×10^{17} n/cm^2, or 3 MGy [300 Mrad] gamma, can be set for mineral insulations and metals used in cable and termination components. Below this dose, little or no aging effects should be noted in such materials. Note that few locations within primary containment could experience this level of exposure.[22]

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[21] ASTM E 1027-1984 gives generalized procedures on preparing and exposing test samples to ionizing radiation, and reporting test results.

[22] The neutron flux calculated at the inner reactor pressure vessel beltline wall of a late 1980s BWR is roughly 1×10^9 n/cm^2-sec (all neutron energies >0.1 MeV) at 100% power (per the FSAR). Assuming 60 years of operation at 80% of capacity, the total neutron fluence for this location would be approximately 1.5×10^{18} n/cm^2. Per Regulatory Guide 1.99 [4.69], the neutron fluence is a function of depth in the reactor vessel; accordingly, the expected neutron fluence at the outer (non-wetted) surface of the typical vessel is roughly 20% of that at the inner surface (assuming a beltline vessel thickness of 16.5 cm [6.5 in]. Hence, inorganic or metallic cable components located immediately adjacent to the outer surface of the reactor vessel beltline would be exposed to a maximum 60-year neutron dose on the order of 3.0×10^{17} n/cm^2.

Table 4-7 Representative Radiation Dose Thresholds for Common Cable and Termination Organic Materials [4.60, 4.61]

Material Category	Material Name	Lowest Reported Threshold or Applicable Threshold Range for γ Radiation (Gray)	(Rad)	Estimated Applicable Threshold Range; Neutron (n/cm^2)[1]	Property Measured
Elastomers	EPR/EPDM	10^4	10^6	4×10^{14}	Compression Set
	Neoprene®	10^4	10^6	4×10^{14}	Compression Set
	CSPE	5×10^3	5×10^5	2×10^{14}	Elongation
	Nitrile (Buna N)	10^4	10^6	4×10^{14}	Compression Set
	Butyl	7×10^3	7×10^5	2.8×10^{14}	Tensile Strength
	Viton	10^3	10^5	4×10^{13}	Elongation
	Silicone	10^4	10^6	4×10^{14}	Tensile Strength, Compression Set
Thermo-plastics	XLPE/XLPO	10^4	10^6	4×10^{14}	Elongation, Tensile Strength
	PVC	10^3	10^5	4×10^{13}	Unstated
	Polyethylene	3.8×10^3	3.8×10^5	1.5×10^{14}	Elongation
	ETFE (Tefzel®)	Note 3	Note 3	Note 3	-
Thermosets	Epoxy Resins	2×10^6	2×10^8	8×10^{16}	Varies
	Polyimide (Kapton®)	10^5	10^7	4×10^{15}	Tensile Strength, Elongation
	Phenolic Resins	3×10^3 to 3.9×10^6	3×10^5 to 3.9×10^8	1.2×10^{14} to 1.6×10^{17}	Elongation
	Furanic Resins	3×10^6	3×10^8	1.2×10^{17}	Tensile Strength, Elongation
	Polyester Resins	10^3 to 7.9×10^5	10^5 to 7.9×10^7	4×10^{13} to 3.2×10^{16}	Elongation
	Melamine Formaldehyde	6.7×10^4	6.7×10^6	2.7×10^{15}	Impact Strength

Notes:

1. All data are formulation specific. See the referenced reports.
2. Based on approximate conversion factor of 4×10^8 n/cm^2 = 1 rad (see Figure 4-8).
3. No radiation threshold data were located for ETFE; however, based on manufacturer's data and elongation data at 75% and 50% retention of elongation in Reference [4.60], the radiation threshold may be conservatively estimated at 10^4 Gy [10^6 rad].

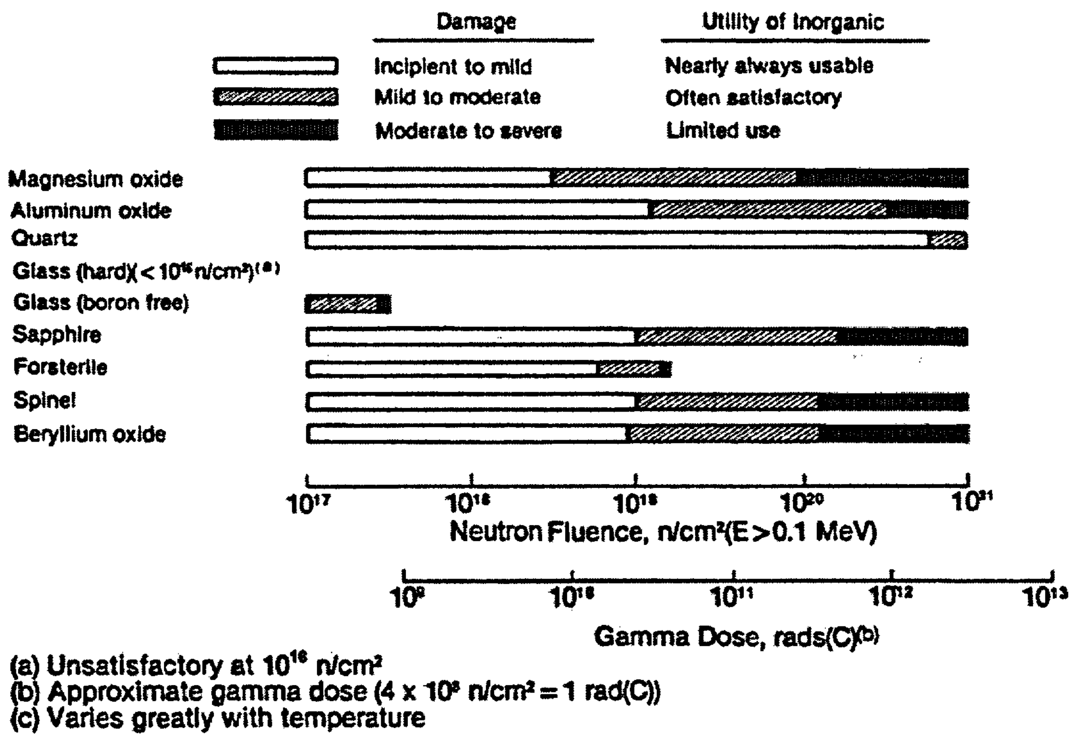

Figure 4-8 Relative Radiation Resistance[c] of Inorganic Insulating Materials Based Upon Changes in Physical Properties
[NOTE: A rad(C) is a rad deposited in the element carbon (C)]

4.1.4.1 Radiation Dose-Rate Effects

In nuclear plants, a variety of polymeric materials are exposed to radiation at relatively low dose-rates for long periods. To estimate the long-term degradation that occurs, many accelerated aging studies have been performed by increasing the radiation dose-rate based on the assumption that the amount of degradation will depend only on the integrated dose. However, evidence exists to indicate that, in air environments, certain polymeric materials can show significant dose-rate effects. A dose-rate effect may be defined as an effect on a material that differs in magnitude or type (for the same total dose) according to the irradiation rate [4.60]. These effects may be transient or permanent. Dose-rate effects are very common in radiation aging of polymeric materials, and can range from very large to insignificant, depending upon such factors as polymer type, aging conditions, sample geometry, and degradation parameter being monitored [4.8].

Dose-rate effects typically involve oxidation mechanisms. When aged at high radiation dose rates, a large fraction of polymeric materials has been found to have physical dose-rate effects caused by diffusion-limited oxidation degradation. A much smaller fraction has chemical dose-rate effects. No evidence exists for dose-rate effects in a nitrogen environment [4.8]. In materials found to have dose-rate effects, usually there was more mechanical degradation for a given dose as the dose rate was reduced [4.8]. Dose-rate effects for PE and PVC were determined at low dose rates of 87 and 44 Gy/hr [8700 and 4400 rad/hr], respectively. A difference in the mechanical properties of these materials irradiated at low dose rates could be identified only after a total dose greater than ~20 kGy [~2 Mrad] had been absorbed, and the difference did not become significant (i.e., >10%) until the total dose exceeded ~100 kGy [~10 Mrad] [4.8]. For other common cable and termination materials (such as XLPE, EPR, and ETFE), synergistic effects were either not noted or occurred at dose rates above those for PE and PVC. There was no evidence in the literature of dose-rate effects occurring at exposure rates less than those indicated above.

Dose-rate effects must be considered from both aging and environmental qualification perspectives for realistic simulation of normal operating and predicted accident conditions. From an aging perspective, the use of test and laboratory data obtained under high dose-rates may result in an underestimate of the degradation of a material for a given dose under normal (low dose-rate) operating conditions. Thus, the aging portion of an EQ test might underestimate the pre-LOCA degradation that occurs under natural aging conditions. From an accident simulation perspective, the degradation resulting from exposure at a comparatively low qualification test dose rate and that resulting from the higher postulated accident dose rate may differ.

Environmental qualification testing does not typically include a segment that addresses the actual radiation dose rate during the component's design life. To do so would require a test program that lasts 40 years or more. As stated previously, the highest anticipated dose rate during normal operating conditions is on the order of 2 Gy/hr [200 rad/hr] inside primary containment. The lowest dose rates discussed in the literature for any material at which dose-rate effects have been observed (more than 10 Gy/hr [1000 rad/hr]) greatly exceed those for the typical plant under normal operating conditions. Although the maximum 60-year total dose inside a typical primary containment is anticipated to be on the order of 0.1 to 1 MGy [10 to 100 Mrad], most of the areas should receive a lower total dose [4.62]. If the dose rate during accelerated testing is more than 10 Gy/hr [1000 rad/hr], the aging results might not be representative of the effects that would actually occur.

For equipment located outside primary containment, the dose rate and TID for most plant areas during normal operations is low (typically less than 1 mGy/hr [0.1 rad/hr] and 500 Gy [50 krad] over 60 years). These dose rates and doses are much lower than the minimum dose rates and doses at which dose-rate effects (and radiation degradation) have been observed. Note, however, that a few areas outside primary containment (e.g., in the proximity of radwaste or BWR main steam systems) may be subject to higher dose rates.

A typical qualification test also does not match the actual radiation dose rate during accident conditions. The maximum accident dose rate for a plant may exceed 100 kGy/hr [10 Mrad/hr] [4.8], whereas the maximum dose rate used during qualification testing is 10 kGy/hr [1 Mrad/hr] and usually is only 40% to 80% of that value. The accident dose rate used for qualification testing is far in excess of the dose rate at which dose-rate effects have been observed, but these effects are considered in the applicable standards and regulations. Exposure at a maximum dose rate of 10 kGy/hr [1 Mrad/hr] is recommended in IEEE 383-1974 [4.72], which has been accepted by the NRC in Regulatory Guide 1.131 [4.73] to establish qualification.

To determine the significance of a potential dose-rate synergism, the analysis or test report used to establish qualification may be reviewed to compare the dose-rate and total dose used in the test with those actually occurring at the installed location. If the dose-rate and total dose at the installed location are not in the same range as values for known synergistic effects for the material or component in question, then the test/analysis dose-rate and total dose may be considered acceptable to establish qualification. Note that components that contain no Teflon® and are subjected to a total dose of less than 1 kGy [0.1 Mrad] may be excluded from further analysis for dose-rate synergisms. At these levels, there is no significant degradation of mechanical or permanent electrical properties, and no indications of significant synergistic effects of radiation combined with either environmental stresses or sensitization to subsequently imposed stresses [4.60].

It should be noted that aging dose-rate effects are also generally of little potential significance for components qualified for accident doses, because the fraction of the total dose applied that is potentially subject to non-conservative dose-rate effects (i.e., the aging dose) is comparatively small.[23]

4.1.4.2 Radiation Aging Sequence Effects

The chemical composition of a polymer determines its possible reaction mechanisms. Environmental conditions generally determine which of these possible reactions will occur and at what rates. This implies that changes in a material subjected simultaneously to radiation and another environmental stress could be different from the changes that would occur in the material if the material were subjected to the stresses separately and sequentially. A "synergistic" effect could occur [4.60].

If some type of reaction occurs in a material because of two environmental stressors, the best approach would be the use of appropriate combined-environment accelerated simulation. On the other hand, if synergistic effects were not important, sequential exposure to the two environments might adequately simulate the ambient aging conditions. The possibility also exists that sequential exposure to the two environments might adequately simulate cases where synergistic effects are important, thereby eliminating the necessity for more complex and expensive exposure to combined environments [4.8].

Important synergisms of low-temperature radiation and elevated thermal environments and important ordering effects in sequential aging experiments can occur, and these are mechanistically related to radiation dose-rate effects. NUREG/CR-4301 [4.8] and NUREG-0237 [4.74] concluded that significant evidence existed for the possible presence of important synergistic effects in combined radiation-thermal environments. If a material was determined to have important synergistic effects in combined radiation-thermal environments, it was probable that sequential aging simulations would give different material degradation results. These results led to an important conclusion, namely, the normal sequential exposure of thermal aging followed by ambient-temperature, radiation aging can result in an underestimate of material damage when strong synergistic effects related to radiation and temperature exist for a material [4.8].

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[23] A typical qualification radiation exposure might include 0.5 MGy [50 Mrad] to simulate the pre-LOCA aging dose and 1.5 MGy [150 Mrad] to simulate the accident dose.

The aging response of many materials to sequential exposure (radiation followed by thermal or thermal followed by radiation) is similar to their response to a combined radiation plus thermal exposure. In materials where significant differences do occur, the radiation followed by thermal sequence is usually more severe than the thermal followed by radiation sequence, and the radiation followed by thermal sequence more closely matches simultaneous exposure conditions. This indicates that the most conservative approach to sequential aging simulations should use the radiation followed by thermal sequence. Significant sequential ordering effects usually occur in materials that also have large synergisms related to radiation and temperature and large radiation dose-rate effects [4.8]. In sequential aging experiments, the thermal exposure can bring about rapid degradation for certain polymeric materials that have been presensitized by previous radiation exposure [4.75].

NUREG/CR-3629 [4.76], which examined the effects of aging sequence, concluded the following:

- For several materials, tensile properties at completion of aging were only slightly affected by both the temperature during irradiation and the order of the sequential aging environmental exposures.

- In general, the choice of temperature during irradiation was secondary to the choice of aging sequence in its effect on polymer properties.

- If the sequential order of irradiation and thermal exposure was important to the aging degradation of tensile properties, usually irradiation followed by thermal exposure was most severe [4.8].

Section 6.3.2 of IEEE Standard 323-1974 [4.77] provides a test sequence to be used for qualification testing, namely that the equipment shall be aged to a simulated end-of-qualified-life condition prior to being exposed to a simulated design basis event. While IEEE 323-1974 also states that "the sequence shall be justified as the most severe for the item being tested," this does not mean that the simulated accident might be performed prior to the simulated aging. Instead, it means that the various components of a sequential aging exposure (radiation and thermal) shall be performed in the order that is the most severe for the item being tested, and similarly, the various components of a sequential accident exposure (LOCA radiation and LOCA steam/chemical-spray exposure) shall be performed in the order that is the most severe. Common sense would indicate that the most realistic method of performing qualification testing is to utilize a simultaneous radiation and thermal aging exposure followed by a simultaneous LOCA radiation and LOCA steam/chemical-spray exposure. However, most test facilities are not capable of performing such simultaneous testing and, therefore, the test sequence usually consists of sequential aging followed by a sequential LOCA.

While certain sequences are not representative of what could actually happen in a plant (e.g., DBE radiation followed by thermal aging), IEEE 323-1974 requires that the test sequence be the most severe. NRC approval should be obtained for any test sequence other than the most severe, and approval should be documented in the licensing basis. A possible basis for justification of an alternate sequence might be that the alternate sequence more realistically simulates the real aging environment.

Various tests performed during the past 20 years have shown that certain properties of some materials vary significantly depending on the sequence of radiation and thermal aging. More damage can occur in some materials if radiation aging is performed before thermal aging. However, test results do not demonstrate that this is always the case, even for the same generic material (that is, different compounds of EPR can give different or contradictory results). Although test data are limited, the results seem to be somewhat dependent on the temperature used for thermal aging. Many of the research reports cited used a temperature that was much lower than the typical range of 121°C to 150°C [250°F to 302°F] used in qualification test programs. When the accelerated aging temperature was closer to those typically used in qualification tests, the results concerning sequence were not conclusive. Consequently, caution must be used when attempting to relate the results of the research tests with those of qualification tests and with actual plant environments.

4.1.4.3 "If-Then" Criteria for Radiation Stressors and Aging Mechanisms

Table 4-8 summarizes radiation stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components.

4.1.5 Chemical/Electrochemical Stressors and Aging Mechanisms

Chemical stressors result from the exposure of cable and termination components to moisture, solvents, fuel oils, lubricants, or other substances. Chemical stressors can affect the structure and properties of both organic and inorganic materials. Because electrical cable is present in most every space in a nuclear plant, and a single circuit may be present in many of the spaces, cable and termination components may be exposed to a wide variety of chemical stressors. In general, chemical stressors are highly local and typically affect only very small portions of the plant cable inventory. The degradation of inorganic (metallic) cable materials is generally electrochemical compared with the purely chemical processes primarily associated with organic material degradation. Each of these degradation mechanisms is described in the following sections.

4.1.5.1 Chemical Attack of Organics

Chemical attack of organic materials used in cables and terminations may occur following exposure to acids, alcohols, alkalines, esters, ketones, oils, oxidizers, salts, solvents, or water. These agents may reach the material through a number of different mechanisms such as accidental or intentional application, airborne transport (atomization), splash or spray, leaching, or direct contact with another material. Chemical attack of polymers may result in dissolution, swelling, or breaking of chemical bonds within the polymer, ultimately affecting its mechanical and/or electrical properties [4.2].

Table 4-8 Radiation Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/ Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Radiation (gamma; in oxygen environment) (4.1.4)	Radiation-induced oxidation; radiolysis	Embrittlement/ reduced elongation; variations in tensile strength; loss of plasticizer; loss of antioxidant	- Hard or brittle jackets, insulation, or other organic components - Material discoloration or crazing - Swelling (moisture absorption)	All cable and termination organic materials	60-year equivalent TID greater than or equal to the applicable value in Table 4-7 (material-specific gamma dose)	Continuous (approximately 0.02 Gy/hr [2 rad/hr] over 60 years; TID of 10 kGy [1 Mrad])	Radiation damage threshold (TID) for most common cable organics is approximately 10 kGy [1 Mrad], see Table 4-7
Radiation (neutron) (4.1.4)	Displacement	Hardening/ embrittlement; reduced creep rate (metals)	- Cracking - Increased conductor rigidity	Inorganic (mineral) insulations and metals	10^{17} n/cm fluence (approximately 3 MGy [300 Mrad] gamma)	Continuous (60 years)	Damage threshold for inorganic (mineral) insulation and metal components only
Radiation (neutron) (4.1.4)	Chain scission; displacement	Embrittlement/ reduced elongation; variations in tensile strength; loss of plasticizer; loss of antioxidant	- Hard or brittle jackets, insulation, or other organic components - Material discoloration or crazing - Swelling (moisture absorption)	All cable and termination organic materials	60-year equivalent TID greater than or equal to the applicable value in Table 4-7 (material specific neutron dose)	Continuous (60 years)	Damage threshold for inorganic (mineral) insulation and metal components only
Radiation (UV) (4.1.4)	Photolysis	Embrittlement/ reduced elongation, variations in tensile strength	- Cracking or crazing - Discoloration	Organic photo-sensitive polymers (including polyethylene, polypropylene, and PVC)	Nonstabilized photo-sensitive material exposed to fluorescent light or located outdoors	(n/a)	Applicable to few cable/termination materials because most are UV stabilized

Significant differences in the chemical resistance of substances exist between categories of polymers (thermoplastics and thermosets) and between individual families within those categories. Furthermore, individual formulations of a particular polymer can have significantly different chemical resistance based on the ratios and types of constituents included in the formulation. The chemical properties of common cable materials are summarized in Table 4-9; these properties are only generalizations and may not be representative of a material's performance upon exposure to specific chemical compounds. In addition, other environmental influences (such as heat, humidity, and radiation) may substantially alter the effect of any chemical interaction so that it is more or less severe. Table 4-9 is meant only as a general guide; manufacturer's literature or other comparable sources should be used to determine the resistance of a particular material to a specific chemical agent under prevailing environmental conditions.

Changes in the appearance of chemically affected organics will vary with the specific material and the chemical to which it has been exposed. For example, changes in color may indicate contact with a strong solvent (often producing a bright or vivid color) or oxidizer (lightened or white color). Changes in the texture of the material (such as surface roughness, cracking, or oily residue) may also result. Also, changes in the mechanical properties of the compound, such as swelling or softness, may occur [4.50]. Table 4-9 shows some common organic materials used in electrical cable and termination construction and their relative susceptibility to certain chemicals [4.2], [4.25], [4.26], [4.50], [4.78], [4.79].

4.1.5.2 Chemical Decomposition of Cable Materials

In addition to exposure from foreign or external chemical substances, cable and termination components may be exposed to chemical by-products of the thermal or radiolytic decomposition of cable jacketing, insulation, fire-resistant coatings, or other organic components. Many materials commonly used in cable construction either contain or are manufactured using potentially corrosive chemicals such as chlorides, peroxides, or sulfurous compounds. Chemical by-products originating from decomposition of cable components may result in several degradation mechanisms, including corrosion of metallic components (conductor, shield, drain wire, or terminations), and softening, swelling, or decomposition of other organics within the cable structure. Plasticizer migration in PVC materials can also result in swelling of adjacent elastomers.

For example, Neoprene® rubber (chloroprene), PVC, CSPE, and CPE all may produce chlorine ions (and hydrochloric acid) upon decomposition. In addition, EPR, EPDM, and other elastomers are cured using peroxide or sulfur compounds that may be leached from the material as it ages or is subjected to certain environmental conditions (such as heat or wetting). Copolymers such as ethylene vinyl acetate (a semiconducting shield material) may also decompose to produce by-products such as weak acids [4.50].

Table 4-9 Chemical Compatibility of Common Cable and Termination Organic Materials [4.2], [4.25], [4.26], [4.49], [4.77], [4.78]

Compatibility	Elastomers							Thermoplastics				Thermosets			
Chemical Agent	EPR/ EPDM	Neoprene	CSPE	Nitrile	Butyl	Viton	Silicone	PVC	Poly-ethylene	XLPE/ XLPO	ETFE (Tefzel)	Epoxy Resins	Polyimide (Kapton)	Phenolic Resins	Furanic Resins
Acids, inorganic	Poor	Poor	Good	Poor	Fair	Good[1]	Poor	Good	Good	Good	Good	Poor[2]	Fair[2]	Fair	Poor
Acids, organic	Fair	Poor	Fair	Fair	Fair	Poor	Good	Good[3]	Poor	Poor	Good	Good	Fair	Good	Good
Alcohols	Fair	Good	Good	Fair	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good
Alkalines	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Poor	Good	Good
Esters	Fair	Poor	Poor	Poor	Fair	Poor	Fair	Poor	Fair	Fair	Good	Fair	Good	Good	Good
Ketones (acetone)	Good	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Good	Fair	Good	Good	Good
Oil, Mineral	Poor	Fair	Fair	Good	Good	Good	Good	Good	Poor	Poor	Good	Good	Good	Good	Good
Oil, Petroleum-based and Fuels	Poor	Fair	Fair	Good	Poor	Good	Poor	Fair	Fair	Fair	Good	Good	Good	Good	Good
Oil, Silicones	Good	Good	Good	Good	Good	Good	Good	Good	Poor	Poor	Good	Good	Good	Good	Good
Oxidizers	Poor	Poor	Poor	Poor	Poor	Good	Poor	Good	Fair	Fair	Fair	Poor	Poor	Poor	Poor
Salt, Inorganic	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Fair[4]	Good	Good
Solvent, Chlorinated	Poor	Poor	Poor	Fair	Poor	Good	Poor	Poor	Poor	Poor	Good	Fair	Good	Good	Good
Solvent, Hydrocarbon	Poor	Fair	Poor	Good	Poor	Good	Poor	Poor	Poor	Poor	Good	Fair	Good	Good	Good
Water (including steam)	Good	Good	Good	Good	Good	Good	Good[5]	Good	Good	Good	Good	Good	Poor	Good	Good

Good = No significant effect   Fair = Mild effect or limited use   Poor = Strong effect or prohibited use

Notes:
1. With exception of chlorosulfonic and chloroacetic acids.
2. Good in weak acids, poor in strong acids.
3. With exception of acetic and formic acids.
4. Poor for alkaline salts.
5. May be swollen by exposure to steam.

Degradation resulting from copper-catalyzed oxidation reactions may occur in certain polymers [4.13], [4.80]. A catalyst is defined as a substance that affects the rate or the direction of a chemical reaction, but is not appreciably consumed in the process [4.81]. Because of its proximity to the insulation, ions from copper-based conductors may act as catalysts for oxidation reactions within the insulation, thereby accelerating its degradation [4.82]. This will occur primarily in areas where the insulation is in direct contact with the conductor. Note that often little (if any) degradation of the conductor will occur as a result of this catalysis. Also note that tinning a copper conductor will not prevent this type of reaction because small amounts of copper will migrate through the tin coating.

By-products are also generated from chemically crosslinked XLPE as a result of the high temperature/pressure curing process. By-products such as acetophenone, cumene, and alpha methyl styrene are produced as the chemical crosslinking agent (dicumyl peroxide) decomposes. The results of testing aimed at defining the effect of these chemicals on electrical aging (ac and impulse breakdown strength) indicate that some effect does exist[24]; however, this effect is complex in nature, relatively small in magnitude, and depends not only on the concentration of the by-products but also on their mixture. Hence, no clear-cut rule can be formulated regarding the effects of these chemicals on aging of XLPE insulation [4.83].

Another potential aging mechanism is hydrolytic[25] degradation of Mylar (polyethylene terephthalate) shield film under exposure to high temperature and moisture. In this mechanism, water increasingly reacts with the Mylar polymer as temperature is increased[26] [4.84]. Normally, the Mylar shield in an electrical cable is contained completely within an overall jacket; however, moisture may ingress to the shield through the ends of the cable (which may be loosely wrapped, such as in twisted shielded pair configurations) or through cuts or other damage to the jacket.

It should be noted that, in general, the effects of the chemical decomposition processes on the overall cable inventory appear to be negligible because the fraction producing such by-products is small and the severity of the effects of these by-products is limited.

4.1.5.3 Electrochemical Attack of Metals

Corrosion is a destructive process that is characterized by either chemical or electrochemical attack on metals. Direct chemical corrosion occurs in instances of highly corrosive environments, high temperatures, or both. More common is electrochemical corrosion, which accounts for most degradation experienced by metals exposed to moisture or atmosphere. Electrochemical corrosion can occur at a junction between two dissimilar metals (galvanic reaction) or within one homogeneous metal. Homogeneous metals corrode as a result of variations in electrostatic potential between various regions of the metal (caused by anodic and

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[24] The ac breakdown strength of compression-molded XLPE is increased, whereas the impulse breakdown strength is reduced.

[25] Hydrolysis refers to a reaction with water; in this case, a reaction of the ester group linking the polymer chain with water.

[26] Figure 3 of "Electrical Insulation Deterioration" [4.84] indicates less than 100 hr average life at 100% RH at 110°C, approximately 1 year at 70°C, and roughly 20 years at 50°C.

cathodic areas, inclusions, residual stress, etc.); this potential results in electron flow from anodic to cathodic areas, eventually producing pitting and wastage.

Numerous different types of corrosion may occur, depending on the types of metal involved and the environment. A discussion of each type of metal and its applicable corrosion(s) is beyond the scope of this guideline; however, several common factors can be identified. These include the presence of an electrolyte (such as water), soluble ions in the electrolyte (such as chlorides), elevated temperature, and high oxygen concentration. In addition, some forms of corrosion depend upon the presence of other factors (such as tensile stress). The occurrence and rate of corrosion is affected by a number of factors, including the type of metal, the type and properties of the fluid (electrolyte) in contact with the metal, the presence of other influences (such as stress), and the concentration of oxygen and ions present. Corrosion of cable systems may be enhanced by the presence of stray dc currents from open ground circuits or strong fields.

A related phenomenon is the oxidation of metals to metal oxides. In this case, dissolved oxygen combines with the metal at the surface of the component to form an insoluble metal oxide [such as ferric oxide (rust)]. These oxide layers may have significantly different electrical and physical properties than the underlying parent metal. For example, metallic electrical contacts that oxidize with a less conductive species may experience higher electrical resistance and therefore result in overheating of electrical junctions or interference with circuit operation. In some cases (e.g., passivated metals such as Inconel), the formation of an oxide layer can actually protect the metal and subsequently reduce the rate of certain types of corrosion.

Corrosion of metallic components is important because the electrical and mechanical properties of the component may be affected. Corrosion can attack the surface of conductive components such as electrical contacts, thereby increasing their resistance and reducing their electrical conductivity. Also, if left unimpeded, corrosion may result in loss of the mechanical integrity of a component; this property loss may be significant if the component is under mechanical stress (either during normal or transient conditions) so that mechanical failure occurs.

Cable and termination components are generally fabricated from noncorroding or corrosion-resistant materials, or have nonoxidizing compounds applied to them during assembly. Metals used in cables and terminations vary somewhat, based on their application. Cable conductors are typically copper or aluminum alloys, both of which are somewhat resistant to corrosion under normal power plant environments. However, both materials will oxidize so that a surface oxide layer forms. Termination materials may be fabricated from a variety of different conductive materials (ferrous or nonferrous), and therefore may experience varying rates of corrosion/oxidation [4.21], [4.58]. As previously stated, various chemical by-products may also leach from organic cable and termination components under certain circumstances; these chemicals may result in premature corrosion or oxidation of nearby metallic components.

4.1.5.4 Loss of Fire Retardants

Fire retardants contained in common nuclear plant cable and termination insulating materials volatize under thermal exposure [4.85]. As the cable is thermally aged, increased volatization of certain flammable polymer constituents also occurs, resulting in no increase or even a decrease in flammability. Reference [4.86] documents flammability testing of aged and unaged EPR and XLPE (BIW Bostrad and Rockbestos Firewall) cables which exhibited reductions of flammability with increased thermal aging for both cable types.

Radiation aging has been observed to have a substantially smaller effect on fire-retardant volatization for some materials, and a broad array of irradiated insulation/jacket combinations (including EPR/Neoprene®, EPR/CPE, and CSPE) passed vertical flame tray testing [4.87]. Therefore, flammability testing of new cable is considered to be conservative in demonstrating the fire retardancy of thermally aged or irradiated materials.

The loss of fire-retardant compounds in cable insulation and jacketing due to thermal aging or irradiation is considered insignificant[27] in that it has been demonstrated that the actual flammability of the most common materials (including XLPE, EPR, and CSPE) either decreases, remains roughly constant, or only increases slightly. This occurs because flammable volatiles within the chemical formulation are lost at nearly the same rate as the fire-retardant [4.88], [4.89], and [4.90].

4.1.5.5 Effects of Oxygen

Another consideration in aging and degradation of organic material relates to the concentration of oxygen in the local atmosphere. As previously discussed, dose rate and synergistic effects all require oxygen. Many aging studies of polymers to date have been conducted in inert or low-oxygen environments; comparatively few studies have been performed in air (roughly 20% oxygen) [4.8]. In addition, many studies focus on analysis of the pure base polymer and not on the more complicated formulations often found in commercial cable and termination materials. However, the great majority of cable systems installed in the typical nuclear plant possess both of these attributes (e.g., operate in a relatively high oxygen concentration and are composed of more complex formulations).

Oxygen effects can be divided into two major categories: physical effects and chemical effects [4.8]. Physical effects are concerned primarily with diffusion-limited oxidation, whereas chemical effects involve oxygen reactions. Substantial evidence indicates that the dominant aging processes for some materials may be quite different in oxidative and non-oxidative (inert) conditions.[28] Oxygen is also generally required for dose-rate effects to occur.[29]

The thermal and radiation-induced degradation described in previous sections may proceed without the presence of oxygen; however, oxidative degradation processes initiated by heat or radiation (thermoxidative or radiation-induced oxidation) within polymers are often dominant over these mechanisms. Accordingly, although a few polymers actually age slower in oxygen (as opposed to nitrogen or other inert gases), the presence of oxygen increases the aging rate of

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[27] Note that this aging mechanism is considered "significant but not observed" in that functionality may be affected, yet no indications of occurrence/effects exist.

[28] NUREG/CR-4301 [4.8] (citing NUREG/CR-3643) describes the aging of Viton fluoroelastomer, which becomes hard and brittle under high dose-rate exposure (limited oxygen permeation), and soft and stretchy at low dose-rates (high permeation).

[29] Note also that NUREG/CR-4301 [4.8] identified no evidence of the existence of dose-rate effects in a nitrogen environment.

most common cable polymers [4.60], [4.62], [4.64]. Higher concentrations of oxygen often result in a greater oxidation reaction rate and hence, more rapid degradation of the physical properties of the material. The aging may also affect the material in nonuniform fashion; if oxygen diffusion occurs slowly with respect to the rate of reaction, sections of the polymer unexposed to oxygen will experience less deterioration (e.g., diffusion-limited degradation) [4.5], [4.60], [4.91], [4.92]. The mechanical properties of the outer surface of the cable polymer will sometimes dictate those of the polymer as a whole. For example, reduced elongation or cracking at the surface of a cable's insulation may result in a crack or tear propagating through the thickness when the cable is bent or pulled. In natural aging (i.e., low temperature, low dose rate) environments, oxidation processes normally dominate [4.8], and oxygen permeation is more complete, thereby resulting in more uniform aging. If cracks in a diffusion-limited material quickly propagate from the hardened outer surface through the thickness, proper simulation of natural aging can result.

For most cable and termination polymers, environments with reduced oxygen concentration will produce reduced rates of aging. Accordingly, organic cable and termination components located inside nitrogen-purged primary containments (typically a few percent oxygen) may experience a somewhat lower aging rate than they would in more heavily oxygenated environment. Although the rate of degradation is also coupled to several other factors (including temperature, ohmic heating, radiation dose/dose rate, and cable configuration/construction), and the effects are difficult to quantify, the presence of oxygen is often a very significant determinant of the aging rate for these materials.

4.1.5.6 Effects of Ozone

In addition to the effects of oxygen described above, the degradation of certain organic insulation and jacketing materials may be affected by ozone (O_3) in the surrounding media. Ozone is generated in air as a result of the interaction of ionizing radiation with oxygen, or by corona discharge ionization. Applicable cable standards (e.g., ICEA S-19-81 [4.93]) discuss ozone performance and testing requirements for ozone-resistant cables.

Reference [4.7] documents an investigation of the effects of ozone on styrene-butadiene rubber (SBR) and Buna-N rubber under gamma irradiation. This study concludes that the heterogeneous degradation of these materials due to irradiation is the result of two processes: (1) radiation-induced oxidation coupled with oxygen diffusion effects, and (2) ozone effects in the surface regions of the sample. The study also suggests that ozone and ionizing radiation may be synergistic in their effect on these materials.

References [4.94] and [4.95] indicate that, in the absence of ionizing radiation, tensile stress on elastomers tends to increase the likelihood of ozone-induced damage in the form of macroscopic surface cracks that propagate progressively through the thickness of the material. The testing described in Reference [4.7] subjected SBR specimens to irradiation under tension (15% elongation), resulting in the formation of substantial cracks at a dose of 0.3 kGy [30 Mrad].

There was no mention in the literature of the applicability of these observations to other commonly used cable and termination organic materials; however, elastomers with double bonds are most susceptible to ozone effects. Note that Buna-N and SBR account for only a very small percentage of organic cable and termination components currently in use (see, for example, Table 3-4 of this AMG). It can be postulated that the effects of ozone are implicitly considered in the material-specific radiation threshold and degradation data referenced in Section 4.1.4, because a good number of these studies were conducted in oxygenated environments. However, it should be noted that (1) many studies were conducted in inert environments (nitrogen, argon, or vacuum), and (2) some studies performed in air were conducted with limited volumes of oxygen that may have been largely consumed during testing (p. 2.6-1 of [4.8]). It cannot be said with surety, therefore, that all radiation threshold values set forth in Section 4.1.4 include the effects of ozone degradation. Examination of the chemical properties of common cable and termination organics, however, does indicate a good resistance to ozone. For example, EPR/EPDM, CSPE, PVC, silicone rubber, and Viton are all quite ozone resistant ([4.2], p. 474 of [4.31]).

4.1.5.7 "If-Then" Criteria for Chemical Stressors and Aging Mechanisms

Table 4-10 summarizes the chemical stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components.

4.1.6 Combined Aging Environments

4.1.6.1 Synergisms

Combinations of stressors acting on a given cable or termination component may produce synergistic degradation effects. A synergistic effect is defined as an effect caused by two or more stresses applied simultaneously, which is different in magnitude or type than the summed effects of the same stresses applied separately [4.60]. Two commonly acknowledged synergisms applicable to components covered under 10CFR50.49, namely, dose-rate effects and sequence effects, are discussed in Section 4.1.4.1. Appendix H provides additional information on the regulatory requirements related to these two effects. Other potential synergistic stressor combinations that may affect cable and termination aging are discussed in Section 4.1 and include (1) voltage stress in the presence of moisture (medium-voltage cable insulation); (2) bending stress (tensile elongation) of thermal aged and/or irradiated organic cable materials; (3) thermal cycling and gravity (vertical-horizontal cable runs); (4) thermal aging/irradiation of organic materials in oxygenated environment; and (5) exposure of susceptible metallic cable/termination components to oxygen, moisture, and ionic species.

4.1.6.2 Sandia Research on Combined Thermal-Radiation Aging Environments

Investigations performed by Sandia National Laboratories into combined thermal and radiation aging environments are documented in References [4.5], [4.6], [4.9], [4.70]. As discussed in Section 4.1.4.2, aging of most materials under a sequential aging regimen is comparable to that of a combined (simultaneous) environment. However, for some materials under certain conditions, this may not be the case. Hence, the properties of several common cable insulation and jacket materials under combined thermal/radiation environments were studied in an attempt to better understand the behavior of these materials under "normal" plant aging conditions.

Table 4-10 Chemical Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/ Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
External chemical agents (4.1.5.1)	Chemical reaction with organics	Variations in elongation, tensile strength, density	-Softening -Material discoloration -Swelling	All cable and termination organic materials	Cable jackets, insulation, or other organic components exposed to direct chemical contact	Varies with duration	See Table 4-9
Internal chemical by-products (4.1.5.2)	Corrosion of metals; chemical reaction with organics	Reduced strength and integrity of metals; variations in elongation, tensile strength, density (organics)	Pitting, wastage, breakage, corrosion by-product formation; high electrical resistance (metals); softening, material discoloration, and swelling (organics)	Chemically X-linked XLPE; chlorinated elastomers (CSPE, Neoprene®, etc.)	None readily determinable	Generally long-term	Copper-catalyzed reactions may affect all elastomers
Heat and/or radiation (4.1.5.4)	Loss of fire retardants	Increased flammability	None evident	All materials with fire-retardant additives	None readily determinable	Generally long-term	Flammability may increase, decrease or remain constant with aging, yet magnitude of overall effect is small. Most modern materials contain fire retardants.
Moisture, heat (4.1.5.2)	Hydrolytic degradation	Changes in density, tensile strength	Reduced shield integrity, noise	Mylar (polyethylene terephthalate)	Cable shielding exposed to high temperature (above roughly 50°C) and high humidity/ moisture	Varies with temperature and humidity	Significant moisture ingress or shield exposure required

Table 4-10 Chemical Aging Summary for Cable and Termination Components (cont'd)

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/ Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Oxygen, moisture, heat, soluble ions (4.1.5.3)	Electro-chemical corrosion	Reduced tensile and fatigue strength; reduced electrical conductivity	Pitting, wastage, breakage, corrosion by-product formation; high electrical resistance	Primarily ferrous metals, although cuprous and aluminum alloys may be affected	Metal components in wet, oxygenated environments	Generally long-term	May affect conductors, shield/drain, and terminations
Oxygen, moisture (4.1.5.3)	Oxidation of metals	Electrical conductivity	High electrical resistance; discoloration	Metals	Low-current instrument applications where contact electrical resistance is critical	Generally a long- term effect; however, may occur relatively rapidly under certain conditions	Gold-plated contacts used in many applications to minimize oxidation
Oxygen (4.1.5.5)	Thermoxida-tive, radiation-induced oxidation of organics	Elongation, tensile strength	Surface hardening, embrittlement	Most organics	Susceptible materials in oxygenated environments subject to ionizing radiation	Varies	
Ozone (4.1.5.6)	Oxidation of organics	Elongation, tensile strength	Surface hardening, embrittlement	SBR, Buna-N[1]	Susceptible materials in oxygenated environments subject to ionizing radiation	Varies	

Notes:

1. May also affect other materials; see discussion in Section 4.1.5.6 of text.

The approach used in the Sandia investigations was to expand upon existing time-temperature superposition methodology (commonly embodied by the Arrhenius relationship) through development of functional relationships using isothermal dose for a given amount of damage versus dose-rate curves for various materials. These relationships were then extrapolated to predict the time to equivalent damage (TED) as a function of dose rate for various aging temperatures. In this manner, the time to achieve a given damage (in this case, degradation of material tensile elongation to a predetermined value) can be predicted for a given aging temperature, thereby providing an estimate of material longevity under combined thermal and radiation environments.

Figure 4-9 shows a plot of TED versus radiation dose rate for an EPR material, as predicted by the time-temperature-dose rate superposition model.

Results of the Sandia model predictions for very low dose rates show generally good consistency to those of the standard time-temperature (Arrhenius) model. For example, as shown in Figure 4-9, the curve for the 65°C aging temperature indicates a time to reach 100% absolute elongation in excess of 100 years for a dose rate of 0.1 Gy/hr [10 rad/hr], or 53 kGy [5.3 Mrad] over 60 years. Therefore, at dose rates much lower than 0.1 Gy/hr, the predicted life (TED) is far in excess of 100 years. The Arrhenius model (Figure 4-1) predicts a time to reach 50% absolute elongation of several hundred years at 65°C; hence, the results of both models are seemingly consistent. Other materials show similarly consistent results at low dose rates. One significant inconsistency is evidenced by the data for silicone rubber; the Sandia model indicates a lifetime between 10^3 and 10^4 years at 65°C and low dose (<0.01 Gy/hr), whereas the Arrhenius projection of lifetime in Figure 4-1 is in excess of 10^6 years at the same temperature. Closer examination of the activation energies used, however, shows a great disparity between the Sandia value (21 kcal/mole, or 0.91 eV) and the value derived from a manufacturer's qualification report (1.80 eV)[30]; this disparity explains the large difference in results, and underscores the sensitivity of Arrhenius lifetime predictions to the use of formulation-specific activation energy.

As part of the Sandia studies, the concept of "approximate life" is used to facilitate comparisons between materials. Approximate life is defined as the time required for the elongation of a material to decrease to 100% absolute under "normal" plant conditions of 45°C [113°F] and 0.1 Gy/hr [10 rad/hr]. Note that this concept is completely distinct from that of qualified life previously described. Approximate life simply provides an estimate of the longevity of a material under the assumed plant conditions, based on the time-temperature-dose rate superposition model. Table 4-11 lists some of the approximate life values predicted by the Sandia model for various materials in combined thermal-radiation aging environments.

[30] Note that Rockbestos was both the manufacturer of the silicone cable used by Sandia and the source of the test report containing the thermal aging data used to develop Figure 4-1.

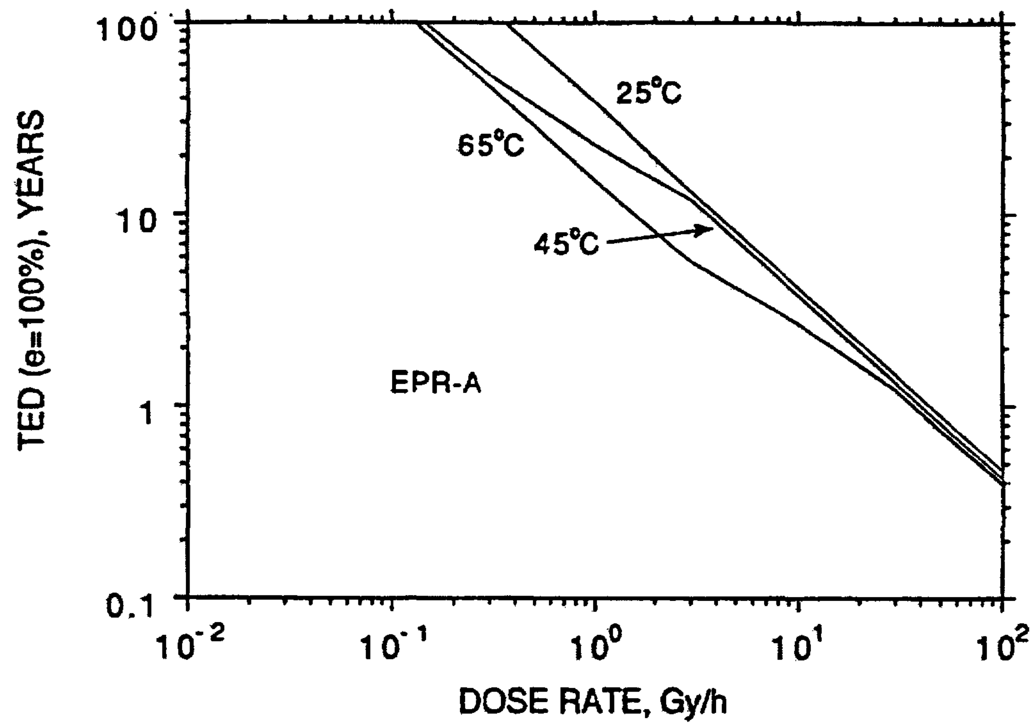

Figure 4-9 Time to Equivalent Damage (TED) versus Radiation Dose for Anaconda EPR (FR-EP) Insulation Material

It should be noted that part of the basis for the approximate life values listed in Table 4-11 was a radiation dose rate of 0.1 Gy/hr (10 rad/hr), which equates to a total dose of approximately 53 kGy [5.3 Mrad] over 60 years. This is roughly the same order of magnitude as the damage threshold radiation value for many cable system polymers (see Table 4-7), and equates to doses found only in locations within primary containment. A dose rate of 10 rad/hr is substantially above the dose rate for most areas outside primary containment (in which the bulk of plant cable is located); hence, the lifetimes predicted for these areas under the Sandia model in References [4.5], [4.6], [4.9], and [4.70] would necessarily be longer, and would approximate thermal-only (e.g., time-temperature superposition) aging as the dose rate approaches zero. Thus, the approximate life values listed in Table 4-11 would seem to be primarily applicable to cable system components located inside of primary containment, where radiation degradation becomes significant. Also, the end of life criterion used in determining the Table 4-11 values is 100% absolute elongation, which is more conservative than the criteria to be proposed in Section 5.2.2.1.1, and used in Table 4-2 and Figures 4-1 and 4-5.

Table 4-11 Approximate Life Values for Cable Insulation and Jacket Materials

Material	Application	Approximate Life[1] (Years)
CSPE (Hypalon®)	Jacket	~90
EPR	Insulation	>100
ETFE (Tefzel®)	Insulation	~100
LDPE	Insulation	~10
Neoprene®	Jacket	~5
PVC	Jacket	~60
Silicone Rubber	Insulation	~50
XLPE (including XLPO)	Insulation	>100

Notes:
1. Derived from SAND90-2009 [4.9] and SAND91-0822 [4.70].

4.1.7 Discussion of Material Similarity

Although it is common to describe conductor insulations using the name of the base polymer (such as EPR or XLPE), the constituents used to make electric cable insulation include materials other than the base polymer in order to obtain specific performance characteristics that cannot be obtained from the base polymer alone. Typical of an actual cable insulation composition are the following: base polymer, clay, fire retardants, anti-oxidants, coloring agents, and anti-radiation compounds. Table 4-12 shows the chemical composition of a typical EPR formulation for nuclear plant cable [4.70].

In general, the larger the fraction of nonbase polymer additives, the more widely the physical characteristics and performance of the compound may vary from those of the base. Additives often constitute more than half of the formulation. Because the additives are proportioned on a weight basis and usually have higher densities than the base polymer, the base polymer still may account for a large percentage of the volume of the insulation. Manufacturers have their own proprietary formulations for each type of application of an insulation identified by the base polymer. Some manufacturers often do not even identify the base polymer, choosing to maintain this information as proprietary. However, because all insulations must meet common requirements of the standard issued by ICEA, the basic characteristics of an insulation are the same regardless of the manufacturer. Some of the performance requirements that any insulation must meet are the following:

- minimum tensile strength
- minimum elongation unaged and aged
- minimum fire resistance
- minimum dielectric strength

- temperature rating
- water resistance measured by specific inductive capacitance (SIC) or specific insulation resistance (SIR)
- thickness tolerances

Table 4-12 Chemical Formulation of a "Typical" EPR Cable Material [4.70]

Constituent	Relative Amounts (by weight)
EPDM	90
Low density polyethylene	20
Zinc oxide	5
90% Red lead dispersion	5
Paraffin wax	5
Zinc salt of mercaptobenzimidazole	2
Low temperature reaction product of acetone and diphenylamine	1
Treated calcined clay	60
Vinylsilane	1
SRF black	2
Diadduct of hexachlorocyclopentadiene and cyclooctadiene	33
Antimony oxide	12
Dicumyl peroxide	3

The specific composition of a material may play an important role in the longevity or performance of a particular cable or termination organic material with respect to thermal, radiation, or other aging influences. Thermal or radiation aging evaluations such as those previously discussed ideally should be based on material aging data pertinent to the specific formulation in use at the plant as opposed to data for a generically similar material. This is particularly true of environmentally qualified components, because the demonstration of post-accident functionality is dependent on the properties of the specific materials used during qualification testing. For non-EQ components or those qualified by analysis, use of generic aging data may be the only viable alternative for the reasons stated in the next paragraph. While there is substantial generic behavior of materials, examination of laboratory test data for various cable system materials during preparation of this guideline [4.6], [4.8], [4.9], [4.60], [4.61], [4.66], and [4.70] has indicated that the performance of two ostensibly similar materials (e.g., belonging to the same generic class) may vary widely based on differences in chemical formulation.

At present, the exact chemical compounding of many organic cable system components cannot be readily determined because (1) manufacturers will often maintain the formula of their material as proprietary, (2) variations in the product may occur within a given production period in the manufacturing facility, (3) the manufacturer may not keep records of adequate specificity for the required historical time period, and (4) many manufacturers of cable installed in nuclear plants are no longer in business, or the product lines have been sold and marketed under different trade names and formulations. Furthermore, the cable/termination manufacturer's source for the base polymer or other constituents of a given material may have changed over time. 10CFR50, Appendix B quality assurance requirements are applicable only to safety-related components; hence, manufacturer traceability for chemical formulation is more likely to exist for such components. For nonsafety-related components (especially those manufactured many years ago), information on precise formulation may be lost altogether. Note, however, that many plants use the same type of cable for both safety- and nonsafety-related applications in an effort to maintain uniformity and reduce the number of different cable products used in the plant and maintained in stores.

Generally, cable system components produced by a given manufacturer can be differentiated in terms of their production date/lot number. The specific cable lot or production date may be obtained through examination of plant or carrier records (including delivery tickets, purchase orders/specifications, and receipts) or, in lieu of this information, contacting the manufacturer directly (if still in business). However, knowledge that a cable reel purchased by the plant is from one lot as opposed to another, or is of one formulation rather than another, is of little practical value unless these differences can be correlated to differences in material aging performance or qualification. For example, one formulation of a generic polymer may have advantageous thermal aging properties; if it can be demonstrated that cable manufactured with that polymer is installed, the estimated (and actual) life of that cable may be extended accordingly.

With regard to EQ components, 10CFR50.49(f) indicates that electrical equipment important to safety may be qualified through testing or analysis of identical or "similar" items. No additional regulatory guidance as to what constitutes an adequate demonstration of material similarity was located during the preparation of this guideline. ANSI/IEEE 323-1983 [4.96] discusses material similarity and indicates that the construction materials of the item to be qualified should be the same or equivalent to those tested; any differences identified should be shown not to affect safety function.

Note that a certificate of conformance (C of C) is typically issued by the component manufacturer to indicate that a particular component was certified to a particular qualification test report. It is the utility's responsibility to ensure that the materials, configuration, service environment, etc. of the installed component are comparable to the parameters in the qualification test report.

4.2 Determination of Applicable Aging Mechanisms and Effects

This section defines the applicable aging mechanisms resulting from stressors identified in Section 4.1. Stressors acting on cables and terminations and their components include:

- Thermal
- Electrical
- Mechanical
- Radiation
- Chemical and Electrochemical
- Oxygen

Generic aging mechanisms associated with these stressors include the following:

Thermal

- Thermal degradation of organic materials

Electrical

- Voltage-induced degradation (including electrical treeing)
- Partial discharge
- Moisture-induced degradation
- Loss of surface insulating properties (including surface tracking)
- Water treeing

Mechanical (Conductor and Metallic Termination Components)

- Vibration-induced fatigue
- Tensile elongation due to creep
- Maintenance handling wear (including work hardening)
- Incidental physical damage
- Electrical fault-induced tensile damage

Mechanical (Insulation, Jacket, and other Organic Components)

- Vibration-induced cutting or abrasion
- Elongation and cutting/abrasion due to creep
- Incidental physical damage
- Electrical fault-induced tensile elongation
- Compression set
- (Note: installation damage is not considered an aging mechanism.)

Radiation

- Radiolysis of organics
- Photolysis of organics

Chemical and Electrochemical

- Direct chemical attack of organics
- Chemical decomposition of organic materials

- Electrochemical attack of metals (including oxidation and corrosion)
- Loss of fire retardants

Oxygen

- Thermoxidative degradation
- Radiation-induced oxidation

Aging mechanisms for each cable and termination subcomponent considered to be significant are discussed in Section 4.2.1; however, the applicability of some aging mechanisms to actual cable systems may be very limited or the frequency of their occurrence may be extremely low. For example, conductor corrosion is expected to affect only an extremely small fraction of the cable population. For most cables, this aging mechanism will be of no consequence. Similarly, UV-induced degradation of organics is significant only for circuits that use components which are both susceptible to UV and exposed to substantial UV sources (a very small fraction of the total population). Hence, Section 4.2.2 identifies that subset of significant aging mechanisms which is considered most important to continued cable and termination functionality. Those aging mechanisms considered nonsignificant (i.e., which have no identifiable effect on functionality if left unmitigated) are discussed in Section 4.2.3.

4.2.1 Significant Aging Mechanisms

An aging mechanism is considered to be significant when it may result in the loss of functionality of a component or structure during the license renewal period if it is allowed to continue without mitigation. Loss of cable or termination functionality resulting from an aging mechanism is determined through examination of the design function of each subcomponent and the potential effect of the aging mechanism on that function. In the following tables, these aging mechanisms have been substantiated where possible through evaluation of operating history. Tables 4-13 through 4-17 summarize significant stressors, aging mechanisms, associated degradations, and potential effects of these degradations for each cable and termination subcomponent.

