August 6, 2010

NOTE TO: File

FROM: Brian Holian, Director
Division of License Renewal
Office of Nuclear Reactor Regulation

SUBJECT DOCUMENTS TO BE DECLARED PUBLIC

I certify that documents listed below can be made public.

1. E-mail from Brian Holian to Sonary Chey, dated August 5, 2010

2. E-mail from Dave Lochbaum to Brian Holian, dated June 23, 2010

3. E-mail from Brian Holian to Dave Lochbaum, dated July 22, 2010

4. Plan Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants

5. Plan Support Engineering: Aging Management Program Development Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants

Chey, Sonary

From: Holian, Brian
Sent: Thursday, August 05, 2010 11:55 AM
To: Chey, Sonary
Subject: Emails on question on Low Voltage Cable to be made publicly available
Attachments: RE Aging management; elec cable follow-up_ Final .txt

ADAMSAccessionNumber ML102170247

Sonary,
Since an email response that I drafted on low voltage electric cable has some generic interest (and is more than just a follow-up to a question from a public meeting), please put this email with the two attachments (the incoming email, and my response) in ADAMS as publicly available.

- Brian

From: Holian, Brian
Sent: Thursday, July 22, 2010 4:44 PM
To: 'Dave Lochbaum'
Cc: pmblanch@comcast.net
Subject: RE: Aging management; VY follow-up

Mr. Lochbaum,

I'm replying to your June 23rd email which attached two documents on aging management
programs for low and medium voltage cables that were recently issued by the Electric Power
Research Institute. I have cc'd Mr. Paul Blanch because he was copied on your original email,
and it was Mr. Blanch who alerted you to the reports.

I called you on July 1 to let you know that NRC was indeed aware of these reports and provided
a brief discussion of some of the history of the issue. I also stated that I received feedback from
the recent Vermont Yankee annual assessment meeting, where there was some discussion of
this issue, and affirmed to you that it is not an "accepted NRC fix to replace water with sand" in
cases where electrical cables are submerged. I also verified with you that I would follow up by
email to your questions, which related to whether the new "safety measures" (contained in the
EPRI reports) would be imposed on the existing fleet; and if they will be, then why weren't they
done earlier, etc. I coordinated this email response with, the Division of Engineering in NRR, and
Region I.

Background

The following is a list of some of the generic correspondence related to this topic. The NRC
issued Information Notice 2002-12, "Submerged Safety-Related Cables," dated April 21, 2002,
Information Notice 1989-63, "Possible Submergence of Electric Circuits Located Above the
Flood Level Because of Water Intrusion and Lack of Drainage," dated September 5, 1989, and
Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures That Disable
Accident Mitigation Systems or Cause Plant Transients," dated February 7, 2007. In June of this
year the NRC issued Draft Regulatory Guide DG-1240, "Condition Monitoring Program for
Electric Cables Used in Nuclear Power Plants."

In Generic Letter 2007-01 the NRC informed the industry that cable insulation degradation due to
continuous wetting or submergence could affect multiple underground power cable circuits at a
plant site which potentially could affect the function of multiple accident mitigation systems or
cause plant transients. In GL 2007-01 NRC requested licensees provide information on their
monitoring of inaccessible and underground electrical cables. This information, and the NRC's
analysis of the operational experience with buried and submerged cables, informed

the issuance
of Draft Regulatory Guide DG-1240 and NUREG/CR-7000, "Essential Elements of an Electric
Cable Condition Monitoring Program".

Status

The NRC is actively evaluating operating experience to ensure that industry is properly
managing the effects of aging of buried and submerged cables. The NRC also revised its
inspection guidance requiring NRC inspectors annually review the licensee's management of
submerged cables. The NRC has taken enforcement action against licensees for their failure to
adequately monitor submerged cables. For example, Vermont Yankee received a non-cited
violation in Inspection Report 05000271/2010002 because "Entergy did not select and review
safety-related cables that were not qualified for continuous submergence and failed to
demonstrate that the cable would remain operable." In response to this action Entergy
commenced dewatering of the affected manholes, and initiated a preventive maintenance plan to
ensure proper conditions.