4.2.2 Significant and "Observed" Aging Mechanisms

Significant and "observed" aging mechanisms are those significant aging mechanisms that have been shown to occur with a relatively higher frequency than background within the applicable voltage category. Classification of an aging mechanism as significant and observed is based upon analysis of operating and maintenance experience. Those aging mechanisms that are reflected in substantial proportions of the NPRDS and/or LER failure reports for a given voltage category, are evidenced in information provided by host utilities or in surveys, or are otherwise cited as significant in industry sources or studies, may be designated as significant and observed mechanisms. This empirical approach is used because it describes an aging mechanism and provides information on the frequency of occurrence in relation to other aging mechanisms. This approach also implicitly identifies only those aging mechanisms applicable to appreciable portions of the total cable population (within a given voltage category) because such mechanisms will, in general, result in greater numbers of failures. Furthermore, it helps eliminate purely "hypothetical' aging mechanisms and effects.

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Conductor	Electro-chemical stress (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces	Increased resistance and heating at terminations	Generally requires severe damage to jacket/insulation wall coupled with moist environment; more of a concern for fine stranded conductors or high current applications
	Vibration, manipulation	Fatigue; work hardening	Embrittlement of conductor	Broken or weak conductor; high resistance	Usually at or near terminations; rare condition
	Tensile stress	Creep; tensile elongation; cold flow	Elongation of conductor; loosening of termination	High connection resistance/heating; reduced strength	Rare; most often associated with improperly installed and/or supported cables. Cold flow of aluminum conductors only
Insulation (including semi-conducting shield)	Heat	Thermal degradation of organics (environmental and ohmic/induced currents); loss of fire retardants	Embrittlement, cracking, melting, discoloration	Reduced IR; electrical failure; noise; changes in flammability	
	Radiation	Radiolysis and photolysis of organics; loss of fire retardants	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure; changes in flammability	Photolysis only applicable to sensitive materials exposed to significant UV sources
	Chemical agents	Chemical degradation of organics	Softening, swelling, flowing, cracking, discoloration	Reduced IR; electrical failure	Material specific; limited number of cables exposed
	Moisture; contaminants	Moisture intrusion; water treeing; contamination with dirt or foreign material	Formation of water trees; contamination by soluble/insoluble ions	Reduced IR; electrical failure	Water treeing for medium-voltage cable only
	Voltage	Voltage-induced degradation (including partial discharge); loss of surface insulating properties (including surface tracking)	Tracking path formation; dielectric breakdown	Reduced IR; electrical failure	Slow, long-term mechanism applicable to medium-voltage cable operating at or above 4 kV
	Copper ions from conductor	Copper-catalyzed oxidation	Embrittlement, cracking, discoloration	Reduced IR, electrical failure	Identified in both radiation and thermal environments for polyolefin materials (EPR, LDPE, XLPE, XLPO).

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Oxygen	Thermoxidative and radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor.
	External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure	Work in area; personnel traffic; poor support practices
Conductor Jacket	Heat	Thermal degradation of organics; loss of fire retardants	Embrittlement, cracking, discoloration	Note 1; changes in flammability	
	Radiation	Radiolysis of organics; loss of fire retardants	Embrittlement, cracking, discoloration, swelling	Note 1; changes in flammability	
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, discoloration	Note 1	Material specific; affects few cables.
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR, electrical failure	In oxygen environments, this is usually the dominant stressor
	External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Note 1	More common in panels or covers where wiring could be subject to tight bends, sharp edges, or pinching in covers during reassembly. Work in confined space may aggravate this type of aging.
Shielding (including drain wire, shielding wraps, and braid)	Heat	Thermal degradation of organics	Embrittlement, cracking, melting, discoloration	Reduced shield effectiveness (increased noise or leakage)	Applicable only to organic portions of shield (such as mylar) if any
	Radiation	Radiolysis of organics	Embrittlement, cracking, discoloration	Reduced shield effectiveness (increased noise or leakage)	Applicable only to organic portions of shield (such as mylar) if any. No photolysis
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, discoloration	Reduced shield effectiveness (increased signal noise or leakage currents)	Material specific; assumes penetration through outer jacket

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Tensile or other mechanical stress	Creep; tensile elongation	Elongation/breakage of drain wire	Reduced shield effectiveness; accumulation of charge	Usually associated with improper installation or support of cable
	Electro-chemical (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion of shield and drain wire	Reduced shield effectiveness; accumulation of charge	
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failures	In oxygen environments, this is usually the dominant stressor
	Heat and humidity/ moisture	Hydrolytic degradation	Loss of shield integrity	Reduced shield effectiveness (increased noise/leakage)	Rate of degradation proportional to both moisture (humidity) and temperature
Outer Jacket	Heat	Thermal degradation of organics	Embrittlement, cracking, melting, discoloration	Reduced mechanical integrity and protection from environment	
	Radiation	Radiolysis; photolysis (of UV sensitive materials only)	Embrittlement, cracking, discoloration, swelling	Reduced mechanical integrity and protection from environment	Swelling of jacket may make re-termination difficult
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, discoloration	Reduced mechanical integrity and protection from environment	Material specific
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor
	External mechanical influences	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced mechanical integrity and protection from environment	Work in area; personnel traffic
Armor/Sheath	External mechanical influences	Work hardening or deformation of metallic sheath	Bending or crimping; reduced flexibility in localized areas	Reduced mechanical integrity/protection from environment	

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Electro-chemical (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion of metal sheath	Reduced sheath integrity; moisture/chemical intrusion	
	Chemical agents	Corrosion and oxidation of metals; chemical degradation or organics (where installed)	Direct corrosion or chemical attack	Reduced mechanical integrity/protection from environment	Material specific; most materials specifically used to resist corrosive environments

Notes:

1. Degradation of the conductor jackets of some bonded insulation/jacket systems may produce damage to the underlying insulation. This generally occurs only in cases where the aging of the jacket is substantial, and substantial tensile stress (such as that during bending of the conductor) is applied. See Section 4.1.3.4 of this guideline for further information.

Table 4-14 Summary of Connector Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Connector Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Electrical contacts	Electro-chemical stresses (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion/oxidation of external contact surfaces	Increased resistance and heating; loss of circuit continuity	
	Mechanical stress; manipulation	Wear; fatigue; work hardening	Bending/breakage of contacts; wear of contact surfaces	Increased circuit resistance and heating; loss of continuity	May result from frequent assembly/disassembly of connection
	Dirt/ contaminants; moisture	Contamination with dirt or foreign material	Fouling/contamination of contact surfaces	Increased resistance; loss of continuity	
Electrical terminations/ solder joints	Tensile/ fatigue stress; manipulation	Creep; tensile elongation; fatigue; work hardening	Embrittlement/breakage of solder joints; loosening of compression fittings	Increased resistance/heating; loss of continuity	
Dielectric materials (organic)	Heat	Thermal degradation of organics	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	
	Radiation	Radiolysis and photolysis of organics	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	Photolysis only for exposed UV-sensitive organic materials
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor.
	Voltage; contaminants	Partial discharge; loss of surface and/or volumetric insulating properties	Tracking path formation; dielectric breakdown	Reduced IR; electrical failure	High voltage stress required
O-Rings/seals	Heat	Thermal degradation of organics	Embrittlement, cracking, swelling, or discoloration	Leakage or moisture intrusion	May be aggravated by assembly/disassembly of connector
	Radiation	Radiolysis of organics	Embrittlement, cracking, swelling, or discoloration	Leakage or moisture intrusion	May be aggravated by assembly/disassembly of connector
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking,discoloration	Seal failure	In oxygen environments, this is usually the dominant stressor
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, swelling, or discoloration	Leakage or moisture intrusion	Material specific; may be aggravated by assembly/disassembly of connector

Table 4-14 Summary of Connector Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Connector Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Compressive stress; manipulation	Wear	Cutting, chafing, abrasion, or adhesion during connector assembly/disassembly	Reduced integrity; leakage	
		Stress relaxation	Increased compression set	Leakage	Varies as function of material and aging environment
Hardware (coupling mechanism, cable clamp, and backshell)	Electro-chemical stress; moisture	Corrosion and oxidation of metals	Corrosion, oxidation	Loss of mechanical integrity; loose electrical connections; increased stress on cable or wire components	Occurs mostly in connectors located in moist or wet environments
	Mechanical stress; manipulation	Wear; fatigue; work hardening	Deformation/breakage of components	Loss of mechanical integrity; loose electrical connections; increased stress on cable or wire components	Overtightening; repeated assembly/disassembly (for maintenance or surveillance); work in area/personnel traffic; stress from attached cable

Table 4-15 Summary of Compression and Fusion Fitting Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Compression Fitting Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Crimped fitting	Electro-chemical	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces	Increased resistance and heating; loosening of crimp; breakage of lug	
	Mechanical stress; manipulation; insufficient crimp	Fatigue; work hardening	Embrittlement or deformation of lug; loosening of crimp on conductor	Poor electrical contact (high resistance)	Crimp may loosen with time due to thermal expansion, vibration, or other effects (see cold flow of aluminum conductors; Table 4-13)
Mechanical clamp assembly (bolt/hardware)	Electro-chemical	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces and clamp mechanism	Increased resistance and heating; failure of mechanism/loosening of conductor	
	Mechanical stress; manipulation	Fatigue; work hardening	Embrittlement or deformation of clamp mechanism and lug; loosening of lug on conductor	Poor electrical contact (high resistance)	Clamp may loosen with time due to thermal expansion, vibration, or other effects; may be tightened
Fusion fitting	Electro-chemical	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces of lug and weld	Increased resistance and heating; failure of fusion weld/loosening of conductor	Corrosion of weld depends on type of fusion process and materials used
	Mechanical stress; manipulation	Fatigue; work hardening	Embrittlement or deformation of lug; loosening of lug on conductor	Poor electrical contact (high resistance)	Fusion welds typically highly resistant to mechanical stresses

Table 4-16 Summary of Splice Insulation Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Splice Insulation Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Insulation/ sealing system (including heat shrink and tape wrap)	Heat	Thermal degradation of organics (environmental and ohmic/induced)	Embrittlement; cracking; melting; discoloration	Reduced IR; electrical failure	
	Radiation	Radiolysis and photolysis of organics	Embrittlement; cracking; discoloration	Reduced IR; electrical failure	Photolysis applicable only to exposed UV-sensitive materials
	Chemical agents	Chemical degradation of organics	Softening; flowing; cracking; discoloration	Reduced IR; electrical failure	Material specific
	Moisture; contaminants	Moisture intrusion	Contamination by soluble/ insoluble ions	Reduced IR; electrical failure	
	Voltage	Partial discharge, loss of surface and/or volumetric insulating properties	Tracking path formation; dielectric breakdown	Reduced IR; electrical failure	Slow, long-term mechanism applicable to medium-voltage systems operating at or above 4 kV
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement; cracking; discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor
	External mechanical influences	Wear or low-cycle fatigue	Cutting; cracking; abrasion; tearing	Reduced IR; electrical failure	Work in area; personnel traffic

Table 4-17 Summary of Terminal Block Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Terminal Block Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Terminal hardware and accessories	Electro-chemical (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion/oxidation of terminals/lugs	Increased resistance and heating; loss of continuity; failure of hardware	
	Mechanical stresses/ manipulation	Wear; fatigue	Loosening; deformation or breakage of hardware	Increased resistance or loss of circuit continuity	Wear/damage during landing of terminations
Terminal block (dielectric)	Heat	Thermal degradation of organics	Embrittlement; cracking; discoloration	Reduced IR; electrical failure	
	Radiation	Radiolysis or photolysis of organics	Embrittlement; cracking; discoloration; swelling	Reduced IR; electrical failure	Photolysis applicable only to exposed UV-sensitive materials
	Chemical agents	Chemical degradation of organics	Softening; cracking; discoloration	Reduced IR; electrical failure	Material specific
	Moisture; contaminants; voltage	Loss of surface insulating properties; contamination with foreign materials	Contamination by dirt or other particulates; formation of tracking paths	Reduced IR; tracking; eventual electrical failure	Failure more likely with combination of dirt followed by condensation.

Although the total or absolute rate of occurrence for a specific aging mechanism or effect cannot be reliably determined from the information sources used in this study, a good estimation of the relative frequency of occurrence can be made. For example, it was determined from the NPRDS data in Section 3.7 that thermal degradation of low-voltage cable insulation accounted for a much higher percentage of failure reports than conductor corrosion. Therefore, it may be inferred that the rate of occurrence of thermal degradation is much higher than that of conductor corrosion. It should be remembered that because the data and industry information indicate that the overall failure rate for cable and terminations of all voltage classes is extremely low (see Section 5.4.2 of this guideline), even these "principal" aging mechanisms are often of little consequence to the continued functionality of the plant cable systems as a whole. Accordingly, no truly significant aging mechanism/component combinations will be excluded through consideration of only the "significant and observed" aging mechanisms and effects. Finally, as noted in Section 3, current operating experience does not include accident reliability data and normal operating condition data may not be useful for predicting accident reliability.

An additional consideration relates to possible changes in the rate of aging or failures identified in industry/plant data (such as NPRDS or LERs). Specifically, aging mechanisms or effects that may not be observed at one point in time may later become more significant. Therefore, the list of significant and observed aging mechanisms is not necessarily limited to those described here; subsequent indications of increased failure rate/degradation in the data, especially as more plants reach the end of their current operating period, may dictate consideration of additional mechanisms and effects not currently included as "significant and observed."

It should be noted, however, that data from plants of ages ranging from a few years to more than 30 years were used as the basis for the determination of significance, and no aging mechanisms or effects occurring solely during the license renewal period (previously referred to as "age-related degradation unique to license renewal," or ARDUTLR) were identified as part of this study. Furthermore, no appreciable enhancement or acceleration of aging stressors is anticipated for most plants (for example, the mean ambient temperature or dose rate for cables/terminations located in a given plant space is not expected to increase significantly as the plant ages). Therefore, the likelihood of substantially increased effects or failure rate resulting from aging mechanisms currently categorized only as "significant" is considered low.

Section 3.7.6 identified the following aging mechanisms as occurring at a relatively high frequency in comparison to other mechanisms:[31]

Low-Voltage Cables (including Panel and Hookup Wire)

- Localized thermal/thermoxidative aging and embrittlement of insulation and jacketing[32]

- Bulk thermal/thermoxidative aging of insulation/jacketing due to ambient and ohmic effects

[31] Based on review of the operating history (NPRDS and LER) and other available industry sources.

[32] Where required for environmental qualification considerations.

- Localized radiolytic degradation of insulation/jacketing
- Localized degradation of insulation/jacketing due to external mechanical stressors

Terminations

- Oxidized, corroded, or dirty connector contact surfaces
- Loosening or breakage of compression fitting lugs

Medium-Voltage Cables

- Wet aging of voltage-stressed insulation

Neutron Monitoring Cables

- Oxidized, corroded, or dirty connector contact surfaces
- Localized thermal, radiolytic, and incidental mechanical damage to neutron detector circuit cables located in proximity to the reactor vessel

Based on the above considerations, these mechanisms were designated as the most significant aging mechanisms for electrical cable and terminations used in low- and medium-voltage and neutron monitoring systems. These mechanisms are summarized in Table 4-18.

In addition, one other related consideration regarding cable/termination aging was identified in Section 3.7.6:

- Damage to medium-voltage cable insulation during installation

Cable installation damage is discussed further in Section 6 of this guideline.

4.2.3 Nonsignificant Aging Mechanisms

Those aging mechanisms identified in Section 4.1 but that did not meet the criteria for significance are described in the following three subsections.

4.2.3.1 Aging of Filler Material

Filler material is used to fill the interstices between individual conductors and maintain the mechanical rigidity in some cables. Degradation of this material does not affect the aging or functionality of the cable as a whole; the only potential results are "wicking" of moisture along conductors (if the ends are open and wet), loss of mechanical rigidity, or possible release of chemical by-products from the decomposition of the filler.

Table 4-18 Summary of Cable and Termination Stressors, Significant and Observed Aging Mechanisms, Degradations, and Potential Effects

Voltage Category	Component	Subcomponent(s)	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Low	Cable	Insulation and jacketing	Heat, oxygen	Thermal/thermoxidative degradation of organics (environmental and ohmic/induced currents)	Embrittlement, cracking, melting, discoloration	Reduced IR; electrical failure; increased vulnerability to failure in harsh environments	
			Radiation, oxygen	Radiolysis and photolysis of organics; radiation-induced oxidation	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure	Photolysis only applicable to exposed UV sensitive materials
			External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure	Work in area; personnel traffic; poor support practices
	Connector	Contact surfaces	Electrochemical stresses (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion and oxidation of external surfaces of contacts	Increased resistance and heating; loss of circuit continuity	
	Compression fitting	Lug	Vibration, tensile stress	Deformation and fatigue of metals	Loosening of lug on conductor; breakage of lug	Loss of circuit continuity; high resistance	
Medium	Cable	Insulation	Moisture and voltage stress	Moisture intrusion; water treeing	Formation of water trees; localized damage	Electrical failure (breakdown of insulation)	

Table 4-18 Summary of Cable and Termination Stressors, Significant and Observed Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Voltage Category	Component	Subcomponent(s)	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Neutron detecting	Cable	Insulation	Heat, oxygen	Thermal/thermoxidative degradation of organics (environmental)	Embrittlement, cracking, melting, discoloration	Reduced IR; electrical failure	Typically occurs near heat source such as reactor vessel
			Radiation, oxygen	Radiolysis of organics; radiation-induced oxidation	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure	Typically occurs near or under reactor vessel
			External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure	Incidental contact, work in area
	Connectors	Contact surfaces	Electrochemical stresses (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion and oxidation of external surfaces of contacts	Increased resistance and heating; loss of circuit continuity	

4.2.3.2 Electrical Fault-Induced Mechanical and Thermal Stress

Faults occurring in power circuits may induce significant forces and mechanical stresses on cable and termination components.[33] However, in most plants, (1) the total number of faults occurring on an annual basis in relation to the number of power circuits in the plant is extremely small, (2) the number of faults occurring on any one circuit during its lifetime (if any) is also extremely small, (3) the fault clearing time is extremely short so that significant forces are experienced by the cable for only a brief period, and (4) many cable runs are in conduits, duct banks, or otherwise constrained so that damaging forces on cable and termination components due to acceleration of the cable cannot be developed. Thermal stresses resulting from these events, although potentially large in magnitude, usually last only for very short durations and occur so infrequently as to be an insignificant contributor to the thermal aging degradation of organic cable and termination components.[34]

4.2.3.3 Aging of Tape Wrap

Mechanical tape wrap is used to maintain the mechanical rigidity of some electrical cables during its fabrication. Degradation of purely mechanical tape wraps poses no threat to cable functionality in that these wraps serve no real function after manufacture of the cable. However, degradation of aluminized Mylar or other similar wraps used for shielding is considered a significant aging mechanism.

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[33] Faults do not include electrical overload conditions for the purposes of this discussion.

[34] Note, however, that thermal degradation (such as insulation melting) may occur under extreme conditions of conductor temperature.

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5. EVALUATION OF AGING MECHANISMS AND EFFECTS

5.1 Aging Management Review

The amended version of 10CFR54 [5.1] discusses the concept of an "aging management review"; specifically, the Integrated Plant Assessment (IPA) described in Section 2.4 of this AMG must list those structures and components subject to an aging management review, and must demonstrate that the effects of aging on the functionality of such structures and components will be managed to maintain the current licensing basis so that there is an acceptable level of safety during the period of extended operation. Furthermore, the time-limited aging analyses required by 10CFR54.21 for some SSCs,[1] which form the basis of a plant operator's conclusion regarding the capability of those SSCs, must consider the effects of aging and be based on explicit assumptions defined by the current operating term of the plant. The specific methods to be used by the plant operator in meeting these requirements are not mandated; each operator can select the most appropriate method(s) or technique(s) for the plant's aging management review.

Section 5.2 of this guideline discusses maintenance, surveillance, and condition monitoring techniques applicable to electrical cable and terminations. Section 5.3 identifies those practices and programs that are currently being used by plant operators to maintain these systems. Section 5.4 evaluates the effectiveness of these systems in mitigating the significant and observed aging mechanisms identified in Section 4.2. Section 6.3 discusses proposed methodologies for performing an aging management review.

5.2 Maintenance, Surveillance, and Condition Monitoring Techniques for Evaluation of Electrical Cable and Terminations

Maintenance, surveillance, and condition monitoring are performed to ensure that the characteristics or attributes of components that are essential for operation are maintained. The following generic activities may be performed during the operation, maintenance, testing, and condition monitoring of cable systems:

- Visual or physical inspection
- Measurement of component or circuit properties
- Operability testing
- Cleaning
- Component repair or replacement

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[1] The most notable example of a time-limited aging analysis (TLAA) for electrical cable and terminations is that pertaining to the qualified life of environmentally qualified components pursuant to 10CFR50.49. 10CFR54.21(c) requires such analyses to remain valid for the license renewal term; the analysis must be updated or the effects of aging otherwise demonstrated to be adequately managed during the extended operating period.

- Thermographic inspection
- Monitoring of temperature or other environmental conditions
- Analysis of circuit loading and operating time
- Arrhenius analysis and use of accelerated aging data

Each of these maintenance, testing, and condition monitoring activities is discussed in the following subsections. Note that despite the apparent quantity of industry standards applicable to electrical cable and terminations (Appendix C), little specific guidance is available for *in situ* tests to evaluate the component condition or remaining qualified life. The great majority of these standards do not address anticipated modes of failure. One notable exception is IEEE 1205-1993 [5.2], which provides useful information on identifying, assessing, and mitigating the effects of aging degradation in Class 1E equipment. Although not specifically oriented toward cables and terminations, much of the guidance is generically applicable to these devices.

5.2.1 Physical Properties by Inspection

One of the most powerful techniques for evaluating the aging of cable systems is periodic visual and mechanical inspection, because the effects of many degradation stressors (including heat, chemicals, radiation, mechanical stress, moisture, and contaminants) are readily detectable in this fashion. By simply observing physical changes in cable system components, their relative condition can often be ascertained. For example, a cable that shows cracking or whitening and is brittle is likely to have been exposed to heat and/or radiation. Similarly, a cable that has softened and discolored may have suffered external chemical damage. However, the effectiveness of this technique at detecting degradation may be limited in certain circumstances; depending on the type of degradation mechanisms at work, a cable or component that exhibits no outward indications of degradation may nonetheless be degrading at a significant rate.[2]

Physical properties to consider when inspecting components include:

- Surface condition (including cracking, crazing, texture)
- Color
- Size (swelling, shrinkage, deformation, or compression set)
- Physical integrity (tight or loose)
- Flexibility or embrittlement (requires manipulation in accordance with an inspection procedure)

[2] This limitation is also true of many other techniques, as discussed later.

In addition, the presence of one or more of the following may indicate degradation:

- Dirt, dust, contamination
- Moisture/humidity
- Chemicals
- Corrosion by-products
- Wear products

When inspecting a cable or termination component, several qualitative measures may be used. These include a relative determination of cable flexibility (as opposed to that of a new or significantly aged specimen); inspection of the scope, configuration, and depth of cracking evident in a material upon bending; and evaluation of material hardness (for example, by pressing a fingernail into the material). Much information can often be gained simply by comparing the cable under evaluation with another of the same type installed at another plant location. However, unless the component will be replaced, care must be exercised to ensure that any existing degradation is not aggravated by this inspection.

Physical access, adequate lighting, etc. are required to perform an inspection. Consequently, it may not be possible to inspect some cables, for example, armored cable, cable routed in conduit, and cable inside fire barriers. Focused periodic inspection of cable segments at end devices, terminations, or near "hot spots" will likely be the most beneficial, because most cable and termination degradation appears to be localized. Bulk runs of cable may also be inspected; however, experience has tended to indicate a much lower incidence of significant bulk run aging compared to that occurring near end devices due to the typically higher incidence of localized stressors (such as heat, radiation, and chemicals) near the end devices.

Degradation affecting internal termination components (such as O-rings, contact surfaces, etc.) can only be visually assessed through disassembly of the termination; hence, maintenance activities that involve such disassembly provide a good opportunity to perform these inspections. Some components can be inspected during non-maintenance periods or without disassembly. For example, terminal blocks can be visually inspected during operation for signs of surface tracking, insulator cracking, or other degradation. Similarly, corrosion of metallic components can often be directly observed. Looseness of a connector or lug can often be identified by moving the attached cable or grasping the termination when it is deenergized.

One additional factor should be considered when performing visual/physical inspections. Based on the data presented in Section 3, much of the degradation noted in cable and terminations (especially low-voltage systems) appears to occur at or near the end device. Therefore, unless the entire run of cable is to be inspected, these efforts should be conducted preferentially in the vicinity of end devices or near high stress areas, with bulk cable runs inspected on a sampling basis. Because most plant maintenance activities are also focused on these end devices, maintenance provides a good opportunity to conduct coincident inspections of nearby cable and terminations. Accordingly, credit may be taken for those cases where cable system inspections are performed during maintenance. Note, however, that to take credit, records containing evidence of performing inspections or inspection results must be retained.

Table 5-1 correlates various degradation mechanisms to their applicable inspection techniques and indications. Note that these techniques are meant only as a guide and may not be a suitable substitute for a more detailed evaluation and/or root cause analysis. Furthermore, if some signs of degradation are noted through inspection, plant operators may wish to employ more quantitative methods for assessing component condition.

5.2.2 Measurement of Component or Circuit Properties

Diagnostic techniques to assist in assessment of the functionality and condition of power plant cables and terminations are described in this section. Some of these techniques are useful for evaluating installed cables, whereas others are destructive tests that must be conducted with samples of cable materials removed from service. Some of these methods are useful for predicting the long-term performance of cables, and others are useful primarily for troubleshooting. The remainder consist of laboratory tests for characterizing the properties and performance of specific cable materials. A limited number of these techniques are at a stage of development to permit practical application, whereas others require further investigation and evaluation to determine their usefulness as a condition monitoring, troubleshooting, or laboratory evaluation tool. Currently available techniques are described in Section 5.2.2.1; those still under development are discussed in Section 5.2.2.2.

The diagnostic techniques described below may also be categorized in terms of the type of degradation they address. Localized degradation, as the name indicates, refers to aging effects that are spatially localized within small areas or to one portion of a circuit. Bulk degradation refers to aging that affects a relatively large portion of one or more circuits. For example, thermal exposure of a termination and cable end connected to a motor would constitute localized aging. Conversely, thermal aging of a number of circuits in an area with a high ambient temperature would be considered bulk aging. With respect to diagnostic techniques, the distinction is significant, because bulk degradation cannot necessarily be inferred from measurement of a localized component area, and vice versa.

Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal- and radiation-induced aging. For low-voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed. For medium-voltage cables, however, changes in mechanical properties may or may not precede electrical failure. Accordingly, the test and diagnostic techniques applicable to low-voltage systems may differ substantially from those used for medium-voltage systems.

Table 5-1 Inspection Techniques Applicable to Various Degradation Mechanisms - Cables and Terminations

Stressor Category	Aging Mechanism	Indications/Effects Detectable Through Inspection	Potential Causes	Applicable Inspection Techniques	Accelerating Factors/Remarks
Thermal	Thermal/ thermoxidative	Hardening, embrittlement, cracking, discoloration, surface crazing, shrink-back, melting (in extreme cases for thermoplastics)	Ambient or localized thermal exposure; ohmic heating	- Visual inspection - Flexibility determination - Evaluation of hardness	Oxygen, radiation may accelerate
Radiation	Radiolysis, oxidation	Hardening, embrittlement, cracking, discoloration, surface crazing, swelling (with moisture)	Ambient or localized radiation exposure	- Visual inspection - Flexibility determination - Evaluation of hardness	Oxygen, thermal aging may accelerate
	Photolysis	Crazing, surface cracking, or discoloration of UV-sensitive materials	UV exposure (indoor or outdoor)	- Visual inspection of surface - Flexibility determination - Identification of UV source	Comparatively few organics are UV sensitive
	Displacement	Embrittlement, discoloration, or hardening of metals	Neutron exposure	- Visual inspection - Evaluation of hardness/flexibility	Requires very high neutron dose
Mechanical	Bending/ manipulation	Cracking of embrittled organics	Bending or handling during maintenance or inspection	- Visual inspection - Flexibility determination - Evaluation of hardness	Frequently handled components most susceptible
	Wear (terminations only)	Friction; wear products	Assembly/disassembly; inadequate lubrication	- Visual inspection - Feel during assembly/disassembly	Frequently maintained components most susceptible
	Cable creep	Piling of cable; cuts, abrasions, or other external damage to cable jacket/insulation; broken or deformed terminations	Thermal cycling of cable in vertical-horizontal runs; improper support or fairleader	- Visual inspection	Sharp edges/corners at point of cable contact can increase likelihood of occurrence
	Work hardening	Hardening, discoloration, and ultimate failure of metals	Bending or handling during maintenance	- Visual inspection - Evaluation of hardness/flexibility	Frequently handled or maintained components most likely
	Damage from external influences	External cuts, tears, chips, or abrasions (Note 1)	Personnel traffic; equipment vibration; incidental contact; poor maintenance or installation practices	- Visual inspection	High maintenance or traffic areas, restricted spaces, exposed sharp corners or edges, manholes

Table 5-1 Inspection Techniques Applicable to Various Degradation Mechanisms - Cables and Terminations (cont'd)

Stressor Category	Aging Mechanism	Indications/Effects Detectable Through Inspection	Potential Causes	Applicable Inspection Techniques	Accelerating Factors/Remarks
Electrical	Water treeing (cable only)	No external indications of degradation	Exposure of susceptible insulation materials to submergence/wetting while energized	- Visual inspection for submergence/wetting	Medium-voltage cable only
	Partial discharge/ ionization	Visible or audible ionization; flashover	Degraded insulation; nearby metallic objects/edges	- Visual/audible inspection	May produce rapid localized degradation of insulation
	Surface tracking	Formation of visible tracking paths; discoloration	Degraded insulation in alternatively wet/dry location w/ contaminants	- Visual inspection	May produce rapid localized degradation of insulation
	Moisture intrusion	Visible moisture, discoloration, corroded metallic components nearby, damaged cable jacket/insulation	Submergence/wetting of susceptible material	- Visual inspection	Most common insulation and jacket materials impermeable to water
Chemical	Chemical reaction with organics	Discoloration, softening, swelling, odors	Spill, spray, or other contact with chemical agent; decomposition of jacket/insulator	- Visual inspection - Evaluation of material hardness	See Table 4-7 for compatibility of materials with various substances
	Oxidation of metals	Discoloration; formation of surface layer	Oxidation of nonprotected metals	- Visual inspection	Accelerated by oxygen and susceptible material
Electro-Chemical	Corrosion of metals	Discoloration; formation of corrosion byproducts such as iron oxides or cuprous chloride; pitting; wastage	Exposure of susceptible metals to moisture and oxygen	- Visual inspection	

Notes:

1. Damage may occur internally for softer materials such as silicone rubber.

5.2.2.1 Currently Available Cable Condition Monitoring, Testing, and Troubleshooting Techniques for Cables

Currently available condition monitoring, testing, and troubleshooting techniques are listed in Table 5-2. These techniques can be classified as either destructive, nondestructive, or essentially nondestructive. Destructive techniques, as the name implies, result in destruction of all or part of the specimen under evaluation. Nondestructive techniques have no deleterious effect on the specimen. Essentially nondestructive techniques generally use small specimens for destructive testing; however, these specimens are so small that they may be removed from an active cable or termination with little or no repair required.

The following paragraphs describe the basic theory of each identified technique as well as its potential uses related to cable systems and terminations. These descriptions are not meant to be exhaustive analyses of each technique, but rather an overview from an aging management perspective.[3] Experimental results related to specific cable materials are included where available. Note that the list of references presented under the "implementation" section of each discussion is not necessarily comprehensive; other relevant guidance or research may be available, potentially in the form of internal plant procedures or proprietary data. IEEE 943-1986 [5.3] also provides some general guidance in selecting tests for power cable condition evaluation.

Currently available maintenance, testing, and condition monitoring techniques are summarized in Tables 5-3 through 5-5.

5.2.2.1.1 Destructive Techniques

Two measurements from a destructive technique known as ultimate tensile testing are discussed in this section:

- Elongation-at-break
- Tensile strength

Elongation-at-Break

General Description

Elongation-at-break (elongation) is a mechanical property that evaluates a material's ability to elongate under tensile stress without cracking or rupture. Elongation testing is performed by taking a dumbbell- or tube-shaped sample of the material and pulling it in an apparatus that applies tensile stress by elongating (stretching) the specimen at a fixed velocity.

[3] A CEA Report (Project No. 139D875) evaluating many of the techniques discussed below is expected to be published in 1996. The EPRI Cable Diagnostic Matrix is expected to be published in 1996 as well. This latter document will provide a step-by-step methodology for the evaluation and analysis of various types of cable and termination applications based on information supplied by the plant engineer.

Table 5-2 Destructive, Nondestructive, and Essentially Nondestructive Condition Monitoring Techniques

Type	Technique	Degradation Addressed	Test Type	Test Category	Field/Lab Test[1]	Trouble-shooting (TS) or CM
Destructive	Tensile Testing, Elongation-at-Break	Localized[2]	Hands-on	Mechanical	Lab	CM
	Tensile Testing, Tensile Strength	Localized[2]	Hands-on	Mechanical	Lab	CM
Non-destructive	Compressive Modulus	Localized[2]	Hands-on	Mechanical	Field	CM
	High Potential (Hi-pot)	Bulk	Remote	Electrical	Field	TS
	Insulation Resistance (IR)	Bulk	Remote	Electrical	Field	CM, TS
	Insulation Power Factor	Bulk	Remote	Electrical	Field	CM
	Polarization Index (PI)	Bulk	Remote	Electrical	Field	CM
	Capacitance	Bulk	Remote	Electrical	Field	TS
	Partial Discharge	Fairly Localized	Remote	Electrical	Lab	CM, TS
	Time Domain Reflectometry	Bulk	Remote	Electrical	Field	TS
	Tan Delta/Low Frequency Tan Delta	Bulk	Remote	Electrical	Field	CM
	Density [Computed Tomography (CT)]	Localized[2]	Hands-on	Physical	Lab	CM
Essentially Non-destructive	Density (gradient columns)	Localized[2]	Hands-on	Physical	Lab	CM
	Oxidation Induction Time (OIT)	Localized[2]	Hands-on	Chemical	Lab	CM
	Oxidation Induction Temperature	Localized[2]	Hands-on	Chemical	Lab	CM
	Fourier Transform Infrared (FTIR)	Localized[2]	Hands-on	Chemical	Lab	CM
	UV Spectroscopy	Localized[2]	Hands-on	Chemical	Lab	CM
	Gel Content	Localized[2]	Hands-on	Chemical	Lab	CM
	Plasticizer Content	Localized[2]	Hands-on	Chemical	Lab	CM
	Electron Spin Resonance (ESR)/Nuclear Magnetic Resonance (NMR)	Localized[2]	Hands-on	Chemical	Lab	CM

Notes:

1. Field techniques may also generally be used in the laboratory.
2. Test is performed on localized sample of material; properties of bulk of material can be inferred.

Table 5-3 Currently Available Destructive Condition Monitoring and Test Methods for Electrical Cable and Terminations

Destructive Technique	Type	Applicable Voltage Category	Parameters Measured	Physical Principle	Aging Mechanisms Addressed	Insulation/Jacket Types	Limitations	Remarks
Ultimate Tensile Testing	Lab	All	Elongation-at-break (%; relative or absolute)	Measurement of changes in elongation of cable insulation/jacket specimens with aging	Thermal, radiolytic, mechanical, and chemical degradation of insulation/jacket	All (Note 1)	Destructive; requires specially prepared samples	Industry standard for measuring effects of aging
	Lab	All	Tensile strength (MPa or psi)	Measurement of changes in tensile strength of cable insulation/jacket specimens with aging	Thermal, radiolytic, mechanical, and chemical degradation of insulation/jacket	All (Note 2)	Destructive; requires specially prepared samples; generally poor correlation with aging for most materials	Infrequently used but easily measured at the same time as elongation-at-break

Notes:

1. Variation of elongation with aging is material specific; however, elongation for most materials is inversely related to embrittlement.
2. Variation in tensile strength with aging is highly material specific; some materials show increase in tensile strength with aging, some decrease. Many do not change monotonically.

Table 5-4 Currently Available Nondestructive Condition Monitoring and Test Methods for Electrical Cable and Terminations

Nondestructive Technique	Type	Applicable Voltage Category	Parameters Measured	Physical Principle	Aging Mechanisms Addressed	Insulation/Jacket Types	Limitations	Remarks
Compressive Modulus (Indenter)	Field or Lab	Low	Compressive "modulus" (N/mm or lb/in)	Estimation of insulation and jacket aging; identifying and profiling of installed cables	Thermal, radiolytic, and chemical degradation of insulation/jacket	CSPE, Neoprene®, PVC,[1] SR, or EPR-composites	Outer surface must harden or soften with aging; effectiveness on XLPE limited (currently under investigation)	Effective at identifying both localized and bulk aging
Hi-pot	Field	Medium	Leakage current, voltage	Detection of medium-voltage cable insulation degradation via applied high potential	Thermal, radiolytic, voltage, chemical, or mechanical damage to insulation	All	Effective on shielded cable only; may not reflect bulk dielectric aging	Affected by configuration
Insulation Resistance	Field, Lab	Low, Medium	Resistance (ohms)	Detection of gross cable insulation degradation via measurement of bulk dielectric and circuit resistance	Thermal, radiolytic, voltage, chemical, or mechanical damage to insulation	All	May not reflect actual dielectric properties of insulation; affected by temperature, humidity, and cable length	Most effective on shielded cable; may not always be effective
AC Impedance	Field, Lab	Low, Medium	Insulation power factor	Detection of insulation degradation via dielectric loss and capacitance	Thermal, radiolytic, voltage, chemical, or mechanical damage to insulation	All	Often not reflect dielectric aging; AC systems limited by maximum leakage current	
Polarization Index	Field, Lab	Medium	Ratio of resistances	Detection of insulation degradation via time-dependent behavior of insulation resistance	Thermal, radiolytic, voltage, chemical, or mechanical damage to insulation	Note 2	Not generally effective on low-voltage or extruded insulation	
Capacitance (dielectric constant)	Field, Lab	Low, Medium	Capacitance	Detect presence of moisture or degraded insulation	Moisture intrusion; insulation degradation	All	Generally not reflective of dielectric aging	Most effective on shielded cable
Partial Discharge	Lab	Medium	Discharge	Detection of degradation or voids in cable insulation	Thermal, chemical, or voltage-induced degradation of insulation; water treeing; moisture intrusion	All	Large ac source; sensitive to surface contaminants/humidity	Shielded cable only
Dissipation Factor	Field, Lab	Medium	Tangent of phase angle	Measurement of dielectric loss of insulation	Degradation of dielectric materials; moisture intrusion	All	Effective on shielded cable only; may not reflect dielectric aging	
TDR	Field, Lab	Low, Medium	Impedance	Detection of changes in component/circuit impedance	Oxidation/corrosion of terminations; degradation of insulation	All	Signature affected by connected components; requires interpretation. May not reflect dielectric aging	Precise signatures required to detect aging trends
Computed Tomography	Lab	All	Density	Spatial profiling of polymer density	Thermal, thermoxidative, radiation-induced aging	All	Complex; not presently amenable to *in situ* evaluation	

Notes:
1. Compressive modulus of some PVC compounds may not be sensitive to irradiation.
2. Polarization Index is not effective on many extruded polymer insulations due to their short dielectric time constants.

Table 5-5 Currently Available Essentially Nondestructive Condition Monitoring and Test Methods for Electrical Cable and Terminations

Essentially Nondestructive Technique	Type	Applicable Voltage Category	Parameters Measured	Physical Principle	Cable/Termination AMs Addressed	Insulation/Jacket Types	Limitations	Remarks
Density	Lab	All	Density (g/cc, or specific)	Measurement of changes in cable insulation/jacket density with aging	Thermoxidative and radiation-induced oxidation degradation of insulation/jacket	CSPE, EPR, Neoprene®, PE, PVC, some XLPEs	Note 1	Density columns and Archimedes principal
Oxidation Induction Time (OIT)	Lab	All	Time to exothermic reaction (OIT)	Estimation of remaining thermal life of polymer through anti-oxidant concentration	Thermoxidative and radiation-induced degradation of insulation	EPR, PE, XLPE	Note 1	Uses differential scanning calorimeter (DSC)
Fourier Transform Infrared (FTIR)	Lab	All	Infrared Transmittance versus wave number	Detection of oxidation (carbonyl group) within polymer; correlates aging with changes in polymer chemical structure	Thermoxidative degradation of insulation; radiation-induced oxidation degradation for some materials	EPR, PE, XLPE	Note 1; results sometimes difficult to interpret	
UV Spectroscopy	Lab	All	UV Transmittance versus wave number	Detection of phenyl groups and evaluation of antioxidant content of PE insulation	Thermoxidative and radiation-induced oxidation degradation of insulation	HMWPE	Note 1; results sometimes difficult to interpret	
Gel Content	Lab	All	Induction time for change in gel content and swell ratio	Determination of extent of crosslinking and/or chain scission reactions within material	Thermoxidative and radiation-induced oxidation degradation of insulation	Butyl, PVC, XLPE	Note 1	
Plasticizer Content	Lab	All	Percent plasticizer	Determination of remaining percentage of plasticizer (and volatility) as estimate of remaining life	Thermoxidative degradation of insulation	PVC	Note 1	No correlation with radiation aging demonstrated
Electron Spin Resonance (ESR)/Nuclear Magnetic Resonance (NMR)	Lab	All	Absorbance and Magnetic Field Strength (H)	Characterization of water and polymer reaction during water tree growth (medium-voltage) - NMR; characterization of free radicals - ESR	Water treeing - NMR; thermoxidative and radiation-induced oxidation degradation of insulation - ESR	Note 2	Note 1; insensitive; requires skilled operator.	Use in cable and termination polymer aging evaluations appears limited; some usefulness in study of water dynamics in insulation

Notes:

1. Test measurements and their correlation with aging are material specific. Requires a small sample of aged material for analysis. Since this is a sampling technique, results are location specific. Results are not indicative of dielectric strength.
2. ESR potentially applicable to all materials that produce free radicals during degradation. NMR may be applicable to some materials.

The length of a given portion of the specimen is measured to determine the elongated length at which the specimen breaks. Results of this test can be expressed either as a percentage of the initial length (absolute elongation) or as a percentage of the initial elongation-at-break (relative elongation). Relative elongation is more commonly used.

Elongation can be correlated to the ability of the insulation to undergo localized tensile strain, such as that produced during cable flexing or thermal transients. For low-voltage cables, embrittlement of the insulation and jacket may result in insulation failure during operation.

Scission (bond breaking) generally produces reduced tensile strength; however, elongation may increase, decrease, or remain essentially constant, depending on the type of polymer and the level of degradation. Crosslinking (formation of bonds) primarily results in reduced elongation and increased hardening and tensile strength [5.4], [5.5].

Advantages/Disadvantages

Elongation-at-break corresponds well with the level of thermal and radiation aging for most materials, decreasing smoothly and monotonically as aging increases. This technique is especially useful for low-voltage applications, where the electrical properties of the cable are directly coupled to the mechanical properties of the insulation. However, XLPE and other polyethylenes often show a less smooth correlation between elongation and thermal aging; for some polyethylenes, a long induction period of little change in elongation is followed by a more rapid decrease and embrittlement [5.6], [5.7]. Other materials (such as CSPE and butyl rubber) are somewhat different, with an initial drop followed by a smooth, slower decline.

On the other hand, quantitative generic acceptance criteria for elongation are difficult to formulate due to variations in material properties, uncertainty associated with the elongation measurements, and varying flexural requirements of cable installed in various applications [5.8]. As the ratio of the bend radius to diameter for a given cable decreases, the strain on the outer radius of the bend increases and the insulation (or jacket) will eventually rupture. For most extruded rubber or crosslinked polymer materials, long molecular chains within the material will "stretch" under stress, thereby resulting in some relaxation of the stress at the outer radius shortly after bending. In addition, the rate of application of strain is important in that some specimens with significant remaining elongation may rupture if bent rapidly enough. While it is possible for a cable with 0% remaining elongation to remain functional during a design basis event, the 0% elongation condition is too fragile to be qualified for continued service. Jacket and insulation materials on cables that are manipulated frequently or subject to mechanical loading may crack and fault when the residual absolute elongation is low ($\leq \sim 25\%$). Reference [5.9] indicates that a "reasonable" range for an absolute elongation acceptance criterion would be 50 to 100% (e.g., for e_0 of 250%, this is equivalent to 20 to 40% relative elongation). Okonite NQRN-1A, Appendix 2 [5.10] indicates that 40% relative elongation is highly conservative. Reference [5.11] (page 12-5) indicates that (1) the common assumption that 50% relative elongation is a very conservative criterion for embrittlement is supported by EPR and Hypalon® test results and (2) absolute elongation, *e*, should be used as the degraded property of importance. Note that, although a large volume of data on the elongation of cable materials has been compiled to date, reliable acceptance criteria have not yet been formulated.

A specimen several inches in length must be cut from a portion of the component to perform elongation testing. This requirement has significant drawbacks for condition monitoring of installed components. The removal of sections of cable is unrealistic for all but a few plants that either have a significant number of cables abandoned in place or have preexisting spares.

For condition monitoring of artificially aged test specimens (i.e., specimens that are not naturally aged), the effects of diffusion-limited oxidation (DLO) must be addressed. Non-uniform aging through the thickness of a material can occur in specimens subjected to accelerated temperature and/or radiation conditions. Elongation measurements of artificially aged test specimens can be correlated with naturally aged materials by accounting for the effects of DLO.

Implementation

Elongation testing is performed in accordance with ASTM D638 [5.12], D 412 [5.13], and Section 6 of the ICEA standard applicable to the tested material [e.g., the applicable standard for EPR materials is ICEA S-68-516 (NEMA WC8)]. Material elongation may also be evaluated using mandrel bending or similar techniques; however, test acceptance criteria are not available for mandrel bending and other techniques. Criteria for evaluating cable materials based on their mandrel bend characteristics are not difficult to develop (e.g., the absence of cracking in either insulation or jacket materials after wrapping a cable on a mandrel could be used as acceptance criteria because elongation is directly dependent on mandrel radius. Alternatively, Reference [5.14] describes the use of fractional strain (a product of elongation and tensile strength) as a measure of polymer degradation. This latter technique tends to display somewhat different results for certain materials (as opposed to standard elongation testing) by virtue of the tensile strength component.

Tensile Strength

General Description

Tensile strength measures the actual stress (force per unit area) required to rupture a sample of the material under evaluation. Because the geometry of the sample specimen can affect the results, test specimens are specially prepared and a precision test apparatus is used to accurately measure the ultimate stress at failure. Specimens are pulled at a predetermined rate at a given temperature in accordance with ASTM Standards.

Variations in tensile strength with aging generally result from changes in the molecular structure of the polymer. As molecular scission occurs, tensile strength is generally reduced due to the breaking of long-chain molecules. Crosslinking, on the contrary, produces additional molecular bonding between these chains and therefore an increase in tensile strength [5.15]. Depending on the predominant aging mechanism for a particular type of material at a given point in life (as well as other factors), tensile strength will vary accordingly.

Advantages/Disadvantages

For many cable and termination polymers, tensile strength has little correlation to, and changes little with aging [5.9]. A decrease in material elongation is closely related to the level of embrittlement; tensile strength, however, is not nearly as sensitive to embrittlement as elongation [5.8]. As polymers age, tensile strength generally increases while elongation decreases [5.5]. However, for some materials, tensile strength can increase and then decrease with aging. In addition, a few materials (such as butyl rubber) have been identified in which tensile strength decreases gradually with thermal aging [5.6]. This behavior makes tensile strength data more difficult to interpret. Also, tensile strength testing is destructive and potentially affected by DLO; therefore, it suffers from the same limitations as elongation testing.

Implementation

ASTM Standards D638 [5.12] and D412 [5.13] , and the applicable ICEA standard [e.g., the applicable standard for EPR materials is ICEA S-68-516 (NEMA WC8)], provide the methodology for performing tensile strength testing.

5.2.2.1.2 Nondestructive Techniques

The nondestructive techniques discussed in this section are:

- Compressive modulus
- High potential (Hi-pot)
- Insulation resistance (IR)
- Polarization index (PI)
- Insulation power factor
- Capacitance
- Tan delta/low frequency tan delta
- Partial discharge (PD)
- Time-domain reflectometry (TDR)

Compressive Modulus

General Description

Compressive modulus, a mechanical property of insulation and jacket materials, may be used to monitor the aging of electrical cables and other polymer applications.[4] The concept behind compressive modulus testing is simple; an anvil, moving at a fixed velocity, is pressed into the side wall of a cable while the force is monitored. A load cell or similar force-measuring device connected to the anvil monitors the force applied. Once the anvil touches the material, its total travel is on the order of a fraction of a millimeter (a few hundredths of an inch). The

[4] The term "modulus" typically refers to the modulus of elasticity. The Standard Handbook for Mechanical Engineers definition is the ratio of the increment of unit stress to increment of unit deformation, and is expressed in lb/in^2. However, the term has been used in relation to the Indenter system for describing the ratio of the change in applied force to material deformation (lb/in).

compressive modulus is calculated by dividing the change in force by the change in position during inward travel.

Figure 5-1 depicts the relationship between compressive modulus, elongation, and aging for a specific cable type. The data in Figure 5-1 was extracted from Ogden's indenter development testing files for a material designated "TR," and is representative of a number of materials. The legend abbreviations for material (TR) are:

Th(TR):	Thermal (only) aging, indenter reading
Rad(TR):	Thermal and radiation aging, indenter reading
Th(TR)R:	Thermal (only) aging, relative elongation (e/e_0) reading
Rad(TR)R:	Thermal and radiation aging, relative elongation (e/e_0) reading

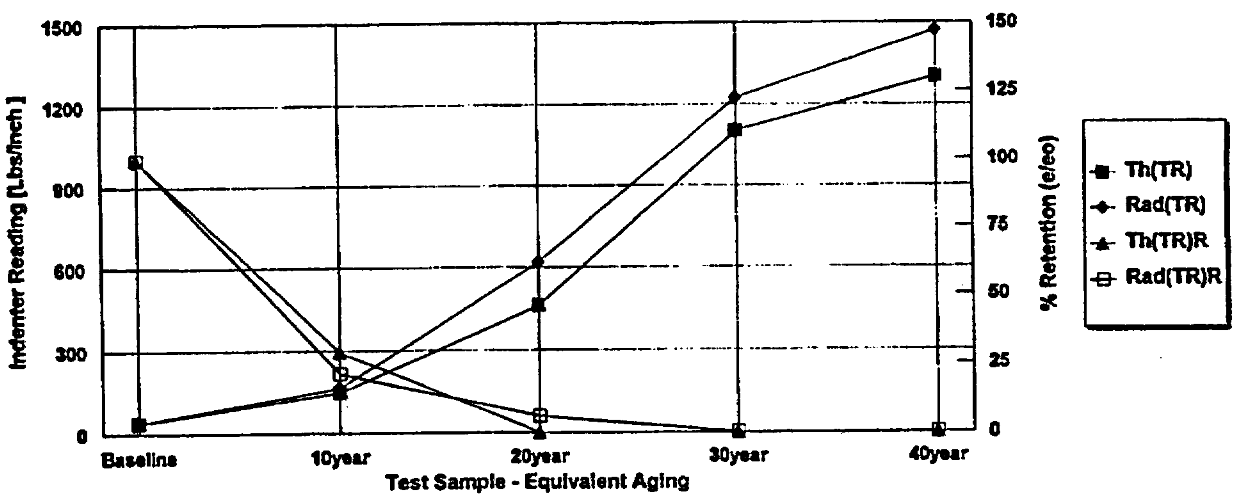

Figure 5-1 Relationship Between Compressive Modulus and Aging

Advantages/Disadvantages

Compressive modulus is an effective technique for insulation or jacket material that exhibits an orderly change in properties as it ages.[5] Certain rubber and rubber-like materials (some types of EPR, silicone rubber, Neoprene®, PVC, and CSPE) can be monitored in this manner. The effectiveness of this technique for measuring the aging of crosslinked polyethylene is currently under investigation; early results of one testing program indicate that XLPE which has been considerably aged may exhibit trendable changes in compressive modulus, particularly at advanced levels of aging [5.16]. See also Reference [5.17], which indicates that degradation of XLPE can be tracked using compressive modulus. Other programs have indicated no correlation between modulus and aging for XLPO/XLPE. In addition, if Neoprene®

[5] Note that direct measurement of the compressive modulus of the insulation is not possible for jacketed specimens unless portions of the underlying insulation are exposed. However, in some instances, the condition of the insulation may be correlated to the changes observed in the outer jacket modulus through knowledge of the aging characteristics of both materials.

or CSPE jackets have been used on cables with crosslinked polyethylene insulation, the jackets may be used as indirect aging indicators for the insulation.

Comparison of elongation with compressive modulus by Sandia National Laboratories showed a good degree of correlation; elongation was found to be a more sensitive aging indicator at lower doses, whereas compressive modulus was the more sensitive aging indicator at higher doses [5.9]. Data from one cable aging research program currently under way indicate that for certain materials, the sensitivity of the compressive modulus technique (i.e., the change in modulus for a given change in elongation) is relatively low until jacket/insulation elongation has declined significantly. Accordingly, the technique may not be wholly effective at detecting early changes in elongation for these materials. Other limitations associated with the use of compressive modulus include the requirement to develop a correlation between outer jacket and insulation aging for jacketed cables, and physical configuration effects (e.g., larger variations in modulus due to variations in the number of conductors or the presence of shielding material) for certain of types of cable.

Implementation

The Indenter (Figure 5-2) is an example of a currently available test device using the compressive modulus concept. The system is self-contained and portable, and may be used for both *in situ* and laboratory evaluation [5.18], [5.19]. Laboratory and field test programs have evaluated the efficacy of the Indenter system at monitoring component polymer aging. Results of these programs indicate that compressive modulus and elongation both showed good correlation with aging for jacket materials, except for XLPO and other polyethylenes [5.9], [5.20]. In addition to the test programs, actual field use of the system for evaluation of cable aging has also indicated good correlation between thermal aging and modulus, and the system has been proven effective at evaluating and profiling cable damage resulting from localized heat and radiation sources (i.e., hot spots) [5.18], [5.21]. An EPRI report details initial laboratory and in-plant trials with the Indenter system [5.22]. In parallel with the EPRI program described above, a French utility has recently completed an evaluation of the Indenter system for use in their plants, indicating satisfactory results [5.23].

One method of estimating the aging of environmentally qualified cable is through comparison of the compressive modulus measured for cable samples of the same type artificially aged to the thermal and radiation levels in the original environmental qualification program(s) with those measured on installed cables. Modulus readings less than those obtained from the artificially aged specimens would be indicative of comparatively less aging. From this method, the inference may also be made that so long as the modulus of the installed cable remains less than that of artificially aged specimens that survive accident testing, accident performance will be maintained. Note, however, that most qualification test specimens were thermally aged and irradiated to comparatively low elongation values; therefore, use of the qualified condition as the aging endpoint may not be practical or desirable for cable that is required to maintain significant elongation (e.g., that which is routinely bent or manipulated). In such cases, limitations on bending may be imposed, or such cables periodically inspected for cracking. Furthermore, potential effects of natural (i.e., low-temperature, low-dose rate) aging may not be fully accounted for using this model. Several utility test programs are under way to correlate compressive modulus and elongation under both accelerated and natural aging conditions.

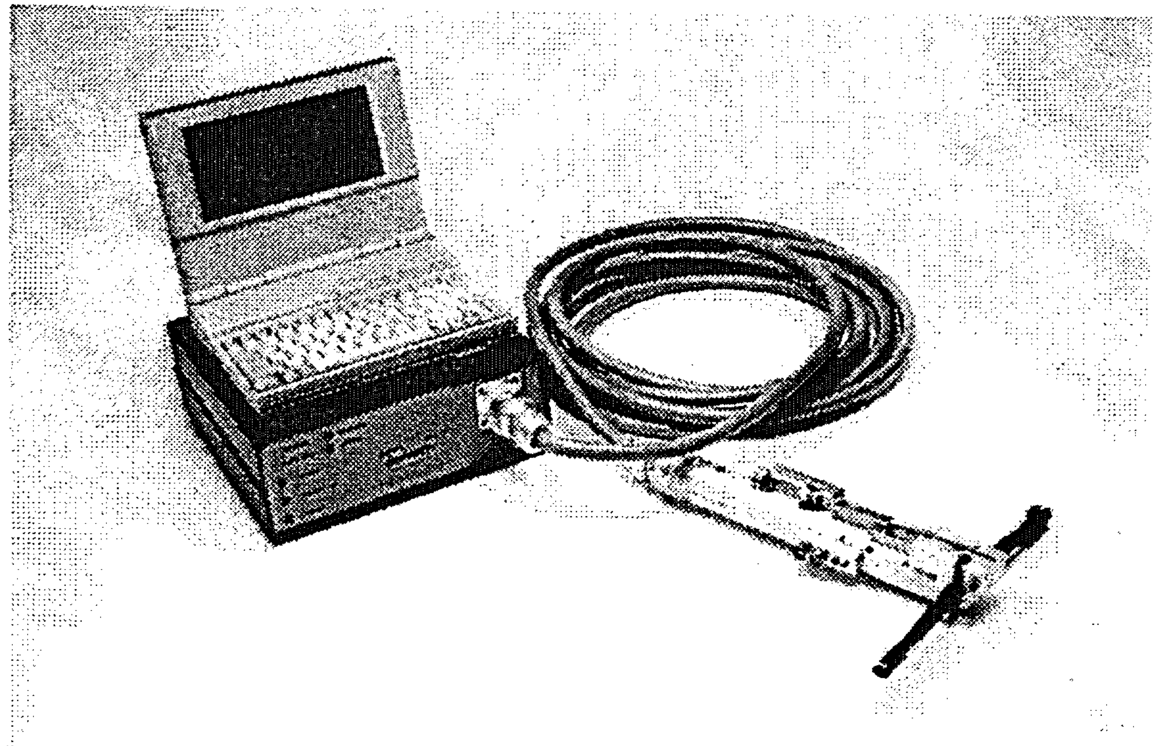

Figure 5-2 Indenter Polymer Aging Monitor

High Potential

General Description

Two primary types of high-potential (hi-pot) testing may be used: breakdown and withstand. Hi-pot breakdown testing involves the application of either an ac or dc signal to a cable to determine the voltage at which breakdown of the dielectric occurs (breakdown voltage). Hi-pot withstand testing is used to demonstrate that insulation can withstand a given over-voltage condition, and to detect weak spots in the insulation that could later result in in-service failures. Hi-pot breakdown testing may be considered destructive, whereas withstand testing is not. Accordingly, hi-pot breakdown is generally not applied to installed cable. In addition, the use of alternating current during over-voltage testing may be more damaging to cable insulation integrity; therefore, dc is preferred for post-factory testing. [5.24] (see p. 125). However, some operators consider ac hi-pot testing to be more sensitive to locating minute flaws or damage; see Reference [5.25] for a discussion of ac hi-pot and partial discharge testing.

Factory hi-pot tests are generally performed at comparatively high voltage levels (typically 300 Vdc/mil or 125 Vac/mil) or to the customer's specifications. In addition, cables are acceptance tested immediately after installation to detect gross damage, usually at voltage levels on the order of 80% of the factory tests [5.26].

Post-acceptance, dc hi-pot withstand testing is normally performed only on shielded medium-voltage power cable,[6] using one of two methods: go/no-go, or stepped or incremented voltage application. In the first method, the voltage applied to the cable is raised rapidly in one step to the desired dc value; if breakdown of the dielectric occurs (as indicated by increasing or stable, non-zero test current), the test is failed. In the second method, a dc voltage is applied and then raised in increments (five or more are recommended). At each increment, exponential decay of the current is expected (based on polarization of the dipoles in the material, and dissipation of the capacitive and absorptive currents). If the current continues to increase after a new voltage step, the dielectric is approaching breakdown and the test is halted. Caution must be used to ensure breakdown is not reached and the insulation potentially damaged. So long as the instability falls sufficiently above the normal operating voltage of the circuit, the cable may be returned to service until the next evaluation or replacement [5.27]. Note that maximum withstand voltages used in post-acceptance testing may vary significantly based on the industry standard and manufacturer of the cable.

Even if no post-acceptance testing of the cable systems is performed directly, many plants will perform high-voltage testing of loads or end devices through the connected power cable and terminations. For example, testing of motor winding insulation is commonly performed via the load center or switchgear. However, the voltage levels associated with such testing are typically far below those that would be imposed upon dc hi-pot testing of the cable itself.

Another high potential test that may be used to locate cable faults after installation is known as "thumping"; this process involves subjecting the faulted cable to high voltage dc until the voltage collapses (fault arcing). The test is often performed several times successively in order to localize the fault; hence, multiple voltage transients and reflected high-voltage waves may be imposed on a given section of cable insulation during the process [5.28].

Advantages/Disadvantages

Hi-pot breakdown testing may be of more use to older insulation systems (such as oil/paper, butyl, and natural rubbers)[7] and early types of EPR and XLPE; it is effectively useless on new, relatively unaged EPR or XLPE. This stems primarily from the inability to positively relate breakdown voltage and material condition. XLPE has higher initial dielectric strength than EPR of similar rating. Evidence indicates, however, that the dielectric strength of wet-aged XLPE insulation decreases initially and then stabilizes at a value somewhat below that of EPR [5.26], [5.29]. For either material, however, hi-pot breakdown testing is not effective as an aging measurement tool because the variation in breakdown voltage is not constant or predictable, and the possibility of insulation damage is high as breakdown is approached. Withstand testing, on the contrary, is useful at demonstrating continued cable functionality at a given over-voltage level without jeopardizing insulation integrity, although no correlation to aging has been shown.

Use of ac hi-pot and partial discharge testing on newly installed cable has been shown to be effective at identifying gross defects in shielded cable. For unshielded cable, however, two

[6] Although commonly used as production acceptance tests, hi-pot testing is not normally performed on low-voltage cable after installation.

[7] These types of insulations were not characteristically used in nuclear power plants.

problems exist: (1) since a uniform ground plane is not defined, some of the sites of defects or damage on the insulation may not be exposed to sufficient voltage stress to be identified, and (2) some sites may be exposed to very high stress and actually be damaged during testing. Further research is being conducted in this area [5.30]. In addition, ac hi-pot test equipment is larger and more unwieldy than comparable dc sets.

As discussed in Section 4.1.2 of this guideline, one EPRI study [5.31] indicates that dc hi-pot testing did not adversely influence the ac breakdown strength of unaged or artificially aged XLPE insulated cables. However, the study did indicate that hi-pot testing of artificially aged cables with reduced dielectric strength resulted in more rapid degradation than similar cables not subjected to this testing, and that the effects of dc testing were most apparent on specimens that contained a new section of cable, a splice, and an aged section of cable. Also observed was an increased failure rate with multiple hi-pot test applications.

Reference [5.32] documents dc hi-pot testing of virgin specimens of three low-voltage cable types[8] at 240 Vdc/mil. Each specimen was subjected to 20 test cycles (5 min energized, 5 min deenergized, designed to simulate actual testing) while submerged in water and then subsequently energized to determine breakdown voltage. The breakdown voltages of the cycled specimens were then compared with those of specimens not exposed to testing to determine the effects (if any) of the hi-pot exposure. The study concluded that testing at 240 Vdc/mil did not degrade the cables.

Implementation

A number of standards (e.g., IEEE Standard 400 [5.33]; IEEE Standard 141, Chapter 11 [5.24]; IEEE 943 [5.3]; ICEA S-68-516/S-66-524 [5.34]; and AEIC CS5 and CS6 [5.35] and [5.36]) provide guidance for the performance of dc high potential testing, including recommended test voltages. Note that IEEE Standard 400 specifies voltages that are, in general, much higher than those recommended by the ICEA and AEIC standards.[9] ASTM Standards D149 [5.37] and D3755 [5.38] give practical information concerning ac and dc hi-pot testing of materials.

Substantial concern exists that hi-pot testing may adversely affect the life of medium-voltage cable [5.31], [5.28]. Many cable manufacturers provide guidance on hi-pot testing of their cables for periods up to 5 years after installation; beyond this age, the effects of environment on the cable with respect to potential damage from hi-pot testing should be evaluated [5.39], [5.40]. If testing is to be performed on shielded medium-voltage power cable, the guidance of IEEE 400 [5.33], IEEE 690 [5.41], AEIC Standards, and ICEA Standards should be considered. Unshielded medium-voltage cables should not be hi-pot tested; rather, the insulation resistance should be measured.

[8] Okonite Okolon, Brand Rex XLPE, and Rockbestos silicone rubber.

[9] AEIC cable standards (including CS6-87 {EPR} [5.35] and CS5-87 {XLPE} [5.36]) are oriented toward purchase specifications and manufacturing. Several specifications for medium- and high-voltage cables specify the hi-pot testing to tabulated values when manufactured, to 75% of tabulated values during installation, to 80% of tabulated values after installation but before service, to 65% of tabulated values for the first 5 years of service, and to 40% of tabulated values after 5 years of service. No discussion of the rationale for this schedule or limitations of the test's value was located.

Insulation Resistance (IR)

General Description

Insulation resistance (IR) testing typically uses a direct current to measure the electrical resistance of a dielectric such as cable insulation to provide an indication of its overall dielectric capability. The measured resistance of an insulation material depends on several factors, including the geometry of the system being measured and the dielectric resistivity of the material. Due to the arrangement of the conductor in a typical cable with respect to the insulation, the section of the insulation with the lowest dielectric resistivity will generally determine the characteristics of the entire cable (parallel resistor concept). The resistance of dielectrics is usually both time and frequency dependent; this behavior results from the polarization or charge displacement within the material. Accordingly, current flowing through the dielectric can be broken down into conductive, capacitive, and absorptive components. Charge displacement within the material generally occurs within various time frames, ranging from a few nanoseconds to several seconds or even minutes, depending on the atomic and molecular processes being considered. Accordingly, one or more time constants[10] based on exponential decline of the polarization current (i.e., transient capacitive and absorptive components) can be empirically determined for each material. Insulation resistance is typically measured using commercially available equipment (megohmmeters) with differing dc voltage levels to measure resistance [5.42]. Voltages of 500 Vdc, 1000 Vdc, and 2500 Vdc are common, although higher voltages may be used.

Advantages/Disadvantages

IR may give some indication of the aging of connections; however, it is generally considered of little use in predicting the aging of a cable [5.4]. IR properties of dielectrics may change little until severe degradation of mechanical properties occurs. These measurements display some gradual changes with aging, but are generally nowhere near as sensitive to aging as techniques based on mechanical properties (such as elongation or compressive modulus) [5.6], [5.43], [5.44], [5.45]. Conversely, even gross insulation damage may not be evidenced by changes in IR; for example, an insulation cut-through surrounded by dry air may not significantly affect IR readings. Acceptance criteria are difficult to determine due to the many factors that affect IR, including temperature along the cable, humidity, and the condition of the terminations. Testing is usually conducted as a pass/fail and values may not be recorded. Data from one utility indicate some variation in IR as a function of voltage on low-voltage cables [5.26].

IR is insensitive to thermally induced degradation for SBR, PVC, butyl rubber (BR), PE, and EPR [5.46]. Therefore, this technique may be insensitive to advanced thermal degradation before the onset of significant cracking. Once cracking of the insulator occurs, other techniques (such as partial discharge) may be effective at detecting these defects [5.46]. The use of computerized IR testing with multiple sampling over time may allow further refinement of this method.

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[10] Multiple time constants result from the use of more than one material in the chemical formulation.

The dc insulation resistance of unshielded cables (i.e., those with no metallic shield in proximity to the outer surface of the insulation) tends to be somewhat erratic due to the absence of a well-defined ground path; IR, therefore, depends primarily on the surface conditions of the insulation. Because variations in the surface condition at different locations on the same cable may exist, it is very difficult to formulate any conclusions regarding aging trends based on the IR obtained from these types of cables. IR can be useful for detecting shorts in insulation that has been wetted or exposed to steam (even in localized areas) due to the increase in ion mobility [5.45], [5.47], [5.48]. Surface IR may also be measured on terminal blocks and similar components as an indication of the presence of degradation or tracking paths.

Plant operators have used a high-voltage IR test on medium-voltage cable to differentiate between gross water-aged/damaged rubber insulation (which should be replaced in the short-term), and comparatively unaged or undamaged cable that may be operated for a longer period [5.49].

Implementation

Installed cables are tested for IR per IEEE Standards 422-1986 [5.50], 690-1984 [5.41], and 43-1974 [5.51]. IEEE Standard 422 testing is performed to determine whether any damage has occurred to the cable during storage or installation. The standard explicitly states that these tests may not detect damage that may eventually result in cable failure. IR is measured between any possible combination of conductors in the same cable, and between any conductor and station ground (with all other conductors grounded). In acceptance testing, IR is used to detect gross installation problems prior to energization. Detection of such problems can prevent catastrophic damage at first energization. See also the general guidance contained in IEEE Standard 141 [5.24] and ASTM D257 [5.52] concerning the measurement of insulation resistance in materials.

Polarization Index (PI)

General Description

Insulation resistance varies as a function of time proportional to the polarization current through the dielectric as described above. The polarization index (PI) is the ratio of the polarization current at two different times. PI is traditionally measured using the polarization currents at times of 1 min and 10 min after application; however, because the rate of change of the polarization current may vary with temperature, materials, or equipment configurations, these times may be varied as required to obtain a meaningful result for a specific application. The basic theory of this test is to compare the initial capacitive, conductive, and absorptive currents in the dielectric material with the conductive current at a later time. The ratio is indicative of the state of the dielectric; the higher the ratio, the better the condition of the insulation. A low polarization index, where conductive currents dominate capacitive and absorptive currents, may indicate electrically degraded insulation [5.42]. A value of less than one can indicate high volumetric leakage [5.15]. The conductive current through the insulation is generally related to ion mobility; polymers generally have high dielectric resistivity because their ion mobility is low. The introduction of water into the material can be especially effective at reducing dielectric resistivity, as water facilitates ion mobility within the material and also generally contains ions of its own. Resistivity generally decreases with increasing temperature. Also, resistivity increases with increasing electrical frequency due to the inability of the polarizing charges to react to the rapid changes in electric field induced by the test signal [5.42], [5.43].

Advantages/Disadvantages

PI measurements are subject to many of the same limitations as IR, as they are based on common measurements. Caution must be exercised in interpretation of PI test results, because trending of the ratio over time may provide more insight into insulation condition than the results of an individual test (which does not appear to be sensitive to aging effects).

PI is insensitive to thermally induced degradation for SBR, PVC, BR, PE, and EPR [5.46]. Therefore, advanced thermal degradation before the onset of significant cracking may not be readily detected. Once such cracking of the insulator occurs, other techniques (such as partial discharge) may be effective. The effectiveness of PI for other degradation mechanisms (i.e., wet cables) has yet to be assessed [5.46].

Implementation

See previous discussion of insulation resistance.

Insulation Power Factor

General Description

Insulation power factor testing (or Doble testing) is a means by which the condition of cable insulation may be assessed. The basic premise of this testing is the detection of changes in the dielectric properties of the insulation, which can be associated with the effects of thermal, radiation-induced, voltage (partial discharge), or mechanical damage or wetting. The power factor of an insulation is defined as the cosine of the angle between the charging current and voltage vectors [5.53]. In simple terms, insulation power factor is a measure of the stored energy of the charging current.

When a dc potential is initially applied to insulation, charging current will vary as a function of time; a finite period of time is required for the insulation to "charge," after which the charging current will stabilize. This effect stems from the energy required to realign dipoles within the insulation, commonly known as the dielectric absorption loss. However, when an alternating current is applied to the same insulation, the dielectric field (and therefore alignment of the dipoles) is never fully accomplished due to the alternating fields; hence, the charging current remains relatively high, and the dielectric losses roughly constant with time.

An insulation power factor test apparatus measures the charging current and dielectric loss from which the power factor, capacitance, and ac resistance may be determined. As the length of insulation being tested increases, the charging current and dielectric loss (in watts) at a given voltage also increases. However, the ratio of the charging current and dielectric loss is a constant, independent of length, for a given cable. This ratio will change if insulation properties change or material defects are present.

Insulation power factor tests are generally applicable only to shielded medium-voltage cable, and are made with the circuit out of service [5.26], [5.53], [5.54]. Normal test voltages used for power factor testing are on the order of 1 to 10 kVac. Typical power factor values for cables having metallic armor or grounded shield are 3 to 5% at 20°C; power factors for ungrounded or unshielded cables may be higher. Increases in power factor with temperature are relatively small for most modern cable types [5.54].

Advantages/Disadvantages

Insulation power factor testing is generally more effective at locating insulation defects or deterioration than dc tests such as IR. It provides a measure of the overall condition of the insulation, which is independent of the amount of insulation being tested; however, the greater the amount of insulation tested, the less any defects can be localized [5.54]. Therefore, isolation of suspect cable runs or components during testing is beneficial. Because the technique uses an ac signal, it more accurately simulates operating conditions for ac systems (the majority of cable systems in the typical plant). In addition, because dielectric absorption losses in an insulation are related to the moisture content and the presence of other impurities, small changes in the moisture content of an insulation may result in significant changes in the dielectric losses and therefore the required charging current. These changes may be readily detected through measurement of the charging current and comparison with previous values.

Note that the physical limitations of the test set (in terms of producing the required charging current) may limit the length of cable that may be tested at one time. Maximum testable cable lengths are typically on the order of 500 to 1000 feet (152 to 304 m).

Implementation

NEMA WC-54 1990 (ICEA T-26-465) [5.55], ASTM D150 [5.56], and References [5.53] and [5.54] provide information and guidance on power factor testing of electrical cables and materials. Additional information may be found in the minutes of the Doble Client Conference, available only to Doble Engineering Co. clients. Figure 5-3 shows a simplified schematic of a test circuit.

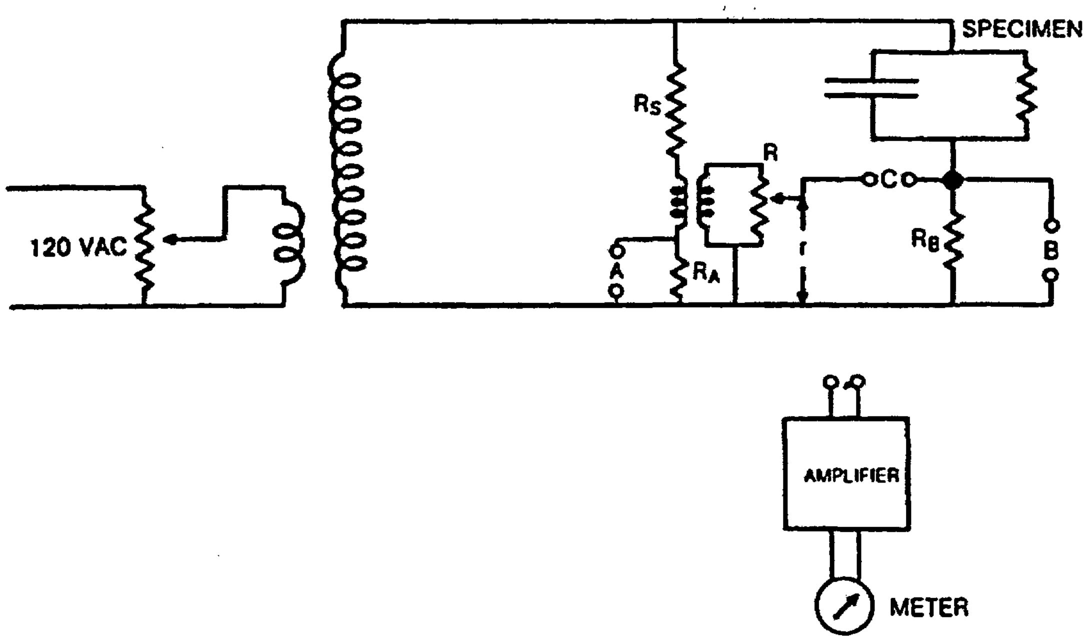

Figure 5-3 Simplified Schematic of Insulation Power Factor Test Circuit (Courtesy of Doble Engineering Co.)

Capacitance

General Description

Capacitance measurements are used to detect moisture in cable insulation, and in adjacent conduit and duct banks. Moisture present in the insulation or jacketing may substantially increase the measured capacitance. In shielded cables, the measured capacitance depends only on the interposing dielectric (in this case, the insulation between the conductor and the shield). In unshielded cable applications, the capacitance measurement will reflect the capacitance of both the cable and the space surrounding the cable. Therefore, moisture located either in the jacket/insulation or immediately surrounding the cable will affect the capacitance.

Advantages/Disadvantages

Because the capacitance of a cable or termination may or may not be affected by aging-related degradation of dielectric materials, its use as an aging measurement tool is limited. Wet insulation may reflect a change in capacitance; however, this change cannot be coupled to the condition of the insulation. Because the presence of (or changes in) the ground plane may affect the capacitance reading taken on an unshielded cable, comparison of capacitance readings to detect moisture intrusion may be better suited to shielded applications; however, submersion of unshielded cable is readily detected as well. The capacitance of dry insulation is generally affected little by increases in temperature; however, the capacitance of wetted insulation may increase significantly [5.26], [5.53], [5.57].

Implementation

Capacitance measurements may be made through a variety of commercially available equipment such as a capacitance bridge or one of the integrated electrical measuring systems such as ECAD® or CHAR™ described later. Reference [5.57] provides some discussion of the use of capacitance measurements on power cable. See also Section 6 of the applicable ICEA standard [e.g., the applicable standard for EPR material is S-68-516 (NEMA WC8) [5.34], see the portion of Section 6 addressing EM-60 testing] and ASTM D150 [5.56], D470 [5.58], and D4566 [5.59].

Tan Delta/Low Frequency Tan Delta

General Description

Tan delta (dissipation factor) is an electrical test technique that measures the tangent of the loss angle at a single ac frequency. Tan delta indicates the variation of the circuit's dielectric impedance; this variation is primarily the result of bulk cable conductance and capacitance. The loss angle between the real and imaginary components of the signal is indicative of the dielectric losses of the insulation at that frequency. Low-frequency dissipation factor testing is similar to dissipation factor testing yet is measured at lower signal frequencies in order to take advantage of differing dielectric properties as a function of frequency [5.60]. [Note: Time-domain spectroscopy (TDS), a related technique, is discussed later in the next subsection.]

One researcher noted that increases in Tan delta with aging for XLPE were very noticeable, but the overall magnitude of these changes was much smaller than that for PVC. This was thought to be consistent with low molecular loss features that characterize XLPE. For PVC, a rapid initial decrease in Tan delta with thermal aging, followed by relative stability, was noted. This behavior can be correlated with observed changes in plasticizer content of the material [5.46].

Advantages/Disadvantages

The most significant limitation with this technique is that it is difficult to apply in the field to unshielded cables [5.46]. Other limitations are that (1) the system can only measure an "average" of the insulation, (2) a shield (ground reference) is required to avoid significant environmental interference, and (3) the test must be performed with the end devices disconnected.

Implementation

Tan delta is measured using currently available electrical equipment (such as a waveform generator and spectrum analyzer). ASTM D150 [5.56] and D470 [5.58] and References [5.57] and [5.112] provide some guidance on Tan delta measurement.

Partial Discharge (PD)

General Description

Partial discharge testing involves the application of an ac high voltage to a cable insulation system to detect high frequency discharges at sites of insulation degradation. In nondegraded insulation, partial discharging becomes significant only when voltages well in excess of normal are applied. In degraded cable (such as that with insulation cracks, cuts, inclusions, voids, or damaged shielding), the voltage required to induce discharging may decrease substantially, thereby indicating degradation [5.26] and [5.47]. Figure 5-4 shows a typical partial discharge pulse (partial discharge voltage as a function of time).

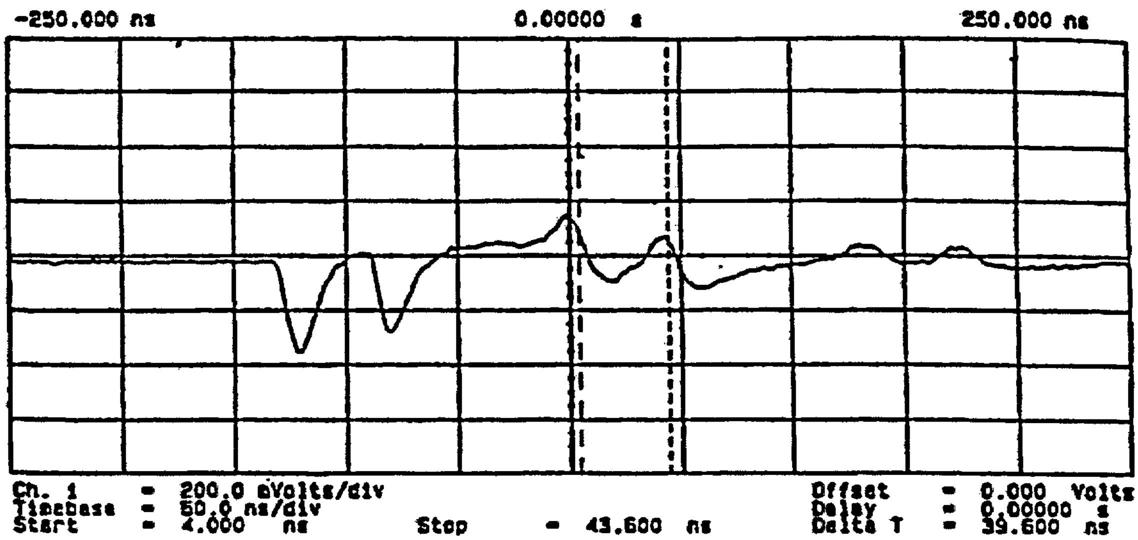

Figure 5-4 Partial Discharge Pulse for Defect in XLPE Cable Insulation (Courtesy of Ontario Hydro)

Advantages/Disadvantages

Limitations associated with partial discharge testing include the requirement that cables be disconnected from their loads for testing (to avoid noise interference and potential damage to the load), and a large and heavy test set (ac power supply). In addition, partial discharge testing is best suited to testing of shielded cables, although some work has been done on testing of unshielded cables. Test data indicate that partial discharge is effective at determining the presence of certain defects in the cable's insulation or shield. Partial discharge was detected on unshielded 5-kV cables in which adjacent conductors were grounded. Attempts to perform PD testing on 600-V cables did not have similar success in one program [5.30]; however, another test program indicated that PD holds some promise for detection of low-voltage incipient defects [5.66]. A further difficulty in testing either shielded or unshielded cables is attenuation of the PD signal as it propagates from the discharge site to the measurement locations.

Implementation

IEEE Standard 454-1973 [5.61], ASTM D470 [5.58] and D2633 [5.62], and References [5.30], [5.48], and [5.46], [5.63], [5.64], [5.65], [5.66], [5.67], [5.68] provide additional information and guidance on partial discharge testing.

Time-Domain Reflectometry (TDR)

General Description

Time-domain reflectometry (TDR) testing is used to characterize the impedance of an electrical circuit [5.4], [5.69], [5.70]. TDR is a technique that applies an electrical radio frequency (RF) pulse into an out-of-service circuit to determine the impedance characteristics of that circuit. Reflection of the pulse occurs at those points in the circuit where the electrical impedance changes. The electrical impedance of a circuit is determined by both real (resistive) and complex (inductive or capacitive) components within the circuit. When the pulse encounters a change in impedance, a portion of the signal is reflected from the impedance change interface back toward the point of origin. The magnitude of this reflection is a function of the relationship between the change in impedance at the interface and the characteristic impedance of the circuit. Small changes or discontinuities in impedance result in accordingly small reflections, whereas large variations in impedance produce large changes. TDR equipment generally plots the reflection coefficient as a function of time (which can be directly related to distance through knowledge of the signal propagation speed) to identify and locate changes in circuit impedance. If a baseline plot of the circuit has been previously obtained, direct comparison of the two TDR signatures can be made to identify changes in characteristics. Generally, these identifiable changes are from gross variations in condition such as wetting of a once-dry circuit, or increased resistance at a connector interface.

Advantages/Disadvantages

The primary function of TDR testing is diagnosis or troubleshooting, and TDR has been demonstrated to be effective at detecting and locating degraded components. However, its effectiveness as a predictive aging measurement or condition monitoring tool is quite limited in that very precise baseline signatures of each circuit would be required to distinguish the small changes in cable and termination properties induced by aging. This is especially true for cable insulation degradation, because changes in circuit impedance resulting from changes in cable capacitance due to aging are negligible with respect to test method capabilities. For other circuit components such as connectors, splices, and terminations, more readily apparent changes in the TDR signature due to corrosion or loose connections may be noted [5.4], [5.30], [5.69]. Some data indicate that TDR is capable of detecting small changes in voltage stress in both shielded and unshielded cables [5.26]. However, the data also indicate that isolation of the cable from external effects may be required to detect such changes in unshielded cables.

Implementation

See discussion of integrated measurement techniques that follow.

Integrated Measurement Techniques (ECAD® and CHAR™)

General Description

The ECAD® (Electronic Characterization and Diagnostics, CM Technologies Corp.) and CHAR™ (Automatic Characterization System, CHAR Services, Inc.) systems are used for condition monitoring and troubleshooting of de-energized plant circuits, including components such as penetrations, terminal boards, and splices. Development of these systems began after the need for in-containment testing of circuits was identified at Three Mile Island. The system applies dc, low frequency ac, and radio-frequency (RF) test signals to a circuit to monitor its electrical characteristics. These low-voltage dc and ac measurements provide lumped values of circuit loop resistance, inductance, insulation resistance, capacitance, and dissipation factor. Figure 5-5 shows a typical ECAD® system.

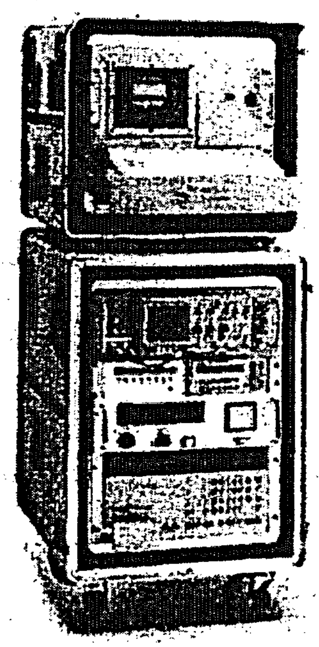

Figure 5-5 ECAD® Integrated Testing Suite

Advantages/Disadvantages

Measurements of these parameters can provide information relating to degradation of circuit components such as deterioration of insulation, intrusion of moisture (wetting), or corrosion, as well as other circuit problems (opens, faults, improper grounding, noise, and development of shunt ground paths). Both system calibration and testing are computer-driven, thereby enhancing accuracy and test repeatability. Data obtained during testing are automatically stored to facilitate rapid testing and subsequent retrieval.

The ECAD® and CHAR™ systems are effective primarily for troubleshooting; although they do provide trendable data, no definitive correlation between measurement of such electrical parameters and cable/termination longevity has been established. Also, temperature and humidity measurements are required to allow compensation of some readings (such as insulation resistance) [5.70], [5.71], [5.72].

Implementation

ECAD® and CHAR™ testing are performed in accordance with manufacturer's guidance and applicable plant procedures (see, for example, Reference [5.70]).

5.2.2.1.3 Essentially Nondestructive Techniques

The eight essentially nondestructive techniques discussed in this section include:

- Density
- Oxidation induction time (OIT)
- Oxidation induction temperature
- Fourier transform infrared (FTIR)
- UV spectroscopy
- Gel content
- Plasticizer content
- Electron spin and nuclear magnetic resonance

Density

General Description

The density of a material is defined as the mass per unit volume. Exposure of many common cable polymers in air over time has been shown to result in measurable changes in the material's density; accordingly, these changes may be used to estimate the degree of aging experienced by the specimen [5.73], [5.74]. See Figure 5-6. Although generally small in magnitude (usually less than a few percent), these readily measurable changes may result from the effects of thermal, chemical, and radiation exposure either alone or in combination. Mechanically induced changes in density can also occur, such as those resulting from long-term compression of the material, changes in its physical structure, or residual stress from the formation process [5.9], [5.75], [5.76], [5.77].

Scission, crosslinking, and oxidation of polymers can affect their molecular structure and thereby their physical properties (including density) [5.15], [5.75]. Changes in density resulting from these processes are not uniform; in general, they vary as a function of exposure to temperature and radiation, and spatially within a given material.

Several techniques for measuring density may be employed. One method extracts a small sample (<1 mg) of the material for measurement in a density gradient column. The sample required is small and this method is considered essentially nondestructive. As with any other technique that removes a small sample of material from the cable, the results obtained from the analysis may be highly site specific (localized), and may not be directly applicable to the bulk of the material. Somewhat larger samples (~5 mg) can be measured using the Archimedes approach in which density is calculated from the difference in the sample's mass when weighed in air and in a liquid.

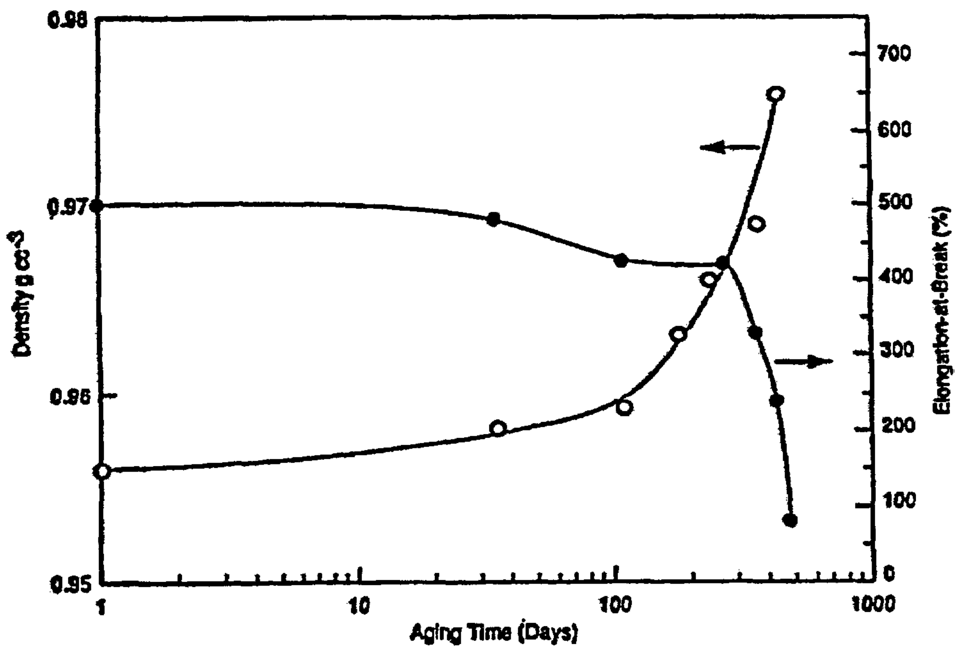

Figure 5-6 Density versus Aging for XLPE Insulation (Courtesy of Ontario Hydro)

Another technique for measuring polymer density uses computed X-ray tomography (CT) to profile the density of the material while it is still installed on the cable. This method scans the cable in "slices," measuring X-ray absorption (Houndsfeld CT number); density is almost directly proportional to the absorption for most polymers [5.78]. Absorption data obtained from all the slices are convolved by computer to form a three-dimensional representation of the density of the cable.

Advantages/Disadvantages

The CT density measurement technique is potentially capable (with additional development) of some *in situ* monitoring of both the cable jacket and insulation with no material sampling required, and would more effectively capture the three-dimensional density variations within the material being examined [5.78]. This is in contrast to the sampling methods, Archimedes and density gradient columns, which require removal of samples. Note, however, that access to many installed cables may be sufficiently limited to preclude the use of currently bulky CT equipment.

Screening data from one test program indicate that for some insulation and jacket materials, bulk density changes consistently with aging (generally increasing). For other materials, however, density did not appear to change significantly or unidirectionally, although the expected density changes were of the same magnitude as the scatter in the data (i.e., the test protocol was not implemented carefully) [5.9]. Density measurement could be an effective CM technique for certain materials; however, additional, more comprehensive evaluation must be performed to identify those materials susceptible to the technique and to establish acceptance criteria for those materials. Further development of test methodology is being pursued at Sandia; very promising, preliminary results were released in Summer 1996.

Implementation

ASTM Standard D792 [5.79] describes density and specific gravity measurements. ASTM D1505 [5.80] discusses density measurement via the density-gradient technique. Computed tomography (CT) is discussed in ASTM Standards E1441 [5.81] and E1570 [5.82].

Oxidation Induction Time (OIT)

General Description

Oxidation induction time (OIT) is a means of evaluating aging by measuring the period of time before a small sample of insulation experiences rapid oxidation when subjected to a continuous elevated temperature in an oxygen environment. The test evaluates the amount of antioxidants remaining in an insulation material. As long as the antioxidants are not entirely depleted in the material, the mechanical and electrical properties for many materials remain relatively stable. Even a few percent of the initial antioxidant is often sufficient to prevent mechanical degradation of a polymer. When the antioxidants are depleted, the material properties will begin to degrade, in some cases relatively rapidly.

OIT testing is currently being developed for use in monitoring the condition of insulation and jacket materials of cables in nuclear power plant service. To perform an OIT test, a small sample of insulation or jacket (~8 mg) must be removed from the cable. OIT testing is performed using a differential scanning calorimeter (DSC), in which the material is heated to approximately 215°C (419°F) in oxygen and held at this temperature (the exact temperature depends on the material being studied). The energy required to sustain the temperature is monitored. When the energy required to maintain temperature begins to decrease, the material has begun an exothermic reaction, indicating that the antioxidants have been depleted and that rapid oxidation is occurring. The period from the start of the test until the point of rapid oxidation is the oxidation induction time. For experimental convenience, the test temperature is selected so that the OIT of an unaged sample is approximately 45 to 60 min; aging leads to reductions in the OIT. OITs of less than 1 min often indicate that the insulation has reached embrittlement; at values greater than 1 minute, significant elongation is often, but not always, present for polyolefin materials [5.46], [5.83], [5.84].

Figure 5-7 provides examples of OIT results for an XLPE insulation aged at various temperatures. OIT changes in an orderly manner in proportion to the degree of aging.

Promising results have also been noted relating OIT to elongation. Comparison of OIT with elongation indicates that OIT is an early indicator of oxidative aging (decreases rapidly with increased aging) [5.46]. For certain materials, physical parameters such as elongation or tensile strength can be misleading if taken alone, and OIT may be more useful as a life prediction technique [5.73].

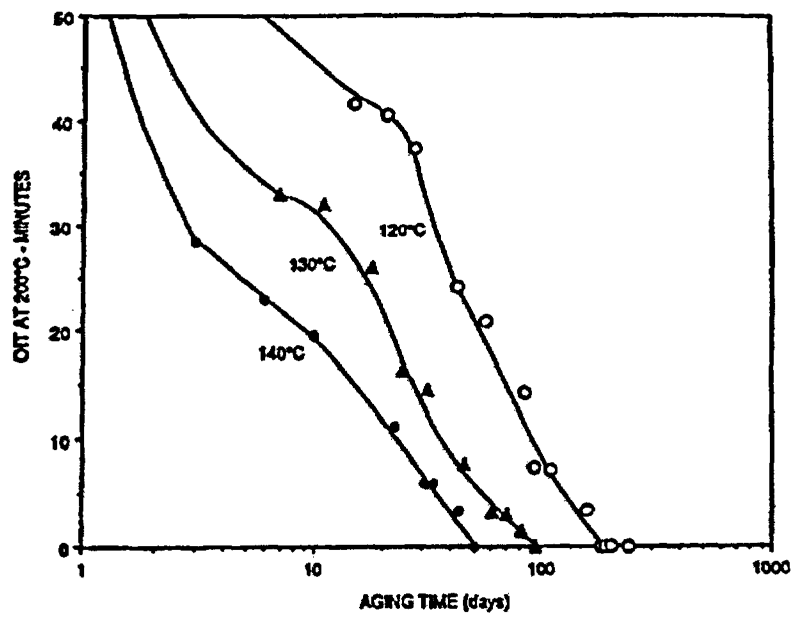

Figure 5-7 Oxidation Induction Time at 200°C [392°F] after Aging at 120°C [248°F], 130°C [266°F], and 140°C [284°F] for XLPE (Courtesy of Ontario Hydro)

Advantages/Disadvantages

OIT results for many XLPE formulations are relatively easy to evaluate in that there is a clear change in the OIT plot when the reaction transition occurs. Figure 5-8 shows a "clean" OIT profile for a XLPE. The intersection of the slope of the stable heat flow region and that of the decreasing heat flow region is used to determine the OIT. Some materials, such as highly filled EPRs, have plots that are more difficult to interpret in that there are smaller amounts of polymers in the material and they are mixes of polymers that react in a less orderly fashion than single polymers do. An OIT profile may require substantial interpretation due to its complexity.

The test can be considered to be essentially nondestructive; although samples have to be removed, they are generally small enough that cables do not have to be destroyed or removed to obtain them. Samples are expected to be taken by removal of terminal lugs, stripping a small segment of insulation (0.5 cm or less) and re-lugging the conductor. If information is required about the cable at some point other than the termination, scrapings of the jacket or insulation can be taken, and the scrapings may be shallow enough that repairs to the insulation are not necessary. As with any other technique that removes a small sample of material from the cable, the results obtained from the analysis may be highly site specific (localized), and may not be directly applicable to the bulk of the material.

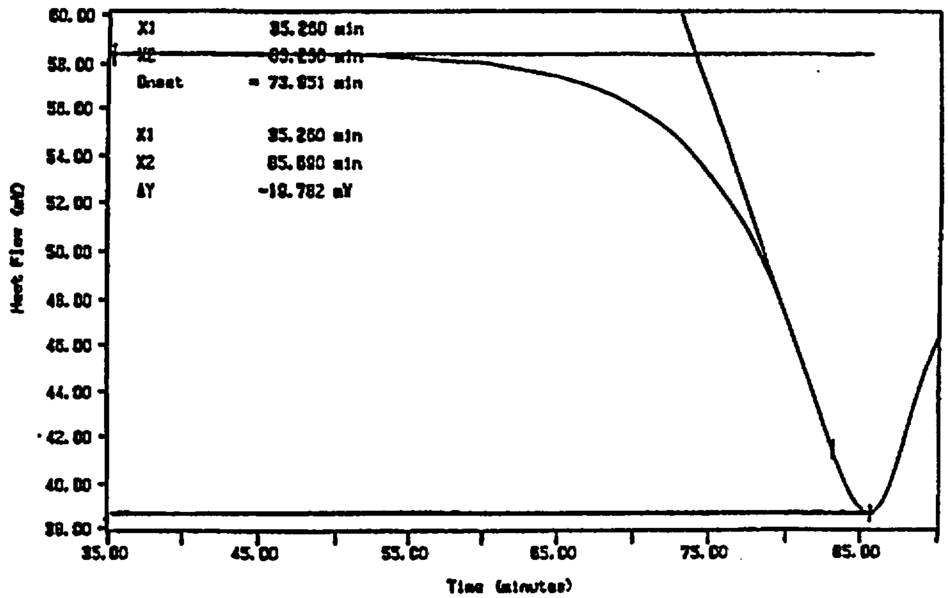

Figure 5-8 Differential Power Curve and OIT Extrapolation for XLPE Material Aged to 0.1 MGy [10 Mrads] (DSC Temperature of 215°C [419°F]) (Courtesy of Dr. A. Reynolds, University of Virginia)

Implementation

OIT testing is an established test methodology. Efforts currently under way (sponsored by the Electric Power Research Institute) will provide a standard methodology and acceptance criteria for nuclear power plant cable. Acceptance criteria for OIT may be developed by a number of methods, including (1) repeating the aging[11] portion of the EQ program and measuring the corresponding OIT values (as previously described for compressive modulus) or (2) by correlating OIT values at various levels of aging to elongation or some other physical parameter. An EPRI report detailing OIT developmental efforts is expected to be published in 1996.

ASTM Standards D2633 [5.62], D3895 [5.85], and D4565 [5.86] discuss procedures and methodology for performing oxidation induction time testing and specimen preparation. References [5.6], [5.46], [5.73], and [5.87], [5.88], [5.89], [5.90], [5.91], [5.92], [5.93], [5.94] provide additional information.

[11] Diffusion-limited oxidation during aging would make this approach conservative. This approach could be implemented for other methodologies, with similar results.

Oxidation Induction Temperature

Oxidation induction temperature is similar to the OIT testing described above, but uses a constant rate of temperature increase (as opposed to a constant temperature) to measure the aging of a given sample. The objective of the testing is to determine the temperature at which an exothermic (or endothermic) reaction occurs; this temperature is representative of the loss of antioxidants and therefore the degree of aging of the specimen. For less severely aged material, the length of the test is shorter than that for OIT. Other attributes of the process (such as required equipment and specimen size) are identical to OIT testing described above.

Fourier Transform Infrared (FTIR)

General Description

Fourier transform infrared (FTIR) spectroscopy uses changes in the infrared absorption spectrum of a polymer to detect chemical changes resulting from various aging influences. It is useful in studies of oxidative processes, because chemical functional groups that contain oxygen (such as ketones and ethers) are easily detected by this technique. As infrared radiation impinges upon the subject material, chemical bonds of these groups are stretched, bent, or rotated, thereby absorbing some of the incident energy. Due to the physical characteristics of these molecules, absorption information is present at wave numbers[12] between 650 and 4000 cm^{-1}. Fourier transformation is a technique by which multiple spectra for a sample are obtained and mathematically "added" to reduce the effects of random noise and interference [5.95].

Two primary methods are used in basic infrared spectroscopy: transmittance and multiple internal reflectance (MIR). Transmittance is useful for thin films where degradation has likely occurred throughout most of the material. However, for thicker materials that have experienced only surface degradation, MIR is useful for identifying the effects of the degradation for the surface layers only. Figure 5-9 shows an absorbance (inverse of transmittance) spectrum for an XLPE insulation as a function of thermal aging.

FTIR spectroscopy may be performed using a comparatively small sample of the material under analysis; however, the size of the sample is somewhat determined by the type of material being tested. For example, many EPR/EPDM compounds contain significant percentages of clay fillers, which dictate the use of different operating modes[13] (and therefore sample sizes) in some equipment. In addition, the type of sample preparation required may be different; grinding of the material may be required to permit a representative reading to be obtained. Accordingly, characterization of the technique as essentially nondestructive may be misleading in cases where larger samples are required.

Experimental data indicate that aged and oxidized polyolefins exhibit a carbonyl band at a wave number of roughly 1730 cm^{-1} [5.46]. The behavior of XLPE, PE, and EPR is similar in that absorption peaks occur after a lengthy induction aging period. The presence of the carbonyl

[12] Wave number = 1/wavelength

[13] Such as acoustic sensing (PAS) or attenuated reflectance (ATR).

band also indicates the oxidation of irradiated XLPE; however, this technique has proven less successful for EPR, SBR, and PVC. In one experiment, carbonyl formation preceded sharp declines in elongation for XLPE and HDPE in every case. For EPR, carbonyl formation was coincident with the decline in elongation. For most cable insulating materials, the carbonyl peak may be detected in advance of embrittlement [5.46].

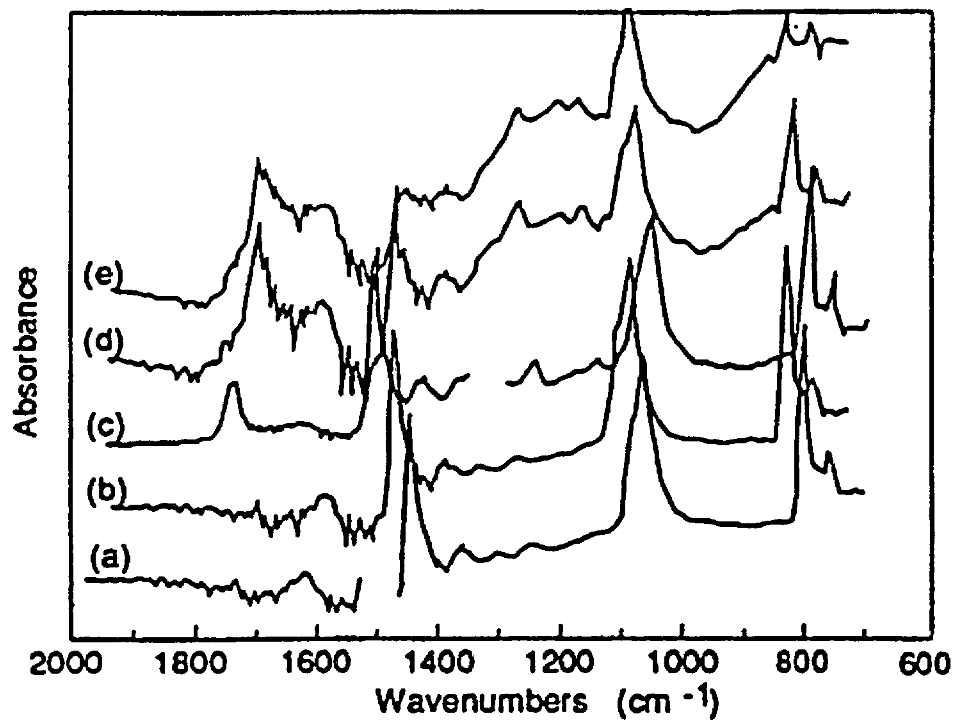

Figure 5-9 FTIR Spectra of Filled XLPE Insulations for (a) unaged material, and thermally aged at 130°C [266°F] (b) for 99 days, (c) for 235 days, (d) for 330 days, and (e) for 425 days (Courtesy of Ontario Hydro)

Advantages/Disadvantages

Some limitations are present for FTIR spectroscopy, including the relatively expensive, complex test apparatus and the requirement for prepared samples; hence this technique is currently suited for laboratory measurements, but not measurement of installed cables. Note also that FTIR spectra are highly material specific, thereby often requiring significant interpretation. Results may also be applicable only to the localized area from which the specimen was drawn. In addition, the appropriate test methodology and mode (i.e., transmittance, reflectance, etc.) largely depends on the type of material being tested and the information sought (e.g., antioxidant type/concentration versus level of aging/depletion).

Implementation

ASTM Standard D2140 [5.96] provides guidance on performance of FTIR spectroscopy on some materials. As previously indicated, the test methodology is highly material specific. No other relevant standards were identified in the literature.

UV Spectroscopy

UV (ultraviolet) spectroscopy uses UV radiation for the detection of phenyl groups of antioxidants in non-crosslinked HMWPE. This technique is similar in principle to infrared spectroscopy, but addresses different polymer chemical constituents, due to differences in the wavelength of the incident radiation [5.97]. See the previous discussion of the FTIR technique. ASTM Standards E275 [5.98], D1416 [5.99], and E169 [5.100] provide information on UV spectroscopy.

Gel Content

General Description

When a polymer is dissolved[14] in a solvent, the amount of polymer that is nonsoluble is referred to as the gel content. The weight of solvent picked up by the gel at equilibrium determines the weight swelling ratio. Laboratory measurements of gel content and swelling ratio can give an indication of whether a polymer has undergone scission or crosslinking reactions. In general, when a polymer undergoes crosslinking, the gel content increases and the swelling ratio decreases. Chain scission causes the opposite effects. In a non-crosslinked polymer, solubility decreases as crosslinking increases. The solvents xylene and toluene are commonly used for measuring solubility for XLPE and EPR, and SBR and butyl rubber, respectively.

For some XLPEs and EPRs, gel content and swell ratio remain relatively constant until just before material embrittlement; however, this behavior appears to be formulation specific. See Figure 5-10 for PVC (left) and butyl rubber (right) materials. PVC exhibits a long induction period of thermal/irradiation aging before becoming insoluble due to crosslinking as indicated by the step increase in the gel content curve. For butyl rubber, the insoluble fraction decreases dramatically as the material undergoes chain scission resulting from thermal aging/irradiation [5.46].

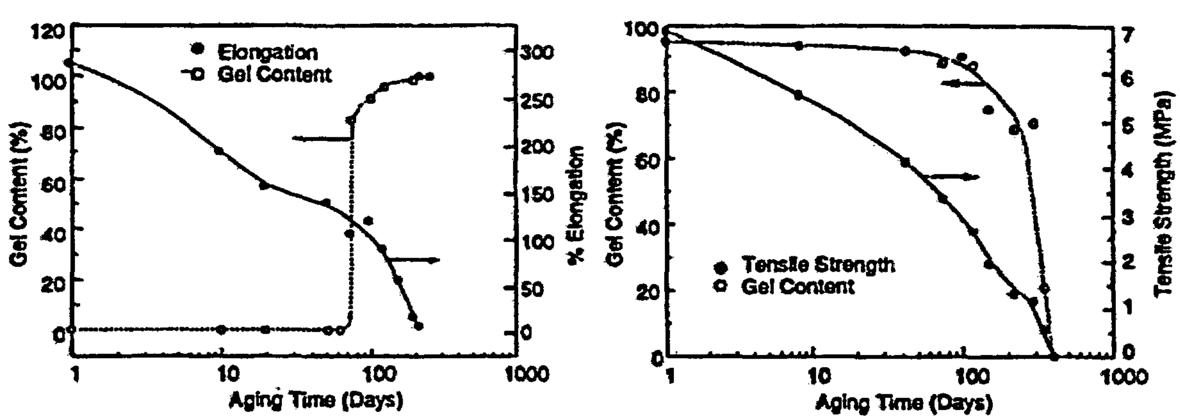

Figure 5-10 Gel Content, Elongation, and Tensile Strength vs. Aging at 120°C [248°F] for PVC and Butyl Rubber (Courtesy of Ontario Hydro)

[14] The term "extracted" is used to describe a situation where a polymer is dissolved in a solvent.

Advantages/Disadvantages

Samples used for analyzing gel content are significantly larger than those used for OIT testing (typically on the order of a few grams versus ~10 mg for OIT). This is still a relatively small amount of material and the analysis may be performed without removing large quantities of cable material. However, gel content is highly material specific, with some materials exhibiting little correlation to aging during the initial induction period. By the nature of the sampling procedure, the results are also localized.

Implementation

See ASTM Standard D2765 [5.101] for guidance on performing gel content and swelling ratio analyses.

Plasticizer Content

General Description

Plasticizers are organic liquids or solids added to hard or tough resins to impart flexibility or other desired mechanical qualities [5.102]. Common materials most likely to contain plasticizers include PVC and CSPE; whereas PE, EPR/EPDM, and SR generally do not contain plasticizers. Plasticizer content is a measure of the remaining fraction of plasticizer within cable and termination materialsand is determined using a chemical extraction process. During the early stages of aging, plasticizer content tends to decrease fairly rapidly and is related to elongation-at-break. At later stages, plasticizer content is relatively stable while elongation continues to decrease (Figure 5-11). Degradation in the earlier stages appears to be controlled by plasticizer content, whereas in the later stages, it seems to be controlled by oxidation and other aging processes. It may be inferred that a minimum plasticizer content is required to prevent embrittlement of PVC, and that the volatility of the plasticizer governs PVC's overall longevity (Figure 5-11) [5.103]. No relationship between plasticizer content and radiation aging has been identified for PVC [5.46]. No data pertaining to plasticizer content as a function of aging for other materials were identified in the literature.

Advantages/Disadvantages

As with all sampling methods, analysis of plasticizer content indicates the aging of only a localized portion of the component from which the sample was drawn. Measurements require only a small sample of the material under analysis.

Implementation

See ASTM Standard D2765 [5.101].

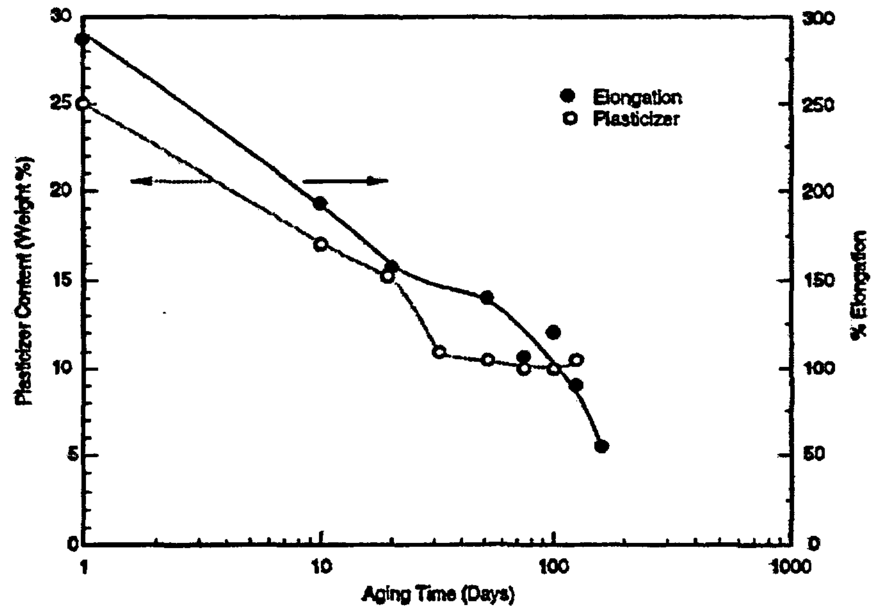

Figure 5-11 Plasticizer Content and Elongation vs. Aging at 120°C [248°F] for PVC (Courtesy of Ontario Hydro)

Electron Spin and Nuclear Magnetic Resonance

General Description

Electron spin resonance (ESR) provides information about the structure and concentration of free radicals in polymers based on the magnetic alignment of free (unpaired) electrons in these materials. Energy in the form of microwaves (at the resonant frequency for the free radical of concern) is applied in a direction perpendicular to an applied magnetic field, the strength of which is varied. At certain levels of magnetic field intensity, the microwave energy will be absorbed by the specimen and an absorption peak will result. The concentration of a given radical is proportional to the amount of incident energy absorbed. Because the concentration of certain radicals may vary as a function of aging of the material, the aging of the material can be tracked based on the concentrations of radicals detected. ESR is somewhat similar in application to FTIR described previously, because the absorbance maximum is related to the concentration of a given radical (i.e., the intensity of the absorbance peak will vary with aging).

Nuclear magnetic resonance (NMR) spectroscopy is a technique which records transitions between the energy levels of magnetic nuclei in an external magnetic field. NMR spectroscopy involves absorption of the energy of electromagnetic radiation in the radio-frequency region by a sample placed in an external magnetic field. NMR is more widely used as a method for determining the chemical structure of organic compounds [5.95]. It has historically been evaluated for use in the characterization of the water-polymer reaction occurring during water tree growth in polyethylene insulations; however, its sensitivity and usefulness in this application appears low [5.97].

Advantages/Disadvantages

Both NMR and ESR are laboratory techniques that require a specimen of material for analysis; thus, neither are suitable for *in situ* testing. The test equipment is comparatively sophisticated, costly, and requires significant operator training and skill. Furthermore, interpretation of ESR and NMR data is not always obvious. Subtle variations in the chemical composition of a material with aging may not be immediately detectable using these techniques. The response spectra for different materials are often highly specific as well. Therefore, from a practical standpoint, these techniques have limited use in evaluating the aging of polymers in nuclear plant cables and terminations.

Implementation

NMR and ESR laboratory testing equipment is currently available from commercial suppliers. ASTM E386 [5.104] and D5292 [5.105] provide some guidance on NMR spectroscopy. ASTM E1607 [5.106] provides information on ESR spectroscopy.

5.2.2.2 Condition Monitoring, Testing, and Troubleshooting Techniques Under Development

Numerous maintenance, testing, and condition monitoring techniques for electrical cable and terminations have been explored and evaluated in recent years. In addition to the methods described in the preceding section of this AMG, five other techniques are currently under investigation and/or development to determine how accurately they characterize cable and circuit component aging. These include:

- Ionized gas
- Time domain spectroscopy
- Near infrared reflectance (NIR)
- Sonic velocity
- Torque tester.

Ionized Gas

General Description

Ionized gas testing results from the desire to develop a nondestructive electrical means of testing unshielded cable (i.e., most of the low-voltage cable used in nuclear plants). The basic principle of this technique is based on injecting an easily ionizable gas into the conduit surrounding a cable. The ionized gas moves the ground plane closer to the surface of the cable which makes breakdowns in the cable dielectric easier to detect.

For cable located within conduit, one technique for developing a ground plane at the surface of the insulation is to fill the conduits with water and perform a high potential test between each of the conductors and the water. However, filling conduits with water is problematic in that conduits are not tightly sealed and water can leak onto surrounding energized electrical equipment, causing the potential for fault or flashover. Removal of the water at the end of the test is also difficult, and definitions of acceptable test voltages are not available for such testing.

To provide an alternative to the use of water as the ground plane and to determine acceptable test voltages, the use of ionizable gas for providing in-conduit ground planes during high-potential testing is being developed as are acceptance criteria based on as-low-as-possible test voltages. Although the cables are called low-voltage cables with 600- to 1000-Vac ratings, the thicknesses of the insulation are capable of withstanding very high voltages. Data from the program indicate that 30-mil-thick insulation can withstand voltages on the order of 22 to 26 kVac, which is much higher than the manufacturing proof tests, and much higher than desirable for in-plant testing. High-potential tests are go/no-go in nature. If the insulation successfully withstands the test voltage, a statement can be made that at least the amount of insulation thickness associated with the test voltage acceptance criteria remains in place (i.e., even though one cannot state that no damage has taken place, an indication of the minimum possible remaining wall can be made). Similarly, if a large enough number of plant circuits are tested without failure, the absence of gross installation damage may be inferred.

Advantages/Disadvantages

Research has determined that high-potential testing of cables in ionized helium yields high-potential test results similar to those when the ground plane is provided by water, as described in EPRI TR-104025 [5.107] (see Figure 5-12). In the associated tests, specimens of cable with a 30-mil insulation thickness with varying depths of insulation damage from 0 to 30 mils were tested to breakdown. The tests showed a significant reduction in breakdown voltage between testing with conduit filled with air and the conduit filled with water. Argon has shown a reduction in breakdown voltage of roughly a factor of 3 over air [5.108]. When testing in air, identification of complete through-wall damage required nearly 14 kVac, whereas only 1 to 2 kVac were required with water and helium. The slight difference in results with water and helium is predominantly related to the voltage at which the helium ionizes. Once the helium ionizes, the stress across the insulation under test increases significantly with most of the test voltage across the insulation under test. The research to date has shown the method to be viable and not to be destructive to cables surrounding the cable under test. In addition, dilution of the helium rapidly decreases its ability to ionize; therefore, if helium escapes from the conduits under test, there will be no possibility of causing flashovers in surrounding electrical equipment that uses air as an insulation medium (e.g., circuit breakers and switches).

Limitations associated with this technique include the ability to test cables in conduit or sealed raceways only, the cost and difficulty in filling the raceway with inert gas, and the relative difficulty in interpreting the results. Furthermore, no correlation with test results to the level of thermal/radiation aging has been demonstrated.

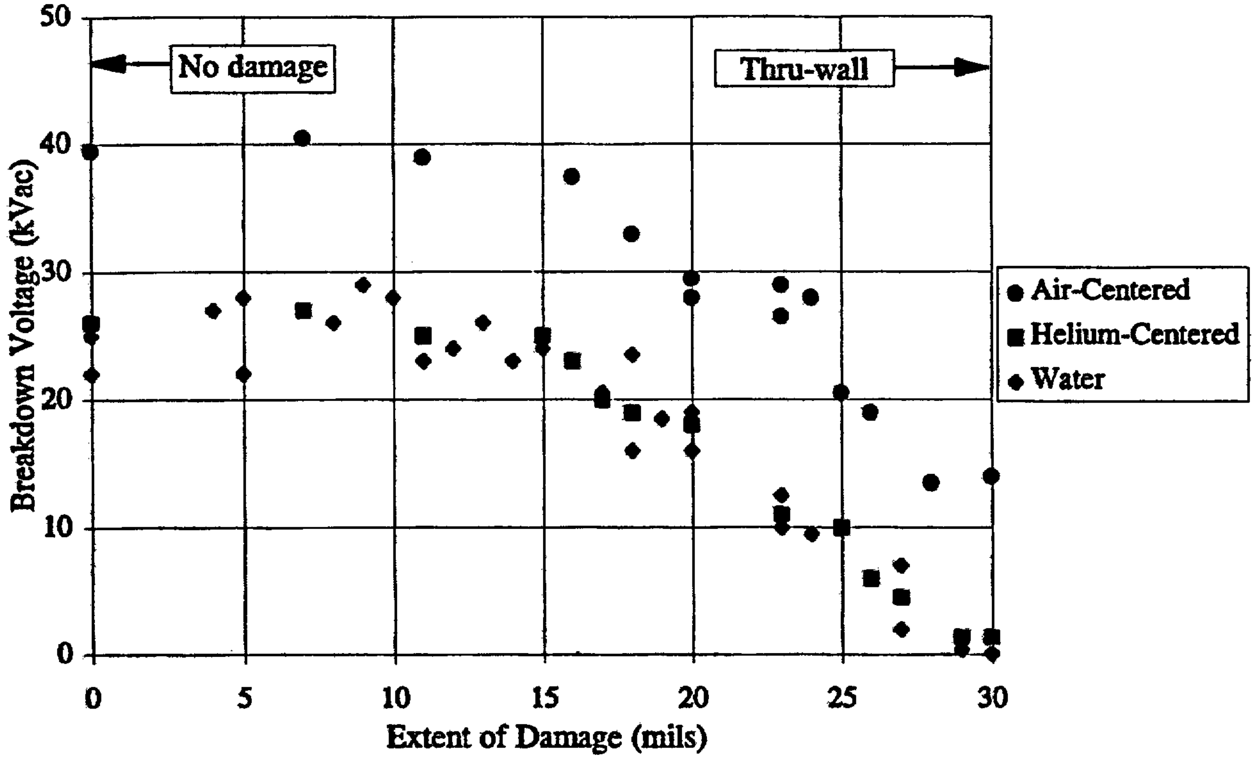

Figure 5-12 Breakdown Voltage versus Insulation Damage in Various Media (Courtesy EPRI/Sandia National Laboratories)

Implementation

A test methodology is currently available for in-plant tests; however, to date, no such testing has been performed at a plant, and further development of the process is under way [5.107], [5.108], [5.109].

Time-Domain Spectroscopy

General Description

Time-domain spectroscopy (TDS) is a nondestructive technique that measures the dissipation factor (tan delta) as a function of frequency; it determines the frequency spectrum of the dielectric loss of a material from its time domain behavior upon various voltage excitations. Under prolonged exposure to a power plant environment, polymers in cable insulation undergo oxidation. As a result of these chemical changes, free radicals (ions) are released and polar molecules formed. The tan delta spectrum of these aged materials is expected to vary (increase) as the frequency falls below approximately 1 Hz (see Figure 5-13). Alternating current (AC) excitation voltage results in changes in the orientation of the polarized molecules, which lags the application of the electric field. This results in a permittivity with both complex and real components, and the energy required to reorient the dipoles/charges becomes a function of frequency. The energy expended is defined as the dielectric loss, or tan delta [5.110], [5.111], [5.112].

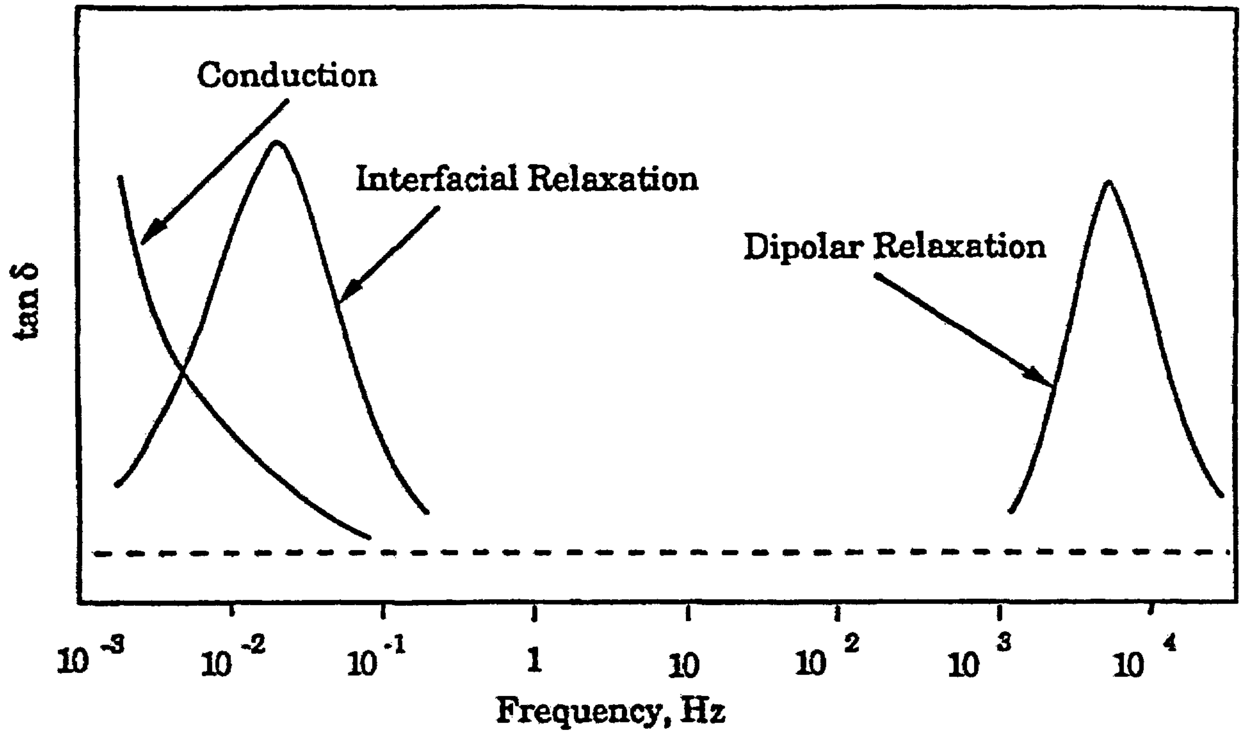

Figure 5-13 Dissipation Factor (Tan Delta) versus Frequency for Typical Cable Insulation

The time-domain current signature is converted to the frequency domain in order to determine the frequency spectrum. The technique is not concerned with particular features along the cable, but rather with the insulation as a whole. It is anticipated that environmentally induced changes in the cable insulation would alter the relaxation of the material; these changes may be useful in determining future problems with the insulation, such as embrittlement. The changes are considered to be highly material specific, and would need to be determined on a case-by-case basis.

One study indicates that after thermal aging of cable insulating systems containing EPR and EPDM compounds (resulting in embrittlement/reduced elongation), TDS spectra showed systematic changes at the low frequency end of the spectrum and occasionally in the 3- to 6-Hz range. Aging in oil or wet environments produced more significant changes in TDS than in elongation. The electrical properties of the cable materials are probably affected to a greater extent than the corresponding mechanical properties when aging is conducted under these conditions [5.110]. Another study showed promising laboratory results in that both low- and high-frequency tan delta varied significantly between wet- and dry-aged EPDM/CSPE specimens [5.26].

Advantages/Disadvantages

Limitations of TDS for installed cables include the capability of the system to measure only an "average" of the insulation, the requirement for a shield (ground reference) to avoid significant environmental interference, and the need to perform the test with the end devices disconnected. In addition, cable length will limit the maximum frequency that can be attained [5.113]. However, with further development, this technique could prove useful in evaluating not only thermally aged and embrittled cable, but also cable aged in a moist or wet environment.

Implementation

A prototype of a portable field test instrument has been produced. However, as of this writing, the device has undergone only limited laboratory testing [5.110], [5.111], [5.112].

Near-Infrared Reflectance (NIR)

General Description

Near-infrared reflectance (NIR) uses near-infrared radiation in an attempt to track the aging of organic cable materials. Strong NIR absorbers are formed as cable insulation and jacket polymers age. NIR radiation impinging upon the cable material provides a transmittance spectrum; this spectrum is converted to an absorption spectrum (first derivative) to eliminate baseline shift. Major absorption spectrum features seen in the NIR region result from combinations/overtones of fundamental vibrations in the mid-IR region. Changes in molecular side groups can give better insight into changes in material physical properties than variations seen in the mid-IR. The concentration of these groups increases with aging [5.74].

Results on actual specimens from one program indicate that NIR can indicate the extent of PVC jacket aging with relative accuracy [5.74].

Advantages/Disadvantages

Many of the limitations associated with FTIR analysis described previously also apply to NIR. However, portable NIR equipment for in-situ measurement is considered feasible [5.74]. For NIR to be effective, a set of well-characterized calibration samples whose aging is precisely known must be used. During experimentation, various regions of the NIR spectrum were found to correlate well with aging of some materials. The decrease in the derivative of absorbance correlates with observed decreases in elongation with aging. Regression analysis of the derivative and aging time provides a slope and intercept of the calibration curve.

Implementation

Near-infrared reflectance equipment is commercially available [5.74]. Reference [5.114] provides additional guidance on the use of NIR for polymer characterization.

Sonic Velocity

General Description

Changes in density occur in various polymers (especially PVC) as they age. The velocity of sound through a polymer is related to both its density and modulus. Sonic velocity is a means of detecting polymer aging through variations in the propagation velocity of sound; this technique uses an acoustic signal to measure the velocity of propagation through cable materials and thus to estimate their aging.

Advantages/Disadvantages

Experimental data show that sonic velocity techniques are capable of detecting small changes in density, thereby indicating some degree of sensitivity to aging (Figure 5-14). Testing has been performed on samples of various cable materials, and results appear to correlate well with corresponding values of elongation, jacket density, and elastic modulus. Sonic velocity curves obtained for jacket formulations displayed a similar result (a rapid initial increase in velocity as jacket aging increased). Variations within specimens of the same general material (PVC) were attributed to differences in chemical formulation rather than construction or geometry. However, the correlation between changes in sonic velocity and density, and aging appears to depend on the type of cable tested. One implication of this observation is that a separate curve must be developed for each different cable or jacket type; accordingly, this technique may be better suited to condition monitoring (i.e., periodic monitoring of same cable) rather than use as a quantitative measurement of cable material aging [5.74].

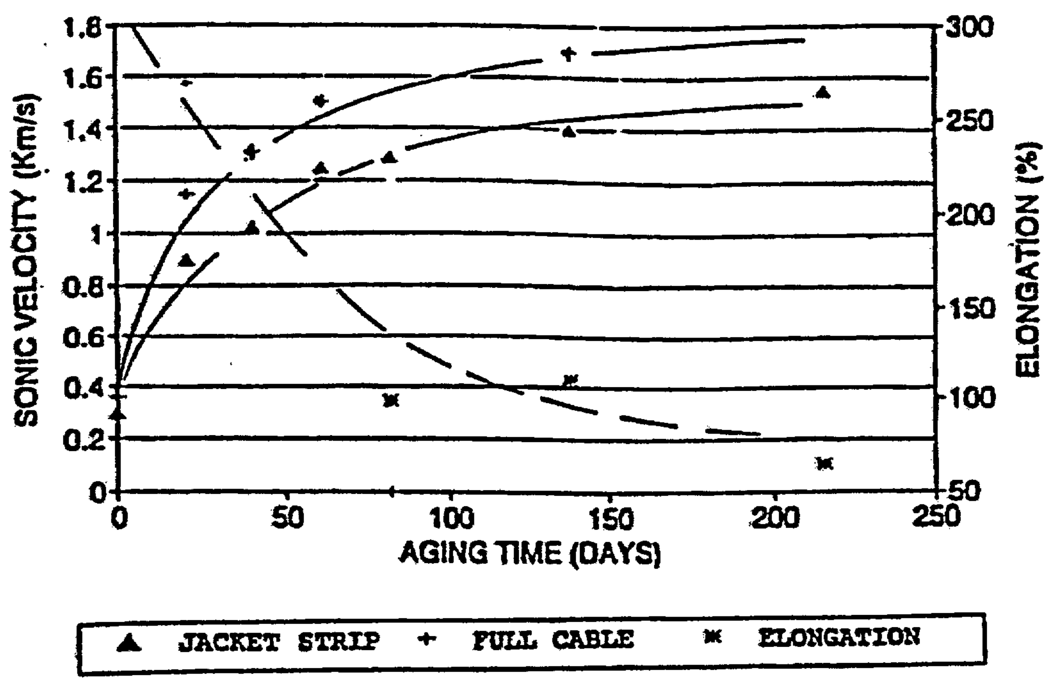

Figure 5-14 Sonic Velocity versus Thermal Aging for XLPE/PVC Medium-Voltage Cable (Courtesy of Ontario Hydro)

Implementation

Equipment for measuring sonic velocity is currently available (see, for example, Reference [5.74], which describes use of a commercial dynamic modulus tester and oscilloscope for performing sonic velocity measurements).

Torque Tester

General Description

The torque tester is a mechanism that imparts a torsional stress to cable insulation and/or jacketing to estimate aging. The magnitude of this stress for a given torsional displacement can be related to the age of the cable. The torque tester is similar in concept to other devices that correlate mechanical properties such as elongation-at-break to aging of cable materials and electrical performance. This device is undergoing development in Japan.

Advantages/Disadvantages

Since the torque tester measures mechanical properties of the outer jacket or insulation, it is expected to have attributes comparable to those of similar mechanical techniques (such as compressive modulus); however, this has not been substantiated.

Implementation

A prototype test instrument has been produced. However, as of this writing, the device has undergone only limited laboratory testing [5.115].

5.2.2.3 Natural Versus Artificial Aging Programs

In an attempt to more completely understand the long-term aging behavior and performance of electrical components (including cables and terminations), investigation into the relationship between natural aging and artificial aging is continuing. Under high acceleration factor aging programs (such as those performed during environmental qualification), components are normally thermally aged and irradiated within the space of a few weeks or months, often at acceleration factors of 1000 or more, to simulate long-term exposures (e.g., 40 years). A commonly held view is that such methodology results in conservative life estimates (see, for example, Appendix 2 of Reference [5.10]). One potential problem with this approach is the possibility that such accelerated aging is not completely representative of the aging that would occur under actual plant conditions (i.e., aging effects or mechanisms that may be present under highly accelerated conditions may not be present under natural aging conditions, and vice versa). Hence, the accuracy or applicability of the results obtained by highly accelerated aging may be somewhat compromised in return for obtaining the information in a compressed time frame.

At the other end of the aging spectrum is condition monitoring and assessment of naturally aged specimens, which proceeds under nonaccelerated conditions. Under this approach, the components are permitted to age naturally (i.e., as they would under normal operating environments), and their condition is monitored periodically to determine the types and magnitude of degradation. The advantage of this approach is that it is completely representative of aging under actual plant conditions; however, for components located in relatively benign environments, the end result is not obtained until significant time (several decades) has elapsed. Plants implementing periodic condition monitoring and assessment will therefore have little predictive capability with respect to their cable systems.

Accordingly, "low acceleration factor" aging programs attempt to bridge the two ends of the spectrum by placing cable specimens and other components in plant environments resulting in aging acceleration factors on the order of 5 to 10 times that of normal plant ambient conditions, thereby producing results within a reasonable period of time (roughly 5 to 10 years). The acceleration factors in these programs are considered low enough so that any effects associated with highly accelerated aging are minimized, thereby (in theory) providing useful results before the end of the plant lifetime. This concept has substantial implications for the evaluation of cable and termination longevity, because it may provide plant operators with information useful in accurately predicting the long-term behavior of their cables. In instances where highly accelerated aging has generated an extremely conservative result (i.e., a useful lifetime much shorter than the actual lifetime under a given set of plant conditions), plant operators may be able to use such information to adjust their monitoring and/or replacement intervals, thereby resulting in reduced cost and effort over time.

Programs of this type are currently under way both domestically and abroad. Several such programs are more completely described in References [5.75] and [5.116], and in Section 5.2.2.4.

5.2.2.4 Cable Aging Research Programs

EPRI Cable Aging Research Program

The EPRI Cable Aging Research Program was instituted to provide data and methodology for use by utilities in resolving cable-related problems and in making appropriate decisions concerning testing, continued use, and replacement of cables. Findings from this program may also be useful in responding to increased regulatory interest related to issues such as synergisms and dose rate effects as the industry's cable systems grow older.

The EPRI Cable Aging Research projects under way or planned consist of the following; existing EPRI reports are noted where applicable:

1. Artificial versus Natural Aging Program, EPRI NP-4997 [5.75]
2. In-plant Trials and Development of Indenter Polymer Aging Monitor, EPRI TR-104075 [5.22]
3. Cable Diagnostics Matrix
4. Detection of Localized Cable Damage Using Pre-ionized Gas, High Potential Testing, EPRI TR-101273 [5.108] and EPRI TR-104025 [5.107]
5. Oxidation Induction Time Methodology Development

6. Cable Life Database
7. Improved Conventional Testing of Power Plant Cables, EPRI TR-105581 [5.103]

Appendix J of this report discusses these projects in greater detail.

NRC EQ Task Action Plan (TAP)

In mid-1993, the U.S. NRC Office of Nuclear Reactor Regulation (NRR) initiated an EQ task action plan (EQ TAP) which sets forth specific activities of the Office of Nuclear Regulatory Research (RES) and NRR relating to the qualification of electrical components. Potential safety issues addressed by the EQ TAP include equipment preaging techniques, conservatisms in the qualification process, variations in cable manufacturing, effects of operating conditions/environments, and condition monitoring methods. One of the primary focal points of this effort relates to low-voltage cables.[15] Reference [5.117] discusses the status of the EQ TAP as of October 1995.

Specific activities under the EQ TAP include a programmatic review of environmental qualification, data collection and analysis, research on condition monitoring techniques and aging methods, an assessment of the risk associated with EQ equipment, and meetings with various industry representatives and experts. A NRC-sponsored workshop [5.118] was held in late 1993 to assist in focusing the cable research program; one of the major conclusions being that significant research and testing had already been performed in this area, and such work should be reviewed prior to continuing. Accordingly, a literature review was initiated to consolidate and assess existing information, and identify those issues (if any) which could be resolved based on past or ongoing work. NUREG/CR-6384 [5.119] and earlier papers [5.120] discuss the results of the literature review conducted by Brookhaven National Laboratories. These results indicate that several topics are at present unresolved and warrant additional research, including: (1) natural aging versus artificial aging, (2) the effects of environment and installed cable configuration, (3) the effects of cable construction on longevity (including the bonded jacket issue), and (4) the effectiveness of various condition monitoring techniques (including FTIR, OIT, Indenter, TDR, IR thermography, insulation resistance, ac impedance, and visual/physical inspection).

JAERI Cable Aging Research Program

The cable aging program conducted by JAERI (Japan Atomic Energy Research Institute) has three primary components; (1) life prediction of cables installed in operating nuclear plant environments, (2) detection of cable degradation using non-destructive means, and (3) aging database compilation.

As part of the life prediction effort, various types of cables were aged in a simultaneous thermal/radiation/oxygen environment, and analyzed to determine the effects of acceleration factor and various combinations of aging stressors. JAERI research in this area is nearing completion.

[15] These cables were selected since they are not routinely replaced, and may adversely impact plant safety through loss of intended function.

Additionally, various methods of non-destructive evaluation are being considered, including the torque tester (see Section 5.2.2.2), and thermal decomposition (OIT). Results indicate that each of the methods are useful for some cable types tested, but no method is universally applicable. This portion of the program is scheduled for completion in 1998.

Finally, cable aging and degradation data obtained from JAERI, cable manufacturers, and universities within Japan will eventually be evaluated and summarized in a database. Completion date of this project is unknown [5.121].

5.2.3 Surveillance or Other In-Service Testing

Surveillance testing is defined as the "observation or measurement of condition or functional indicators to verify that an SSC can function within acceptance criteria" [5.122]. Surveillance testing of cable systems is rarely if ever performed; however, surveillances (operation) of connected loads are frequently performed. Testing of cable systems is generally limited to troubleshooting or problem localization.[16] Hi-pot and insulation resistance testing are methods typically used by plant operators to confirm or localize suspected or known problems; however, these tests may not detect insulation damage or other circuit degradation prior to severe deterioration, thereby limiting their effectiveness for condition monitoring. For low-voltage cables, even a small thickness of undamaged insulation may provide sufficient dielectric strength to prevent detection of degradation by these tests [5.26]. Also, repeated hi-pot testing may have deleterious effects on insulation integrity, and the test voltages required for the cable insulation may greatly exceed those allowable for connected loads, thereby requiring disconnection of the load.

Despite these considerations, some plant operators do periodically test some or all of their medium-voltage (5 kV) circuits. One such program identified uses 25 kV dc hi-pot and 5 kV ac power factor testing of safety-related, non-safety related, and important to operations cables. Lower voltages are employed when end devices are not disconnected to stay within the manufacturer's ratings for the end device. Cable testing is generally performed at intervals of every two or three refueling outages on a rotating basis, and encompasses a large percentage of the 5 kV cables installed. The testing schedules may be modified based on maintenance or other plant activities.

5.2.4 Preventive and Corrective Maintenance

Cleaning

Because the low overall failure rate of cable system components due to dirt and contaminants does not justify the burden of routine and periodic "preventive" cleaning, none is typically performed. Cleaning of cable and termination components is usually limited to that performed concurrent with other maintenance or testing or in response to indications of anomalous behavior or failure. As indicated in Section 4, dirt and contaminants will have little effect on the longevity of the bulk of the cable and termination population; however, in certain

[16] With the exception of periodic hi-pot testing of connected loads via the load center (and cable) at comparatively low voltages.

cases, the their presence may reduce the longevity of certain components (such as terminal blocks exposed to wetting and voltage stress, which may develop surface tracking paths). In addition, contact surfaces used in high-sensitivity low-impedance circuits such as neutron detecting system connectors may oxidize; periodic cleaning of these surfaces is one of the most effective ways of preventing oxidation from affecting circuit operation.

Repair

Cables and terminations are repaired in those instances where the aging or degradation of the cable is such that its functionality may be restored without total replacement. For cables, repair is usually limited to splicing in new sections of cable and/or retermination. For example, a cable end that has been heat damaged by exposure to a process device may be cut back a short distance from the end device, and a junction box installed at a convenient location. This precludes having to replace the entire run of cable from its source. For terminations, repair may take the form of subcomponent replacement (for example, replacement of O-ring seals in leak-tight connectors) or retaping of taped splice insulation. However, in most cases, the entire defective component assembly is replaced to minimize the possibility of future problems, especially if the stressors affecting the degraded subcomponent may also affect other subcomponents.

Some plant operators advocate repair of failed segments of medium-voltage power cable (via removal of the failed segment and splicing of a new segment) based on the idea that those sections that have not failed during operation are now proven to be somewhat more reliable than the newer "untested" cable. No data as to the validity or effectiveness of this approach were located in the literature. See, however, Section 4.1.2.7 of this guideline, regarding the effects of dc testing on specimens that contained a new section of cable, a splice, and an aged section of cable.

Replacement

In general, no preventive replacement of cable system components occurs with the exception of environmentally qualified components that are approaching the end of their qualified lives.[17] However, in instances where the continued longevity of the cable or termination is in question, it will usually be replaced. This is especially true in situations such as maintenance or refueling outages, where the replacement of the component may only be practical during a limited time frame, and failure of the component may have a significant impact on plant operations and/or safety. Another factor weighing in the replacement decision is cost; replacement of circuit components (especially long runs of cable located in conduit) is often extremely expensive and time-consuming. See Reference [5.123], which discusses the cost effectiveness of preserving the qualification of selected EQ components (including cables and termination) compared with replacement or refurbishment for one nuclear plant.

It should be noted that components that are replaced at periods of less than 40 years are exempt from the aging management review requirements of 10CFR54. Similarly, components

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[17] Environmentally qualified components are managed under a separate plant program pursuant to 10CFR50.49.

that are routinely replaced through periodic or planned maintenance may be eliminated from an aging assessment (as described in IEEE Standard 1205 [5.2]) so long as the replacement interval is short enough to ensure no loss of functionality due to aging.

5.2.5 Temperature and Radiation Monitoring

Infrared Thermography

All materials radiate infrared energy. The hotter the component, the more energy radiated. Infrared thermography is a nondestructive maintenance and surveillance technique used to detect and evaluate component heating. Infrared detectors can sense infrared radiant energy and produce electrical signals proportional to the temperature of the targeted component. Thermography is not a condition monitoring technique itself; rather, it can be used to identify and describe thermal aging *influences* on cable systems. The instruments use optics to gather and focus energy from the targets onto infrared detectors. Infrared detectors are available in two basic types, namely, spot measuring and scanning, and have sensitivities on the order of ±0.1°C (±0.2°F) with rapid response times. Reference [5.124] provides a detailed description of the systems.

Due to the large amounts of cable (linear footage) in the average power plant circuit, 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 in that exposed cable runs or components with elevated temperatures can be readily compared with surrounding components and sections of the system. If thermographic scans had been performed, then comparisons could be made and variations in thermal images could be evaluated to determine if these hotter areas are developing or changing. In cable runs, abnormally hot electrical connections and terminations could be indicative of problems in the conductor coupling. For example, an excessively hot splice might indicate a high resistance connection. The overheating could degrade the surrounding organic materials and cause eventual electrical failure. Identifying such high-temperature components could allow correction of the condition before significant degradation occurred. At a minimum, more frequent observation of the suspect component could be performed to determine if the condition was stable or worsening.

Environmental Monitoring

Environmental monitoring is a general term for methods by which nuclear plant operators may more accurately characterize the environment(s) in which their cable systems operate. The aging of cable and termination components is related to the thermal, radiation, mechanical, electrical, and chemical environment in which they operate. Although the operating environments for many circuits cannot be significantly altered to reduce thermal or radiolytic degradation,[18] more complete understanding of these environments may be useful for extending the lives of both environmentally qualified and nonqualified cables and their associated terminations. In the environmental qualification context, assumptions made regarding the service

[18] Some cables may be rerouted or shielded to minimize localized thermal effects; however, this is not applicable to most plant cable.

environment of cable system components may be overly conservative or not representative of actual thermal or radiation exposure. By more accurately characterizing the exposure of bulk cable systems in various plant areas (especially those where heat or radiation exposure currently limit the qualified life of these components), increases in qualified life may be realized. This technique may also have applicability to nonqualified applications, in that estimates of cable and termination longevity based on thermal or integrated radiation dose analyses may vary significantly with use of actual versus estimated temperature or radiation exposure data.

Appendix G discusses use of a degradation-weighted average temperature technique to more accurately characterize thermal environments for environmentally qualified components. Note, however, that use of the equivalent degradation weighted temperature will always predict less degradation than that by use of maximum temperature. Hence, use of the degradation-weighted methodology should be considered when evaluating thermal degradation of cable system components, since (1) use of an arithmetic average may be non-conservative, and (2) additional life may be predicted in those applications whose existing degradation predictions are based on maximum temperature.

Current methods used in monitoring plant environments include real-time data collection, use of passive monitoring devices and data loggers, and extrapolation of known environments to other plant locations. Real-time systems involve the use of portable or installed instrumentation that directly indicates the parameter being measured (such as a thermocouple or area radiation monitor). Passive devices, such as film dosimeters and lifetime monitors, are installed in various areas of the plant for a predetermined period to estimate the integrated exposure at that location. Data or bit loggers are similar; however, these devices generally record information historically (e.g., as a function of time), and are periodically removed and their information downloaded for analysis. Extrapolation involves the modeling of environments in areas that are not well characterized or instrumented using data from other plant areas and factors such as equipment heat loading, heating, ventilating and air conditioning (HVAC) system performance, heat flux through walls and floors, and meteorological conditions. Note that these methods may be employed in parallel to provide a more comprehensive description of plant environmental conditions than is possible with one method alone. Reference [5.125] discusses environmental monitoring in detail, including programs employed by various utilities. IEEE Standard 1205-1993, Annex B [5.2] provides additional guidance on this topic.

Determination of Circuit Loading and Operating Time

In addition to environmental monitoring, determination of circuit loading can be important to the evaluation of cable system longevity. Thermal degradation of installed cable and terminations may result from either environmental conditions (i.e., those external to the equipment) or ohmic heating. Temperature rise due to ohmic heating of the conductor should be considered in those instances where the effect on insulation or jacket aging is appreciable. For most plant cables (both low- and medium-voltage), ohmic heating is of little concern. Cables used in nonsafety-related circuits tend to run warmer than those used in safety-related circuits (due to their increased use and often higher loading); however, conservatisms included during the design of these cables adequately account for such conditions. For both safety-related and nonsafety-related circuits, a quick evaluation can be performed for specific insulation and jacket materials to confirm that ohmic heating is not a concern. See Appendix G for additional information.

Initially, low- or medium-voltage power loads operated for substantial fractions of the installed cable life and high ampacity circuits should be considered for further evaluation. Those loads that are operated continuously or near continuously may be readily identified through understanding of plant operations, examination of plant operating or run-time logs, and discussions with plant personnel responsible for the operation of the equipment. High ampacity circuits can be identified from cable loading calculations and tabulations. Infrared thermography could be used to identify "hot" cables and confirm that the appropriate cables were identified by the screening processes described above.

Other circuits installed in the same tray, conduit, or duct bank as the heavily loaded cable(s) should also be evaluated because these may suffer premature thermal aging as well. Ampacities specified for power cable (such as those in the National Electrical Code [5.126]) are derated based on the number of conductors installed, the type of raceway, and the separation maintained between cables (see, for example, ICEA P-54-440 [5.127] for cable in open-top trays, and "grouping factors" described in Reference [5.128]). However, because the derating merely ensures acceptable conductor temperature in relation to the thermal rating of the insulation, premature thermal aging similar to that experienced by the heavily loaded conductors may in theory occur for both the heavily loaded cable(s) and those in the same raceway, regardless of the latter's operating current.

Another consideration for nuclear plant cable systems relates to the use of fire barrier material. Based on 10CFR50, Appendix R requirements, portions of certain plant circuits/raceways are wrapped or encased in fireproof materials (the most notable variety being "Thermo-Lag 330") [5.129]. These materials act as thermal insulators for the circuits they surround, thereby reducing the rate of heat dissipation from an enclosed cable. Accordingly, the maximum allowed conductor temperature will be reached at a lower current (for the same size conductor), and the ampacity of these installations must be reduced. An ampacity derating factor for each fireproofed configuration (e.g., horizontal cable tray, vertical conduit) is therefore specified by the manufacturer or calculated. Note that in some cases the need for fire barriers was included in the cable design and selection process, whereas in others the need for a fire barrier may have been identified well after cable installation. A fireproofed raceway segment can be evaluated for potential thermal aging concerns through use of the ampacity formulas described in Appendix G and knowledge of the load current at which the circuit in question operates.

Load center and transformer feeder cables can also be considered for possible ohmic temperature rise effects. This equipment is unique in that it supplies power to a number of loads; feeder cables/terminations usually operate in closer proximity to their rated ampacities for this reason. In general, feeder cables for these load centers/transformers constitute a small fraction of the total plant cable inventory.

It should also be noted that due to high electrical resistance (resulting from poor contact, oxidation, etc.), some power circuit terminations may operate at temperatures well above ambient. Such heating can result in premature aging of organic termination components, as well as cable materials in proximity to the termination. Infrared thermography can be effective at identifying such terminations.

5.2.6 Use of Environmental Qualification Test and Aging Data

In addition to the activities previously described, test and aging data derived from environmental qualification (EQ) programs and manufacturer's testing may be used as an aging management tool. This information has obvious importance for EQ cables and terminations in terms of determining qualified life, and it may be just as readily applied to nonqualified equipment to assist in the evaluation of their lifetime. Use of EQ aging and test data is particularly powerful because many of the cables and terminations used in non-EQ circuits are similar or identical to those used in qualified circuits. In those instances where identical materials are not used in both types of applications, knowledge of the aging behavior of a similar material can be used (with appropriate caution) to infer the behavior of the generic class of material. Although the ultimate endpoint or lifetime criteria may be different for the two classifications of equipment, the data are nonetheless relevant.

Section 4.1 of this guideline presents background information on the use of thermal aging data and the Arrhenius relationship for such evaluations. Furthermore, discussions of radiation threshold and combined aging environments are presented to assist the reader in evaluating materials used in non-EQ cables and terminations for longevity.

5.3 Commonly Used Maintenance, Surveillance, and Condition Monitoring Techniques

Vendor and utility maintenance procedures from a number of sources were reviewed to identify those maintenance and surveillance techniques listed in the preceding section that are commonly used to maintain electrical cables and terminations. In addition, personnel from appropriate maintenance organizations at several nuclear plants were contacted for further insight on maintenance practices employed for each class of equipment. Industry sources and reports were also reviewed for applicable data and information. Based on this review, the following cable maintenance and troubleshooting techniques were identified as currently in common use:

- Measurement of insulation resistance (IR)
- AC and DC high potential-testing (hi-pot)
- Measurement of capacitance, inductance, and polarization index
- Visual observation of cable and terminations
- Cleaning of connector contacts at time of associated equipment maintenance.

Low-Voltage Cables and Terminations

Little maintenance or testing of low-voltage cables or terminations is conducted in most nuclear plants. This is due to a number of factors, including their relative reliability, the large number of circuits involved, the lack of practical maintenance attributes (i.e., a cable cannot be "disassembled and cleaned" as with other equipment), and the relative ineffectiveness of currently available techniques for detecting incipient failure. Maintenance of low-voltage systems is therefore primarily corrective in nature, with repairs and visual inspection only being conducted as required or during maintenance of connected loads or nearby equipment.

Neutron Monitoring Cables and Terminations

As with the low-voltage circuits described above, little maintenance or testing of neutron monitoring systems routinely occurs. Although the functionality of the circuit as a whole is periodically verified, little cable- or termination-specific preventive maintenance is conducted. Many of these circuits are located inside primary containment and in proximity to the reactor vessel, thereby making routine maintenance during operations impractical. However, some neutron monitoring system manufacturers do require periodic IR measurement and evaluation of the detector cable systems, which can be performed from outside primary containment.

Medium-Voltage Cables and Terminations

Reference [5.26] indicates that testing of 4-kV and 13.8-kV (i.e., medium-voltage) cables is commonly performed at three different times: after fabrication and prior to shipping of the cable by the manufacturer, prior to use (post-installation) by the plant operator, and during the service life of the cable. Factory testing typically includes ac and dc hi-pot (at 125 and 300 volts/mil, respectively), partial discharge, and water absorption. Acceptance tests include hi-pot (ac or dc, usually at some fraction of factory test voltage) and insulation resistance (IR). As previously indicated, in-service tests are generally only performed in the event of problems with the circuit. Hi-pot and insulation resistance testing are typically used by plant operators to confirm or localize suspected or known problems; however, these tests may not detect insulation damage or other circuit degradation prior to severe deterioration. One plant operator was found who periodically tests medium-voltage (5-kV) power circuits. Furthermore, many plant operators, although not directly testing the cable itself, will test the end device of a circuit at the switchgear or load center. For example, a motor may be hi-pot tested at levels commensurate with the turn-to-turn voltage of the motor winding, thereby indirectly testing the cable and terminations interposed between the motor winding and the load center. IR and PI tests are also often performed from the applicable load center.

Table 5-6 summarizes the common corrective and preventive maintenance, surveillance, and condition monitoring techniques, currently used by nuclear plant operators to maintain their cable systems, and the intervals at which they are carried out.

Table 5-6 Summary of Stressors, Significant and Observed Aging Mechanisms, and Applicable Maintenance, Surveillance, and CM Techniques

Voltage Category	Component	Subcomponent	Applicable Stressors	Aging Mechanisms	Common Preventive Maintenance, Surveillance, or CM Techniques	Periodicity	Common Corrective Maintenance Techniques	Other Potentially Useful Maintenance or CM Techniques
Low	Cable	Insulation and Jacketing	Heat	Thermal degradation of organics (environmental and ohmic/induced currents); loss of fire retardants	Visual Inspection	Inspection of accessible portions during routine operations or equipment maintenance only	Visual Inspection, IR, Polarization Index, Capacitance; Repair or Replacement as required	Compressive Modulus, OIT, Thermography, Temperature Monitoring, Analysis of Circuit Operation
			Radiation	Radiolysis and photolysis of organics; loss of fire retardants	Visual Inspection	Inspection of accessible portions during routine operations or equipment maintenance only	Visual Inspection, IR, Polarization Index, Capacitance; Repair or Replacement as required	Compressive Modulus, OIT, Radiation Monitoring
			External mechanical stresses	Wear or low-cycle fatigue	Visual Inspection	Inspection of accessible portions during routine operations or equipment maintenance only	Visual Inspection, IR, Polarization Index, Capacitance; Repair or Replacement as required	
	Connector	Contact Surfaces	Electro-chemical stresses	Corrosion and oxidation of metals	Visual Inspection, Cleaning	Inspection/cleaning generally only during maintenance	Visual Inspection, TDR, Capacitance; Repair or Replacement as required	
	Compression Fitting	Lug	Vibration, tensile stress	Deformation and fatigue of metals	Visual Inspection	Generally only during maintenance	Visual Inspection, TDR; Repair or Replacement as required	Thermography for power circuits
Medium	Cable	Insulation	Moisture and voltage stress	Moisture intrusion; water treeing	Visual Inspection; dc hi-pot (withstand, shielded cables only)	Generally only during maintenance	Visual Inspection, IR, Polarization Index, Capacitance, TDR, ac and dc Hi-pot, ac Power Factor; Repair or Replacement as required	
Neutron Detecting	Cable	Insulation	Heat	Thermal degradation of organics (environmental)	Visual Inspection	Inspection of accessible portions during routine operations or equipment maintenance only	Visual Inspection, IR, Polarization Index, Capacitance; Repair or Replacement as required	Compressive Modulus, OIT, Temperature Monitoring
			Radiation	Radiolysis of organics	Visual Inspection	Inspection of accessible portions during routine operations or equipment maintenance only	Visual Inspection, IR, Polarization Index, Capacitance, TDR; Repair or Replacement as required	Compressive Modulus, OIT, Radiation Monitoring
			External mechanical stresses	Wear or low-cycle fatigue	Visual Inspection	Inspection of accessible portions during routine operations or equipment maintenance only	Visual Inspection, IR, Polarization Index, Capacitance, TDR; Repair or Replacement as required	
	Connectors	Contact Surfaces	Electro-chemical stresses	Corrosion and oxidation of metals	Visual Inspection, Cleaning	Inspection/cleaning normally only performed during system maintenance	Visual Inspection, TDR, Capacitance; Repair or Replacement as required	

Industry Testing of Field-Aged or Failed Cables

In addition to the tests discussed above, the cable industry has used the following destructive tests on specimens taken from the field after being in service to characterize aging of cable materials and evaluate failures:

1. Tensile strength and elongation
2. Moisture absorption

    a. Specific inductive capacity (SIC) or dielectric constant
    b. Power factor (PF)
    c. Insulation resistance (IR)

3. ac or dc high voltage test [5.130]

These tests are most often used to analyze installed cables that have failed in order to determine the root cause of failure. Segments of the failed cable are shipped to the manufacturer (or other test facility) for evaluation after the cable is removed from the plant; its mechanical and electrical properties may then be evaluated and compared with those of new cable of a similar type.

5.4 Programs and Techniques Applied to Components

5.4.1 Evaluation of Current Practices

10CFR54 [5.1] requires that the Integrated Plant Assessment (IPA) list those structures and components subject to an aging management review (AMR), and demonstrate that the effects of aging on the functionality of such structures and components will be managed to maintain the current licensing basis so that there is an acceptable level of safety during the period of extended operation. Furthermore, the time-limited aging analyses required by 10CFR54.21, which form the basis of a licensee's conclusion regarding the capability of SSCs, must consider the effects of aging and be based on explicit assumptions defined by the current operating term of the plant.

The methods by which the licensee meets these requirements may vary; each licensee can select the method(s) or technique(s) most appropriate for their individual AMR. The methodology employed by this AMG for determining the effects of aging on cable and termination components was to identify maintenance or surveillance practices currently in use, and compare them with the significant aging mechanisms to determine which mechanisms are not currently addressed.

Table 5-6 shows the principal aging mechanisms for cables and terminations, and lists the preventive and corrective maintenance and surveillance techniques currently used to address these mechanisms. As evidenced by the table, relatively little preventive maintenance or condition monitoring specific to these components is performed. Experience indicates that most cable runs do not degrade significantly, which may be largely attributed to the hardiness of cable constructions, their relatively benign environments, and their protection by conduit or other raceways [5.18], [5.21]. Most of the damage or degradation to low-voltage cable systems results from exposure to external stresses such as localized high temperature (either ambient or resulting from connection to a hot component), or radiation, or mechanical damage such as cutting or chafing. Many times such damage occurs at or near the end device. For medium-voltage cable, the primary concern is wetting coupled with applied voltage stress. For both low- and medium-voltage bulk cable systems, use of preventive maintenance or testing is more difficult to justify, because the ability of currently available techniques to detect or monitor these types of degradation is limited at best, and the overall failure rate of both low- and medium-voltage systems is very low to begin with (see Section 5.4). Hence, the greatest part of current maintenance and testing activity related to nuclear plant cable systems is corrective or reactive; visual and physical inspection, replacement, and cleaning are essentially the only preventive maintenance activities performed on cable or terminations, and these are usually performed only during maintenance on related equipment. In those cases where known or identified problem areas exist, increased preventive maintenance and monitoring may be employed, or the degraded component simply replaced as required.

Table 5-6 also shows additional techniques that may be used in controlling and monitoring the aging of cable systems. As opposed to the predominantly corrective measures currently employed, other techniques (including thermography, environmental monitoring, measurement of compressive modulus or OIT, and analysis of circuit loading/duty cycle) may be effective for (1) identifying individual circuits or groups of circuits undergoing significant aging, (2) monitoring component aging, or (3) controlling their rate of aging. For example, analysis of circuit loading/duty cycle may help identify those circuits at risk for premature thermal aging due to ohmic heating. Environmental monitoring and Arrhenius analysis may be useful for extending the qualified lives of environmentally qualified cable. Measurement of compressive modulus or OIT may be useful in monitoring the aging of installed circuits through correlation of their physical condition to predetermined criteria. Identification and management of aging of cable system components is discussed further in Section 6 of this guideline.

In addition to individual maintenance, surveillance, and condition monitoring techniques, programs that have the result of managing aging effects on cable and termination components were considered. For example, maintaining compliance with 10CFR50.49 can be considered an aging management program for EQ circuits[19] because the net effect is to maintain adequate post-accident component functionality through establishment of a qualified life. All plants have existing environmental qualification programs that include some portion of the total cable/termination inventory within their scope. Similarly, a structured circuit inspection program based on plant-specific operating experience and coupled with root-cause analysis and appropriate corrective action could be considered an aging management program. Many of the plants contacted as part of this study have similar programs in place. It is also important to note that many existing plant activities not specifically focused on cable and termination aging management may often be credited with addressing aging effects. Incidental inspection of cable ends and terminations during end-device maintenance provides a good illustration of such activities; these are often formalized, occur routinely (based on the maintenance cycle for the end device), and include a means for implementing corrective action if degradation is observed.

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[19] Note that the techniques used in determining qualified life (such as Arrhenius and environmental analysis) are often directly applicable to non-EQ circuits; see Section 4.1 for additional information on application of these techniques.

Hence, despite the limited number of cable- and termination-specific monitoring or preventive maintenance activities identified above, aging management is often provided by other plant programs and activities.

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

A comparison of the currently employed maintenance and surveillance techniques and the principal aging mechanisms (Table 5-6) demonstrates the following:

1. Not all of the aging effects resulting from significant and observed aging mechanisms are being detected by methods currently employed by plant operators or fully managed by existing programs

2. Not all of these aging mechanisms are fully detectable by currently existing techniques.

In effect, Table 5-6 shows that the aging of cable system components is often left unmitigated until some sort of problem or failure is detected. However, these conclusions must be considered in light of the overall significance of this aging in terms of cable system performance.

Figure 5-15 shows failures for low-voltage cable, panel/hookup wire, and terminations for the years 1974 through 1993. The total number of failures for each category was divided by the number of nuclear plants in operation[20] during each year to estimate the number of failures per plant per year. As shown in the figure, the peak failure rates recorded were approximately 0.7 failures per plant per year for low-voltage terminations (all), 0.7 for panel/hookup wire, and 0.3 for cable. Average cable failure rates are also substantially lower than those for the other low-voltage components. Note that those failures not affecting functionality are also included in this number, so that the actual number of failures affecting function would likely be somewhat less.

Figure 5-16 shows failures for medium-voltage cable and terminations for the years 1974 through 1993. The peak failure rates recorded were 0.12 termination failures per plant per year (1975), and roughly 0.04 cable failures per plant per year (1983). Based on extrapolation of the worst-case observed failure rate data, each plant would experience a medium-voltage termination failure roughly every 8 years on average, and a medium-voltage cable failure every 25 years. Figure 5-17 illustrates similar data for neutron monitoring systems, which show that the peak and average failure rates for terminations are greater than those for the associated cables, yet both are still quite low (fewer than 0.6 failures per plant per year).

[20] These data were obtained from the American Nuclear Society's annual list of world nuclear power plants published in Nuclear News. The Institute of Nuclear Power Operations was contacted to attempt to determine the number of plants reporting to NPRDS by year; however, data covering the entire period were not available.

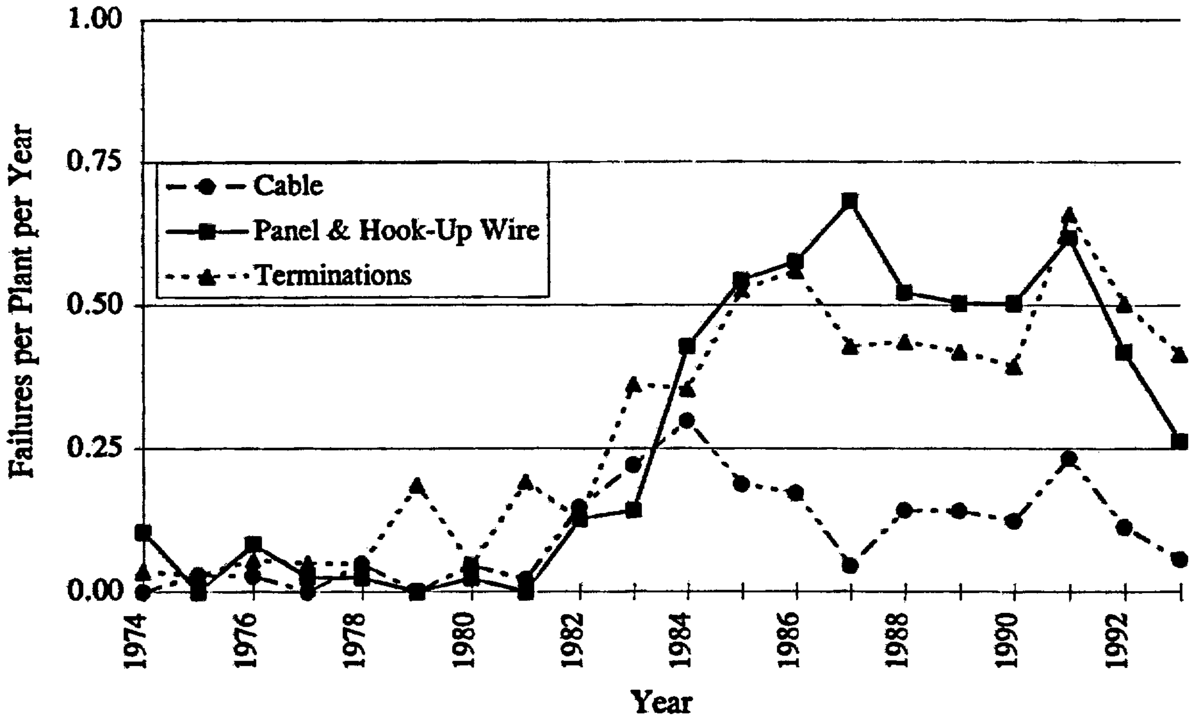

Figure 5-15 Low-Voltage Cable and Termination Failures versus Time (NPRDS)

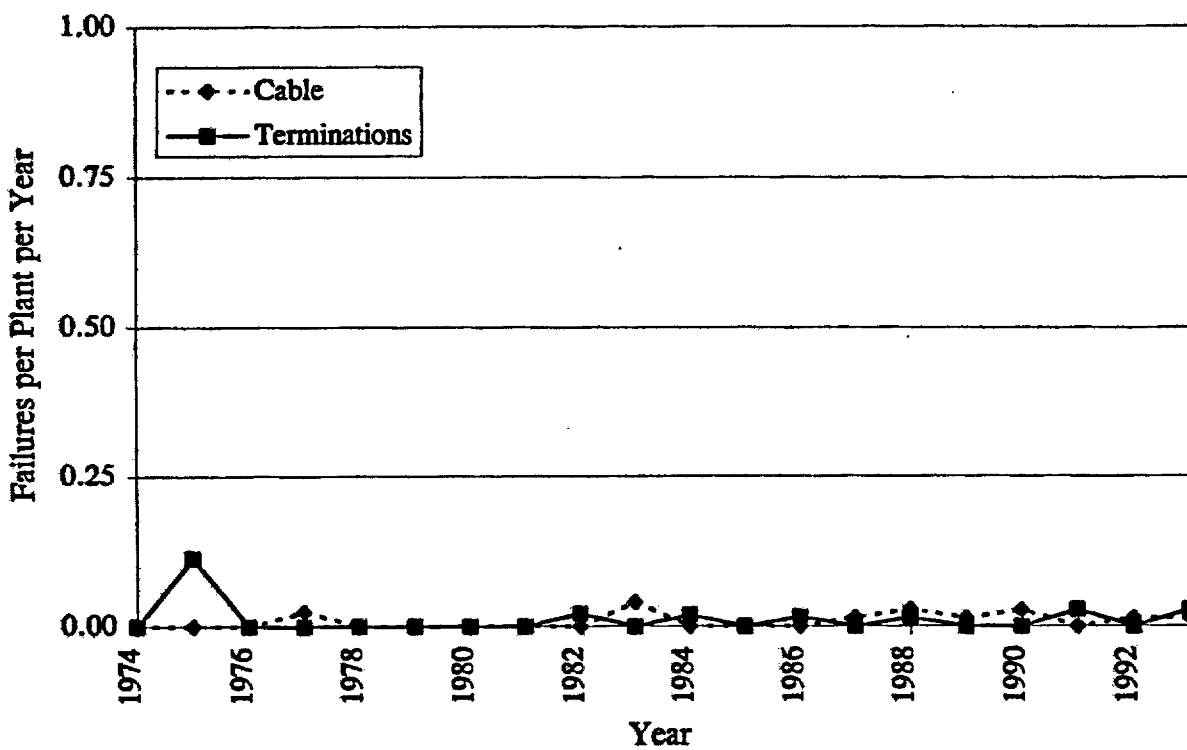

Figure 5-16 Medium-Voltage Cable and Termination Failures versus Time (NPRDS)

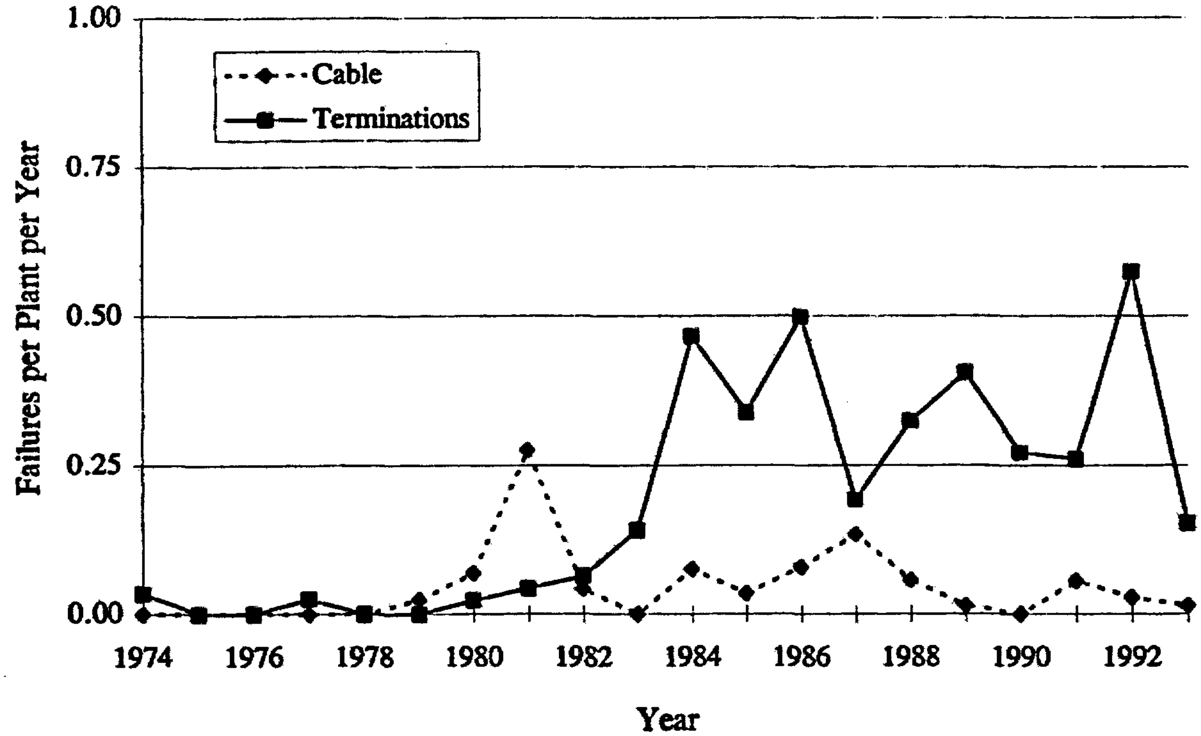

Figure 5-17 Neutron Monitoring Cable and Termination Failures versus Time (NPRDS)

The failure rates determined above may somewhat underestimate actual failure rates because (1) not all plants in operation in a given year report their failures to Nuclear Plant Reliability Data System (NPRDS) and (2) plants that do report to NPRDS may not report all of their failures. However, even if the number of failures for any voltage category is quadrupled (e.g., assuming only half of the operating plants report, and only half of the actual failures experienced by these plants are reported), the total number of failures per plant per year is still extremely low in light of the large number of circuits in the typical plant.[21] When considering the number of low-voltage circuits and terminations at the typical nuclear plant (several thousand), the number of low-voltage failures for all components is extremely small (roughly one tenth of 1% of the total number of cables and circuits per plant per year). There are far fewer medium-voltage circuits in a typical plant (estimated at roughly 100 or less), and the number of failures/circuit is similar to the results for low-voltage circuits. The failure rate for neutron monitoring systems (1 to 2% per year, assuming approximately 100 circuits per plant) is significantly greater than the failure rate for low- and medium-voltage circuits.

The cause(s) of the apparent rise in failure rate for both low-voltage and neutron monitoring circuits beginning in about 1980 is unknown; numerous possible explanations (including an increase in the percentage of operating plants reporting to NPRDS, increased plant management sensitivity resulting from events at TMI-2, or an actual increase in the component failure rate)

[21] One plant (PWR) contacted as part of the study indicated that the plant has more than 50,000 individual circuits installed in two units.

exist. Note also that analysis of the component age at failure yielded no clear trend or distribution for any of the equipment categories.

The low failure rate for cable and terminations indicated by the NPRDS data is also evidenced through review of other failure data sources, including the available literature, NRC documentation, Licensee Event Reports, surveys, and discussions with host utility personnel. As discussed, these sources tend to indicate that cable systems experience an extremely low rate of failure during normal plant operating conditions, and aging of bulk cable systems is generally not a concern. The failure rates extrapolated from the data are considered to be conservative with respect to the cable inventory as a whole for the following reasons: (1) the NPRDS and LER databases contain reports relating to both bulk and localized cable and termination aging, and (2) a large number of circuits installed in the typical nuclear plant will not be subject to localized aging influences.

NPRDS reports were also analyzed based on the their age at the time of failure (assuming installation coincident with plant startup). No real trends were apparent for any voltage category. However, some indication of a declining failure rate for low-voltage components was noted over the time period of the analysis (roughly 25 years), thereby suggesting that these components may become more reliable as they age (at least for some period).[22] Note that the data for medium-voltage systems was considered numerically insufficient to make any similar inference.

Coupled with the low failure rate for cable systems and their components is the concept that known and identified problem areas in such systems are subject to increased attention by plant maintenance personnel. For example, a cable routed near process piping, which is known to degrade more rapidly than other portions of the run, will typically be examined and replaced more frequently than nonaffected portions. Similarly, connectors located in high moisture or corrosive environments will generally be inspected more frequently for signs of corrosion than those installed in unaffected circuits. Maintenance personnel also routinely identify and replace severely aged electrical cable.

In summary, the overall hardiness of electrical cables and terminations and the relatively benign service environments for most circuits have resulted in little significant degradation for most circuit components. This is evidenced by failure data evaluated during this study and by a variety of different industry literature and analyses. Many of the problems that do occur are highly localized and are often corrected during maintenance on connected or adjacent equipment. However, consistent with the observations noted at the beginning of this section, the following aging mechanism/component combinations should be considered for further aging management activities:

- Localized thermal, radiolytic, or mechanical degradation of low- or medium-voltage cable insulation and jacketing (where jacketing is required for environmental qualification)

[22] This behavior may be a manifestation of the frequently observed "bathtub" curve; the failure rate decreases initially, remains essentially stable for a period, and then increases with increasing age.

- Localized thermal, radiolytic, or mechanical degradation of neutron-detecting circuits or other cable insulation in proximity to or under the reactor vessel

- Thermal degradation of low- and medium-voltage power cable insulation for circuits subject to continuous or near-continuous loading at high currents

- Degradation of medium-voltage power cable insulation routinely exposed to appreciable wetting

- Oxidation and/or corrosion of connector contact surfaces associated with low-voltage and neutron detecting circuits (and similar low-current/impedance-sensitive applications)

- Loosening of compression fittings on cable/wire conductors.

The following aging considerations are also identified:

- Damage to medium-voltage cable insulation, jacketing, and shielding resulting from inadequate installation practices

- Damage to low-voltage panel and hookup wire resulting from maintenance activities.

- Damage to aged low-voltage cable resulting from movement or maintenance activities.

- Potential failure of bonded jacket/insulation systems on environmentally qualified cable during accident exposure.

It should be noted that no significant increase in the failure rate of low-voltage cables and terminations considered as part of this AMG is anticipated as the end of either the original or the license renewal periods is approached. This conclusion for normal plant operating conditions is based on the following:

- No aging mechanisms other than those identified in this AMG are known or expected to occur during this period (i.e., no mechanisms "unique" to the license renewal period have been identified).

- No change in the character of existing aging mechanisms or rate of degradation induced by these mechanisms is anticipated.

- Significant conservatism (via design, qualification, and other analyses) often exists with respect to component longevity.

For low-voltage cable insulation, the primary failure mechanism of concern (loss of dielectric properties) has been shown to be coupled primarily to the mechanical properties of the insulation. Specifically, cracks or breaches in the insulation's integrity are generally required for failure to occur. Although such degradation may occur in a localized fashion for a limited number of cables (especially those subject to manipulation in an embrittled state), no such problem is anticipated for the bulk of low-voltage cable runs in the typical plant, due to the relatively benign environments. Cable located in more severe general area environments (such as inside primary containment) is generally constructed of materials that, even under these environments, have shown substantial longevity.[23]

One potential consideration relates to the use of bonded jacket/insulation systems on low-voltage EQ cables (see Section 3.7.1). NUREG/CR-6095 [pp.12-13, 5.32] (citing results from NUREG/CR-5772 [5.9] as well) suggests that exposure at aging temperatures above approximately 54°C [129°F] over a 40-year period with simultaneous irradiation increases the probability of producing the bonded jacket failure mechanism observed for Okonite conductors during LOCA testing, and that failure is almost certain (during LOCA exposure) after exposure at 72°C (162°F) with simultaneous irradiation for 40 years. As discussed in NRC Information Notice 92-81 [5.131], further evaluation or monitoring of bonded construction EQ cables located in spaces that are exposed to long-term aging temperatures in excess of about 54°C [129°F] should be considered. The results of any follow-on analysis and/or testing addressing this issue should also be factored into the evaluation of longevity for the license renewal period.

For medium-voltage cables, the primary aging and failure mechanisms appear to be related to the types of materials employed, the presence of moisture, and the presence of significant voltage stress. Resistance to embrittlement is not a major determinant in the longevity of such cables, and the rate of degradation or proximity to failure is not readily determinable. Hence, the ability to estimate the future performance of these systems is far more limited than that for low-voltage cables. Accordingly, the failure rate for medium-voltage systems may increase, remain constant, or decrease as time in service progresses. Note that some plants are actively replacing medium-voltage cables potentially at risk for failure with new cables specifically designed to combat the effects of water treeing (one of the more significant causes of failure); this may also result in a lower overall failure rate with time.

[23] For example, environmentally qualified cable is thermally aged and irradiated (consistent with the 40-year initial licensing period) and subsequently subjected to a postulated LOCA environment that can be construed to demonstrate substantial additional longevity for such cables used in nonqualified applications.

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6. CONCLUSIONS AND RECOMMENDATIONS

This AMG has presented a comprehensive examination of currently available information regarding cable and termination construction and materials, the stressors that cause aging, applicable aging mechanisms and effects, and the currently available methods that can be used to monitor and control aging. Section 6.1 presents both general and specific conclusions relating to the aging of cable and terminations drawn from an analysis of the information presented in preceding sections. Section 6.2 presents several recommendations for managing aging of cables and terminations, based on the conclusions of Section 6.1. Section 6.3 presents a proposed methodology for performing an aging management review of cable systems pursuant to 10CFR54 [6.1].

6.1 Conclusions on Aging of Cables and Terminations

General

The following general conclusions are applicable to aging of electrical cables and terminations:

1. Nearly all cables and terminations that are included within the scope of this AMG have been highly reliable (see conclusion 3 below). They are expected to perform their safety function and meet all regulatory requirements during the current licensing term.

2. The greater part of cables and terminations currently installed in operating plants can be expected to continue to perform their safety function(s) and meet all regulatory requirements during an extended period of operation after the expiration of the current licensing period.

3. The number of cable and termination failures (all voltage classes) that have occurred throughout the industry is extremely low in proportion to the amount of installed cable. However, the data which supports this conclusion is limited in two ways: (1) there is little or no data to quantify performance under accident conditions, and (2) only a few plants have operated for more than twenty years, which is only about one-third of the total expected period of operation for these systems (i.e., 60 years).

4. The stressors and aging mechanisms affecting cables and terminations are generally well understood and characterized; however, knowledge of some areas (including combined and natural aging environments) is more limited.

5. Cable and termination aging can be evaluated on a continuing basis, using theoretical techniques, measurement of physical properties, and periodic inspection.

Specific

In addition to these general conclusions, the following specific conclusions were reached:

<u>Type and Location of Degradation</u>

1. Additional aging management will be required for only a relatively small fraction of the total amount of plant cables and terminations. Specifically, cables and terminations may warrant more careful consideration if they are:

   - located near high heat and/or radiation sources,
   - subject to continuous or near-continuous loading at a significant percentage of their ampacity limits,
   - exposed to submergence/wetting (for medium-voltage cables) or adverse chemical environments,
   - subject to repeated or continuous damaging mechanical stress, or
   - used in impedance-sensitive applications (such as neutron monitoring equipment).

   (See Section 4.1 for specific guidance on applying these criteria.)

2. The mechanical properties of low-voltage cable insulation must generally degrade significantly (such as embrittlement and cracking, or cut-through damage) before any significant effect is seen in the electrical properties. This condition is not generally true, however, for medium-voltage power cable.

3. Most degradation of installed cable (and terminations) appears to occur at or near the end devices/connected loads, as opposed to affecting the bulk runs.

4. Failures of connectors (a subset of terminations) constitute a substantial percentage of all failures noted for low-voltage and neutron monitoring systems. A large percentage of all connector failures can be attributed to oxidized contact surfaces.

5. A large fraction (more than a third) of all low-voltage component failures are related to panel and hookup wire; however, the estimated peak failure rate for wire is low considering the size of the population. A large fraction of panel and hookup wire failures (roughly a third) are not the result of aging influences, but rather stem from design, installation, maintenance, modification, or testing activities.

Plant Activities

1. Current maintenance, surveillance, or testing activities may be partially or wholly ineffective at identifying certain types of incipient cable or termination aging degradation (such as electrical or water treeing, loss of fire retardants, or thermal aging of bulk cable runs in inaccessible areas/raceways). Simple periodic visual/ physical inspection is a highly effective means of assessing the condition of low-voltage cable insulation and jacketing as well as some organic termination components.

2. Installation practices can be a significant determinant in the aging and longevity of medium-voltage power cable systems. Low-voltage cable longevity may also be affected by damage incurred during installation, but to a more limited extent, as addressed in Section 4.1.3.4.

Environmental Qualification

1. Existing environmental qualification practices (such as qualification conservatisms) coupled with design and application conservatisms provide assurance that aging mechanisms and effects will not keep EQ cables from performing their required function(s) during their qualified life. Note that non-EQ components are frequently identical or similar to their EQ counterparts, thereby allowing conclusions and information related to EQ components to be applied to non-EQ equipment.

2. The potential for failure under accident conditions exists for cable with embrittled/cracked insulation. Moisture ingress through cracks may result in failure of the dielectric.

3. The potential for failure under accident conditions exists for certain bonded jacket/insulation systems due to interaction between the conductor insulation and jacket when aged under certain conditions. The laboratory aging conditions under which these failures were observed are not typically experienced in nuclear plant applications; however, the response of these cable systems to accident exposure following aging under simultaneous low temperature/low dose-rate conditions is not well understood at present. Therefore, additional evaluation for suitability during the license renewal period (specifically for those EQ cables located in environments where aging temperature exceeds approximately 50°C [122°F] for 60 years) may be warranted.

4. Generally, the main function of a cable jacket is to protect the insulation during installation. If this is the only function of the jacket, no credit is taken for the jacket during environmental qualification testing.

   Cable jacket integrity may be significant with respect to (a) the possibility of interactive jacket/insulation failures of bonded systems during accident exposure (see Item 3 above), (b) beta radiation shielding, (c) retention of electrical shield integrity in shielded cables, and (d) environmental qualification of associated splices or connectors.

Condition Monitoring Techniques

1. The objectives of condition monitoring are to assess a cable's ability to perform its safety function and obtain an indication or measure of a cable's remaining life. Substantial progress has been made in the past few years in developing methods for evaluating the aging of low-voltage cable. Of these, tests that measure physical properties of the cable insulation/jacket appear most promising at present. In particular, the oxidation induction time (OIT) and compressive modulus (indenter) methodologies appear to have significant potential within certain constraints. Time-domain reflectometry (TDR) is also useful in identifying degraded (i.e., high impedance) terminations or connectors in certain instances.

   Industry and the NRC have prioritized activities to develop and implement new condition monitoring methods which show as much or more promise than the techniques discussed above. An EPRI Cable Condition Monitoring Working Group was recently established to coordinate industry activities. OIT, indenter, TDR, and other subsequently developed methods may be a viable approach to managing the aging of cable system components not otherwise managed by existing practices.

2. No currently available technique was identified as being effective at monitoring the electrical aging of medium-voltage power cable. Some methods may be effective at detecting severe electrical degradation or monitoring certain types of degradation (such as thermal aging); however, correlation of these measurements with the expended or remaining life of these cables has not been demonstrated.

6.2 Recommendations

As indicated in Section 6.1, cables and terminations of the types considered in this guideline are generally very reliable; additional aging management activities appear warranted for only a small fraction of the total cable population. Existing programs, although in some cases not specifically aimed at cable and termination aging, appear effective at managing most of the significant aging effects for these components. This is underscored by the low historical failure rates observed in the empirical data to date. However, existing practices can be improved; such improvements may include better focus of present programs on areas/applications potentially subject to more rapid degradation and identifying and managing those aging effects not completely addressed. Accordingly, the following recommendations regarding cable and termination aging management are presented:

1. Aging management activities should consider specific cable types used in aging susceptible applications, and address the degradation mechanisms of most significance. For low-voltage systems, instances of earlier vintage or more aging-susceptible materials used on cables (such as PVC, butyl, or Neoprene® rubber) that are connected

to heavy continuous loads or routed through "hot spot" areas should be considered. Particular attention should be paid to components or cable segments located near the end device. Similarly, medium-voltage power cables routinely[1] subject to wetting or submersion, and oxidation of connectors used in neutron monitoring circuits should be addressed. Maintenance programs should be examined to determine their effectiveness at identifying and addressing degradation of air-insulated terminations subject to regular vibration, mechanical stress, or condensing moisture/wetting, as well as connections that are routinely manipulated or disconnected/connected. Design changes to such equipment may also be considered.

2. Significant aging management efforts are generally not warranted for cables located in "benign" areas. Accordingly, aging management activities should be focused on cables and terminations installed in more environmentally challenging areas, and the limited number of applications installed in benign areas which are subject to localized stressors.

3. Accurate characterization of plant environments (especially those in more severe areas such as primary containment) is important to effective management of the aging of certain cable systems. Such characterization should be conducted to assist in establishing representative qualified lives for environmentally qualified components, identifying circuits and components that may age faster than the rest of the population (and therefore may warrant additional aging management activities), and used to extend the qualified life of cables in regions with operating environments that are less damaging than the design basis environment.

4. Based on the similarity between many EQ and non-EQ cables and terminations, existing information and analyses related to the aging of EQ components should be considered for use with non-EQ components to assist in management of their aging.

5. Condition monitoring is not currently warranted for all applications of medium-voltage cable. Because no technique is currently developed to a sufficient degree to permit effective monitoring of dielectric aging without the threat of inducing further degradation, preventive measures (such as prevention from submergence) should be considered as means of extending the longevity of medium-voltage cables.

6. In cases where condition monitoring is deemed appropriate (such as where aging effects cannot otherwise be adequately managed by existing practices), a program to determine the baseline aging condition of affected components using a nondestructive test or evaluation method should be considered.

7. If cables are to be replaced for any reason, then plant cable installation practices and procedures should be reviewed to ensure that they prevent cable damage during installation.

[1] That is, other than on an intermittent or periodic basis, so that the cable is not permitted to dry out.

8. Information derived from natural or low-acceleration factor aging programs currently under way may yield a better understanding of degradation resulting from combined environments and natural aging conditions, and should be used to supplement present knowledge regarding the aging of cable and termination materials. In addition, input from ongoing qualification activities (such as follow-on analyses, testing, condition monitoring, and maintenance) should be incorporated into existing programs as appropriate.

9. Environmentally qualified cable potentially susceptible to bonded jacket/insulation failure (such as Okonite EPR/Okolon individual conductors) should be further evaluated for adequacy during the license renewal period. Recent experimental data suggest that the probability of post-accident failure may increase substantially for cables simultaneously exposed to radiation and aging temperatures above 54°C over 40 years (or above 50°C over 60 years).[2] Accordingly, only those circuits subject to such aging environments need be considered.

6.3 Aging Management Review Under 10CFR54

6.3.1 General Approaches to Aging Management Review

Reference [6.2] describes a general framework for performing an aging management review (AMR) that includes (1) identifying SSCs within the scope of the rule, (2) identifying applicable aging effects and their impact on SSC intended function, and (3) determining the ability of applicable plant programs to identify and mitigate these effects. Where aging effects are not completely managed for the period of extended operation by existing programs, appropriate actions must be taken to address these effects.

Several different methodologies can be used in evaluating the aging management of plant cables as part of an AMR. These methodologies relate to how adequate aging management of plant circuits can be demonstrated, or conversely, how circuits potentially requiring additional aging management can be identified.

One possible method involves explicit identification of all or most plant circuits. Initially, all circuits associated with each plant system could be identified; those that are within the scope of the license renewal rule (LRR) and not periodically replaced could then be individually evaluated to demonstrate adequate management of aging effects. This process would then be repeated for each applicable plant system. Alternatively, all circuits within the scope of the LRR could be identified directly (i.e., by examinations of Q-lists, EQ documentation, engineering analyses, etc.) regardless of system, eliminating those that are periodically replaced. The remaining circuits would then be individually evaluated. The major drawback to these sorts of approaches is the requirement to identify and evaluate (to some degree) almost every circuit in the plant, which may number in the tens of thousands. This is extremely laborious and time consuming, especially for plants with limited existing database capability. Accordingly, such approaches are not recommended.

[2] Based on Arrhenius extrapolation using activation energy of 1.04 eV.

A second (preferred) method seeks to "group" circuits based on common stressors, locations, and/or applications. It was previously noted that aging degradation which may affect intended function is generally confined to a substantially reduced subset of plant circuits (e.g., only a small fraction of circuits are exposed to stressors/combinations that produce any meaningful degradation, and much of this degradation is physically localized in nature). The group methodology uses these observations to identify circuits for which no significant aging stressors (and therefore effects) exist and conclude that no additional evaluation is required. Various approaches to grouping circuits for aging management review are discussed in Step 1 of Section 6.3.3.

6.3.2 Determination of Scope of Equipment Subject to an Aging Management Review

Section 54.21 of the LRR requires an AMR for certain "passive" plant systems, including electrical cables and terminations. Little practical guidance is provided in the LRR on the methodology for performing an AMR. The following paragraphs describe information contained in the Statement of Considerations (SOC) for the rule:

1. **Scope of License Renewal** - Nonsafety-related SSCs whose failure would prevent accomplishment of an intended function of a safety-related system, structure, or component are intended to be included in the category of nonsafety equipment described in Section 54.4(a)(2). The plant's current licensing basis (CLB), plant-specific experience or operating history, industry-wide operating experience, and engineering evaluations should be relied upon to determine those nonsafety-related SSCs that are the focus of the review.

2. **Integrated Plant Assessment (IPA)** - A list of equipment (from those SSCs within the scope of license renewal, as described above) that a licensee determines to be subject to an AMR for the period of extended operation is required. The licensee has the flexibility to determine the equipment for which the review is performed, so long as those structures and components that are (i) not subject to replacement prior to expiration of the original license period, and (ii) passive (e.g., perform an intended function without moving parts or change of configuration/properties) are included. Furthermore, the IPA must contain a description of the methodology used in selecting equipment subject to the review, and a demonstration that the effects of aging on this equipment will be managed so that the intended function is maintained during the extended operating period.

Accordingly, all cables and terminations within the scope of the LRR and which are not replaced based on qualified life or some other specified time period are subject to an AMR. Note that most cables and termination components will not be subject to replacement prior to the expiration of the original license period.[3] As previously stated, plant operators may also choose to include cable systems outside the scope of the rule in the AMR process based on economic considerations or continuity of power production. Thus, the cables included by a plant in its AMR may range from literally all plant cables to something considerably less than those considered to be within the scope of the LRR.

[3] Examples of possible exceptions include certain neutron monitoring cables/connectors and motor operated valve/solenoid operated valve (MOV/SOV) terminations.

EQ components comprise a relatively small fraction of the total circuit inventory of the typical plant. All safety-related SSCs (of which EQ components are a subset) are included within the scope of the LRR. Per item 2 above, all passive EQ equipment that is not replaced prior to the expiration of the original operating period is subject to an AMR. Any component that is designated EQ already has a qualified life established based on significant aging mechanisms. In many cases, the qualifiable life exceeds the combined original 40-year design life and a license renewal period of up to 20 more years. All such cables may ultimately be demonstrated to be covered by the existing aging management (i.e., EQ) program for these circuits. There are some cases, however, in which the qualifiable life is less than the combined current and license renewal periods, yet greater than the current license term (i.e., greater than 40 but less 60 years). In such cases, the plant will have to demonstrate both qualification and aging management [per the requirements in the LRR regarding time-limited aging analyses (TLAAs)] for the extended period of license renewal. Thus, the plant will have to either replace the cable or extend the qualified life via reanalysis or retesting.[4] Establishment of the new qualified life will have to be performed prior to the end of the existing qualified life. Furthermore, if subsequent information (such as new research data) indicates that the original qualification did not adequately address all relevant factors, then the original qualification should be reevaluated to take into account such previously unidentified considerations.

The requirement contained in 10CFR54.21 to "identify and list" those structures and components subject to an AMR must also be considered. Due to their large numbers, identifying every plant circuit potentially subject to an AMR at the onset of the AMR process (via Q-lists, plant diagrams, etc.) largely negates the benefits provided by the "grouping" approaches, especially for those plants without existing comprehensive cable databases. The apparent intent of the LRR is to ensure adequate management of aging effects for passive, long-lived components within the scope of the rule; hence, if it can be demonstrated that all such circuits have been evaluated for aging effects and addressed under an AMR, such a demonstration arguably satisfies the rule requirements (in lieu of a strict listing of all circuits considered). One possible approach would be to include all plant circuits within the chosen group methodology, thereby ensuring inclusion of all circuits subject to an AMR. Whatever approach is followed, interpretation of the requirement to "identify and list" may largely depend on an individual plant's ability to demonstrate that all circuits subject to an AMR have been included in the evaluation process.

6.3.3 Generic Methodology for Aging Management Review

A proposed methodology for performing an AMR for electrical cable and terminations is described below. This methodology is based in part on the generic guidance set forth in Reference [6.2], yet is adapted to more specifically address issues unique to cable systems. By implementing this methodology, a reasonable assurance of continued operation in accordance with the current licensing basis (CLB) can be maintained for the equipment within the scope of this guideline. A plant-specific version of such an analysis may be used by plants in their license renewal applications to assist in providing an acceptable basis for demonstrating adequate management of aging effects for cable and termination components pursuant to 10CFR54.29.

[4] Condition monitoring and input from maintenance/testing programs are also permissible as ongoing qualification for extending the qualified life of EQ components.

Note that substantial flexibility exists in choosing which type of approach is employed for demonstrating aging management. No specific method for performing an AMR is described or advocated in 10CFR54. Hence, the following methodology may be modified as necessary by each individual plant based on its individual circumstances. Figure 6-1 illustrates the basic process.

Steps 1 and 2 of the proposed methodology are aimed at identifying that subset of the plant circuit population that potentially requires additional aging management. Step 3 examines plant-specific historical data to further refine this subset. Step 4 identifies existing aging management activities applicable to these circuits, and Step 5 assesses their effectiveness at detecting and mitigating the aging effects of concern. Finally, Step 6 recommends any additional activities that may be required based on the review of Step 5. Note that this approach can be applied in iterative fashion if desired; that is, individual groups of circuits can be completely evaluated prior to beginning evaluation of other groups.

This methodology is not only potentially useful in AMRs under the LRR, but the techniques described below may also be used in structuring cable and termination aging management programs[5] aimed at the current license term. Along these lines, some utilities contacted during this study have developed separate programs focused specifically on cable and termination management from an operations perspective, somewhat independent of license renewal considerations. Other plants have no such dedicated programs, but rely solely on the aging management afforded by existing programs and maintenance activities to help ensure continued functionality of cable systems. The decision to develop or implement such an aging management program for cable systems is discretionary.

Step 1: Identification of Equipment Potentially Requiring Additional Aging Management Activities

The first step of the proposed methodology seeks to identify those circuits for which adequate aging management can be readily demonstrated; these circuits do not need to be evaluated and the circuits that remain will potentially require additional aging management. One of the grouping approaches described below is used to eliminate from further consideration those circuits not exposed to significant aging stressors. Depending on the specific approach employed in this step, the fraction of circuits potentially requiring additional aging management activities can be substantially reduced with comparatively little effort.[6]

[5] Aging management "programs" are referred to only in applicable regulatory documentation with respect to certain environmentally qualified circuits; however, such programs may be used to coordinate aging management activities for other categories of circuits as well.

[6] Application of the plant spaces approach by the authors during development of a proprietary cable aging management program for one nuclear utility resulted in the elimination of several thousand circuits from further consideration.

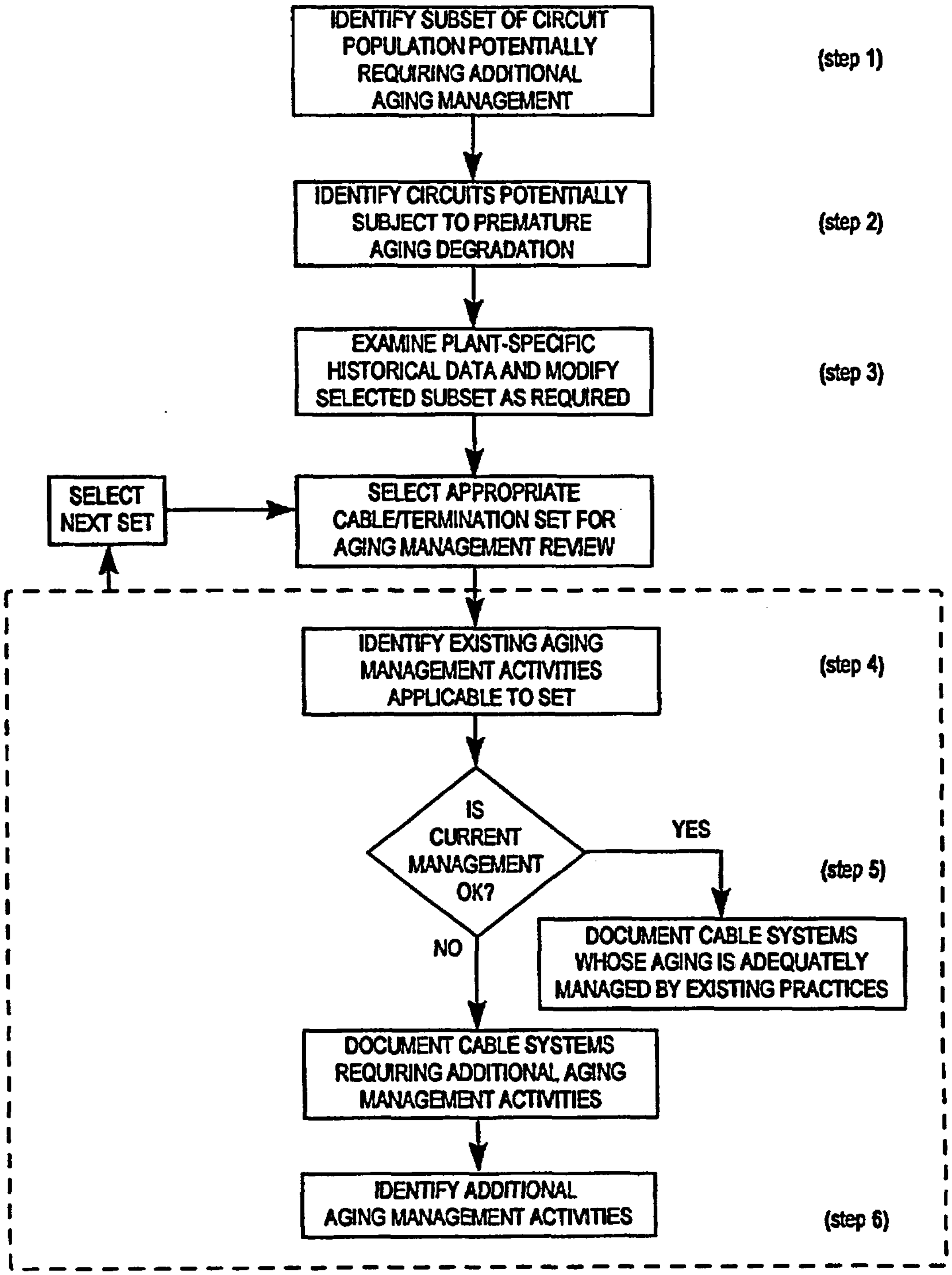

Figure 6-1 Flowchart for Proposed Aging Management Review Process

One variant of the group method is to treat cable systems as a "commodity"; the initial grouping of circuits is performed [based on the primary stressor(s) of concern] without regard to circuit location or whether the circuit is within the scope of the LRR. For example, a service-limiting temperature for cable insulation/jacketing material could be calculated and used as the primary screening tool. Ambient temperatures (and ohmic heating effects) would then be considered to identify the cable population subset of concern. Consideration of other aging stressors (such as radiation or wetting) could also result in more focused reviews of limited numbers of circuits. This approach is greatly simplified in comparison with those previously described; however, caution must be exercised to ensure that all significant stressors are properly addressed during the screening process.

Another approach is to demonstrate aging management for groups of components through analysis or evaluation of the "worst-case" environment or installation. That is, groups of circuits can be evaluated based on their physical similarity to the worst-case application and a showing that the aging stressors of concern are enveloped. For example, consider the application of information and analyses relevant to EQ circuits to non-EQ circuits. As previously noted, many non-EQ components are similar or identical to those used in EQ applications. Furthermore, qualification must be demonstrated for aging environments that are often substantially more harsh than those in which non-EQ circuits are located. Accordingly, an effective demonstration of aging management for these similar/identical non-EQ cables can be made via the existing EQ analyses. Note, however, that the EQ application(s) should be shown to envelope *all* significant stressors for the non-EQ components. In addition, caution should be used in attempting to apply such EQ data and analyses on a generic basis (e.g., apply data for one specific formulation of EPR-based insulation to all EPR-based insulations used in the plant); similarity of material performance (especially with regard to the critical properties of the component) should be positively demonstrated.[7]

A third alternative of the group method involves use of what is called a "plant spaces" approach. Under the plant spaces approach, a structure that does not use or house cable systems within the scope of license renewal may be eliminated from further consideration. For example, an auxiliary pumphouse or switchyard enclosure may contain no circuits that fall within the scope of the LRR. After any such structures are eliminated, a space-by-space evaluation of the environments in the remaining structures is performed taking into account such factors as ambient temperature and localized heat sources, radiation, and moisture.[8] In many cases, these spaces may be coincident or closely parallel established EQ environmental zones. Specifically, the effects of aging for all low-voltage instrument and control cables/terminations and all medium-voltage cables/terminations that are installed in areas having all of the following characteristics can be demonstrated to be adequately managed:

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[7] As previously noted, even small variations in chemical formulation of some compounds can significantly affect their physical properties, including resistance to various aging stressors.

[8] Data from plant operating logs, environmental monitoring programs, and similar sources can be used to evaluate individual spaces.

- The room ambient temperature never exceeds the 60-year service-limiting temperature applicable to the material(s) of concern.[9]
- The threshold radiation dose for the material(s) under consideration is greater than the 60-year normal total integrated dose (TID) for all areas in the room.[10]
- There are no cables or connections that must be moved or manipulated frequently (more than once or twice per refueling cycle).
- The area is free from significant wetting or submergence, and cables are not located below flood levels.
- There is no salt or other corrosive or chemical environments.
- There are no hot process lines or end devices.[11]

The only type of circuit within such "benign" spaces that must be analyzed further is any low-voltage power circuit that is energized for long periods and loaded with currents that are a significant percentage of the conductor ampacity (see Section 4.1 and Appendix G).[12] Heavy loads that operate for long periods (e.g., fan and pump motors) constitute a very small group of equipment at any plant, and can be identified rapidly on plant drawings along with the connected cable.

In the case of circuits that run through several plant spaces (and environments), the most severe environment is used as the basis for decision. For example, a cable running through both a benign and severe environment would be retained for evaluation and review consistent with the more severe area. Hence, only those circuits completely contained within benign areas would be shown to have their aging effects managed as part of this step of the AMR process.

Step 2: Identify Circuits Potentially Subject to Premature Aging or Degradation

After using one of the "group" approaches in Step 1 to identify the subset of circuits for which aging management can be initially demonstrated, the operating and environmental conditions applicable to the remaining circuits are examined. By selecting only those circuits (or groups of circuits) that are exposed to *significant* environmental, operational, or installation stressors, the number potentially requiring additional aging management activities may be further

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[9] The application of a broad criteria like a service-limiting temperature is not practical to implement unless all relevant materials of construction for the plant circuit components of interest (i.e., those components whose thermal degradation will adversely affect functionality, such as cable insulation) are considered. For the materials of interest, an evaluation of an appropriate material property (such as elongation-at-break) is performed to establish a time duration (e.g., 60 years) and temperature endpoint, or service-limiting temperature. In lieu of such a plant-specific analysis, 31°C [88°F] may be used as a conservative 60-year service-limiting temperature for all materials, except certain neoprene jacket materials. As shown in Figure 4-1, typical cable insulation and jacket formulations can be exposed to temperatures up to about 50°C for 60 years with an endpoint condition of 50% absolute elongation.

[10] Material-specific analyses can be performed to establish TID limits. In lieu of material-specific analyses, a conservative 60-year TID value of 1 kGy [0.1 Mrad] can be used for materials listed in Table 4-6 of this guideline.

[11] Note that if hot spots exist, affected circuits may be identified and managed on an individual basis. In this fashion, additional flexibility is afforded the plant in eliminating from consideration spaces that have hot spots, but meet all of the other screening criteria.

[12] The effects of heavily loaded cables within trays or conduits are considered as part of the ICEA design standards for each type of insulation.

reduced. Specific guidelines for this selection process by voltage category/function (based on the observations and conclusions set forth above) are as follows:

a. **Medium-Voltage Power Circuits.** Medium-voltage power circuit components generally degrade due to either environmental influences (including wetting/submergence, high ambient temperature, or chemical/electrochemical interactions) or operational influences (circuit loading/percent of time energized). Under certain circumstances, these components may also degrade as a result of damage incurred during installation. Therefore, if individual medium-voltage circuits are subjected to one or more of these influences, then they should be considered for further aging management. Likely candidates would include those circuits:

   - routed near or connected to high-temperature equipment,
   - located in areas of high general area (ambient) temperature,
   - routinely or continuously operated with high currents relative to their ampacity limits (thereby resulting in significant ohmic heating),
   - routinely wetted or submerged,
   - subject to salt or other corrosive or chemical environments, or
   - suspected of suffering damage as a result of installation.

b. **Low-Voltage Power Circuits.** Low-voltage power circuit components generally degrade due to either environmental influences (including ambient temperature, radiation, or chemical/electrochemical interactions) or operational influences (circuit loading/percent of time energized). Moisture or wetting does not characteristically have any significant effect on low-voltage circuit insulation; however, it may adversely affect metallic cable or termination components. Installation damage is of little concern for low-voltage cable due to comparatively low-voltage stress. Therefore, low-voltage power circuits that meet the following criteria should be considered for further aging management:

   - routed near or connected to high-temperature/high-radiation equipment,
   - located in areas of high general area (ambient) temperature or radiation,
   - frequently or continuously operated at current values in proximity to their ampacity limits (power circuits only), or
   - subject to salt or other corrosive or chemical environments, especially at their terminations.

c. **Low-Voltage Control and Instrumentation Circuits.** Low-voltage control and instrumentation circuit components degrade primarily as a result of environmental influences such as ambient temperature, radiation, or chemical/electrochemical interactions. Circuit electrical loading is not an aging concern in these applications due to extremely low currents. Moisture or wetting may adversely affect metallic cable or termination components. Oxidation of connector or termination contacts may have a significant impact on impedance-sensitive circuits. Therefore, low-voltage instrumentation or control circuits that meet the following criteria should be considered for further aging management:

- routed near or connected to high-temperature/high-radiation equipment,
- located in areas of high general area (ambient) temperature or radiation,
- subject to salt or other corrosive or chemical environments, or
- operate at extremely low currents or are otherwise sensitive to small variations in impedance.

d. **Terminations.** In addition to the criteria set forth in items (a) through (c) above, certain other environmental/operational conditions may significantly accelerate the degradation of termination components in particular. These include:

- frequent manipulation (such as determination and retermination during maintenance)
- attachment to vibrating end devices or components
- thermal cycling due to circuit loading variations (power).

Step 3: Examination of Plant-Specific Historical Data

Another highly valuable mechanism for identifying circuits possibly requiring further aging management activities is the plant's maintenance history. By examining maintenance records, operating history, plant-specific failure data, and canvassing plant electrical and maintenance personnel for input, circuits routinely experiencing degradation of the types described above may be readily identified. Additional information can be gained by investigating the potential effects of any plant leakage or chemical spills, walking through plant spaces where cable is installed during plant operation, and identifying potential high-temperature/radiation areas within the plant through discussions with knowledgeable heating, ventilating, and air conditioning (HVAC) system engineers or health physics personnel.

This step is important from at least two standpoints. First, any additional circuits for which aging management is not demonstrated, and which were not included as part of the evaluation under Steps 1 and 2, can be identified. In this fashion, a plant's experience derived from operating and maintaining the equipment can be incorporated as a "safety net" to identify high-stress environments and applications that may not always be readily apparent. Second, the aging and degradation of many circuits selected for inclusion under these steps can be validated. (Note that at the completion of this step, the subset of the plant circuit population potentially requiring additional aging management activities should be completely identified.)

Another component of the historical review should include evaluation of root-cause analyses. Such analyses are important in identifying common environmental or operational stressors that result in component failure. Circuits exposed to these stressors that were not previously identified should be considered for further aging management.

Step 4: Identification of Existing Aging Management Activities

Next, existing plant aging management activities are identified; this information will be used in Step 5 to support the ultimate determination of aging management effectiveness for the subset of the cable/termination population identified by the end of Step 3. A generic list of activities that potentially detect and/or mitigate the effects of aging is compiled for each separate classification of component based on voltage category and the specific application under consideration.[13] For example, a general list of potentially applicable activities for medium-voltage power cable may include the following:

- periodic visual/physical inspection of cable jacketing, terminations, or splices (during maintenance or otherwise)
- surveillance or operability testing of end devices which demonstrates cable system functionality
- periodic hi-pot testing of the cable or end devices
- periodic thermographic inspection of circuits and their terminations
- routine monitoring and pumping of spaces where water accumulates and medium-voltage circuits are located.

Hi-pot testing is not performed for low-voltage systems; however, Arrhenius analysis (pursuant to 10CFR50.49 [6.3]) and environmental monitoring may be used. Similar lists may be developed for the other categories of equipment. Once these lists are developed, they may be applied to the circuits (or groups of circuits) identified at the completion of Step 3 to determine which activities are applicable to which circuits.

Step 5: Evaluation of Aging Management Effectiveness

After a list of potentially applicable activities is generated, these activities are evaluated against the aging stressors and effects previously identified for a specific circuit or group of circuits. This evaluation is based on the stressors and effects that were used to initially select the circuit/group for further consideration. For example, adequate aging management for low-

[13] Note that other methods of categorization may be used; voltage category was chosen as the basis for this illustration because both the types of aging degradation effects and the aging management techniques used are often different for different voltage categories.

voltage circuits located in a high ambient temperature environment (such as primary containment) would be evaluated with regard to the ability of the listed activities to identify and mitigate thermal aging effects such as jacket/insulation embrittlement and cracking. Similarly, adequate aging management for low-voltage, impedance-sensitive instrumentation circuits such as neutron monitors would be judged in terms of detection or prevention of oxidation or corrosion of connector contacts.

Criteria that can be used in determining whether aging effects are managed by such programs include:

1. detection and mitigation of aging effects before loss of intended function (i.e., the failure of the component is progressive, the periodicity of monitoring is such that detection occurs before loss of function, and the environmental conditions during normal operation and design basis events are similar and/or the CM technique has the ability to detect indications during normal conditions that could result in fault conditions during a design basis event)

2. the ability to monitor parameters of the component that can be correlated to aging effects,

3. the existence of specific acceptance criteria, alert, or action values for determining the need for corrective action,

4. specific inclusion of the equipment under evaluation within the program(s),

5. the presence of administrative program controls and formal reviews, and

6. continued participation and evaluation of industry efforts and advancements in condition monitoring.

Alternatively, an analysis of the aging effects which demonstrates that intended function is maintained during the period of extended operation even if the relevant aging effects are not detected or addressed may be used as a basis for demonstrating that the aging effects are managed for the component under consideration. Plant-specific or industry failure history, engineering or environmental qualification analyses, or similar sources can be used to support this conclusion.

Another consideration relates to the use of sampling techniques for aging management. Aging management programs that address equipment aging on a sampling or rotational basis (e.g., which sample a percentage of the total inventory of similar circuits exposed to similar stressors) may be used in support of the demonstration of aging management for the entire inventory, assuming (1) the most severe applications are monitored as part of the program, and (2) the specific aging management activities address particular aging stressors and effects relevant to the entire inventory. As an example, a group of similar circuits all located within a comparatively high-temperature plant space that were not eliminated from further consideration in Step 1 could be managed by periodically monitoring the most severe application within the space for thermal degradation effects. However, a similar cable in that same space that is subjected to a different aging stressor (such as localized mechanical damage) may not be adequately managed by such activities.

Step 6: Identification of Additional Aging Management Activities

The output from Step 6 is a list of additional aging management activities required to demonstrate adequate management of aging effects. These activities may take the form of either enhancements to existing programs (such as expanding the scope of testing/inspection, trending of data, or changing the frequency of performance), or creation of new programs or initiatives (such as establishment of a condition monitoring program, or design changes to equipment). Factors to be considered in determining appropriate additional activities include:

a. **Existence of Suitable Aging Management Methods.** In some cases where management of aging effects cannot be directly demonstrated, the availability (or lack thereof) of suitable condition monitoring or management techniques must be considered. As illustrated in Section 5, some types of degradation are not directly monitored through existing techniques. As an example, water-treeing of medium-voltage power cable is not detected or mitigated through application of any currently available aging management activity or condition monitoring technique; therefore, management of this effect is demonstrated largely through control of critical aging stressors (i.e., removal of water and ionic impurities) as opposed to measurement of physical properties.

b. **Circuit Type, Accessibility, and Amenability.** For both EQ and non-EQ circuits, only certain techniques will be applicable based on whether the circuit is low or medium voltage. Tests such as polarization index, hi-pot, and partial discharge are primarily applicable to medium-voltage power circuits. Similarly, because thermal or radiation aging does not appear to significantly affect the longevity of most medium-voltage power cables, tests that detect thermal or radiation-induced damage are of limited usefulness on these applications. Hence, circuits requiring additional aging management activities must be matched to appropriate techniques based on their voltage category.

   Based on inherent physical limitations, certain types of techniques may not be practical for use on all plant circuits. For example, electrical measurement techniques may be difficult to implement if the circuits to be tested are difficult to de-terminate and re-terminate. Similarly, techniques that directly measure some physical or chemical property of the cable insulation may not be useful for cable enclosed in conduit.

c. **Information from Natural Aging Programs.** Information derived from ongoing industry programs for natural or low-acceleration factor aging can be used in the evaluation of the longevity of cable and termination components. As previously described, such programs may provide information that more accurately predicts the long-term behavior of cable and termination materials (as opposed to highly accelerated aging or qualification programs, which may have substantial inherent inaccuracies or conservatisms). The types and frequency of aging management and condition monitoring may therefore be adjusted based on such information.

Furthermore, for environmentally qualified components, the controlling regulatory requirements allow the use of such information for the extension of qualified life.

d. **Cost versus Benefit.** The cost of implementing certain techniques or programs must be balanced against the potential benefit of the monitoring. For example, circuits with low replacement cost may be better replaced at conservative intervals to avoid potential operational failure as opposed to instituting a condition monitoring or testing program. However, with most plant circuits (especially those located inside conduit in primary containment), per-foot replacement costs can be exceedingly high and the costs of condition monitoring/testing programs comparatively low so that these programs are economically justified. Other factors to consider include the risk significance of the failure of the component(s) under consideration, personnel radiation exposure (man-rem) associated with monitoring versus replacement, and potential impacts on scheduling.

e. **Availability of Naturally Aged Specimens.** In a limited number of plants, abandoned or spare circuits installed alongside of operational circuits may be available for comparative analysis. By extracting a small section of the circuit that has been exposed to similar environmental stresses, an inference regarding the condition of the operational circuit may be made and adequate aging management demonstrated. As with the sampling techniques previously described, caution must be exercised to ensure that the naturally aged specimen used as the basis for evaluation is representative of the inventory for which management is being demonstrated.

As indicated in Section 6.1, OIT and compressive modulus techniques appear to be useful for evaluating cable and termination material condition as a function of aging. Generally speaking, these techniques will be most effective for those applications where thermal or irradiation aging of dielectric material occurs and is of significance to the functionality of the component (such as low-voltage cable). TDR and similar techniques may be useful in detecting age-related degradation of certain circuit component (including terminations and electrical connections). Testing protocols for TDR, density, etc. techniques have been, or are in the process of being, developed to allow their application to installed specimens for condition monitoring purposes. The Cable Diagnostic Matrix [6.4] currently under development by EPRI more specifically addresses alternatives for cable condition monitoring.

6.3.4 Use of Previous Aging Management Reviews and References

Substantial industry and utility effort has been expended to date in examining the effects of aging for long-lived passive components used in commercial nuclear plants. In some cases, generic topical reports and aging evaluations have been or are being produced to address the requirements of the LRR, some of which will be submitted to the NRC for review and acceptance. Plant owner's groups, industry organizations, public document room indices, and similar sources can help identify such references. Furthermore, license renewal applications by other utilities may provide substantial resources for a plant beginning the AMR process if they are available. To make effective use of this growing volume of material, the following considerations should be observed:

a. **Scope, Assumptions, and Limitations.** The scope of the reference chosen should be similar to that of the aging management review. In addition, assumptions and limitations inherent in the reference analysis should be compatible with those for the plant in question. Equipment configuration, functions, materials, design parameters, and operating conditions should also be compared; differences in these areas may limit the applicability of the reference, or require supplemental analysis or evaluation to demonstrate that the conclusions reached in the reference regarding aging effects are applicable to the plant equipment as installed.

b. **Demonstration of Aging Management.** The reference selected should identify the aging effects pertinent to the equipment under consideration and their impact on intended function. Assumptions and bases used for determining these aging effects should be applicable to the plant in question; this can be verified through a review of the specific plant's failure/maintenance history and similar sources. The aging management programs and activities identified in the reference that are used to detect and mitigate the aging effects described should be compared with those in the plant; any differences should be justified, or other activities/enhancements that address these differences demonstrated.

6.4 References

6.1 Title 10, U.S. Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," published in the Federal Register, Vol. 60, May 8, 1995 (page 22461).

6.2 NEI Report 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 0, The Nuclear Energy Institute, Washington, D.C., March, 1996.

6.3 Title 10, U.S. Code of Federal Regulations, Part 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," (10CFR50.49), published in the Federal Register, Vol. 48, No. 15, January 21, 1983 (pages 2730 to 2734).

6.4 "Cable Diagnostic Matrix," prepared for EPRI by Ogden Environmental and Energy Services, December 1995 (draft).

APPENDIX A. DEFINITIONS

Notes:

1. Definitions are derived from one of the following sources unless otherwise noted:

   a. EPRI TR-100844, "Nuclear Power Plant Common Aging Terminology" [A.1]

   b. "Glossary of Terms and Definitions," Okonite [A.2]

   c. "Wire and Cable Reference Glossary," ITT Surprenant [A.3]

   d. Standard Handbook for Electrical Engineers [A.4]

2. Also see Appendix D, which contains a list of acronyms.

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abrasion resistance the ability of a wire, cable, or material to resist surface wear

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

acceptance criterion specified limit of a functional or condition indicator used to assess the ability of an SSC[1] to perform its design function

accident environments the postulated conditions resulting from either a LOCA or HELB inside primary containment, or from a HELB outside primary containment [A.5]

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

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

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

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

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

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

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

[1] System, structure, or component

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

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

allowable pulling tension the maximum force before a cable becomes permanently weakened in strength, pressure, tension, etc.

ampacity the current in amperes a conductor can carry continuously under the conditions of use without exceeding its temperature rating [A.6]. Current-carrying ampacity, expressed in amperes, of a wire or cable under stated thermal conditions [A.7].

analysis a process of mathematical or other logical reasoning that leads from stated premises to the conclusion concerning specific capabilities of equipment and its adequacy for a particular application [A.8]

area of conductor the size of a conductor cross section

armor a metallic sheath or shield wrapped around cable for added mechanical protection

Arrhenius model an aging model for chemical degradation developed from the basic probabilities of collision of reacting molecules. The model relates the rate of degradation to absolute temperature by a simple exponential function

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

braid a fibrous or metallic group of filaments interwoven in cylindrical form to form a covering over one or more wires

breakdown synonym for *complete failure*

breakdown of insulation failure of an insulation resulting in a flow of current through the insulation. It may be caused by the application of too high voltage or by defects

cable a factory assembly of two or more conductors having an overall covering [A.6]. A conductor with insulation or a stranded conductor with or without insulation and other coverings (single-conductor cable) or a combination of conductors insulated from one another (multiple-conductor cable) [A.7]

cable assembly a completed cable and its associated hardware ready to install

cable creep a phenomenon where portions of a cable move or creep in relation to the supporting raceway or structure due primarily to thermal variations and gravity effects

cable filler the material used in multiple conductor cables to occupy the spaces formed by the assembly of components, thus forming a core of the desired shape

cable system a circuit or group of circuits, including the cable and terminations

capacitance the property of a system of conductors and dielectrics which permits the storage of electrically separated charges when potential differences exist between the conductors

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

coating a material applied to the surface of a conductor to prevent environmental deterioration, facilitate soldering, or improve electrical performance

coaxial cable a cable consisting of two cylindrical conductors with a common axis, separated by a dielectric

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

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

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

complete failure failure in which there is complete loss of function

composite cable a cable consisting of two or more different types or sizes of wires

concentric stranding a central wire surrounded by one or more layers of helically wound strands in a fixed round geometric arrangement

condition surrounding physical state or influence that can affect an SSC

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

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

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

condition trending synonym for ***condition monitoring***

conductor

- bare: a conductor having no covering or electrical insulation whatsoever
- covered: a conductor encased within material of composition and thickness that is not recognized by this Code as electrical insulation
- insulated: a conductor encased within material of composition and thickness that is recognized by this Code as electrical insulation [A.6]

conduit a tube or trough in which insulated wires and cables are run

copper-clad aluminum conductors conductors drawn from a copper-clad aluminum rod with the copper metallurgically bonded to an aluminum core. The copper forms a minimum of 10% of the cross-sectional area of a solid conductor or each strand of a stranded conductor [A.6]

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

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

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

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

design basis conditions synonym for ***design conditions***

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

design basis event conditions service conditions produced by design basis events

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

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

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

design service conditions synonym for ***design conditions***

deterioration synonym for ***degradation***

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

diagnostic evaluation synonym for ***diagnosis***

duct an underground or overhead tube for carrying electrical connectors

duty	continuous duty:	operation at a substantially constant load for an indefinitely long time
	intermittent duty:	operation for alternate intervals of (1) load and no load; or (2) load and rest; or (3) load, no load, and rest
	periodic duty:	intermittent operation in which the load conditions are regularly recurrent
	short-time duty:	operation at a substantially constant load for a short and definitely specified time
	varying duty:	operation at loads, and for intervals of time, both of which may be subject to wide variation

environmental conditions ambient physical states surrounding an SSC

equipment qualification the generation and maintenance of evidence to assure that the equipment will operate on demand, to meet system performance requirements

equivalent life the length of time at a specific temperature during which the amount of thermal degradation that occurs to an organic material will be equal to that caused by a different temperature applied for a different length of time [A.9]

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

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

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

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

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

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

failure evaluation synonym for ***failure analysis***

failure mechanism physical process that results in failure

failure mode the manner or state in which an SSC fails

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

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

flame resistance the ability of a material not to propagate flame once the heat source is removed

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

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

gauge a term used to define the physical size of a wire

impedance ratio of phasor-equivalent driving force (such as voltage) to the phasor-equivalent response (such as current)

inservice inspection methods and actions for assuring the structural and pressure-retaining integrity of safety-related nuclear power plant components in accordance with the rules of ASME Code, Section XI [A.10]

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

inservice test a test to determine the operational readiness of a component or system [ASME Code, Section XI][2]

inspection synonym for ***surveillance***

[2] Brackets indicate adoption of a formal definition from codes, standards, or regulations

installed life period from installation to retirement of an SSC

insulation the part that is relied upon to insulate the conductor from other conductors or conducting parts or from ground [A.7]

insulation level 100% cable for use on grounded systems or where the system is provided with relay protection such that ground faults will be cleared as rapidly as possible but in any case within one minute

insulation level 133% cable for use on ungrounded or grounded systems or where the faulted section will be deenergized in a time not exceeding one hour

interstices voids or valleys between individual strands in a conductor or between insulated conductors in a multiconductor cable

jacket a protective covering over the insulation, core, or sheath of a cable [A.6]. A thermoplastic or thermosetting covering, sometimes reinforced, applied over the insulation, core, metallic sheath, or armor of a cable [A.7]

lay the total amount of stranding required to form one completed twist of a cable

life period from fabrication to retirement of an SSC

life assessment synonym for *aging assessment*

life cycle management synonym for *life management*

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

lifetime synonym for *life*

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

malfunction synonym for *failure*

margin the difference between the most severe specified service conditions of the plant and the conditions used in type testing to account for normal variations in commercial production of equipment and reasonable errors in defining satisfactory performance [A.8]

mean time between failures arithmetic average of operating times between failures of an item [IEEE Std 100] [A.7]

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

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

normal aging degradation aging degradation produced by normal conditions

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

normal operating conditions synonym for ***normal conditions***

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

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

operating service conditions synonym for ***operating conditions***

operational conditions synonym for functional conditions

overcurrent any current in excess of the rated current of equipment or the ampacity of a conductor. It may result from overload, short circuit, or ground fault [A.6]

overhaul (noun) extensive repair, refurbishment, or both

performance indicator synonym for ***functional indicator***

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

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

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

potting the sealing of a cable termination or other component with a liquid which thermosets into an elastomer

preconditioning synonym for ***age conditioning***

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

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

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

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

pulling tension the longitudinal force exerted on a cable during installation [A.7]

qualification verification of design limited to demonstrating that the electric equipment is capable of performing its safety functions under significant environmental stresses resulting from design basis accidents in order to avoid common-cause failures [A.11] *qualified life* period for which an SSC has been demonstrated, through testing, analysis, or experience, to be capable of functioning within acceptance criteria during specified operating conditions while retaining the ability to perform its safety functions in a design basis accident or earthquake

raceway an enclosed channel designed expressly for holding wires, cables, or busbars, with additional functions as permitted in this Code [A.6]

radiation damage threshold the lowest dose which induces permanent change in a measured property(s) of a material; also, the first detectable change in a property of a material due to the effect of radiation

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

reconditioning synonym for *overhaul*

refurbishment planned actions to improve the condition of an unfailed SSC

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

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

remaining service life synonym for *remaining life*

remaining useful life synonym for *remaining life*

repair actions to return a failed SSC to an acceptable condition

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

residual life synonym for *remaining life*

retirement final withdrawal from service of an SSC

rework correction of an inadequately performed fabrication, installation, or maintenance

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

root cause analysis synonym for *failure analysis*

routing the path followed by a cable or conductor

safety function the required action, non-action, or non-failure of safety-related equipment

safety-related equipment that is 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, and (iii) the capability to prevent or mitigate the consequences of accidents that could result in potential off-site exposures comparable to 10CFR Part 100 guidelines. Safety-related electric equipment is referred to as Class 1E in IEEE 323-1974 [A.12]

screen a semiconducting layer used under and over the insulation of power cables rated over 2 kV to reduce electrical stresses and corona

screened conductor cable a cable in which the insulated conductor or conductors are enclosed in a conducting envelope or envelopes

semiconducting layer an extruded layer or tape of such resistance that when applied between two elements of a cable the adjacent surfaces of the two elements will maintain substantially the same potential.

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

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

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

sheath the overall protective covering for the insulated cable [A.7]

shield as normally applied to instrumentation cables, refers to a metallic sheath (usually copper or aluminum) applied over the insulation of a conductor or conductors for the purpose of providing means for reducing electrostatic coupling between the conductors so shielded and others which may be susceptible to or which may be generating unwanted (noise) electrostatic fields [A.7]

sidewall bearing pressure the crushing force exerted on a cable during installation [A.7]

significant aging mechanism an aging mechanism which could potentially affect the functionality of the equipment if left unmitigated (see Section 4)

significant and observed aging mechanism the subset of significant aging mechanisms which are reflected in empirical and/or anecdotal failure data (see Section 4)

simultaneous effects combined effects from stressors acting simultaneously

solid conductor a single unit not divided into parts

stress synonym for ***stressor***

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

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

surveillance requirements test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within the safety limits, and that the limiting conditions of operation will be met [10 CFR 50.36][A.13] (use only when specific regulatory and legal connotations are called for)

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

tape wrap a spirally or longitudinally applied tape over an insulated or uninsulated wire *synergistic effects* portion of changes in characteristics of an SSC produced solely by the interaction of stressors acting simultaneously, as distinguished from changes produced by superposition from each stressor acting independently

temperature rating the maximum possible normal and accident operating temperatures for a cable; typically written on the outer covering of a cable

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

thermal aging one method of accelerated aging, usually associated with the Arrhenius model

thermal life the period of time for which a piece of equipment has been evaluated, on the basis of Arrhenius plots of materials, to be able to endure thermal conditions and still perform its required safety function during or after the occurrence of harsh environment conditions

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

useful life synonym for *service life*

voltage drop the difference in voltage between the two different ends of a cable

wearout failure produced by an aging mechanism

wire a factory assembly of one or more insulated conductors without an overall covering [A.6]

A.1 References

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A.3 "Wire and Cable Reference Glossary," ITT Surprenant, 1984.

A.4 D. Fink and H. Beaty, Standard Handbook for Electrical Engineers, Twelfth Edition, McGraw-Hill, New York, 1987.

A.5 NRC IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," Nuclear Regulatory Commission, January 14, 1980, [ftp://ftp.fedworld.gov/pub/nrc-gc/bl79001b.txt]

A.6 National Electrical Code® - 1990 (NFPA 70), National Fire Protection Association, Batterymarch Park, Quincy, MA, ©1989.

A.7 IEEE Standard 100-1984, "Standard Dictionary of Electrical and Electronics Terms," Institute of Electrical and Electronics Engineers, 1984.

A.8 IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," The Institute of Electrical and Electronics Engineers, Inc., corrected copy June 1976

A.9 EPRI NP-1558, "A Review of Equipment Aging Theory and Technology," prepared by Franklin Research Center for the Electric Power Research Institute, September 1980.

A.10 ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, 1995 Edition, The American Society of Mechanical Engineers.

APPENDIX B. DESCRIPTION OF COMPONENTS

B.1 Component Descriptions - Cable and Wire

Conductors

Conductor electrical and mechanical properties are largely the result of the material used in fabrication of the conductor. In addition to the electrical requirements, mechanical properties of the conductor (such as tensile strength, weight, diameter, and thermal coefficient of expansion) is considered when choosing a material. Cable conductors used in nuclear plant applications are normally manufactured from copper (coated or noncoated), aluminum, or copper-clad aluminum.[1] Coating of copper conductors helps prevent conductor corrosion and ease insulation stripping and termination soldering. Copper-clad aluminum is predominantly used to prevent corrosion of the conductor [B.1], [B.2], [B.3], [B.4].

Copper conductors are the most popular type of conductor because of the following advantages: copper volume conductivity is greater than that of aluminum, thereby requiring less insulation, jacketing, and other materials; copper cable is smaller at equal ampacity levels, thereby requiring smaller conduit; and, copper cable is more economical.[2] In addition, aluminum conductors are susceptible to cold flow (creep), which can result in high resistance connections and increased ohmic heating. Contact of aluminum conductors with dissimilar metals may result in electrolytic corrosion if interposing coatings are not applied. Furthermore, aluminum conductors oxidize to a compound (aluminum oxide) that is nonconducting; therefore, special preparation of the termination area is required to remove and inhibit the formation of aluminum oxide. One benefit of aluminum conductors is their comparatively low weight for the same ampacity; therefore, based on the cost differential between aluminum and copper, aluminum conductors are usually only considered for larger sizes of power cable.

In the United States, conductors are most often sized according to the American Wire Gauge (AWG) system,[3] which is based on a constant mathematical ratio between diameters of successive gauge numbers (thus, the smaller the AWG number, the larger the cable). Typical indices for measuring conductor size include AWG number or kcmil (1 kcmil = 1 MCM = 1000 circular mils). A mil is defined as one thousandth of an inch, whereas a circular mil is the area of a circle one mil in diameter (equal to 0.7854 square mils) [B.1].

Most cable conductors are stranded, which is the twisting together of wire strands to form a conductor. ASTM B33 [B.5] defines the construction of a stranded copper conductor;

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[1] Other conductor materials include copper-clad steel, copper-chromium alloy, zinc-coated steel, copper beryllium alloy, aluminum-clad steel, and bronze; however, no cables using these materials were identified as being in use in U.S. commercial nuclear plants in any appreciable quantity.

[2] For a few years during the 1970s, the price of copper increased dramatically from its historical norms. Aluminum wires and connections were used in much greater quantities until the price of copper decreased to its typical market level.

[3] Other wire gauge measurements, such as the Steel, Birmingham, Standard (British), Old English, Millimeter, and German wire gauges are in varying degrees of use outside the nuclear industry.

the stranding class denotes the number and size of wires used in forming a given conductor. The purpose of stranding conductor cable is to produce a greater amount of flexibility. However, stranding generally results in increased weight and electrical resistance (due to increased conductor length), and may slightly reduce the tensile strength of the conductor. Most of the cable installed in nuclear plants uses stranded conductors; exceptions may include some coaxial/triaxial cables, mineral insulated (MI) cable, and thermocouple extension wire. Figure B-1 shows the conductor configuration of a typical nuclear plant medium-voltage power cable. Figure B-2 shows a typical shielded low-voltage control cable.

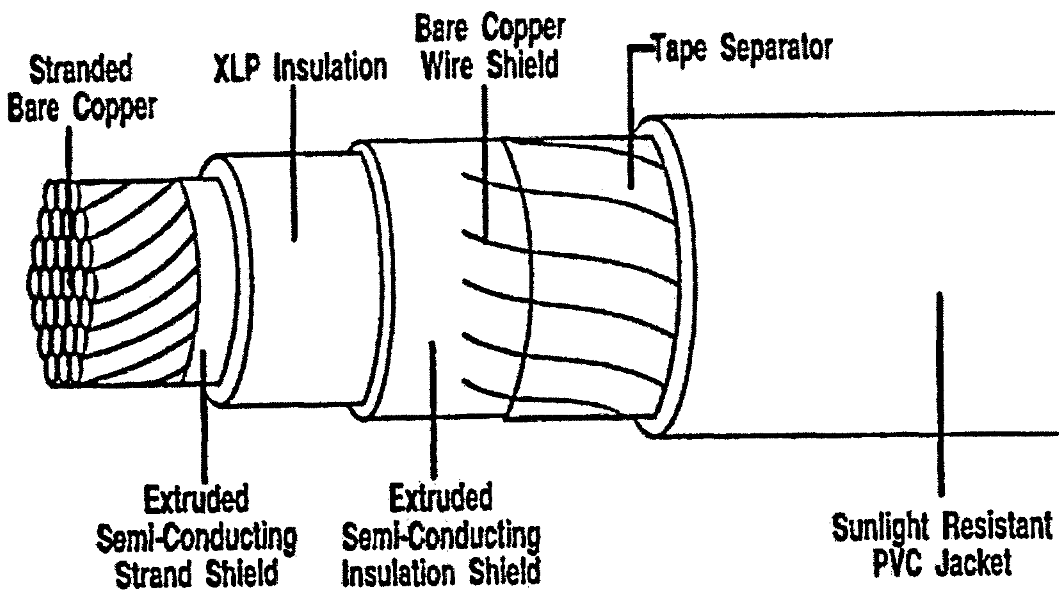


Figure B-1 Cross Section of Typical Medium-Voltage Electrical Power Cable

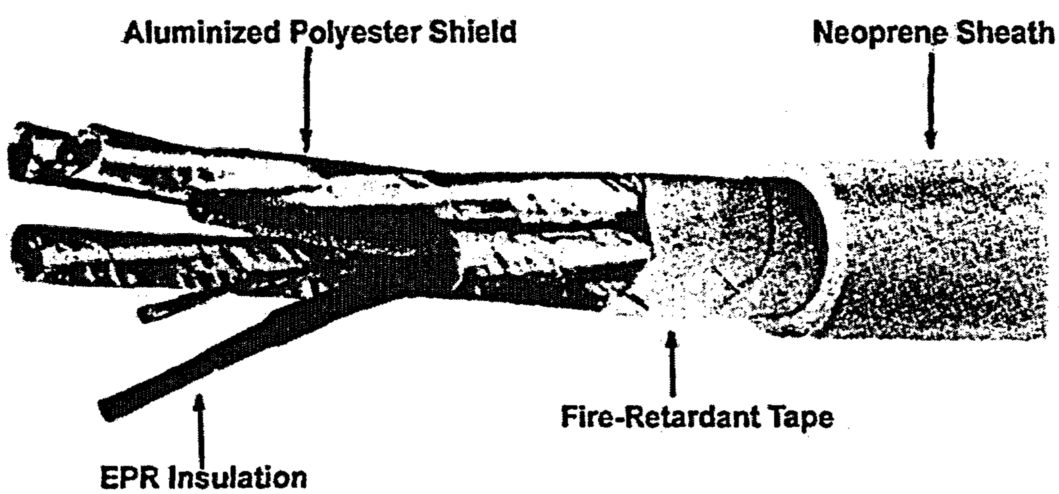


Figure B-2 Typical Low-Voltage Shielded Control Cable

Thermocouple extension wire generally uses solid metal alloy conductors; these alloys are chosen for their specific electrical characteristics (i.e., dissimilar metals produce an electromotive force (emf) or voltage that varies with the temperature of the junction). The inclusion of these alloys permits use of a known temperature-versus-voltage response curve. These cables are often composed of a twisted, shielded pair of conductors to minimize electromagnetic noise interference [B.2], [B.3]. A thermocouple extension is composed of the same materials as the junction to prevent formation of additional potentials at the interface between the junction and the extension cable.

Appendix C is a partial listing of standards related to electrical conductors.

Electrical Insulation and Semi-Conducting Shield

Essentially any material that has a high resistance to the flow of electric current can be used as insulation on an electrical cable. Material selection is based on the intended application and function, including the intended service voltage. Standard insulation ratings for nuclear plant cable include 300 and 600 Vac; 2, 5, 8 and 15 kVac; and 125 or 250 Vdc. Normal operating voltages are typically well below the ratings (i.e., 480 Vac for 600-V rated cable, 4160 Vac for 5-kV rated cable, etc.). Voltage applied to the dielectric may increase significantly during transient system operation, switching, surges, or faults.

The ability of an insulation to withstand such voltage stress without significant current flow through the insulation is measured by the material's dielectric strength. Dielectric strength is related not only to the electrical and physical properties of the insulation material, but also to the thickness of that material. Hence high dielectric strength material may be used in lesser thicknesses to achieve the same insulation capability as a lower dielectric strength material. Use of thinner insulation has substantial benefits with regard to cost, overall cable size and weight, and heat dissipation. Insulation thicknesses suitable for a given voltage rating are specified by ICEA and AEIC standards for each of the common cable insulating materials.

The following cable design characteristics are influential in the selection of a particular material: insulation temperature rating (with respect to normal and accident maximum operating conditions), dielectric strength, moisture resistance, flame resistance, flexibility, size, and weathering properties. Other mechanical and electrical properties that can influence the selection of a material include tensile strength, elongation, modulus of elasticity, hardness, partial discharge level, dissipation factor, insulation resistance (IR), and power factor [B.1], [B.2], [B.3].

Certain manufacturers' medium-voltage cable uses a "shield"[4] layer installed between the conductor and the insulation. The purpose of this layer is to reduce or control the dielectric stress between the conductor and the insulation and drain charges at the surface of the insulation such that large potential gradients do not occur at discontinuities between the insulation and the conductor. This layer is typically semi- or nonconducting, and provides several functions, including (1) reduction or elimination of voids between the conductor and insulation,

[4] This is not a shield in the sense of an electric or magnetic field shield. It is a mechanism to limit aging degradation of insulation due to voltage stress.

(2) reduction of electrical stress across the insulation, and (3) reduction of charge injection into the insulation [B.3], [B.6].

Voltage Withstand

Most power plant cable is not subject to lightning- or switching-induced surges; however, most cables are designed with sufficient basic impulse insulation level (BIL) capability so as to withstand the significant voltage stress resulting from these events. This capability is typically expressed in terms of voltage withstand capability (i.e., 110-kV BIL for a 15-kV power cable), and is somewhat higher for cable than that of other electrical distribution equipment. In general, however, the 60-Hz requirements of a cable dictate the insulation characteristics (rather than the BIL requirements) [B.1], [B.3].

Overload Characteristics

Insulation level, which is a measure of the material's ability to withstand fault conditions for given periods of time without experiencing dielectric breakdown, is another measurement of the capability of an insulating material. It is related to the thermal capability and physical properties of the material. Selection of a insulation level for a specific application is made based on the phase-to-phase voltage, and the type of system (i.e., grounded or ungrounded). Three distinct levels are specified [B.1], [B.2], [B.3], [B.6]:

100% Level: These cables may be applied on systems with sufficient protection such that ground faults will be rapidly cleared (within 1 min). 100% cables are primarily used on grounded systems.

133% Level: Cables in this category are used in primarily in ungrounded systems or where the clearing time requirements of the 100% level can not be met. A maximum clearing time requirement of 1 hr is imposed on cable of this type.

173% Level: Cables in this category are used in applications where the duration of the ground is indefinite.

Insulation Materials

Cable and wire insulation and dielectric materials include the following [B.1], [B.2], [B.3], [B.4], [B.6], [B.7], [B.8], [B.9], [B.10], [B.11], [B.12], [B.13], [B.14].

- Cross-linked polyethylene/polyolefin (XLPE/XLPO)
- Low molecular weight polyethylene (LMWPE)
- High molecular weight polyethylene (HMWPE)
- Chlorinated polyethylene (CPE)

- Hypalon® (Chlorosulfonated polyethylene (CSPE))
- Ethylene propylene rubber (EPR)
- Neoprene® rubber
- Nitrile rubber
- Butyl rubber
- Polyvinyl chloride (PVC)
- Silicone rubber (SR)
- Tefzel® (ethylene tetrafluoroethylene (ETFE))
- Kapton® (polyimide)
- Alkane imide
- Mineral insulation (MI)
- PEEK (polyethyl-ethyl ketone)

Each of these materials has unique thermal, irradiation, mechanical, chemical, and dielectric properties that make it suited for specific types of nuclear plant applications. Note that some materials (such as neoprene, PVC, and Hypalon®) may also be used as jacketing materials. Generally, these materials may be divided into two categories: organic and inorganic. Organic insulating materials (by far, the more prevalent of the two) can be further classified by their thermal characteristics as either thermosetting, thermoplastic, or elastomeric.

Thermosets are polymers that are cured or permanently set into shape. This curing is an irreversible reaction known as crosslinking, which results from exposure to heat or ionizing radiation. Once crosslinked, the material cannot be returned to its original state. Thermoset materials include polyesters, urethanes, epoxies, phenolics, and silicones [B.15].

Thermoplastics are not cured or permanently set with heat. These materials will melt under sufficient heat and may be subsequently reformed. Thermal degradation of the material limits the number of times a thermoplastic may be reheated and reformed. The molecular structure of thermoplastics is flexible compared with that of thermosets. Common thermoplastics include polyethylenes (crosslinked, and low/high density) and polypropylenes, polyimide,[5] vinyl (PVC), and fluorocarbon polymers (such as Teflon® and Tefzel®) [B.15].

[5] Polyimide (Kapton®) does not melt but rather decomposes at extremely high temperature.

Elastomers are rubber-like polymers whose service temperature is above their glass transition temperature.[6] Rubber is a natural material, whereas synthetic rubbers are materials synthesized to reproduce the best characteristics of natural rubber. Common cable elastomers include EPR, CSPE, styrene-butadiene rubber (SBR), butyl, nitrile, silicone, and neoprene rubbers [B.15].

Elastomers and thermoplastics (specifically EPR/EPDM and XLPE, respectively) are the most commonly used materials for nuclear plant cable insulation based on their low relative cost, good overall mechanical and electrical properties, and good availability. See discussion of EPRI NUS database contained in Section 3 of this guideline.

Polyethylene (a polyolefin) is a common cable insulation material. Three different grades or types are specified: low density, medium density, and high density polyethylene. High density polyethylene is used primarily in medium-voltage applications. Low-density is often used as a dielectric in coaxial or triaxial cables. Polyethylene may also be of the crosslinked variety, which refers to the chemical bonding or crosslinking between individual polyethylene molecules that occurs within the material. Low/medium/high density polyethylene has somewhat differing properties than crosslinked polyethylene. Various manufacturing processes control the size, disposition, and amount of crosslinking occurring in a specific type of polyethylene. Crosslinking in polyethylene used in electrical cable applications is usually achieved by one of two methods: chemical crosslinking or radiation crosslinking. The former method uses a chemical agent (such as a peroxide) to induce the crosslinking reaction, where as radiation (typically an electron beam) is used for the latter. Exposure to either of these processes results in a material with substantially increased properties over standard polyethylene [B.15], [B.16].

Other variants of the polyethylene family include chlorinated polyethylene (CPE) and chlorosulfonated polyethylene (CSPE, or Hypalon®). CPE is chemically cured and produced in varying grades based on chlorine content; higher chlorine content yields better fuel/oil resistance, gas impermeability, and tear resistance, whereas lower content gives better heat resistance and compression set. Hypalon® is an ethylene co-polymer that is added in varying quantities to elastomers to improve their properties such as ozone, chemical, or abrasion resistance. Hypalon® and CPE are used primarily as jacketing materials in nuclear plant cable, although some use of these materials as insulation has occurred [B.2], [B.15].

Polyvinyl chloride (PVC) is widely used as insulation due to its good mechanical and electrical properties, and low relative cost. It is also highly resistant to moisture and many chemicals. However, PVC is not very resistant to thermal or irradiation degradation, and hence is not frequently used in applications subjected to such environments.

Silicone rubber (SR) is often used as an insulation material in high ambient temperature environments because of its high resistance to thermal degradation. However, SR does have relatively poor resistance to cutting, tearing, and abrasion; therefore, silicone rubber-insulated

[6] Per Reference [B.15], an elastomer is defined as (1) capable of being stretched 100%, and (2) after being stretched and held for 5 min, capable of retracting to within 10% of its original length within 5 min of release.

cables are often encased in a protective sheath or braid. Silicone rubber is also more expensive than typical EPR or XLPE-insulated cables, and is used to a lesser degree in nuclear plants [B.2].

Kapton® is a trade name for a polyimide film developed by E.I. duPont de Nemours Inc. Kapton® is typically applied by wrapping it around the conductor, rather than being extruded or injected. It is often used in conjunction with a fluoropolymer (such as Teflon®) in these applications. Kapton® has high thermal and radiation resistance in comparison to other common insulation materials, yet suffers other drawbacks with respect to properties under exposure to moisture and caustics, and resistance to incidental surface damage such as nicks and cuts. Kapton® is most often found in instrument or solenoid leads or electrical penetration assemblies, and is rarely[7] used in bulk cable runs in nuclear plants [B.17].

Tefzel® is a thermoplastic fluoropolymer with overall excellent electrical and mechanical properties. Tefzel® has a high resistance to thermal degradation and outstanding resistance to most chemicals. Radiation resistance is fair in comparison to other thermoplastics, and markedly better than Teflon® (another fluoropolymer) [B.18].

Specific formulations of the materials listed above vary significantly among different manufacturers, and other ingredients (such as fillers and plasticizers) are included with the base material to enhance material properties and/or reduce cost. The practical significance of different formulations is that each different cable type using ostensibly the same generic material (such as EPR) may have substantially different properties based on the differences in additives and formulation. Furthermore, differences or inconsistencies in the fabrication and extrusion processes (such as void formation or inclusions) may produce significantly different results in terms of the insulation's resistance to voltage stress over time; this is especially critical in medium-voltage cable, which experiences a proportionately higher voltage stress than low-voltage insulation.

Inorganic materials used in power plant cable insulation include various oxides such as magnesium, aluminum, and silicone (hence the term "mineral insulated"). These inorganic materials have extremely high resistance to thermal and radiation exposure; however, they are comparatively expensive, difficult to terminate, and have limited flexibility compared to thermoplastic or elastomeric insulation. In addition, they are typically hygroscopic (i.e., water absorbing) and require sealing from the effects of moisture via metal sheathing. Accordingly, they are used only in very limited applications requiring their unique properties, and only a small fraction of cable installed in the typical nuclear plant is mineral insulated [B.2].

Thermal Ratings

Organic cable insulation typically has three different thermal ratings: one for normal operation (continuous operation at normal current levels), one for emergency overload (short-term use at currents somewhat in excess of normal levels), and one for short circuit conditions (extremely short duration operation at currents substantially in excess of normal levels). These

[7] The most notable use of Kapton in nuclear plants is associated with leads in electrical penetration assemblies.

ratings take the form of maximum conductor temperatures at which the cable may operate, and are not necessarily indicative of the maximum ambient temperature in which the cable may be safely used. Ohmic heating of the conductor is a function of both the ambient temperature in which the cable is located and the relationship of the current to the rated ampacity of the cable; therefore, the effects of both ambient temperature and ohmic heating must be considered when evaluating the suitability of a given cable insulation's continuous thermal rating [B.1], [B.2], [B.3].

The longevity of the cable insulation is primarily related to the temperature at which it operates.[8] The term "continuous" in this context does not connote indefinite lifetime at the rated temperature; rather, it simply means that the cable may be operated for extended periods continuously at that conductor temperature with no significant insulation damage or loss of electrical properties.

Thermal ratings for continuous operation will vary from material to material; however, they generally fall in the range of 60°C to 125°C for most nuclear plant organic cables, with the majority being rated for 90°C [B.1], [B.2], [B.3], [B.4], [B.11], [B.19], [B.20]. Some of the high-temperature thermoplastics (such as Tefzel®) have thermal ratings of 150°C. Thermal ratings for a given insulation material may vary depending on the application and environment in which the cable is used; for example, some industry standards reduce the thermal rating of insulation if it is exposed to moisture (wet versus dry rating). Furthermore, some disparity exists within the industry as to the appropriate rating for a given material. EPR, for example, may be rated at 75°C in one standard and 90°C in another. Variations in thermal rating also occur based on the type or formulation of material used. For example, PVC insulation rated to 60°C, 75°C, and 90°C may be produced by the same manufacturer for different applications.

Thermal ratings for emergency overload are greater than those for continuous operation (typically 130° to 140°C for a cable rated at 90°C continuous temperature). Short-circuit ratings are generally much higher than the overload rating (generally 250°C), owing largely to the comparatively short fault clearing time as compared with operation under overload conditions. In determining the short circuit rating, consideration is given to the type of insulation material and its physical properties such as resistance to thermal aging and melting point [B.1], [B.3].

Flammability

In addition to resistance to thermal degradation, nuclear plant cable polymers are designed to resist combustion and the production of harmful atmospheric contaminants (including smoke and carbon monoxide). During combustion of a polymer, external heat dissociates (pyrolyzes) the material into various liquids and gases that fuel the combustion process. Flame-retardant additives affect this process through a number of different mechanisms, including interference with combustion reactions, reducing the rate of heat transfer from the flame to the polymer (thereby reducing the rate of pyrolyzation), interfering with the flammability of the pyrolysis by-

[8] With the exception of those cables exposed to other environmental or mechanical influences (such as substantial radiation dose) which may be the limiting factor in terms of insulation service life.

products, and reducing the diffusion rate for these by-products to the flame location. Various chemical agents are used (depending on the type of polymer and its predominant combustion processes) to control the flammability of cable materials. These include (but are not limited to) phosphorous, nitrogen, iodine, fluorine, chlorine, antimony, bismuth, and boron. Some consideration should be given to the effect of these agents on the physical, chemical, and electrical properties of the base material; even small amounts of fire-retardant may produce significant changes in these properties [B.10].

Filler Material

Filler material is used in electrical cable to fill the interstitial regions between individual conductors, thereby providing a more rigid and mechanically stable substrate upon which the outer shield and jacketing layers are applied. Filler also helps prevent migration of moisture longitudinally through the inner regions of the cable; accordingly, it is typically composed of nonhygroscopic (non-water absorbing) organic material so as to preclude swelling and potentially damaging stresses on binding tapes, shields, and cable outer jacketing. The filler material may be either extruded around the conductors during the fabrication process or composed of several discrete segments that are included with the conductors prior to application of the binder tape, shielding, and outer jacket. Filler material in this context should be differentiated from that used in the chemical formulation of insulation or jacketing polymers described previously; chemical filler is generally an inert compound used to improve the chemical and physical properties of the insulation/jacket (such as resistance to thermal aging or oil resistance) and/or reduce its cost [B.3], [B.4], [B.10], [B.12], [B.13].

Tape Wraps

Tape wraps are an economical method of providing added electrical or mechanical protection, or providing other functions. These wraps may be used to bind those components enclosed within the wrap together (to add additional mechanical stability and strength, or hold components in place during the manufacturing process), to provide additional electrical insulation or semiconducting properties, to identify individual conductors or conductor groupings, or to provide shielding of the conductors for electric and magnetic fields (see the discussion of shielding below). Tape wraps may be composed of a variety of materials depending on their purpose, including polymers (such as Mylar), metals (generally copper or aluminum), semiconducting materials (including thermoplastics, woven fabrics, or paint), or combinations thereof. These materials are often nonhygroscopic and flame-retardant. Tape wraps are typically applied in a layer between the conductor insulation and the outer jacket or shield (if installed), depending on the design requirements of the cable. Tape wrap thickness will vary based on design requirements, but generally is on the order of 1 to 2 mils. Tape wraps may be applied either radially (wound around the core in a helical fashion) or longitudinally (parallel with the central axis of the cable). Drain wires (uninsulated small-gauge conductors) are frequently used as a ground connection for metallic tape wraps; these wires are laid in physical contact with the metallic wrap during fabrication so that ground potential is maintained on the wrap during cable operation [B.1], [B.2], [B.3], [B.12], [B.13].

Shielding

Shielding is commonly used in instrumentation, control, and thermocouple extension applications to control electromagnetic and electrostatic effects on the conductor from external magnetic and electric fields. Similarly, shielding is used on medium (and high) voltage power applications to reduce electric field intensity generated external to the cable by the energized conductor, and limit radio frequency interference. A third function of shielding is to reduce the magnitude of transient voltages in control cables. Shielding helps preclude an uneven voltage gradient resulting from the electric field distribution of an unshielded cable in contact with ground. In medium-voltage cable (5 kV and greater), a symmetrical radial distribution of voltage stress can be obtained if shielding is used; however, nonshielded power cables may be used up to 8 kV under certain conditions [B.2]. The shield on a coaxial/triaxial cable acts as a conductor (signal return path) as well as shielding electric fields [B.1], [B.2], [B.3], [B.4], [B.12], [B.13].

The electrostatic shield is typically composed of either (1) a metallic tape (usually copper, cupro-nickel, zinc, lead, or aluminum) wound helically over the top of the underlying surface, (2) metallic braid, or (3) concentric wires. Power cable shielding components may also include a semiconducting shield screen, which is applied between the conductor insulation (or filler) and shield. This screen acts to fill the void space between the shield and the insulation. Due to the relatively high potentials at which shielded power cables are operated, a substantial voltage gradient may otherwise exist across this void space (air gap); this could result in ionization of the air and potential electrostatic discharge (corona). This effect would eventually result in deterioration of the insulation and cable failure. The semiconducting screen eliminates these air gaps and any associated voltage stress by equalizing the potential of the shield (ground) to that of the outer surface of the insulation. A drain wire is also used to electrically terminate or ground the shield; significant electrostatic potentials may build up on the shield if not properly grounded. In power cable shields that are grounded at two points, significant ohmic heating may result from circulating currents generated in the shield and drains. Drain wires are normally made of tinned copper or aluminum, and run the length of the cable [B.1], [B.2], [B.3], [B.12], [B.13].

Shielding from the effects of external magnetic fields is accomplished in instrumentation and control cables by twisting pairs or triads of conductors. The use of magnetic materials for shielding is not presently considered cost effective; however, new materials that may reduce this cost are currently under development [B.1].

Jacketing

Jacketing refers to a broad range of coverings used in cable construction, which is designed to protect various cable components from environmental effects. External (outer) jacketing is used to protect the underlying insulation, shields, and tapes from mechanical damage (such as abrasion or cutting), fire, chemicals, sunlight, moisture, and the effects of direct burial. Typical external jacket materials include neoprene, PVC, Hypalon®, chlorinated polyethylene (CPE), Tefzel®, Teflon®, nylon, polyethylene (high molecular weight), polyurethane, and glass or asbestos braids. These materials provide sufficient protective capability without inordinately affecting cable flexibility. Jackets for specialty cables (such as those exposed to high temperatures or radiation) may consist of asbestos, glass, or other such resistant materials. External jacketing may also insulate any shielding or armor from ground, thereby allowing for single point grounding of the cable. In unshielded power cable, potential gradients can exist at the surface of the outer jacket, thereby resulting in tangential voltage stress between various points. If the jacketing material is not properly formulated, current can flow along the surface of the jacketing (surface tracking). Accordingly, special discharge-resistant materials are used to prevent this phenomenon. Jacket thickness varies with cable size, number of conductors, and materials of construction.

Similarly, conductor jacketing serves to protect the individual conductors and insulation from damage or degradation, especially in those applications where the individual conductors are exposed such as near terminations or splices. Some of the materials used in external jacketing may be found on individual conductor jackets (such as Hypalon®, nylon, PVC, and glass/asbestos braid); however, these are generally much thinner layers than the outer jackets, and may be thermally or chemically bonded to the underlying insulation [B.1], [B.2], [B.3], [B.12], [B.13].

Armor and Sheathing

Armor/sheathing is used on some cables to provide additional resistance to mechanical damage, moisture, liquids, and gases. Armor is usually composed of either lead, aluminum, or galvanized steel tape helically wound around the outside of the cable, except in applications where the cable will be exposed to severe environments such as those resulting from direct burial, embedment in concrete, or exposure to corrosive substances, or where single point grounding of the armor is desired; in these latter instances, an outer nonmetallic jacket (such as PVC) is applied over the armor. The edges of the armor tape generally overlap (interlock) so that both uniform protection and adequate flexibility are maintained. Armor may also be braided to provide increased flexibility and smaller diameter than the helical interlocking armor. The thickness of the armor varies based on cable size and material; however, these coverings are usually of sufficient thickness to protect the underlying cable from all but the most severe stressors. In general, only a very small percentage of cable used in the typical nuclear power plant (linear footage) is armored [B.1], [B.2], [B.3], [B.12], [B.13].

B.2 Component Descriptions - Terminations

Compression Fittings (Pressure Connections)

Pressure connectors are terminations used to connect the conductor of a wire or cable to another conductor or termination. They use pressure to form and maintain contact between the connector fitting (lug) and the conductor(s) being terminated. Pressure fittings may be applied to both single and multi-stranded conductors, and generally fall into one of two major categories; crimped or mechanical. Crimped lugs are attached by the pressure applied by a crimping tool, and deformation of the metal of the lug and the cable conductor during the crimping process results in a tight connection between the two components. Once crimped and deformed, the metal lug cannot be reused and is discarded upon removal. Use of the properly sized crimping tool and proper pressure are essential to effective crimp formation; furthermore, the crimp lug must be correctly sized to the conductor being terminated (or fill material used if the lug is oversized).

Mechanical pressure fittings are similar to compression lugs, with the exception that the lug contains a separate mechanism for establishing the pressure connection. For example, a threaded bolt or set screw is used to create the required pressure on the conductor; tightening the bolt/screw deforms the conductor and creates the electrical connection. Because the bolt does not deform significantly when tightened, it (and the rest of the fitting) may be removed and refitted. As with crimped fittings, mechanical fittings must be appropriately sized for the conductor being terminated, and an undeformed section of conductor should be exposed when terminating the cable to ensure proper connection and prevent subsequent loosening of the fitting.

Fusion Connections

Fusion connections are formed by the fusion of the conductor material with that of another conductor via welding, brazing, or soldering. These are permanent connections, which require significant effort to determinate and reattach. Advantages of this type of connection include generally high strength and resistance to loosening caused by vibration or other mechanical stresses (loosening results in high electrical resistance). These types of connections are typically used in applications requiring a permanent, stress-resistant connection (such as medium-voltage power cable), where the allowable space for (or access to) the fitting is limited (such as in a multi-pin connector), or where access may be restricted after the initial connection is made [B.1], [B.3], [B.21].

Terminal Blocks

Terminal blocks are components that are mounted in fixed positions inside an electrical device where a number of wire connections must be made. Terminal blocks simplify the connection of wires from different components. Due to their fixed position, controlled grouping and routing of wires inside electrical enclosures is possible. This orderly layout permits rapid, accurate wire installation and speeds maintenance and troubleshooting operations. Terminal blocks are typically installed inside junction boxes or equipment for protection from both physical and environmental damage. Common nuclear plant terminal block manufacturers include GE, Westinghouse, Marathon, States, Kulka, Weidmuller, and Buchanan.

The common one-piece terminal block usually comes in standard units of 2, 4, 6, 8, or 12 terminals on a single base. The terminals can be located on a rigid insulating member, or between barriers that are open (allowing easy access to the contacts) or closed (protecting the contacts from external effects). The terminals themselves are made of conducting material and generally use a post/nut type arrangement for fastening the wire termination to the terminal. The terminal block base is fabricated from a nonconducting material such as phenolic, nylon, or melamine resin. Terminal blocks may also include other optional attachments such as protective covers and fuse holders.

Other types of terminal blocks may employ individual terminal sections ("blocks") that are connected together in the desired length. These blocks have individual terminals, usually of the compression type (i.e., typically a barrel screw), and are used for various power, control, or instrumentation functions, depending on their size and ampacity. The conductor may either be wrapped around the terminal in a "U" shape, or simply inserted underneath a compression device, which firmly clamps the conductor.

Another common terminal block configuration uses a sliding metal link, which allows easy wire installation and electrical disconnection of the two posts during testing (thereby avoiding wire removal). A metallic clamp-and-bolt arrangement is used to form the sliding link between the two posts. Other features are similar to those of the one-piece or unitized terminal blocks [B.3], [B.21], [B.22], [B.23], [B.24].

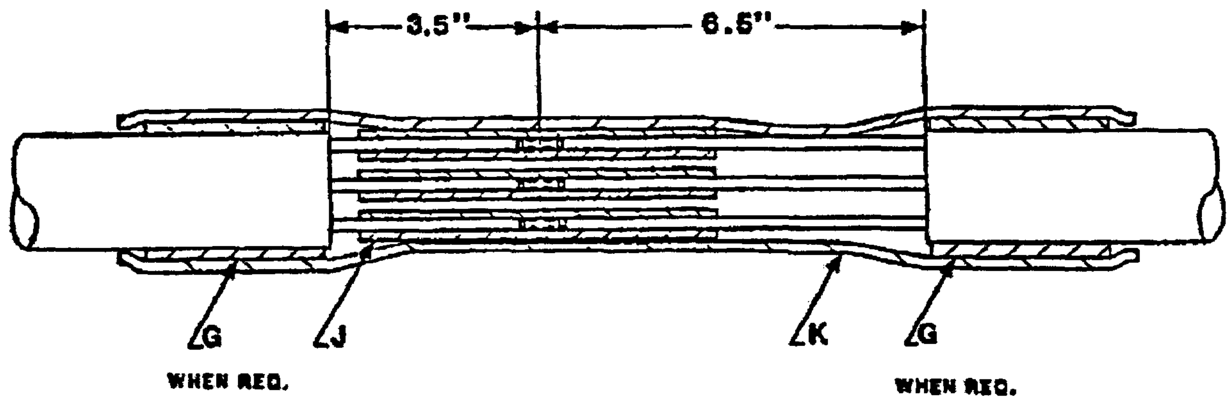
Splices and Splice Insulation

The term splice generally applies to connections made between sections of cable conductors and insulation within a given circuit, rather than those at the end of a circuit (more commonly referred to as terminations). Splices are frequently used to interface between device extension leads (pigtails) and field cable, or connect two or more segments of cable together. The connection of each individual conductor to another generally entails the use of one complete splice assembly, although multi-conductor splice designs have been used. Splices may be used to connect conductors of different types/sizes.

Splices are usually designated based on the voltage range in which they will be used (i.e., low-, medium-, or high-voltage); the greater part of nuclear plant splices are used in low-voltage (i.e., 600 V or less) cable systems. Splices used in higher voltage systems must be carefully constructed due to the comparatively high voltage stress.

Splice junctions are generally designated as being either in-line or V-type. In-line splices are formed by mating the conductors of the respective cables being spliced to one another via a fusion or compression connection (butt splice). V-type splices are formed by mating the terminations of the two conductors in parallel to one another using a nut/bolt arrangement or other mechanical connection. In either case, the splice is designed to provide a low-resistance connection between conductors with minimal voltage drop while maintaining adequate insulation resistance to ground in the expected voltage/current operating range. For some power and control circuits, splice ampacity at rated voltage is critical. For instrumentation and certain control circuits, insulation resistance and leakage current criteria may be of greater importance. In addition, splices used in environmentally qualified applications may have more stringent criteria related to the performance of the splice under accident conditions.

Insulation systems for nuclear plant splices are of one of two types: taped or heat shrink. In addition, splices may be further categorized based on their ability to isolate the spliced connection from the effects of the outside environment. Sealed splices are those that exclude external moisture or contaminants (such as may be encountered in harsh environmental areas). Alternatively, splices used in mild, dry environments may be unsealed. Nearly all splices that are installed in harsh environmental areas and require environmental qualification are of the sealed variety. Figure B-3 shows a typical in-line splice for a control cable.



KEY:
G - Cable Jacket Shim
J - Splice Sealing Sleeve
K - Outer Sealing Sleeve

Figure B-3 Raychem Type NPKC-3-31A Control Cable Splice Kit

Taped Splices

Taped splices are characterized by multiple layers of polymeric insulating tape wrapped over the conductor junction. These tape layers are applied in such a manner (i.e., generally stretched and wrapped at a specified angle and overlap) so as to provide insulation and sealing of the underlying junction. In addition, some of the older varieties of tape splice will use an insulating putty (similar to a potting compound) between the junction and the tape wraps; this putty acts as a further seal against moisture/contaminant intrusion.[9] In general, V-type splices are more susceptible than in-line splices to moisture intrusion because of an interstitial area between the insulation of the two parallel conductors. However, this is only of concern for EQ applications, which require sealing of the junction to ensure continued post-accident operability.

The predominant nuclear plant tape splice manufacturers include Okonite, Kerite, 3M, and Bishop. Okonite and Kerite constitute the bulk of EQ tape splices in use in the industry, whereas 3M and Bishop constitute the bulk of nonenvironmentally qualified splices. Each of these manufacturers use a proprietary tape formulation in their splices, which may be composed of a variety of different materials such as EPR, EPDM, silicone, or PVC.

Okonite T-95 tape is a high-voltage insulating tape that is also heat, corona and moisture resistant. The tape is an ethylene propylene (EP)-based thermosetting compound. Okonite T-95 tape is rated for 90°C continuous operations and 130°C for emergency operations. Okonite #35

[9] These putty compounds are rarely seen in most nuclear plants, especially those of more modern vintage.

jacketing tape is designed for protecting splices only in neoprene, plastic, and other synthetic rubberlike jacketed cables at all voltages. The maximum conductor operating temperature of the tape is 90°C [B.25].

"Kerite tape" is a name given to many types of tape defined in Kerite cable specification drawings. On various drawings, Kerite tapes are listed as Kerite friction tape, Kerite conducting fabric tape, Bishop Biseal 3 tape, vinyl electrical tape, silicone rubber tape, glass electrical tape, insulating tape Type 1, "A" tape, metal tape, and silicone rubber tape Type 1. Hence various types (and manufacturers) of tape appear to have been used in fabricating splices as specified by Kerite [B.14].

Biseal 3 is a Bishop Electric Corporation high-voltage tape. Biseal 3 is used in insulating, terminating, splicing and sealing up to 69 kV. Biseal 3 is a polyethylene-based tape that can be used with the following cable insulations: oil-based rubber, butyl rubber, EPR, thermoplastic and thermoset polyethylene, and PVC [B.26].

Heat-Shrinkable Splices

Heat-shrinkable splices use material that forms a tight, moisture-resistant seal of the conductor junction when exposed to heat. The material, typically in the form of a segment of tubing, is positioned over a preexisting junction (such as one crimped using a compression connector) and then heat-shrunk into place so that the contracting tubing seals against the cable insulation on either side of the junction. Heat-shrinkable splices are most often used inside primary containment because of their moisture sealing ability and relative ease of application.

Raychem is the largest manufacturer of heat shrink splices for the nuclear industry. WCSF-N is the primary Raychem product used in nuclear plant applications. WCSF-N is composed primarily of crosslinked polyethylene (XLPE). Another version of the product, WSCF (U), is similar yet has no adhesive coating. RNF, another Raychem product, was a predecessor to WCSF and may be found in limited nuclear plant applications [B.8], [B.27].

Included in the category of heat shrinkable splices are those manufactured by Sigma-Form, which use a heat-sensitive compound on the inner portions of the insulating sleeve. This compound extrudes throughout the interstices between the junction and outer sleeve (and ultimately out the ends of this sleeve) thereby forming an insulating barrier against external moisture and contaminants.

Plug-in Connectors

Various types of plug-in connectors are used by the nuclear industry, including single- and multi-pin (including Grayboot and Amphenol types), coaxial and triaxial (BNC) type, and a variety of other designs using a plug-and-socket arrangement. The exact configuration of each connector will vary based on its function and required service environment; however, there is some degree of commonality of design. Most plug-in connectors use the following generic components: (1) electrical contacts or pins and their receptacles (used to provide circuit continuity when the connector is assembled); (2) a dielectric material (used to provide electrical insulation between individual contacts/receptacles and other conductive components inside the connector); (3) fastening or retaining hardware (to keep the electrical contacts properly mated, and maintain the physical and leak-tight integrity of the connector); (4) a cable clamp (keeps the cable jacket or insulation properly fastened to the connector to prevent stress on the electrical contacts or solder joints, and seal the interface); (5) a backshell or housing (comprises the outer housing of the connector and protects the other components; and (6) O-rings or seals (used on leak-tight connectors to prevent moisture or foreign material intrusion). Some connectors will use contact surfaces or pins coated with special conductive materials (such as gold) to limit the effects of oxidation on connector operation [B.3], [B.23], [B.28], [B.29], [B.30], [B.31], [B.32], [B.33].

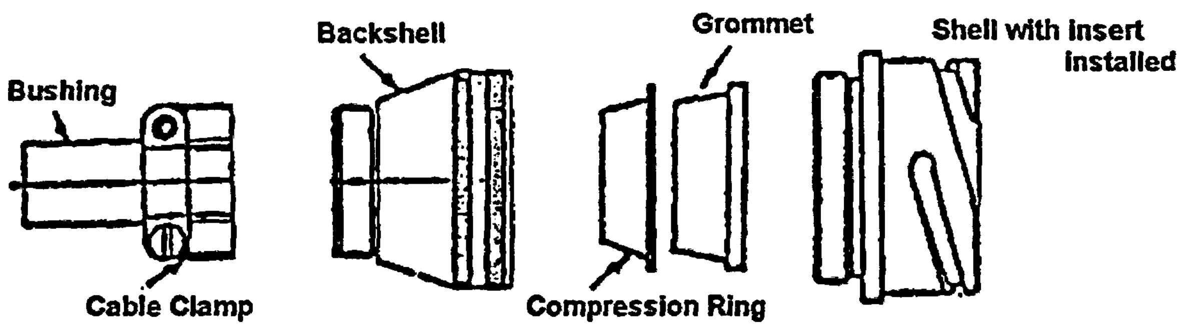


Figure B-4 Typical Connector and Components

B.3 Information Sources

A large volume of proprietary documentation was reviewed to ensure that the general discussions included in this section are representative of nuclear power plant applications. Each plant will need to perform a plant-specific review to ensure that the following documents are representative of its cable system installations:

Construction and Installation Specifications:

- Cable and conduit configurations
- Installation of safety- and nonsafety-related electrical cable in cable trays
- Safety-related and nonsafety-related electrical construction specification for installation of electrical cables in cable trays

Purchase Specifications:

- Safety-related 600 V control cable
- 600 V multi-conductor control cable (EPR or XLPE insulation)

- 600 V multi-conductor control cable (SR insulation)
- 600 V multi-conductor, control, and small power cable (PVC) for all areas outside the Reactor Containment Building for Westinghouse Electric Corporation
- 600 V single conductor, power cable (PVC) for general use for all areas outside the Reactor Containment Building for Westinghouse Electric Corporation
- 600 V power cable (XLPE insulation)
- Safety-related 600 V power cable
- 1000 V power cable (SR insulation)
- 600 V, 5 kV, and 15 kV silicone-rubber insulated lead-covered cable
- Kerite insulated 5-kV power cable
- Insulated 5-kV power cable
- Safety-related 5-kV power cable
- Kerite insulated 15-kV power cable
- Insulated 15-kV power cable
- Cable assemblies - In-core instruments
- Coaxial and triaxial cable (EPR or XLPE insulation)
- Computer, instrument, and specialty cable - multi-conductor shielded cable (EPR or XLPE insulation)
- GE Vulkene non-metallic sheathed insulated copper cable
- Heated junction thermocouple (HJTC) cable and connector assemblies
- Nonsafety-related cable
- Nonsafety-related grounding cable, connectors, and materials
- Nonshielded - twisted pair cable
- RG 11/U triaxial cable (inside and outside Containment)
- Safety-related instrument cable

- Shielded twisted pair & quad instrument cable for areas outside the Reactor Containment Building
- Single twisted pair and multi-pair thermocouple cable for Westinghouse Electric Corporation
- Single twisted pair thermocouple cable for Westinghouse Electric Corporation

Test Manual

- Power, control, & instrumentation cables, XLP or EPR insulated, 600 V

B.4 References

B.1 D. Fink and H. Beaty, Standard Handbook for Electrical Engineers, Twelfth Edition, McGraw-Hill, New York, 1987.

B.2 EPRI NP-7485, Power Plant Practices to Ensure Cable Operability, Nuclear Maintenance Applications Center, Electric Power Research Institute, July 1992.

B.3 EPRI EL-5036, Power Plant Electrical Reference Series, Vol. 4, "Wire and Cable," Electric Power Research Institute, 1987.

B.4 EPRI TR-103841, "Low-Voltage Environmentally-Qualified Cable License Renewal Industry Report, Revision 1," prepared by Sandia National Laboratories and Strategic Resources and Technologies, Inc., July 1994.

B.5 ASTM Standard B33-94, "Tinned Soft or Annealed Copper Wire for Electrical Purposes," American Society for Testing and Materials

B.6 BIW Cable Systems Inc. product catalog, December 1984.

B.7 Brand Rex Industrial Cable products catalog (various dates).

B.8 Raychem Nuclear Products Guide IIA, August 1986.

B.9 Okonite Power, Control, and Instrumentation Cables and Splicing Materials product catalog, September 1984.

B.10 Modern Plastics Encyclopedia 1985-1986, Vol. 62, No. 10A, McGraw-Hill, New York, October 1985.

B.11 AEIC CS6-87, Specifications for Ethylene-Propylene Rubber Insulated Shielded Power Cables Rated 5 Through 69 kV, Association of Edison Illuminating Companies, Birmingham, AL.

B.12 Eaton Dekoron Wire and Cable product catalog (no date).

B.13 Cablec Continental product catalog, September 1991.

B.14 Kerite Cable Data Catalog, "Power Cable," 1993.

B.15 Harper, C. A., Handbook of Plastics and Elastomers, McGraw-Hill, New York, 1975.

B.16 Brady, G. S. and H. Clauser, Materials Handbook, 12th Edition, McGraw-Hill, New York, 1986.

B.17 EPRI NP-7189, "Review of Polyimide Insulated Wire in Nuclear Power Plants," Electric Power Research Institute, February 1991.

B.18 "Properties Handbook - Tefzel," E. I. duPont de Nemours, Inc., 1994.

B.19 ICEA Publication No. S-68-516 (NEMA WC8-1991), ICEA/NEMA Standards Publication, Ethylene-Propylene Rubber Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy.

B.20 ICEA Publication No. S-66-524 (NEMA WC7-1991), ICEA/NEMA Standards Publication, Cross-linked, Thermosetting, Polyethylene Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy.

B.21 AMP Electrical/Electronic Products Catalog EPC-2, 1984.

B.22 Equipment Qualification Reference Manual, Electric Power Research Institute, 1992.

B.23 NUREG/CR-5461, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants," July 1990.

B.24 NRC IE Information Notice 80-08, "The States Company Sliding Link Electrical Terminal Block," U.S. Nuclear Regulatory Commission, March 7, 1980.

B.25 Okonite Report No. NQRN-3, "Nuclear Environmental Qualification Report for Okoguard Insulated Cables and T95 and No. 35 Splicing Tapes," Rev. 3, March 1987.

B.26 Bishop Electric Corp. product literature, "No. 3 Bi-Seal High Voltage Tape" (undated).

B.27 Proprietary Nuclear Environmental Qualification Test Report on Raychem cable splices, Okonite tape splices, Kerite tape splices, scotch tape splices and AMP butt splices, prepared by Wyle Laboratories, March 1987.

B.28 Namco Controls Product Data Sheet, EC-210 Connectors (undated).

B.29 Litton Precision Products International Assembly Procedure, Litton/Veam CIR Series Connectors (undated).

B.30 Proprietary plant information sheet, Figure 7, "Cross Sectional View of ERD Connectors" (undated).

B.31 Proprietary Class 1E qualification test of ERD electrical connectors and mineral insulated cable, November 1984.

B.32 Proprietary environmental qualification report of Bendix electric cable connectors Model MS 3100 Series, January 1985.

B.33 Bow, K. E., J. H. Snow, D. A. Voltz, and W. D. Wilkens, "Specifying, Selecting, and Testing Quality Cable," IEEE Transactions Industry Applications, Vol. 29, No. 3, pp. 631-638, May/June 1993.

The following documents are not referenced in the text; however, the reader will find additional, related information in these documents:

B.34 American Insulated Wire Specification 6383 F for cross-linked polyethylene insulated switchboard wire, UL approved SIS 90°C, 600 Volts, 20 through 4 AWG.

B.35 Anaconda-Ericsson Specification AP-63231-00, Continental Flame-Guard NSGK Instrumentation Cable 600 Volts, September 10, 1982.

B.36 Cablec, Cable Installation Manual, Section V, Testing, Sixth Edition, CABLEC, Marion, Indiana.

B.37 EPRI EL-4201, "Long-Life Cable Development Cable-Processing Survey," Electric Power Research Institute, September 1985.

B.38 EPRI EL-4398, "Long-Life Cable Development: Cable Materials Survey," prepared by University of Connecticut, March 1986.

B.39 EPRI EL/NP/CS-5914-SR, "Application, Construction, and Testing of Generating Station Cables," prepared for Workshop on Power Plant Cable Condition Monitoring, July 1988.

B.40 General Electric Design Specification No. 22A1112, Special Wire and Cable.

B.41 Kerite 9401-H, "Hi Tension News," Kerite and Ohio Brass Companies, 1994 Special Edition.

B.42 The Okonite Company Engineering Data for Copper and Aluminum Conductor Electrical Cables, Bulletin EHB-90.

B.43 Raychem Specification 60, Raychem-Flamtrol Insulated Power, Control, Switchboard, and Instrumentation Wire and Cable, June 1, 1976.

APPENDIX C. DESIGN REQUIREMENTS INCLUDING CODES, STANDARDS, AND REGULATIONS

C.1 Design Requirements: Codes, Standards, and Regulations

The basic requirements for development of electrical cable systems for nuclear power plants are contained in General Design Criteria 17 and 18 of Appendix A to 10CFR50 [C.1], [C.2]. 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 or the application of cable or terminations.

Final safety analysis reports (FSARs) from various plants were reviewed to identify any additional criteria pertinent to cable or termination design. These FSARs provide varying levels of detail about licensing commitments regarding cable systems. In general, however, these documents list only ratings and other data specific to the installed equipment, and provide no further references to applicable standards or design commitments other than the applicable 10CFR50 Design Criteria discussed above.

Various industry standards related to on-site low- and medium-voltage electrical cable and terminations of the type covered in this AMG are listed at the end of this appendix. It should also be noted that cable separation and fire protection requirements may also be applicable, as well as seismic design and qualification of circuit support systems (which are not within the scope of this guideline).

C.1.1 Environmental Qualification

The eight primary codes, standards and regulations listed below define and control all of the activities that must be performed to establish environmental qualification (EQ) for an electrical cable or connection. Note, however, that other Regulatory Guides and IEEE Standards can be used in the process of establishing qualification for specific pieces of equipment.

- DOR Guidelines [C.3]
- NUREG-0588 Rev. 1 [C.4]
- 10CFR50.49 [C.5]
- Regulatory Guide 1.89, Rev.1 [C.6]
- Regulatory Guide 1.97, Rev. 2 [C.7]
- IEEE Standard 323-1971 [C.8]
- IEEE Standard 323-1974 [C.9]
- IEEE Standard 383-1974 [C.10]

Division of Operating Reactor (DOR) Guidelines

The DOR Guidelines were developed in November 1979 as a tool for the NRC staff to use in evaluating EQ submittals from a limited number of older nuclear plants. They were published in January 1980 for the industry's information and guidance. Section 7.0 of Reference [C.3] stated that a plant did not have to demonstrate a qualified life[1] if the plant was already constructed and operating, unless the plant used material(s) that had been identified already as being susceptible to significant degradation due to thermal and radiation aging. Maintenance or replacement schedules were to include consideration of the specific aging characteristics of the material(s), and ongoing programs were to be established to review surveillance and maintenance records to assure that equipment that was exhibiting age-related degradation was identified and replaced as necessary.

NUREG-0588

NUREG-0588 [C.4] applied to all plants in existence at the time it was published except for those covered by the DOR Guidelines [C.3]. NUREG-0588 was initially published for industry comment in December 1979; it was subsequently revised and issued in July 1981. NUREG-0588 divided the population of safety-related electrical equipment into two categories, namely, Category I for equipment qualified in compliance with IEEE Std. 323-1974 and Category II for equipment qualified in compliance with IEEE Std. 323-1971. Section 4 of the Interim Staff Position in NUREG-0588 required that aging effects on all equipment, regardless of its location in the plant, should be considered and included in the qualification program for Category I equipment. Category II equipment had to comply in the same manner for qualification of valve operators and motors; however, for all other equipment the program had to address aging only to the extent that equipment that is composed, in part, of material susceptible to aging effects should be identified and a schedule for periodically replacing the equipment and/or materials should be established.

NUREG-0588 contained two aging-related elements for an EQ program (Category I) that may not be evaluated the same way in a general Aging Management Program developed for 10CFR54:

- Periodic surveillance testing under normal service conditions is not considered an acceptable method for on-going qualification, unless the plant design includes provisions for subjecting the equipment to the limiting service environmental conditions (specified in Section 3, item (7) of IEEE Standard 279-1971 [C.11]) during periodic surveillance testing

- Effects of relative humidity need not be considered in the aging of electrical cable insulation

[1] "The period of time for which satisfactory performance can be demonstrated for a specific set of conditions." [C.9] The definition was changed in the 1983 revision of IEEE Standard 323 to be "the period of time, prior to the start of a design basis event, for which equipment was demonstrated to meet the design requirement for the specified service conditions." The 1983 revision has never been endorsed by the NRC, and the change in definition occurred many years after most qualifications were established for operating plants. Therefore, this more specific/restrictive definition is not applicable to most of the operating plants in the United States.

10CFR50.49

10CFR50.49 [C.5] applies to electric equipment important to safety located in harsh environment areas. However, if the equipment had been previously qualified to the requirements of the DOR Guidelines [C.3] or NUREG-0588 [C.4], then it did not have to be requalified to the requirements of 10CFR50.49. Section (e) (5) of Reference [C.5] requires that equipment qualified by test must be preconditioned by natural or artificial (accelerated) aging to its end-of-installed life condition. If this is not practical, then the equipment can be preconditioned to a shorter designated life and must be refurbished at the end of this designated life unless ongoing qualification demonstrates that the item has additional life.

Regulatory Guide 1.89

Regulatory Guide 1.89, Revision 1 [C.6] describes a method acceptable to the NRC staff for complying with the requirements of 10CFR50.49 [C.5]. In its discussion on aging, Reference [C.6] states that there are considerable uncertainties regarding the processes and environmental factors that could result in such degradation. Because of these uncertainties, state-of-the-art preconditioning techniques are not capable of simulating all significant types of degradation, and natural pre-aging is difficult and costly.

Section C.5 of Reference [C.6] emphasizes the following:

- Periodic surveillance and testing programs are acceptable to account for uncertainties regarding age-related degradation that could affect the functional capability of equipment
- Results of such programs will be acceptable as ongoing qualification to modify qualified life of equipment and should be incorporated into the maintenance and refurbishment/replacement schedules.

Regulatory Guide 1.97

Regulatory Guide 1.97, Revision 3 [C.7] is an application-specific document, which describes a method acceptable to the NRC staff for complying with the Commission's regulations to provide instrumentation to monitor plant variables and systems during and following an accident in a light-water-cooled nuclear power plant.[2] Table 1 of Reference [C.7] presents Design and Qualification Criteria for Instrumentation and states that the instrumentation should be qualified in accordance with References [C.4] and [C.6].

No additional or special guidance is given concerning aging. Consequently, any cables or connectors used with post-accident monitoring equipment and subject to the provisions of Regulatory Guide 1.97 will not have any different aging requirements from those previously stated for References [C.4] and [C.6].

[2] Revision 2 was issued as an active guide in December 1980, and is the revision number specifically cited in 10CFR50.49 [C.5]. None of the changes in Revision 3 had any effect on the aging of cables and connectors that might be used with post-accident monitoring equipment.

IEEE Standard 323-1971

IEEE Standard 323-1971 [C.8] was the first industry standard developed to provide guidance for demonstrating and documenting the adequacy of electric equipment used for the prevention of accidents and the mitigation of the consequences of accidents. It described the basic requirements for the qualification of Class I electrical equipment (equipment that is essential to the safe shutdown and isolation of the reactor or whose failure or damage could result in significant release of radioactive material).

Neither the word nor concept of aging is mentioned; consequently, cables and connectors qualified to the requirements of this standard should not be expected to have much information related to aging. However, this Standard is the one referenced in NUREG-0588 [C.4] for Category II plants. Thus, the concepts of aging management and ongoing aging review discussed previously for Category II plants qualified to Reference [C.4] apply.

IEEE Standard 323-1974

IEEE Standard 323-1974 [C.9] is the definitive industry standard for establishing qualification. It is specifically cited in NUREG-0588 [C.4], 10CFR50.49 [C.5], and Regulatory Guide 1.89, Rev. 1 [C.6]; it is also endorsed by Reference [C.6]. The concept of aging was addressed explicitly for the first time in IEEE Standard 323-1974, and this standard contained the first published definitions for the phrases "equipment qualification" and "qualified life."

Sections 6.3 and 6.6 of IEEE Standard 323-1974 [C.9] discuss aging and on-going qualification, respectively. Neither section considers the concept of aging management as envisioned by 10CFR54. Rather, the focus of Reference [C.9] is qualification by testing, such that even on-going qualification is based on additional periodic type testing instead of condition monitoring.

Because IEEE Standard 323-1974 [C.9] describes the methods to be used for cables and connectors qualified in accordance with the requirements of Category I NUREG-0588 [C.4], 10CFR50.49 [C.5], and Regulatory Guide 1.89 Rev. 1 [C.6], the comments stated previously for References [C.4], [C.5], and [C.6] concerning an aging management program and Aging Management Review apply to Reference [C.9].

IEEE Standard 383-1974

The Forward to IEEE Standard 323-1974 [C.9] states that guidance for demonstrating the capability of specific electric equipment (e.g., cables) may be found in IEEE Standard 383-1974 [C.10]. IEEE Standard 383-1974 provides direction for establishing type tests which may be used in qualifying Class 1E electric cables, field splices, and other connections for service in nuclear power generating stations. Type tests are used primarily to indicate that the cables, field splices, and connections can perform under the conditions of a design basis event. Because the design basis events may occur at any time in the station life, the thermal and radiation aging required in type tests to simulate these conditions may at the same time indicate the ability of cable types to operate under the normal service conditions within the station. IEEE Standard

383-1974 was endorsed, with some exceptions, by the NRC in Regulatory Guide 1.131 [C.12].

C.1.2 Compliance with Applicable Elements of Standard Review Plan, NUREG-0800

Section 8.1 of NUREG-0800 [C.13] 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 electrical cable and terminations.

Table 8-1 of the SRP lists the "Acceptance Criteria and AMGs for Electric Power Systems." Review of this table indicated that eleven documents apply to on site ac power systems. Each document was reviewed for specific criteria related to the control of aging of cable system components important to license renewal. Overall, the review of the NUREG-0800 and the listed documents did not produce any criteria related to cable system aging beyond requirements for testability. Thus, NUREG-0800 provides no direct guidance about the control of aging of electrical cable or terminations.

Standard	Description
AEIC	
AEIC CS5-82	Specification for Thermoplastic and Crosslinked Polyethylene Insulated Shielded Power Cables rated 5 through 46 kV
AEIC CS5-87	Specifications for Thermoplastic and Crosslinked Polyethylene Insulated Shielded Power Cables Rated 5 Through 35 kV
AEIC CS6-82	Specification for Ethylene Propylene Rubber Insulated Shielded Power Cables rated 5 through 69 kV
ANSI (Note: ANSI/IEEE Standards are listed with IEEE)	
ANSI/ANS 59.4-1979	Generic Requirements For Light Water Nuclear Power Plant Fire Protection
ANSI/ASME NQA 1-1979	Quality Assurance Program Requirements for Nuclear Power Plants
ANSI/NFPA 70-1984	National Electric Code (NEC)
CAN	
CAN/CSA-C22.2	No. 241-M91, Standard for Cable Joints with Extruded Dielectric Cable Rated 5,000 V through 46,000 V and Cable Joints for Use with Laminated Dielectric Cable Rated 2,500 V through 500,000 V
ICEA	
ICEA P-32-382	Short Circuit Characteristics of Insulated Cable
ICEA P-54-440/NEMA WC51	Ampacities in Open Top Cable Trays
ICEA S-19-81/NEMA WC3	Rubber Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
ICEA S-61-402/NEMA WC5	Thermoplastic Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
ICEA S-66-524/NEMA WC7	Crosslinked Thermosetting-Polyethylene Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy

Standard	Description
ICEA S-68-516/NEMA WC8	Ethylene Propylene Rubber Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
IEEE	
IEEE 48-1990	IEEE Standard Test Procedures and Requirements for High-Voltage Alternating-Current Cable Terminations
IEEE 55-1953	IEEE Guide for Temperature Correlation in the in the Connection of Insulated Wire and Cables to Electronic Equipment
ANSI/IEEE 100-1984	IEEE Standard Dictionary of Electrical And Electronics Terms
IEEE 141-1986	IEEE Recommended Practice for Electrical Power Distribution for Industrial Plants (Chapter 11, Cable Systems).
IEEE 279-1971	IEEE Standard for Criteria for Protection Systems for Nuclear Power Generating Stations
IEEE 323-1971	IEEE Trial Use Standard: General Guide for Qualifying Class 1E Equipment for Nuclear Power Generating Stations
IEEE 323-1974	IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations
IEEE 323-1983	IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations
ANSI/IEEE 336-1980	IEEE Standard Installation, Inspection, and Testing Requirements for Class 1E Instrumentation and Electric Equipment at Nuclear Power Generating Stations
IEEE 367-1987	IEEE Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault
IEEE 383-1974	IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations
ANSI/IEEE 384-1981	IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits

Standard	Description
ANSI/IEEE 400-1980	IEEE Guide for Making High-Direct-Voltage Tests on Power Cable Systems in the Field
IEEE 404-1986	IEEE Standard for Cable Joints for Use with Extruded Dielectric Cable Rated 5,000 V through 46,000 V, and Cable Joints for Use with Laminated Dielectric Cable Rated 2,500 V through 500,000 V
ANSI/IEEE 422-1986	IEEE Guide for the Design and Installation of Cable Systems in Power Generating Stations
IEEE 575-1988	IEEE Guide for the Application of Sheath-Bonding Methods for Single-Conductor Cables and the Calculation of Induced Voltages and Currents in Cable Sheaths
IEEE 590-1977	IEEE Cable Plowing Guide
ANSI/IEEE 690-1984	IEEE Standard for the Design and Installation of Cable Systems for Class 1E Circuits in Nuclear Power Generating Stations
IEEE 776-1974	IEEE Guide for Inductive Coordination of Electric Supply and Communication Lines
IEEE 789-1988	IEEE Standard Performance Requirements for Communications and Control Cables for Application in High Voltage Environments
IEEE 816-1987	IEEE Guide for Determining the Smoke Generation of Solid Materials Used for Insulations and Coverings of Electric Wire and Cable
IEEE 930-1987	IEEE Guide for the Statistical Analysis of Voltage Endurance Data for Electrical Insulation
IEEE 987-1985	IEEE Guide for Application of Composite Insulators
IEEE 1017-1991	IEEE Recommended Practice for Field Testing Electric Submersible Pump Cable
IEEE 1018-1991	IEEE Recommended Practice for Specifying Electric Submersible Pump Cable - Ethylene Propylene Rubber Insulation

Standard	Description
IEEE 1019-1991	IEEE Recommended Practice for Specifying Electric Submersible Pump Cable - Polypropylene Insulation
IEEE 1064-1991	IEEE Guide for Multifactor Stress Functional Testing of Electrical Insulation Systems
IEEE 1120-1990	IEEE Guide to the Factors to be Considered in the Planning, Design, and Installation of Submarine Power and Communications Cables
IEEE 1202-1991	IEEE Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies
IEEE S-135/ICEA P-46-426	Power Cable Ampacities for Copper and Aluminum Conductors
NEMA	
HP 3-1987 (R1992)	Electrical and Electronic PTFE Insulated High Temperature Hook-Up Wire; Types EE and ET
HP 4-1988	Electrical and Electronic FEP Insulated High Temperature Hook-Up Wire, Types K, KK, and KT
HP 100-1991	High Temperature Instrumentation and Control Cables
HP 100.1-1991	High Temperature Instrumentation and Control Cables Insulated and Jacketed with FEP Fluorocarbons
HP 100.2-1991	High Temperature Instrumentation and Control Cables Insulated and Jacketed with ETFE Fluoropolymers
HP 100.3-1991	High Temperature Instrumentation and Control Cables Insulated and Jacketed with Cross-Linked (Thermoset) Polyolefin (XLPO)
HP 100.4-1991	High Temperature Instrumentation and Control Cables Insulated and Jacketed with ECTFE Fluoropolymers
ICS 4-1983 (R1988)	Terminal Blocks
WC 3-1986	Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy

Standard	Description
WC 5-1992	Thermoplastic-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
WC 7-1993	Cross-Linked-Thermosetting-Polyethylene-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
WC 8-1993	Ethylene-Propylene-Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy
WC 50-1976 (R1993)	Ampacities, Including Effect of Shield Losses for Single-Conductor Solid-Dielectric Power Cable 15 kV through 69 kV
WC 51-1986 (R1991)	Ampacities of Cables in Open-Top Cable Trays
WC 53-1990	Standard Test Methods for Extruded Dielectric Power, Control, Instrumentation, and Portable Cables
WC 54-1990	Guide for Frequency of Sampling Extruded Dielectric Power, Control, Instrumentation, and Portable Cables for Test
WC 55-1992	Instrumentation Cables and Thermocouple Wire
WC 57-1990	Standard for Control Cables
WC 58-1991	Standard for Portable and Power Feeder Cables for Use in Mines and Similar Applications

C.2 References

C.1 Title 10, U.S. Code of Federal Regulations, Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix A, "General Design Criteria for Nuclear Power Plants," Part II, Criterion 17, "Electric Power Systems," published in the Federal Register, Vol. 52, October 27, 1987 (page 41294).

C.2 Title 10, U.S. Code of Federal Regulations, Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix A, "General Design Criteria for Nuclear Power Plants," Part II, Criterion 18, "Inspection and Testing of Electric Power Systems," published in the Federal Register, Vol. 52, October 27, 1987 (page 41294).

C.3 NRC IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," Enclosure 4 to "Environmental Qualification of Class 1E Equipment," Nuclear Regulatory Commission, January 14, 1980.

C.4 NUREG-0588 Rev. 1, "Interim Staff Position on Environmental Qualification of Safety-Related Equipment Including Staff Responses of Public Comments, Resolution of Generic Technical Activity A-24," Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, July 1981

C.5 Title 10, U.S. Code of Federal Regulations, Part 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," published in the Federal Register, Vol. 53, May 27, 1988 (page 19250).

C.6 Regulatory Guide 1.89 Revision 1, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1984

C.7 Regulatory Guide 1.97 Revision 3, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, U.S. Nuclear Regulatory Commission, May 1983

C.8 IEEE Standard 323-1971, IEEE Trial Use Standard: General Guide for Qualifying Class 1E Equipment for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc., April 1971

C.9 IEEE Standard 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc., corrected copy June 1976

C.10 IEEE Standard 383-1974, IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc., 1974

C.11 IEEE Standard 279-1971, IEEE Standard for Criteria for Protection Systems for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc., June 1971 [American National Standards Institute, N42.7-1972]

C.12 Regulatory Guide 1.131, "Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants," U.S. Nuclear Regulatory Commission, August, 1977.

C.13 NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Chapter 8: Electric Power, U.S. Nuclear Regulatory Commission, July 1981.

APPENDIX D. ACRONYMS

This list of acronyms is divided into two parts;

- Part 1 contains acronyms that are used in this Aging Management Guideline, and
- Part 2 contains common electrical cable and terminations, and nuclear industry acronyms.

Part 1: Acronyms Used in this Aging Management Guideline

ac	Alternating current
AEIC	Association of Edison Illuminating Companies
AMG	Aging management guideline
AMR	Aging management review
ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
AWG	American wire gauge
BIL	Basic impulse insulation level
BR	Butyl rubber
BWR	Boiling water reactor
CAN	Canadian National Standards
CCNPP	Calvert Cliffs Nuclear Power Plant
CFR	Code of Federal Regulations
CLB	Current licensing basis
CLWR	Commercial light water reactors (DOE)
CM	Condition monitoring
CPE	Chlorinated polyethylene
CSPE	Chlorosulfonated polyethylene (Hypalon®)
CT	Computed tomography
DBE	Design basis event
dc	Direct current
DLO	Diffusion-limited oxidation
DOE	United States Department of Energy
DOR	Division of Operating Reactors (NRC)
EDG	Emergency diesel generator
emf	Electromotive force
EPDM	Ethylene propylene diene monomer (or Terpolymer)
EPR	Ethylene propylene rubber
EPRI	Electric Power Research Institute
EQ	Environmentally qualified
ESR	Electron spin resonance
ETFE	Ethylene tetrafluoroethylene (Tefzel®)

FIRL	Franklin Institute Research Laboratory
FR	Flame retardant
FRC	Franklin Research Laboratory
FSAR	Final safety analysis report
FTIR	Fourier transform infrared
HDPE	High-density polyethylene
hi-pot	High potential (voltage) testing
HMWPE	High molecular weight polyethylene
HTK	High-temperature Kerite (Kerite proprietary)
HVAC	Heating, ventilation and air conditioning
I&C	Instrumentation and control
ICEA	Insulated Cable Engineers Association (formerly IPCEA)
IE	Inspection and Enforcement (NRC)
IEB	Inspection and Enforcement Bulletin (NRC)
IEC	Inspection and Enforcement Circular (NRC)
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IN	Information Notice (NRC Inspection and Enforcement)
INPO	Institute of Nuclear Power Operations
IPA	Integrated plant assessment
IPCEA	Insulated Power Cable Engineers Association (now ICEA)
IR	Infrared
IR	License renewal industry reports
IR	Insulation resistance
kcmil	One thousand circular mils (same as MCM)
LCM	Life cycle management program (EPRI)
LER	Licensee event report
LOCA	Loss-of-coolant accident
LRR	License renewal rule (10CFR54)
LWR	Light water reactor
MCC	Motor control center
MCM	One thousand circular mils (same as kcmil)
MIR	Multiple internal reflectance
MOV	Motor-operated valve
MR	Maintenance rule (10CFR50.65)
NEC	National Electric Code
NEI	Nuclear Energy Institute (formerly NUMARC)
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Prevention Association
NIR	Near-infrared reflectance
NMAC	Nuclear Maintenance Application Center (EPRI)

NMR	Nuclear magnetic resonance
NPAR	Nuclear plant aging research (NRC)
NPRDS	Nuclear Plant Reliability Data System (INPO)
NRC	United States Nuclear Regulatory Commission
NSIC	Nuclear Safety Information Center
NTS	National Technical Systems
NUMARC	Nuclear Management and Resource Council (now part of NEI)
NUREG	Nuclear regulatory (document series published by the NRC)
OIT	Oxidation induction time
PD	Partial discharge
PE	Polyethylene
PF	Power factor
PI	Polarization index
PLIM	Plant lifetime improvement program (DOE, now the CLWR Program)
PVC	Polyvinyl chloride
PWR	Pressurized water reactor
RCPB	Reactor coolant pressure boundary
RG	Regulatory Guide (NRC)
RH	Relative humidity
RTD	Resistance temperature detector
SR	Silicone rubber
SBR	Styrene-butadiene rubber
SER	Safety evaluation report
SIC	Specific inductive capacitance
SIR	Specific insulation resistance
SIS	Synthetic thermosetting insulation for switchboard wire
SOV	Solenoid-operated valve
SSC	System, structure or component
SSCs	Systems, structures and components
TDR	Time-domain reflectometry
TDS	Time-domain spectroscopy
TED	Time to equivalent damage
TID	Total integrated dose
TLAA	Time-limited aging analyses
TR-XLPE	Tree-retardant XLPE
UV	Ultraviolet
V	Volts
Vac	Volts, alternating current
Vdc	Volts, direct current

XLN	Cross-linked neoprene (ITT Surprenant proprietary)
XLPE	Cross-linked polyethylene
XLPO	Cross-linked polyolefin

Part 2: Common Electrical Cable and Terminations, and Nuclear Industry Acronyms

A	Amperes
ASME	American Society of Mechanical Engineers
BNL	Brookhaven National Laboratory
DBA	Design basis accident
DF	Dissipation factor
DSC	Differential scanning calorimeter
EP	Ethylene propylene
FEP	Fluorinated ethylene propylene
FRMR	Flame retardant, moisture retardant
HELB	High energy line break
LMWPE	Low molecular weight polyethylene
MC	Metal-clad cable (NEC type designation)
MI	Mineral insulated
MSLB	Main steam line break
MV	Medium-voltage (NEC type designation)
NBR	Nitrile butadiene rubber
ORNL	Oak Ridge National Laboratory
PIXE	Proton-induced x-ray emission
PTFE	Polytetrafluoroethylene (Teflon®)
RF	Radio frequency
RG	Designation prefix for coaxial cables (e.g., RG-57)
RHH	NEC conductor type designation for heat resistant conductors
RHW	NEC conductor type designation for heat and moisture resistant conductors
RMS	Root means square
SA	NEC designation for conductors with silicone insulation and glass braid
SF	Service factor
SNL	Sandia National Laboratories

TGA	Thermogravimetric analysis
UL	Underwriters Laboratory
XHHW	NEC conductor designation for XLPE or EP insulation with heat and moisture resistance
Z	NEC conductor designation for ETFE-insulated conductors in dry locations
ZW	NEC conductor designation for ETFE-insulated conductors in wet locations

APPENDIX E. TRADE NAMES FOR CABLE AND TERMINATIONS

Trade Name	Manufacturer	Primary Constituent Material
Alkane	Raychem	Polyalkene
Bostrad 7E	BIW	EPR/EPDM
Dekorad	Eaton/Samuel Moore	EPR/EPDM
Durasheet EP	Anaconda	EPR/EPDM
Firewall EP	Rockbestos	EPR/EPDM
Firewall III	Rockbestos	XLPE
Flamenol	GE	PVC
Flametrol	Raychem	XLPE
FR	Kerite	*
FR-EP	Continental	EPR/EPDM
FR-EP	Eaton/Samuel Moore	EPR/EPDM
HTK	Kerite	*
Hypalon	DuPont	CSPE
Kapton	DuPont	Polyimide
Neoprene	DuPont	Chloroprene
Okoguard	Okonite	EPR/EPDM
Okolon	Okonite	CSPE
Okonite	Okonite	EPR/EPDM
Okonite-FMR	Okonite	EPR/EPDM
Okoprene	Okonite	Chloroprene
Okoseal	Okonite	PVC
Okozel	Okonite	ETFE
Pyrotrol III	Cerro	XLPE
Tefzel	DuPont	ETFE
Ultrol	Brand-Rex	XLPE
Viton	DuPont	Fluoroelastomer
Vulkene	GE	XLPE
WSCF	Raychem	XLPE
X-Olene	Okonite	XLPE

* Kerite polymer formulations are proprietary and their primary constituents not readily ascertainable.

APPENDIX F. DISCUSSION OF NPRDS DATA

This appendix discusses specific attributes and limitations regarding the use of the Nuclear Plant Reliability Data System (NPRDS) database during preparation of this guideline.

F.1 Categorization of Reports

Due to the virtual interchangeability of the terms "cable" and "wire," drawing a clear dividing line between the two categories was difficult. What may be described as a cable in one report is often described as a wire in another. In addition, the distinction between field cable, panel (SIS) or local wire, and wiring internal to various electrical components or subcomponents is often unclear. Some applications have a wire terminated directly on or within a component; some have the wire terminated on a terminal block within a panel or control board. Others have wiring harnesses that emanate from the component. In addition, individual conductors within a cable may be termed "wires." Hence, some effort was made to distinguish field cable from panel or local wiring. Internal component/subcomponent wiring (such as that found in electrical switchgear or instrument drawers) was not considered within scope, except where it could be ascertained that the wire originated from outside the component. Although these criteria are somewhat imprecise and subjective, they do provide some boundary for evaluation of the NPRDS data.

In many NPRDS reports, oxidized or corroded conductor surfaces were identified as being "dirty" or requiring cleaning. This is somewhat confusing in that failures caused by actual dirt or foreign material contamination were also often referred to as "dirty." Accordingly, dirty, oxidized, or corroded components were grouped together with respect to cause of failure because they could not be accurately differentiated in many cases.

Another difficulty encountered while analyzing the NPRDS reports relates to the primary type of failure noted; that is, loose or broken "terminations." It is very difficult to determine from the NPRDS reports exactly what the failed component/subcomponent is. For example, a "loose" termination may include a lug or compression fitting that is loose on the conductor, or a termination that is loose at its point of connection to the device (i.e., loose terminal nut or screw). Similarly, a "broken" termination may mean a lug or fitting that has itself broken, or a wire conductor that has broken in the immediate vicinity of the termination (i.e., termination is broken off). Although apparently trivial, these distinctions are important in characterizing the failure rate of specific components such as wire conductors and compression lugs. Reports in which the connected device terminal hardware was the root cause were considered out of scope.[1]

Failure reports deemed to be applicable were then grouped by major component (i.e., cable, panel (SIS) wiring, splice, compression fitting, connector, or terminal block); each component was then sorted by failed subcomponent, failure mode, failure cause, and method of failure detection. Due to the absence of any substantial information regarding the component

[1] This is true with the exception of loose or broken terminal block hardware, which was considered within scope.

manufacturer, the relative reliability of cable/terminations from various manufacturers cannot be estimated from the available data. Although infrequently stated in explicit terms, the voltage class of the failed component described could almost always be deduced based on the application described in the narrative. No effort was made to classify reports in terms of application type (i.e., power, control, or instrumentation), as these categories are not commonly defined from plant to plant, and substantial overlap often occurs. In several cases, the failure mode and/or failure cause were not identified; these reports were tagged as "unidentified."

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

F.2 Method of Detection

The method of failure detection refers to the circumstances under which the component failure was noted. Different categories of detection method were considered, including detection during maintenance, during surveillance testing, during operations, and during in-service inspection. Those failures detected during operation of the equipment were further categorized as to the effect of the detection on the functionality of the cable, termination, or circuit in general. For example, a cable or wire failure noted during operation that prevented or limited the circuit or connected load from fulfilling its required function was categorized separately from a failure detected during circuit operation that had no appreciable effect on functionality. For conservatism, circuit grounds were considered to affect functionality unless clearly indicated otherwise in the applicable report.

F.3 Cable Insulation Materials

Little specific information regarding cable insulation material was recorded in the NPRDS reports pertaining to cable failure. Some of the reports describing failures of components or subcomponents other than cable insulation (such as the cable conductor, connectors, splices, and terminal blocks) had information regarding the type of insulation material; however, this was not considered relevant to the failure of the insulation. Accordingly, only those reports with insulation data and which related to the failure of the insulation were included in the statistics for insulation failures. The number of such reports was a very small fraction of the total (only a few percent of the total reports related to insulation failure). Therefore, little meaningful inference can be made regarding the failure or degradation propensity of certain types of insulation materials.

APPENDIX G. EVALUATING THERMAL LIFE

G.1 Introduction

In a typical power plant, cables are installed in a variety of configurations. The physical characteristics of each installation are a significant consideration in any assessment to determine a cable's operating temperature. Given identical external environmental conditions and electrical loading, the operating temperature of identical cables installed in conduit, open cable tray, closed cable tray, behind a fire barrier, etc. will all be different. The heat transfer characteristics of each installation must be considered in an evaluation to determine a cable's operating temperature. Finally, local heat sources (e.g., an adjacent power cable) must be considered in the evaluation.

In addition, insulation and jacket materials are subject to a broad range of service conditions. Service conditions are rarely constant with respect to a given stressor. Although a passive device (i.e., one which generates no self-heating) may be maintained at a constant temperature throughout its life, this is the exception rather than the rule. In general, a device will be exposed to a range of temperatures over its lifetime. This variation may be regular (cyclic) or irregular.

The effect of cable loading and ambient temperature on thermal life can be examined for:

- constant cable temperature (see Figure 4-1)
- combinations of constant ambient temperature and constant electrical loading that yield a 40-year or 60-year service life (see Figure 4-5, Table 4-2)
- variable service conditions (see Figures G-1 through G-6)

G.2 Temperature Rating

Any given cable has an associated conductor *temperature rating*, which is "the maximum temperature, along its length, that the conductor can withstand over a prolonged time period without serious degradation" (NEC [G.1] article 310-10). As one will see, the concept of a prolonged time period in the NEC differs substantially from the 40 to 60-year time periods of interest to nuclear power plant operators. Note that the conductor temperature is used as the temperature rating because this is the hottest part of the cable and thus conservatively estimates the temperature to which the cable's insulation and jacket will be exposed. From NEC Tables 310-13 and 310-61, each cable type has an associated conductor temperature rating; typical values are 60, 75, 85, 90, 125, 150, 200, and 250°C (90°C is the most common rating for general purpose cables in a nuclear power plant).

G.3 Ampacity

When a metallic conductor is energized with a current (I), the conductor temperature (T_c) increases above its deenergized temperature due to ohmic heating. Because the conductor temperature rise is roughly proportional to the power (P) dissipated by the conductor ($P = I^2R$), this is often referred to as "I^2R heating."

Ampacity[1] is "the current that a conductor can carry continuously under the conditions of use without exceeding its temperature rating" (NEC article 100); thus, when a conductor is energized continuously with a current equal to its ampacity, the metallic conductor will stabilize at a temperature equal to the cable's temperature rating.

Ampacities are tabulated in standard industry tables for a limited range of simple configurations. For example, assume that a single copper conductor, 8 AWG cable[2] with a 90°C temperature rating is in free air at an ambient temperature of 30°C. From a standard industry ampacity table (NEC Table 310-17, "Ampacities of Single Insulated Conductors, Rated 0 through 2000 Volts, In Free Air Based on Ambient Air Temperature of 30°C (86°F)", for conductors ranging in size from 18 AWG to 2000 kcmil), this conductor has an ampacity of 80 A. This means that if the conductor were energized continuously with 80 A, the conductor temperature would be increased by 60°C, resulting in a final conductor temperature of 90°C.

As the ambient temperature increases, a cable's ampacity decreases. Ampacity correction factors (temperature derating factors) are provided in standard ampacity tables to account for changes in ambient temperature from that used in the table. For example, NEC Table 310-17 requires that the previously cited ampacity of 80 A at 30°C must be multiplied by a factor of 0.91 for ambient temperatures in the range between 36 and 40°C. Thus, if the same single conductor cable described above is at an ambient temperature of 40°C, it will reach its 90°C temperature rating when energized continuously with 72.8 A (=0.91*80) instead of the 80 A required at 30°C. Ampacity correction factors also exist for other parameters such as the number of conductors in the cable; cable diameter; grouping of cables in a single raceway, conduit, or cable tray; installation of a fire barrier; and grouping of multiple conduits in close proximity.

Ampacity correction factors can also be calculated analytically in lieu of using tabulated values. For instance, an equation to correct a tabulated ampacity value for any combination of conductor temperature rating, ambient temperature, and dielectric temperature rise is given by Equation (5) from page III of AIEE S-135 [G.2], namely:

$$I' = I \sqrt{\frac{T_c' - T_a' - \Delta T_d'}{T_c - T_a - \Delta T_d} \times \frac{\tau_c + T_c}{\tau_c + T_c'}}$$

where: I = Current based on conditions associated with T_c and T_a

I' = Current based on conditions associated with T_c' and T_a'

[1] The word "ampacity" is a contraction of the phrase "amperage capacity" to signify the current-carrying capacity of a conductor.

[2] An 8 AWG conductor is used for the example because NEC Table 310-17 requires overcurrent protection for 10 AWG and smaller cables, in addition to the ampacity limits.

T_a	=	Ambient air temperature (°C) (e.g., 30, 40) for the conductor temperature rating
T'_a	=	Ambient air temperature (°C) for the changed condition
T_c	=	Conductor temperature rating (°C) (60, 75, 90, 105, etc.)
T'_c	=	Actual conductor temperature (°C) for the changed condition
ΔT_d	=	The temperature rise due to dielectric loss associated with T_c and T_a. An ac voltage impressed across a dielectric will produce a heat loss which leads to a cable temperature increase. The temperature rise is negligible for low voltage cables and may be relatively small for cables operating at higher voltages, although it increases as the square of voltage [G.3]. Relations for the dielectric loss are given by Equations (36) and (37) of a paper [G.4] that was used to develop IEEE S-135; the temperature rise is proportional to the power factor and specific inductive capacitance (SIC) of the insulation.
$\Delta T'_d$	=	The temperature rise due to dielectric loss associated with T'_c and T'_a
τ_c	=	The inferred temperature of zero electrical resistance • 234.5 for copper • 228.1 for aluminum

The variables ΔT_d and $\Delta T'_d$ are negligible relative to $(T_c - T_a)$ and $(T'_c - T'_a)$, respectively, for most cables of interest and the equation reduces to:

$$I' = I \sqrt{\frac{T'_c - T'_a}{T_c - T_a} \times \frac{\tau_c + T_c}{\tau_c + T'_c}}$$

If a cable ampacity is known for a given conductor temperature rating and ambient temperature, this equation gives the resulting ampacity for a different ambient temperature and conductor temperature rating. This equation yields the same results as the ampacity derating factors from NEC Table 310-17.

In addition to performing ampacity derating calculations, the equations can be rewritten to calculate the conductor temperature (T'_c) that results from a current loading (I') at a given ambient temperature (T'_a), as

$$T'_c = \frac{T'_a(\tau_c + T_c) + \tau_c(T_c - T_a)(I'/I)^2}{(\tau_c + T_c) - (T_c - T_a)(I'/I)^2}$$

The conductor temperature for any current load can be determined using this equation and ampacity data for the configuration of interest (e.g., a single cable in open air). If the cable used in the previous example has a current load of 32 A (= I') at an ambient temperature of 30°C (= T'_a), then the resulting conductor temperature is 38.1°C.

G.4 Thermal Life of Constantly Energized Cables

For the purpose of this example, it is conservatively assumed that there is no temperature drop across the insulation and jacket (i.e., the conductor, insulation, and jacket all operate at the conductor temperature). The temperature for which a 60-year cable life is projected (using 50% retention of absolute elongation-at-break as the end-of-life criterion) can be calculated from the Arrhenius data in Table G-1 and the Arrhenius equation in Section 4.1.1.1.2. This temperature (T_c') can be used to calculate the continuous current loading (I') that results in a projected 60-year cable life. This has been performed for the materials listed in Table G-1, and the results are shown in Figure 4-5. Finally, please note that irradiation aging and other environmental factors, as applicable, must be considered when establishing the service life of a material.

Table G-1 Activation Energy and Thermal Life

Generic Material Type	Activation Energy[1] (eV)	Basis Temperature (°C)	Basis Temperature (°F)	Life[2] @ Basis Temperature (years)
CSPE	1.14	80°C	176°F	13.5
EPDM[3]	1.35	91°C	196°F	40.0
EPR	1.20	135°C	275°F	0.2
ETFE	0.95	148°C	298°F	11.4
Neoprene®	0.94	80°C	176°F	2.5
PVC[4]	0.99	120°C	248°F	0.2
Silicone[5]	1.8	136°C	277°F	40.0
Viton A	1.17	200°C	392°F	1.7
XLPE/XLPO[3]	1.24	150°C	302°F	0.1

Notes:

1. In most cases, the minimum temperature of tests performed to measure activation energy is much higher than temperatures in power plants. This time-temperature extrapolation can lead to significant differences between predictions based on accelerated aging tests and aging under power plant conditions. Recent measurements of activation energy at room temperature (25°C [77°F]) can be used to eliminate the time-temperature extrapolation.
2. End-of-Life is defined as $e_{absolute}$ = 50% for most materials (see notes 3 to 5). Limited sources of non-proprietary data are available. The data in this AMG are adequate to exhibit general relationships only.
3. The end-of-life condition for EPDM and XLPE is 60% relative elongation (e/e_0 = 60%). This endpoint is much more conservative than $e_{absolute}$ = 50%; the service life would increase significantly.

4. The end-of-life condition for PVC is electrical failure, which would leave no margin for design basis event degradation. The actual material specification is MIL-W-5086/2 (a PVC-Nylon). Data were not available for $e_{absolute} = 50\%$.
5. The end-of-life condition for Silicone is 50% relative elongation ($e/e_0 = 50\%$). This endpoint is much more conservative than $e_{absolute} = 50\%$; the service life would increase significantly.

G.5 Variable Service Conditions

Most cables are not energized continuously at a fixed current. Therefore, it is more useful to investigate the thermal life of a cable that is energized for only a fraction of the time, which is known as *duty cycle*. The calculation of thermal life is performed using the following procedure:

1. Calculate the energized cable temperature (Section G.2).

2. For the given duty cycle and design life, calculate how many years the cable will be energized and how many years the cable will be deenergized.

3. Using the Arrhenius relationship, calculate the time at ambient temperature that is equivalent to the energized time and energized cable temperature. Then add this equivalent time to the actual deenergized time to get the total equivalent thermal life at ambient temperature. (The technique to calculate equivalent overall exposure time is similar to that found in Section 4.6, "Consideration of Variable Service Conditions," of EPRI NP-1558 [G.5])

Figures G-1 through G-6 give the results of this calculation for Neoprene® and XLPE. From these figures, it is obvious that the operating time of a power cable that is heavily loaded has significant impact on the total life (or qualified life) of the insulation. The Neoprene® data in Figure G-2 will be used to explain the nomenclature and demonstrate how Figures G-1 through G-6 can be used.

- *X-axis:* The electrical loading of the cable (when it is energized) is plotted on the x-axis. The x-axis is normalized by dividing the energized cable current by the 30°C ambient ampacity.

- *Y-axis:* The remaining life of the cable at the end of its design life (lower left corner of the figure) is plotted on the y-axis. The y-axis is normalized by dividing the remaining life by the material thermal life. Note that:

  - material thermal life is the time required at ambient temperature (lower left corner of the figure) for the elongation-at-break of new material to degrade to 50% absolute.

  - remaining life is the time required at ambient temperature for the elongation-at-break of the material at the end of its design life to degrade to 50% absolute.

- *NEC Ampacity Derating:* The vertical ampacity derating line at 91% is the calculated ampacity for a 40°C ambient temperature. The calculated ampacity (or derated ampacity) is less than the ampacity at 30°C which is used to normalize the x-axis. When the cable is energized with a current equivalent to the ampacity derating line, the conductor temperature will equal the cable temperature rating (90°C, top margin of the figure). When the cable is energized, operating conditions to the left of the ampacity derating line result in cable conductor temperatures less than the temperature rating, and operating conditions to the right of the ampacity derating line result in cable conductor temperatures above the temperature rating. If the ambient air temperature is increased, the ampacity derating line will move to the left on the plot.

- *Y-axis intercept:* An unenergized Neoprene® cable (0% of rated ampacity) has a remaining life of 54% after 60 years of service at an ambient temperature of 40°C. At 0% of rated ampacity (e.g., an I&C cable), the cable carries no current and it operates at the ambient air temperature. The life of Neoprene® at 40°C is 130 years (top margin of the figure, calculated from the Arrhenius equation using Table G-1 data). Therefore, it has 70 years (= 130-60) of remaining life, or 54% (= 70/130) of its thermal life remaining, after a 60 year design life.

- *X-axis intercept(s):* A continuously energized Neoprene® cable (100% duty cycle) in a location where the ambient air temperature is 40°C can be operated at currents up to 37% of its 30°C ampacity for 60 years. If this cable's duty cycle is reduced from 100% to 33%, then a current loading of 52% of the 30°C ampacity results in a remaining thermal life of 0% at the end of 60 years. Such a cable is energized 33% of the time at 52% of the 30°C ampacity and is not energized the other 67% of the time. The cable has no remaining life after operating under these variable service conditions for 60 years, which means that the Neoprene® has degraded to an absolute elongation-at-break of 50%.

  To generalize for a given duty cycle, service conditions to the left of the duty cycle line's x-axis intercept are acceptable for the design life; to the right of the duty cycle line's y-axis would require replacement.

  Operating cables at large current loadings significantly decreases their thermal life, even when energized for a very small percentage of the time. The Neoprene® cable in a 40°C environment that is energized at ~91% of its 30°C ampacity and a 1% duty cycle (i.e., energized for only 0.6 of 60 years) will reach its end-of-life condition after 60 years, but there is little margin to spare.

- *Equivalent thermal aging:* Cable materials subjected to equivalent thermal aging will have identical remaining thermal life. For instance, the thermal degradation for a Neoprene® cable energized continuously at either 31% of its 30°C ampacity, or energized 1% of the time at 87% of its 30°C ampacity, for 60 years is identical as they both use 80% of the material's thermal life (i.e., 20% remaining thermal life).

- *Practical application:* As an example of how a user would implement the figure, consider a Neoprene®-jacketed power cable located in a 40°C ambient environment (where the jacket is required to be intact throughout the cable lifetime) that is energized 10% of the time. Per Table 4.2, 40°C would exceed the maximum recommended ambient temperature for a 60-year lifetime (14°C at 80% of its 30°C ampacity), thereby making this cable a candidate for further evaluation. From Figure G-2, the cable could be operated with a 10% duty cycle at up to ~67% of its 30°C ampacity over a 60-year period and the Neoprene® jacket would still exceed the 50% retained absolute elongation-at-break criteria. Therefore, if the 10% duty cycle circuit is determined to operate below ~67% of its 30°C ampacity, the cable may be eliminated from further consideration.

The thermal life of an energized cable, as shown in Figures G-1 to G-6, depends on a large number of parameters, namely:

1. material activation energy

2. material life at ambient temperature (life at any other temperature will also suffice, as the activation energy can be used to calculate the equivalent lifetime at ambient temperature). Note that cable life depends on the criterion used to define cable life (for this Appendix, the end of cable life is at 50% absolute elongation).

3. ambient air temperature

4. cable current when energized

5. load factor (fraction of time the cable is energized)

6. conductor temperature rating

7. ampacity for the cable configuration at the ambient air temperature (this may require correcting the ampacity from a standard industry table that is based on a different ambient temperature and/or cable configuration)

Because of the large number of parameters, it is not practical to plot the cable life as a function of all the parameters in a single figure. Instead, a set of figures can be created, each showing a set of cable thermal lifetimes versus cable current load for several load factors, while all other parameters are held fixed.

The following comments and observations refer to the data shown in Figures G-1 to G-6:

1. These Figures use the thermal aging data from Table G-1 which provide a generic indication of a given material's thermal aging behavior. It is important to use thermal aging data specific to the material of interest when estimating the allowable temperature for a projected 60-year life.

2. Ampacity is based on continuous operation; however, there are conditions where a cable will be operated for short periods of time at currents above the ampacity (e.g., motor in-rush current). While such overload or transient conditions are not addressed

in the NEC, they are addressed in several other standards. For instance, AIEE S-135 (Appendix III, Section 4) [G.2] and ANSI/IEEE Standard 242-1986 (Section 8.5.2) [G.6] include information on cable overload capacity. Even short-term overload conditions can have a significant effect on thermal life and should be evaluated.

3. A conductor temperature rating is not directly correlated to cable life; a temperature rating of 90°C does NOT mean that the cable can survive for 40- or 60-years at 90°C.

4. The thermal life of a cable becomes less sensitive to changes in temperature as the activation energy is increased. The thermal life of cables with high activation energies does not decrease as quickly with increasing current load or load factor as those with low activation energies.

5. These figures are for cables that are energized. It is important to recognize that even a deenergized cable can be subjected to elevated temperatures if it is in close proximity to an energized cable.

6. These figures are based on rated ampacity values. It is standard practice to size cables so the maximum current load is some fraction of their rated conductor ampacity. This provides a safety factor, or margin, to account for design and load uncertainty, reduced voltage (increased current) conditions, and overload conditions.

7. Ampacity values are based on conductor temperature, which is the hottest point on the cable. The implied assumption is that the temperature of the cable's insulation and jacket is conservatively estimated as being equal to the conductor temperature. In reality, there will be a temperature gradient across the cable insulation and jacket, and the majority of the energized cable's polymer material will be at a temperature somewhat lower than the conductor temperature.

8. Care must be taken to ensure that the proper ampacity is used. Fire barriers, penetration seals, etc. can have a significant ampacity derating.

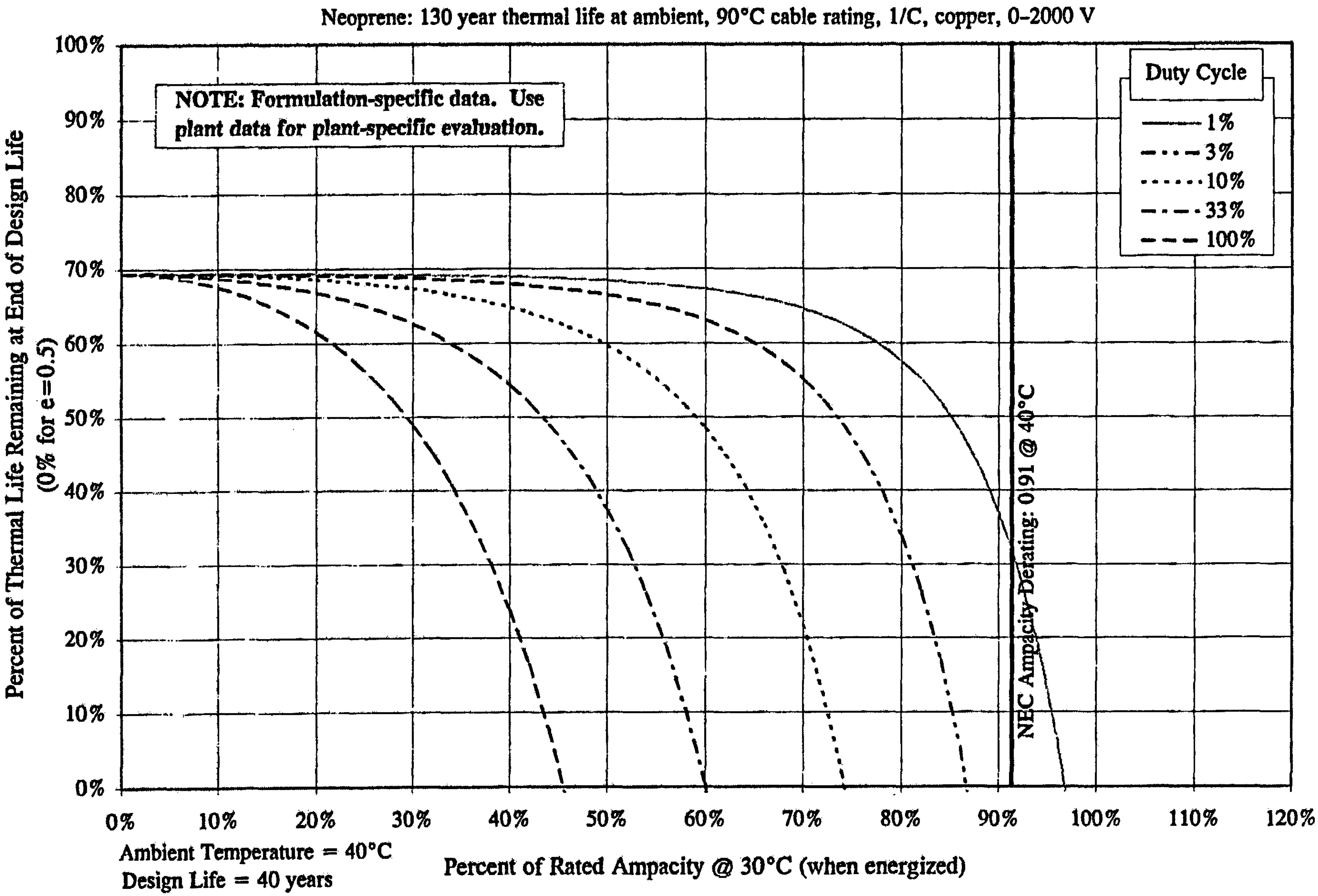


Figure G-1 Ampacity versus Thermal Life With Duty Cycles: Neoprene®, 40°C Ambient, 40 Years

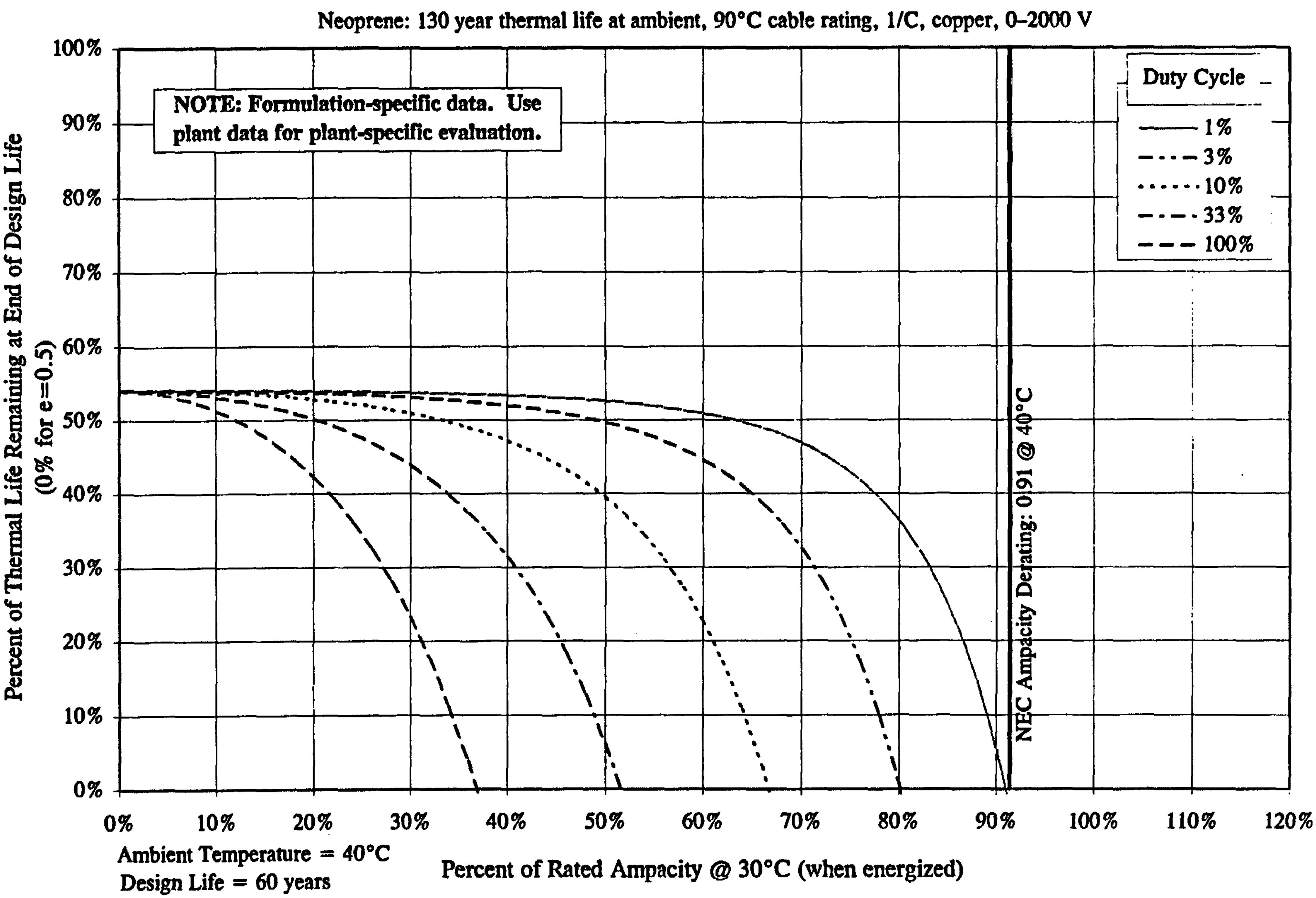


Figure G-2 Ampacity versus Thermal Life With Duty Cycles: Neoprene®, 40°C Ambient, 60 Years

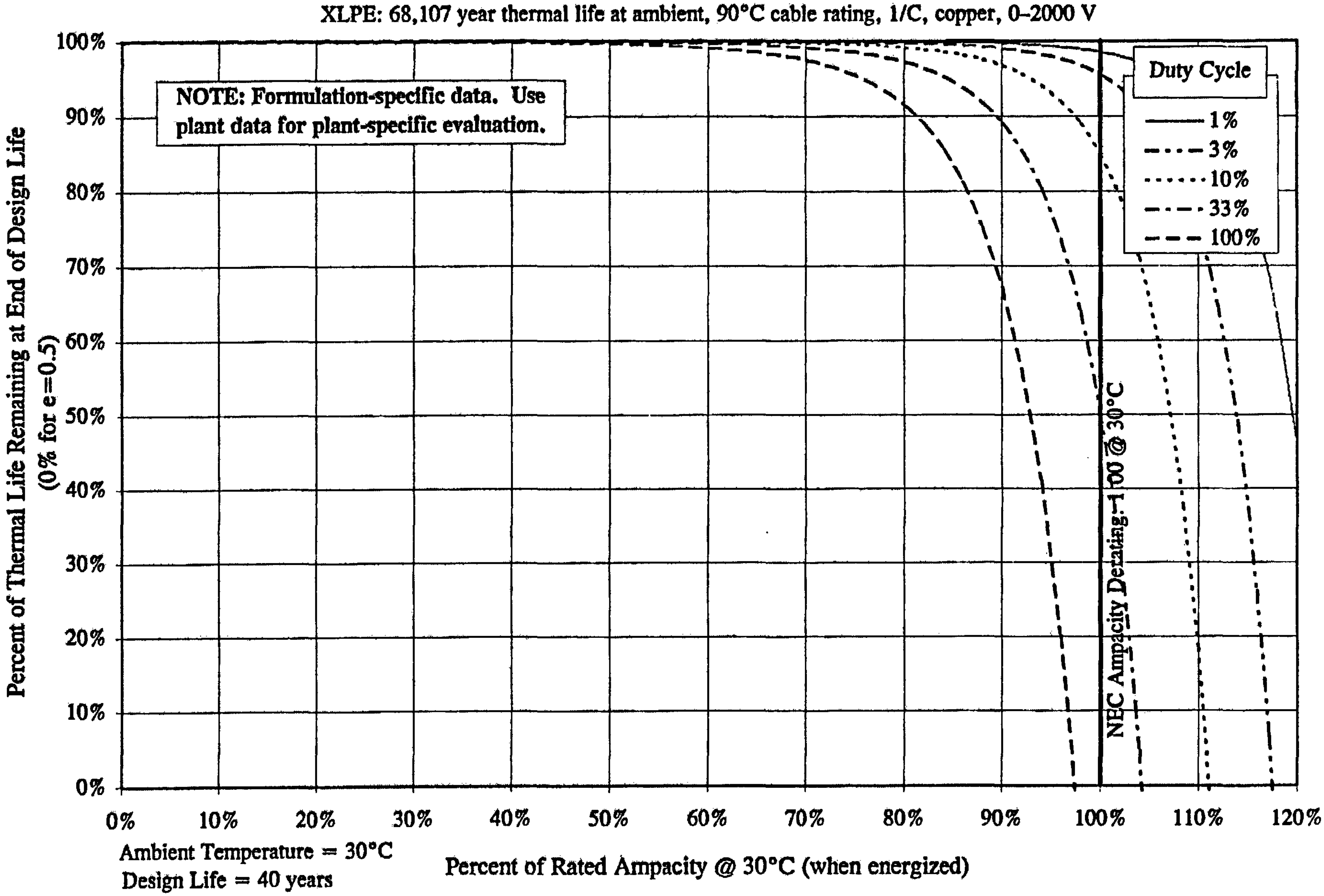


Figure G-3 Ampacity versus Thermal Life With Duty Cycles: XLPE, 30°C Ambient, 40 Years

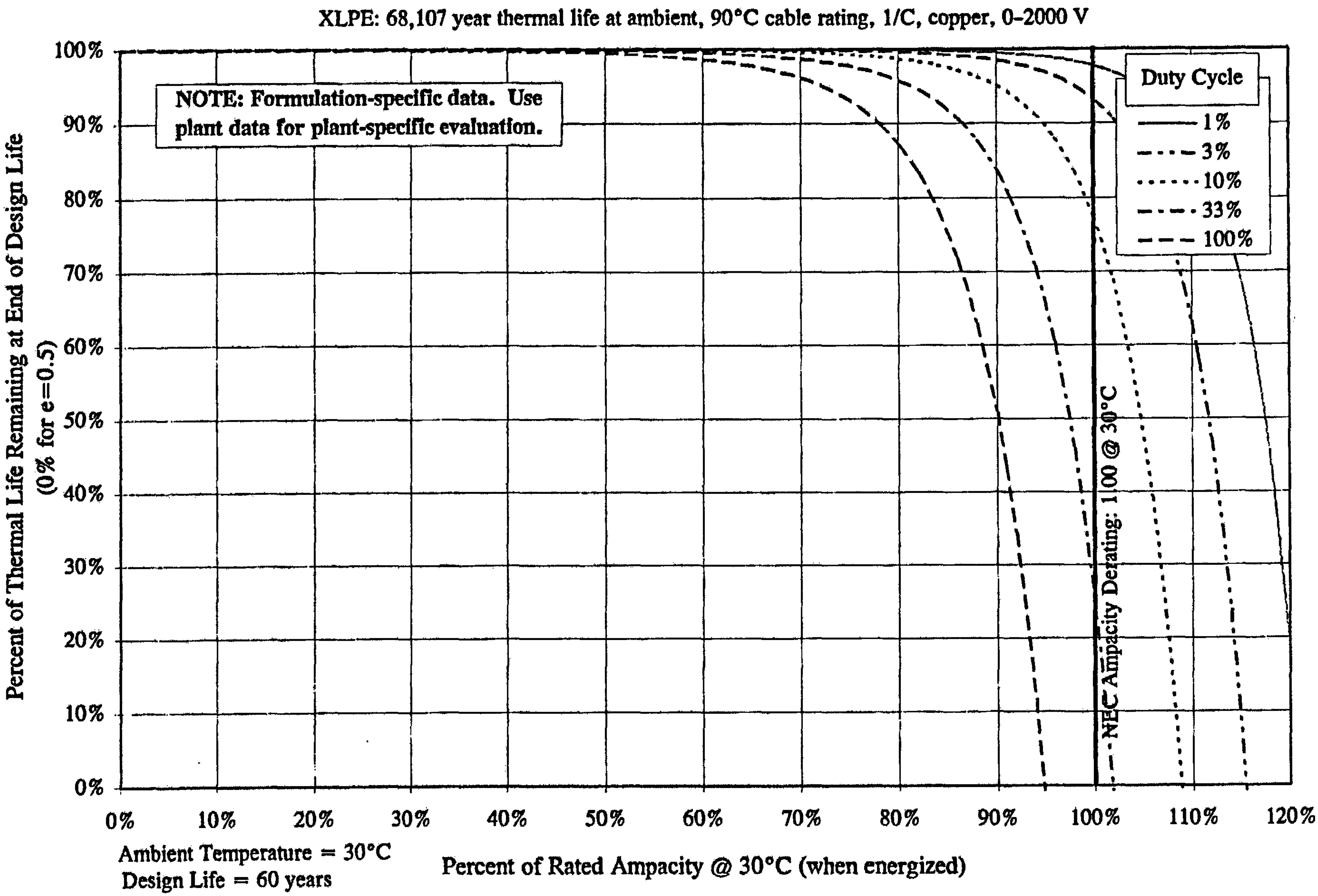


Figure G-4 Ampacity versus Thermal Life With Duty Cycles: XLPE, 30°C Ambient, 60 Years

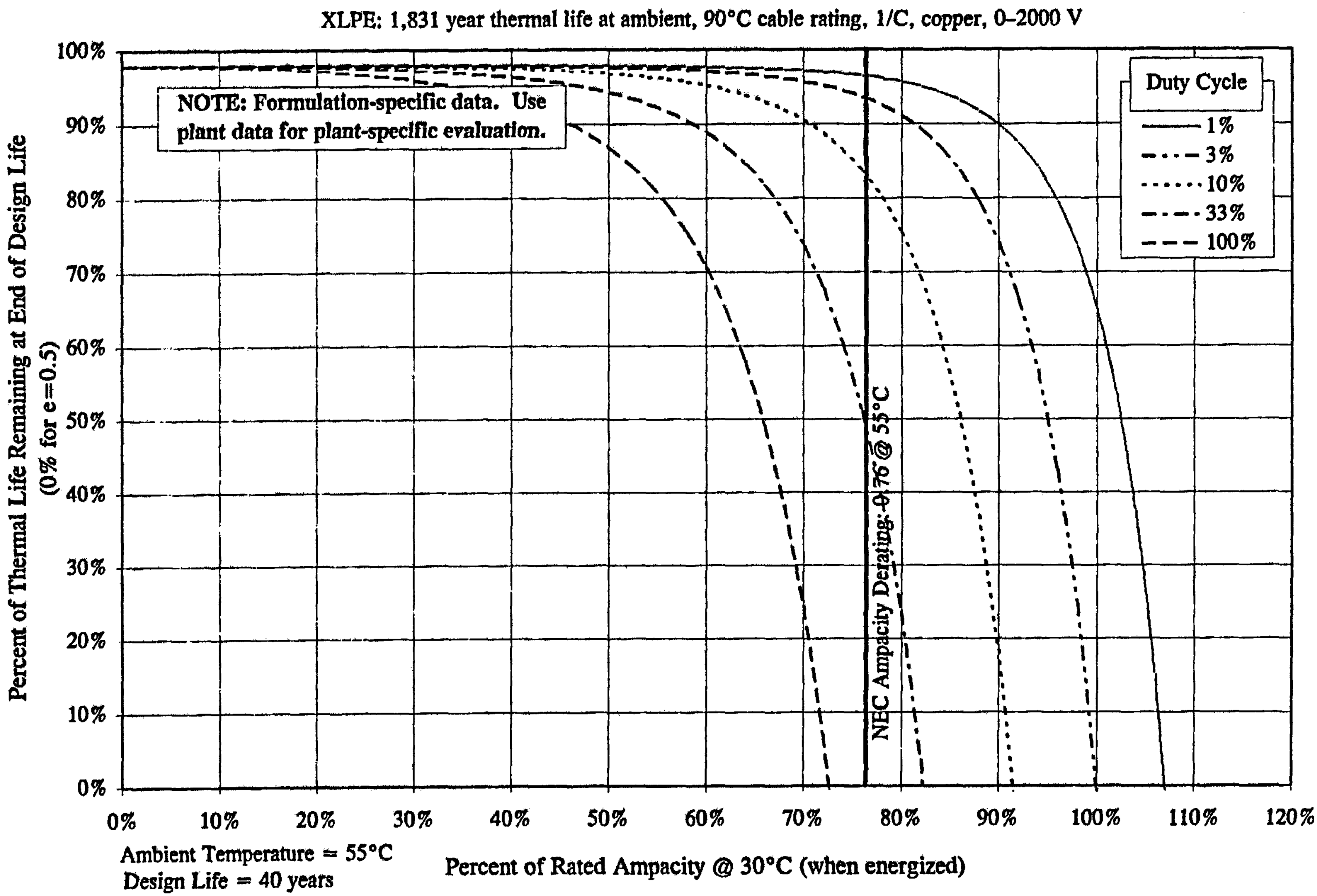


Figure G-5 Ampacity versus Thermal Life With Duty Cycles: XLPE, 55°C Ambient, 40 Years

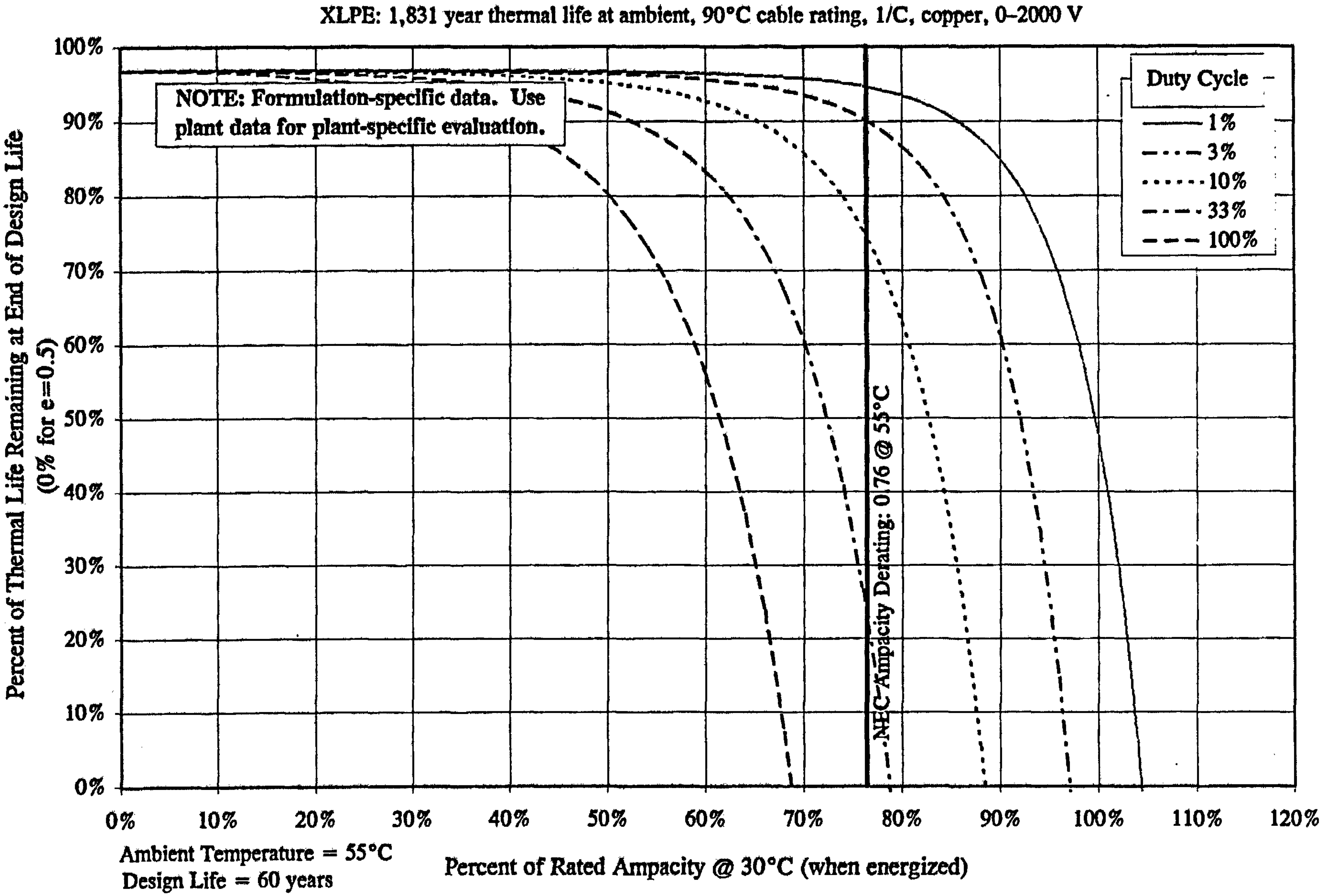


Figure G-6 Ampacity versus Thermal Life With Duty Cycles: XLPE, 55°C Ambient, 60 Years

G.6 References

G.1 ANSI/NFPA 70-1990, "National Electrical Code (NEC-1990)," National Fire Protection Association, Quincy, MA, 1989.

G.2 AIEE Pub. No. S-135, "Power Cable Ampacities: Volume 1 - Copper Conductors," AIEE is now The Institute of Electrical and Electronics Engineers, 1966 (IPCEA Pub. No. P-46-426).

G.3 Kommers, T. A., "Ampacity Ratings for Insulated Conductors," IEEE Conference Record of 1982 Annual Pulp and Paper Industry Technical Conference, The Institute of Electrical and Electronics Engineers, June, 1982.

G.4 Neher, J. H. and M. H. McGrath, "The Calculation of Temperature Rise and Load Capability of Cable Systems," AIEE Transactions, Part III, Vol. 76, p. 752, American Institute of Electrical Engineers (now IEEE), October, 1957.

G.5 EPRI NP-1558, "A Review of Equipment Aging Theory and Practice," prepared by the Franklin Research Center, Electric Power Research Institute, September, 1980.

G.6 ANSI/IEEE 242-1986, "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems," The Institute of Electrical and Electronics Engineers," 1986.

APPENDIX H. REGULATORY REQUIREMENTS RELATED TO SYNERGISMS

H.1 Regulatory Requirements

The first mention of synergistic effects in NRC documents related to EQ appeared in NUREG-0588 [H.1], issued in December 1979. NUREG-0588 did not define the term "synergistic effects," and the response comments received by the NRC from the industry were not in favor of including such a requirement. Nonetheless, the NRC retained the requirement when it issued Rev. 1 of NUREG-0588 [H.2] in July 1981. The complete text [Section 4.(3), page 15] is as follows:

> Synergistic effects should be considered in the accelerated aging programs. Investigation should be performed to assure that no known synergistic effects have been identified on materials that are included in the equipment being qualified. Where synergistic effects have been identified, they should be accounted for in the qualification programs. Refer to NUREG/CR-0276 (SAND78-0799) and NUREG/CR-0401 (SAND78-1452), "Qualification Testing Evaluation Quarterly Reports," for additional information.

The requirement was restated in the EQ Rule, 10CFR50.49 [H.3], when it was issued in February 1983. The wording related to synergism was modified significantly from that in NUREG-0588, Rev. 1; again no definition of synergism was provided. The complete text [paragraph (e) (7)] is as follows:

> Synergistic effects must be considered when these effects are believed to have a significant effect on equipment performance.

Regulatory Guide 1.89, Rev. 1 [H.4], issued in June 1984, described a method acceptable to the NRC staff for complying with 10CFR50.49. The complete text related to synergism [Section 5 a, page 1.89-5] is as follows:

> If synergistic effects have been identified prior to the initiation of qualification, they should be accounted for in the qualification program. Synergistic effects known at this time are dose rate effects and effects resulting from the different sequence of applying radiation and (elevated) temperature.

The wording in the Regulatory Guide can be interpreted in various ways. No definition of synergism is presented, but two examples of synergistic effects in aging programs are given. This is the most recent explicit guidance on synergism.

Appendix A includes a definition of "synergistic effects" from EPRI TR-100844 [H.5]; however, this definition is not endorsed by the NRC.

H.2 References

H.1 NUREG-0588 ("For Comment"), "Interim Staff Position on Environmental Qualification of Safety-Related Equipment, Resolution of Generic Technical Activity A-24," Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, December 1979.

H.2 NUREG-0588, Rev. 1, "Interim Staff Position on Environmental Qualification of Safety-Related Equipment Including Staff Responses of Public Comments, Resolution of Generic Technical Activity A-24," Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, July 1981.

H.3 Title 10, U.S. Code of Federal Regulations, Part 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," published in the Federal Register, Vol. 53, May 27, 1988 (page 19250).

H.4 Regulatory Guide 1.89, Revision 1, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1984.

H.5 EPRI TR-100844, "Nuclear Power Plant Common Aging Terminology," prepared by MPR Associates, Inc., Electric Power Research Institute, November 1992.

APPENDIX I. EPRI CABLE AGING RESEARCH PROJECTS

This section was reproduced from the draft EPRI Cable Aging Research Summary, August 1996. It is included in this AMG for the reader's convenience; current information can be obtained from the EPRI Plant Support Engineering group in Charlotte, NC.

Introduction

Electrical cable installed in fossil and nuclear power plants are expected to offer many years of trouble-free service. In the case of nuclear plants in particular, certain cable has been qualified for a 40-year life. In a limited number of cases, cables have been known to experience failure for a number of reasons, including mechanical damage, chemical attack, thermal degradation, electrical aging, radiation aging, and manufacturing defects. However, virtually all failures experienced have been premature in that their root cause was error-induced (e.g., damage due to handling or excessive high temperature conditions) and not due to long-term aging degradation.

Although rapid or widespread deterioration of cable systems is not expected to occur within the current design life of 40 years, localized problems such as hot spots may require reevaluation of cable life. Also, although it is expected that most cable, in the absence of hot spots, can provide 60 years or more of reliable service, such an extension of qualified life requires an evaluation. Without adequate data and evaluation techniques, utilities may find themselves needlessly replacing cable or entering into extensive evaluation programs. EPRI Cable Aging research will provide valuable data and methodology for use by utilities in making appropriate decisions concerning testing, continued use ,and replacement of cables. This work will also be useful in responding to increased regulatory interest related to generic issues such as synergisms and dose rate effects as the industry's cable systems grow older or cable-specific such as cracking of bonded cable jackets during research tests. The U.S. Nuclear Regulatory Commission is involved with cable performance issues and is presently sponsoring a cable condition monitoring research effort with Brookhaven National Laboratory (BNL). EPRI is cooperating in some of this research.

The EPRI Cable Aging Research Projects currently underway consist of the following:

1. University of Connecticut Artificial versus Natural Aging Program
2. Development of In-Plant Trials of Indenter Polymer Aging Monitor
3. Cable Diagnostics Matrix
4. Detection of Localized Cable Damage Using Preionized Gas, High Potential Testing
5. University of Virginia Oxidation Induction Time Methodology Development
6. Cable Life Database

7. Improved Conventional Testing of Power Plant Cables

8. American Electric Power Service Corporation - EPRI Life Cycle Management Program, Cable Aging Management Program

The purpose of this document is to summarize EPRI Cable Aging Research projects currently underway and to provide a brief status report on each project.

I.1 University of Connecticut Artificial Versus Natural Aging Program (RP-1707-13)

OBJECTIVE:

To demonstrate the validity and conservatism of the thermal and radiation accelerated aging models for organic materials used in electrical equipment that must be environmentally qualified.

DESCRIPTION AND PROGRAM HISTORY:

The Program seeks to understand the aging of polymeric materials used in cables and other components used in harsh environment areas of nuclear power plants by comparing the results of aging under natural in-plant conditions with those under accelerated laboratory aging used in environmental qualification programs. To achieve this goal, 15 bundles containing samples of four commonly used cables and materials used in electrical components or subcomponents of switches and solenoid valves were placed in each of 15 different locations in 8 power plants. The specimens include various types of small electrical devices and cables. The devices include solenoid valves, pressure switches, and electrical feedthroughs. Four types of power, control, and instrument cable from four major suppliers are in bundles at all fifteen of the original plant locations. Three of the types, manufactured by BIW, Kerite and Okonite, have ethylene-propylene copolymer insulation (EPR) covered with chlorosulfonated polyethylene (Hypalon) jackets. The fourth type, manufactured by Rockbestos, consists of a cross-linked polyethylene (XLPE)insulation covered with a Neoprene cover. In addition, each utility has placed one cable type of plant-specific interest in its bundles. Over 6000 specimens are involved. The locations have measured average temperatures ranging from 77°F to 132°F. Temperature monitoring and radiation monitoring devices have been installed with the bundles and are periodically withdrawn and replaced to provide a basic understanding of the environment at the bundles. In addition, utility temperature monitoring information from nearby areas is evaluated to allow adjustment for cyclic variations in temperature.

The initial specimens were placed in the plants in 1985. In 1989-1990, 60 additional bundles containing three cables selected from the NRC-sponsored program at Sandia Laboratories were placed at five of the existing locations (in four plants). The types added were Rockbestos coaxial cable with XLPE insulation, Rockbestos cable with silicone rubber insulation, and Champlain cable with polyimide (Kapton) insulation. Of the Sandia bundles, 13 have been removed. To obtain additional data at more severe aging conditions, five additional specimen bundles were placed at each of two "hotter" locations of Virginia Power's Surry containments during 1988. Of the Surry bundles, four have been removed for analysis. These bundles contain cable specimens of the same type as had been used by the research program at Sandia National Laboratories so that complementary data could be gathered by the two programs.

As part of a separate but similar program, Northeast Utilities (NU) placed, in 1982, three cables of different compositions in its Millstone 2 plant for aging studies. These cables are located in trays above the reactor vessel and experience quite severe conditions. In the case of these special NU specimens, a sample withdrawal consists of cutting off a piece of the cable. A total of six withdrawals of the NU special samples have been made.

Individual specimen bundles are periodically removed from the plants and evaluated. Initial specimen removal was approximately once per refueling cycle; however, due to the long-term nature of this segment of the program, removals are now less frequent so that adequate bundles exist through the end of the current license for the plants. When the bundles are received, elongation-at-break tests, density, and weight measurements are performed on the cable samples and some of the material specimens. All specimens that have been removed from the plants are stored under benign conditions to limit further aging and allow additional testing in the future.

Specimens of the same materials have also been aged under accelerated laboratory conditions and subjected to elongation, density, and weight measurement to allow comparison to the data from the in-plant specimens.

As the program has progressed, additional considerations and concerns have had to be addressed. One of the major problems with the in-plant specimens has been gathering and evaluating in-plant environmental data. A reduction of about 10°C in the average temperature may cause a doubling of time to reach a given level of degradation. Therefore, accuracy of the environmental data is crucial. To gather environmental data, three independent measures are made. One consists of a passive monitoring unit containing three types of dosimeters (two film and one LiF pellet) and a set of maximum-temperature pellets. The second measure is from the closest instruments used by the plant to monitor containment environment. Although not all of these instruments are close enough to be directly useful, they should provide confirming data that can fill in the history between withdrawals of the passive unit. The third and more recent measure involves placing a self-contained digital data logger capable of recording temperatures every hour for up to two years. On the data logger's removal, the temperatures can be downloaded into a computer file. When combined with plant-instrument data, the entire temperature history at each site should be able to be reconstructed accurately.

To date, data from the first 10 years of the long-term natural aging indicate that most of the cable materials have not begun to age appreciably. An exception is the neoprene jacket on the Rockbestos cable that has had a noticeable drop in elongation properties in warm (120° to 140°F) locations. This is not unexpected and the properties have not deteriorated to the point where a significant concern exists.

Because there is a desire to identify changes in advance of the aging of the installed cables in the plants, an additional task was added to the program in 1994. In this program, called the Pace Cable Program, cable specimen bundles have been placed in plant locations that are hotter than the locations where most cables are located such that an acceleration factor of 5 to 8 times that of normal natural aging occurs. In this way, the equivalent of 40 years of aging will occur in only 5 to 8 years so that an understanding of the effects of aging of the materials will be obtained earlier than for the specimens under near normal conditions. (Accelerated aging factors used in qualification programs are on the order of 1000 to 2000, which causes relatively large uncertainties in the degree of aging achieved.) If the behavior of materials under Pace conditions is relatable to real conditions, then these sites could be used for testing and monitoring of new or existing materials. Pace sites were selected at PSE&G and NU.

As a further attempt to understand long-term slow aging of cable materials, oven aging at low accelerated aging temperatures has been implemented in parallel with the Pace Cable Program. Differences between natural and artificial aging may be due merely to the lower levels of temperature and dose rate in the former or to other factors that differ between the plant and the laboratory. Humidity is one example of such a factor. To test the possibility that the differences are only due to lower temperature, samples were placed in ovens with low temperatures, e.g. 140°F (60°C) and 195°F (90°C), to parallel the natural environmental temperatures anticipated at the Pace cable sites.

STATUS:

The program is being performed at the University of Connecticut under the direction of Dr. Montgomery Shaw. An Interim Report (the second) on the project was issued in January 1992 (EPRI TR-100245, Natural Versus Artificial Aging of Nuclear Power Plant Components). The third Interim Report will be published in 1996. Specimens and environmental monitoring modules continue to be retrieved from the plants. Activities for the year 1995 are described under the following topics:

- Environmental Monitoring

  Six dosimeter/temperature (D/T) units were received, and 14 were shipped to the various utilities. Eighteen recovered D/T units were refurbished for subsequent shipments.

  Ten sets of maximum temperature pellets were read from the D/T units received. A total of 45 LiF dosimeters were sent to Northeast Utilities for analysis during 1995, and the results were used to help update the environmental exposure database.

  Environmental data from the plants' monitoring instruments continue to be collected and analyzed.

  Dosimeter/temperature units continue to be received from the host utilities. Some decontamination effort is required. New D/T units continue to be delivered to the host utilities as needed.

- Withdrawals

  Two bundles were received from Washington Public Power Supply System (WPPSS). Additional decontamination work on all the bundles is necessary before testing can begin. At the end of 1995, 99 bundles out of the 225 originally placed will have been received.

  Bundles are being withdrawn from the sites as scheduled.

- Testing

A total of 92 specimens from 15 bundles were tensile-tested during 1995. Of this total, 9 control specimens were tested. A total of 956 density specimens from 15 bundles were analyzed in 1995.

- Analysis

Component Aging. The artificial and natural aging of components are compared using time shifts for temperature and dose rate in a manner described in previous reports. The shifts are determined by minimizing the scatter of the data points about an unknown property decay curve. This work will continue in 1996 as much as funding will allow.

Modeling Study. Procedures for testing the modeling algorithms continue to be developed. The physical property data on the naturally and artificially aged specimens are compared in a number of ways. One method involves constructing predicted property values for the set natural aging conditions using the Arrhenius equation, along with published activation energies, and the equal-dose-equal-damage premise. These predicted values are then compared with the actual values. Another method uses the natural data set, which involves temperatures ranging from 90° to 160°F, to derive an activation energy and dose-effect parameters. The results are then compared with published values. In a third method, two materials that are supposed to behave similarly in both accelerated and natural conditions are compared side-by-side; if they are, in fact, not behaving similarly, the notion that accelerated tests are a valid indicator of aging performance in the field can be rejected.

- Pace Cable Aging

Temperature data for the period July 21 through October 3, 1995, were received from PSE&G for the Pace bundles in containment. The maximum temperatures listed for this period are 159° and 140°F, respectively, for the thermocouples at the top and bottom of the bundles. The average dose rate for the period August 4 through October 3, 1995, was listed as 850 mR/hr.[1] Northeast Utilities is postponing precise site selection and Pace cable placement, pending completion of ongoing engineering work.

Pace cable specimens are installed at the Hope Creek site. Environmental data through October 1995 have been received. Hope Creek has recently been restarted.

- Other

The draft 10-year Interim Report for this project has been written and is at EPRI for draft review and publication.

Actions are in progress to cooperate with Brookhaven National Laboratory in their NRC-sponsored Cable Insulation Condition Monitoring Project by making aged cable insulation samples available for their test program.

I.2 Development and In-plant Trials of Indenter Polymer Aging Monitor

OBJECTIVE:

To develop a non-destructive technique that may be used in a plant to evaluate the aging of nuclear power plant cables that have been subjected to normal or abnormal service conditions.

DESCRIPTION:

Under earlier EPRI programs, a non-destructive test method was developed for evaluating the aging of jackets and insulation of electrical cable. The test evaluates changes in compressive modulus, a mechanical property of the insulation and jacket material. For low-voltage cables, significant mechanical property changes occur due to thermal and radiation induced aging prior to electrical property changes. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed. Commonly, changes in mechanical properties of jacket and insulation systems have been evaluated by means of elongation-at-break testing. However, elongation testing is by nature destructive and requires relatively large specimens, making it undesirable for analyzing installed cables. As an alternative to the destructive elongation-at-break tests, compressive tests were evaluated during the proof of principles research. In this research, compression, relaxation, creep, and recovery properties were evaluated. The research showed that the change in force divided by change in position of a probe pressing against the jacket or insulation of a cable at a constant velocity provided a systematic indication of aging of the material. For materials that harden with age (i.e. most cable insulations and jackets), the measured compressive modulus increases with duration and level of exposure to thermal and radiation stresses.

Therefore, the relative age of a cable insulation can be evaluated on the basis of the change in compressive modulus as measured by a small anvil pressing at the surface at a fixed velocity while measuring the imparted force.

The Indenter is a self-contained system and includes its own data logger. The system includes a laptop computer, a control box, cable, and a cable clamp assembly. The operation of the Indenter is digitally controlled, allowing different velocities and force limits to be used in testing, and contains self-nutting on the force reading to eliminate offset drift effects. The clamp assembly was improved to allow easy application on the cables and contains status indicating lamps. The tests are initiated from the clamp assembly. A long cable was added between the clamp assembly and the control box to allow use of the clamp in areas where the cable under test was remote from a satisfactory staging area.. The entire system is battery operated.

The in-plant trials of the Indenter proved that the system is practical and readily usable. Actual application of the Indenter in the plants proved that it could be readily used in junction boxes, back planes of motor control center, and even in condulets. The in-plant tests proved that reasonable consistency in results could be obtained in the field.

The Indenter concept works for any insulation or jacket that has a systematic change in properties with aging. Rubber and rubber-like materials, such as EPR, silicone rubber, neoprene, PVC and Hypalon, all are monitorable with the Indenter. The suitability of the

Indenter for direct monitoring of the aging of cross-linked polyethylene is currently under investigation. If neoprene or Hypalon jackets have been used on cables with cross-linked polyethylene insulation, the jackets may also be used as aging indicators for the entire cable.

STATUS:

The Indenter in-plant trial use program is complete. Life projection criteria have been developed for a number of cable types, including Okonite, BIW and Kerite. Given the current age and an Indenter measurement of a cable, a projected qualified life can be determined based on actual condition. The report for the in-plant trials and life projection criteria development was expected to be published in early 1996. In commercial, non-EPRI funded programs, the Indenter has been used to evaluate hot-spot conditions at River Bend, LaSalle, and Fermi. An aging evaluation of in-containment cables at Enrico Fermi has been completed. EdF (France) has completed an in-depth evaluation of the Indenter for use in its plants; the results of this evaluation have been satisfactory. The Indenter is available for commercial use via Ogden Environmental and Energy Services Company under license to EPRI.

There is no change in the Cofunding Agreement between EPRI and EdF for the Indenter project. EPRI has the action item.

There is no change on the revision of the licensing details on the sale of the Indenter to commercial customers. EPRI has the action item.

Potential Indenter sales in 1996:

- AEA Technology
- Detroit Edison
- EdF (France)
- Exxon Engineering (Refinery)

I.3 Cable Diagnostics Matrix

OBJECTIVE:

To provide a utility applications based assessment of cable diagnostic techniques currently available or in an advanced state of development.

DESCRIPTION:

During the past 10 or so years, a number of diagnostic techniques have been developed that enable varying degrees of assessment of the condition of power plant cables. Some of these techniques are useful for evaluation of installed cables, whereas others are destructive tests that must be conducted with samples of cable materials removed from installation. Some techniques are useful for trending the long-term performance of cables, whereas others are useful only troubleshooting. The remainder consist of laboratory tests for characterizing the properties and performance of specific cable materials.

This program compiled and consolidated published and technical report information on the principles, applications, cost, and other major test method considerations with particular attention to their applicability. This information was collected into an organized reference document and a computerized database for use by the utilities who operate fossil and/or nuclear power plants. The test method matrix will be accessible on the basis of many topics of concern, including cable construction, failure analysis application, trending analysis application, destructive versus non-destructive test method, etc.

This program primarily addresses power plant low-voltage control and instrumentation cables.

The program is described in the following outline.

1. Review of the available diagnostic tools, including:

    - technical description of the test equipment
    - specific properties measured
    - relative cost of instrumentation
    - portability of test equipment
    - defects/aging to which method is sensitive
    - commercial availability of equipment
    - relative complexity of test performance
    - relative complexity of data interpretation
    - relative availability of reference data
    - potential for damage to the specimen under test and to adjacent circuits
    - sensitivity of method to local and overall degradation
    - type of result provided (go/no-go vs. trending)
    - ability to locate degraded areas along cable application in-situ or laboratory
    - if destructive, relative amount of material required for testing
    - insulation/jacket/shielding materials to which the test is sensitive
    - reference to publications describing the theory involved

2. Development of Cable Diagnostic Matrix

    - compilation of data in a user-friendly format
    - preparation of reference document

3. Summary of the applicability and limitations with present diagnostics techniques

STATUS:

A draft report has been submitted and is under EPRI review for comments.

I.4 Detection of Localized Cable Damage Using Pre-ionized Gas, High Potential Testing (RP-3427-04)

OBJECTIVE:

To provide an electrical test technique for identifying local defects in unshielded low-voltage cable located inside conduits.

DESCRIPTION:

From time to time, concerns have arisen in the industry that require utilities to determine if damage has occurred to low-voltage cables either during or subsequent to installation. The lack of a shield on most low-voltage cables used in nuclear plants has made use of electrical testing to evaluate the condition difficult.

For cables located in conduits, one available technique for developing a ground plane at the surface of the insulation is to fill the conduits with water and perform a high potential test between the conductors and the conduit. However, filling conduits with water is difficult in that they are not tightly sealed and water can leak onto surrounding energized electrical equipment, causing the potential for flashover. Removal of the water at the end of the test is also difficult. Also, clear-cut definitions of acceptable test voltages are not available for such testing.

To provide an alternative to use of water as the ground plane and to determine acceptable test voltages, the use of ionizable gas for providing in conduit ground planes during high potential testing is being developed as are acceptance criteria based on as-low-as-possible test voltages. Although the cables are called low-voltage cables with 600- to 1000-Vac ratings, the thicknesses of the insulation are capable of withstanding very high voltages. Data from the program indicate that 30-mil thick insulation can withstand voltages on the order of 22 to 26 kVac, which is much higher than the manufacturing proof tests, and much higher than desirable for in-plant testing. High potential tests are go/no-go in nature. If the insulation successfully withstands the test voltage, a statement can be made that at least the amount of insulation thickness associated with the test voltage acceptance criteria remains in place (i.e., even though one cannot state that no damage has taken place, an indication of the minimum possible remaining wall can be made).

The research determined that high potential testing of cables in ionized helium yields high potential test results similar to those when the ground plane is provided by water. In the associated tests, specimens of cable with a 30-mil insulation wall with varying depths of insulation damage from 0 to 30 mils were tested to breakdown. The tests showed a significant reduction in test voltage between testing with the conduit filled with air and the conduit filled with water. The tests also showed that testing with the conduit filled with helium had nearly the same results as with the conduit filled with water. It should be noted that when testing in air, identification of completely through wall damage required nearly 14 kVac, whereas testing with water and helium required only 1 to 2 kVac. The slight difference in results with water and helium is predominantly related to the voltage at which the helium ionizes. Once the helium ionizes, the stress across the insulation under test increases significantly with most of the test voltage across the insulation under test. The research to date has shown the method to be viable and not to be destructive to cables surrounding the cable under test. It should also be noted that dilution of the helium rapidly decreases its ability to ionize. Therefore, if helium escapes from the conduits under test, there is no possibility of causing flashovers in surrounding electrical equipment that uses air as an insulation medium (e.g., circuit breakers and switches).

The initial development of the process has been completed under Sandia National Laboratories, and the report of the testing was finalized in 1994 (TR-104025). During the course of the work, conflict of interest concerns on the part of the U.S. NRC dictated that follow-on work be performed elsewhere. The continuation of the program is being performed by Ontario-Hydro Research under the direction of Dr. Jean-Marie Braun[1]. Work started in early 1994. The efforts include:

- Optimization and selection of the ionizable gas to further reduce test voltages
- Evaluation of differences in results from longer lengths of cables ("length effect")
- Determination of the need to monitor current and voltage during the tests to provide more information concerning the degree of damage
- Development of a useful dc test method (dc withstand and transient measurements)

STATUS:

The selection of ionizable gas was investigated; the gas selection issue is now limited to two candidates. Dr. Braun reported that the initial investigations with an 8% conduit fill with one "faulted wire" resulted in successful location of the fault. Both pure helium and neon/0.1% argon will be used to further study which gas will provide a satisfactory voltage gap.

Dr. Braun needs about 3000 meters of #14 or #16 wire to continue the project into Task 2. Cable donations from participating utilities have not yet been made; therefore, the requisite cable will be purchased from a cable manufacturer. Single-conductor EPR-insulated cable will be selected. Although the lack of cable is now holding up progress, some investigation has been made using #17 PVC cable that was available on site.

I.5 University of Virginia Oxidation Induction Time Methodology Development

OBJECTIVE:

Oxidation induction time (OIT) testing is a means of evaluating the degree of aging of polymers subjected to thermal and radiation stresses. The purpose of this program is to develop consistent methodology in using OIT to evaluate the aging of nuclear power plant cables and to prepare life estimation criteria based on measurements of OIT of specimens artificially aged as in environmental qualification programs.

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[1] The results of related research at the University of Connecticut performed by Dr. Matthew Mashikian are contained in EPRI Report TR-101273, Using an Ionizable Gas to Troubleshoot Nonshielded Electric Cables.

DESCRIPTION:

Oxidation induction time (OIT) testing is an alternate and complementary test to that of the cable Indenter. It is a means of evaluating aging of cable materials by measuring the period of time before a small sample of insulation experiences rapid oxidation when subjected to a constant elevated temperature in an oxygen atmosphere. The test evaluates the amount of anti-oxidants remaining in an insulation material. The anti-oxidants are materials that react with oxygen from the atmosphere surrounding the cable before it can react with the polymers of the insulation. As long as the anti-oxidants are not depleted entirely in the material, the mechanical properties (and, therefore, the electrical properties) remain relatively stable. Even a few percent of the initial anti-oxidant is sufficient to prevent oxidation of the polymers. When the anti-oxidants are depleted, the material properties will begin to degrade, in some cases relatively.

OIT testing is performed using a differential scanning calorimeter. A small sample (8 milligrams) of insulation or jacket is removed from the cable, then heated to approximately 215°C in oxygen and held at this temperature. The energy required to sustain the temperature is monitored. When the energy required to main temperature begins to decrease, the material has begun an exothermic reaction, indicating that the anti-oxidants have been depleted and that rapid oxidation is occurring. The period from the start of the test until the point of rapid oxidation is the oxidation induction time. For cable materials, the OIT decreases from approximately one hour when new to a few minutes when near the end of its useful life. The test is essentially non-destructive; although samples have to be removed, they are small enough that cables do not have to be destroyed or removed. Samples are taken by removal or terminal lugs, stripping a small segment of insulation (0.5 cm or less), and relugging the conductor.

Although OIT testing has been in use for a long time, testing protocols for use with nuclear power plant cables have not been previously developed. The following tasks are complete:

- Determination of the Feasibility of Developing Life Projection Criteria
- Correlation of OIT with Elongation at Break
- Standardization of OIT Methodology
- Development of Acceptable Field Sampling Techniques

STATUS:

The project has been performed at the University of Tennessee under the direction of Dr. Albert Reynolds. The project is completed and the report is being published.

I.6 Cable Life Database

OBJECTIVE:

To provide the industry with a computerized database of aging behavior and plant experience data for low-voltage cable. The data will be obtained from manufacturers, qualification tests, research studies, and on-going plant cable evaluations.

DESCRIPTION:

A large quantity of information related to low-voltage cable exists, and useful information will be generated at an accelerating rate in the future. However, the data are not easily accessed or arranged for ease of use or understanding by front-line utility personnel involved in design engineering, qualification, assessing cable system longevity, or troubleshooting.

The Cable Life Database will provide the ready reference resource needed by utilities via a remotely accessible, computerized system. It will contain existing information organized by cable material type, test data from cable monitoring techniques as they are generated, material aging data, and qualification research results. The database will provide a strong reference tool for resolution of day-to-day problems as well as long-term issues. The sources of the initial data will be from utilities, past and on-going EPRI program, government research programs, and the general literature. The database will continue to be updated as new information applicable to low-voltage cable evolves.

The need for organizing available cable data and gathering new data as it is generated is driven by the following factors:

1. Many of the original manufacturers of nuclear plant cables no longer are in business or produce nuclear grade cables. As such, they cannot or will not provide data and information for decision-making and engineering efforts related to cable system longevity. Gathering and organizing existing data related to these manufacturers' cable is desirable before all of it is lost or forgotten.

2. Hot spots leading to more rapid localized deterioration of cable properties have been identified in some plants. Test results from cable removed from these locations may be useful to the industry as a whole in determining the actual effects of elevated normal temperatures. These data from previous hot spots may be instrumental in resolving new hot spot problems as they occur at other utilities.

3. Some plants have had elevated containment temperatures for long durations due to errors or unexpected conditions. These plants need information to determine the extent of cable to be removed and, at the same time, may be able to provide information to the remainder of the industry when the removed cables are tested.

4. Many plants are now or will be addressing cable system longevity. They will need to show that their existing qualifications cover the entire period for which their cables will be installed. The more data that are available related to cable insulation system behavior under

actual conditions (which include synergistic effects), the easier it will be to defend the decisions that are made with respect to retention or replacement of a plant's cables.

Each of these factors indicates that any data that are available (be it descriptions of cable insulation systems and their basic properties, physical or electrical property data, or information related to cable insulation system formulations) should be collected, catalogued, and retained in a format that allows the information to be easily accessed and used by utility and industry personnel.

The database will record information on older cable material formulations, qualification, and aging test results that are in the public domain, and research data important to understanding and controlling aging and synergisms. The database will also record results of condition monitoring and condition evaluation tests as they become available, including acceptance criteria and methodology descriptions.

STATUS:

An evaluation of the type of data to store, the format and structure, and the depth of detail is complete. The project was suspended in mid-1994. Further development of the database is under review.

I.7 Improved Conventional Testing of Power Plant Cables

OBJECTIVE:

To develop improved condition monitoring techniques for assessing the condition of power plant cables, particularly unshielded cables in older thermal plants.

DESCRIPTION:

Many diagnostic tests have been proposed to assess the condition of power plant cables. Electrical tests are inherently attractive, as they offer the potential of assessing an entire cable run rather than a predetermined, accessible area. However, most station cables are unshielded and lack a well-defined, stable ground plane, implying that all electrical tests will be insensitive to anything but gross changes in the insulation. This project -- cosponsored by EPRI, Consolidated Edison Co. of New York, Inc., and the Canadian Electrical Association -- was initiated to determine the potential for electrical testing to detect thermal aging.

Investigators selected cable insulations representative of older thermal plants. Insulation materials included polyvinyl chloride (PVC), styrene butadiene rubber (SBR), ethylene propylene rubber (EPR), polyethylene (PE), and cross-linked polyethylene (XLPE). The cables of interest -- single conductor, twisted pair, triplex and multiconductor, 600 V and 5 kV, shielded and unshielded -- were thermally aged to embrittlement and characterized by physical, chemical, and electrical tests. These tests determined oxidation induction time (OIT), oxidation induction temperature, gel content, solubility, swelling ratio, plasticizer content, density, melting temperature, and crystallinity. Dielectric characterizations included low-frequency dispersion, the appearance of dipolar features, and steady-state conductivity.

A broad range of destructive and nondestructive diagnostic techniques were applied successfully to aged insulation materials and cable configurations. Dielectric characterizations revealed the importance of performing tests other than dc insulation resistance and polarization index, which are insensitive to thermal aging. In all, different tests were particularly suited to different types of insulation. Particularly important were low-frequency insulation analyses to probe the bulk condition of cable insulation and partial discharge testing to detect cracks and defects. A high-voltage instrument was designed during this project to perform low-frequency measurements on long lengths of cables at up to 5 kV with 0.01 to 100 mA sensitivity from dc to 1-Hz bandwidth. The instrument was successfully tested, meeting all design specifications.

STATUS:

The final report was published (TR-105581). Licensing negotiations to commercialize a tester based on low frequencies dielectric spectroscopy are in progress. Efforts are currently underway to obtain funding for further development of the tester for commercialization and the compilation of a standard parameter database.

I.8 American Electric Power Service Corporation - EPRI Life Cycle Management Program, Cable Aging Management Program

STATUS:

The four phases of the project are described below.

Phase 1 - Background Data Collection

The background information on the cable design, type, layout, and ambient environment was determined for all cables (53,250) in the Donald C. Cook Nuclear Plant. The final report has been submitted.

Phase 2 - Life Cycle Management

Every cable in the plant was evaluated for its service life based on thermal and radiation effects. Cables were identified if it was determined that the cable could possibly fail due to thermal aging (radiation effects were found to be negligible) before the end of the 40-year design life of the plant. A subset of the identified cable has been evaluated as risk significant based on the failure mechanism associated with the specific cable. The final report has been submitted.

Phase 3 - License Renewal

This phase evaluates cable, as in Phase 2, for a 60-year service life. The final report has been submitted.

Phase 4 - EPRI Report

This phase combines the efforts of Phases 1, 2, and 3 into a combined EPRI report. The draft has been submitted to AEP and EPRI for review. The final report will be submitted for publication in August 1996.

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