An additional example of the NRC's enforcement action is the non-cited violation at Beaver Valley
(Inspection Report 05000334/412-2009003) for submerged cables. The NRC specifically cited
FENOC's failure to respond to NRC Information Notice 2002-12, noting "FENOC has had several
opportunities to trend as-found data, implement effective maintenance programs, and identify and
thoroughly evaluate long-term adverse conditions for underground safety-related cable exposed to
continuous submerged environments". FENOC committed to either adopt an acceptable method to
demonstrate, continuously submerged, inaccessible, medium-voltage cable will continue to perform
their intended function, or implement measures to minimize cable exposure to significant moisture
through dewatering manholes, or replace the in-scope, continuously submerged medium voltage
cables with cables designed for submerged service (NRC Safety Evaluation Report "Related to the
License Renewal of Beaver Valley Power Station Units 1 and 2", NUREG-1929, Volume 2, October
2009, Appendix A, Commitment 12)

The EPRI documents you referred to were created by industry as a result of NRC questioning
the recent operating experience in this area, and its impact on cable operability and aging. The

NRC is planning a public meeting in the near future (July 28) to further discuss this issue. It is
too early
to say whether the agency will impose aspects from these documents.

It is important to note that under Part 50 of the regulations, licensees continue to be responsible
to
ensure that safety systems function properly when called upon to do so. Current operational
experience shows that cable failures have occurred and therefore, the NRC expects the
licensee's inspection activity should include direct observation that cables are not wetted or
submerged, that cables/splices and cable support structures are intact, and dewatering/drainage
systems (i.e. sump pumps) and associated alarms operate properly. If water is found during
inspection (i.e. cable exposed to significant moisture), corrective actions need to be taken to
keep the cable dry and tests performed to assess cable degradation. Routine regional inspection
continue to verify these aspects.

Also the draft Generic Aging Lessons Learned report revision has been issued for public
comment which expands the aging management program to include cables of 480 volts or

greater.

\- Brian

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(7-94)
NRCMD 3.57

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WHEN ASSEMBLING CORRESPONDENCE**

(USE REVERSE SIDE FOR SIGNATURE TAB)

Chey, Sonary

From: Holian, Brian
Sent: Thursday, August 05, 2010 11:54 AM
To: Chey, Sonary
Subject: FW: Aging management rear-view mirror
Attachments: 20100600-epri-low-voltage-cable-aging-management.pdf; 20100600-epri-medium-voltage-cable-aging-management.pdf

-----Original Message-----
From: Dave Lochbaum [mailto:dlochbaum@ucsusa.org]
Sent: Wednesday, June 23, 2010 11:00 AM
To: Holian, Brian
Cc: pmblanch@comcast.net
Subject: Aging management rear-view mirror

Hello Brian:

You may have heard, but I left the TTC due to lack of gainful employment and returned to my former position with UCS. While I got my old job back, UCS allowed me to do that job from my new location in Chattanooga.

The attached two documents on aging management programs for low and medium voltage cables were issued this month by the Electric Power Research Institute. Both reports are available for free online at www.epri.com.

Paul Blanch, a colleague of mine, alerted me to these reports. Paul attended the annual assessment meeting for the Vermont Yankee plant and mentioned these reports in passing. Paul cited the recent findings at Indian Point and Vermont Yankee of cabling not designed for being submerged having been submerged for considerable durations. Sam Collins, who is returning soon but not soon enough, explained that NRC's accepted "fix" is to replace the water with sand. Unless one buries his head in this same sand so as to more closely monitor the condition of the cables, this "fix" is no "fix" at all.

Both reports were the products of the efforts by an industry working group, named within the reports.

Both reports outline elements of effective aging management programs and either implicitly state or clearly infer that safety will be compromised by failing to successfully implement these measures.

Okay, what about the reactors -- more than half of the existing fleet -- that NRC relicensed without benefit of these nicely defined and articulated safety measures?

If the former aging management methods were complete and sound, why did so many industry people waste so much time compiling reports on redundant, useless methods?

If the former aging management methods were incomplete and unsound, why did so many reactors get relicensed without benefit of these new-fangled safety measures?

I hope that the NRC's license renewal army is aware of these reports and has plans to incorporate this material both on a going forward basis and on the plants already relicensed.

Thanks,
Dave Lochbaum
UCS

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ELECTRIC POWER
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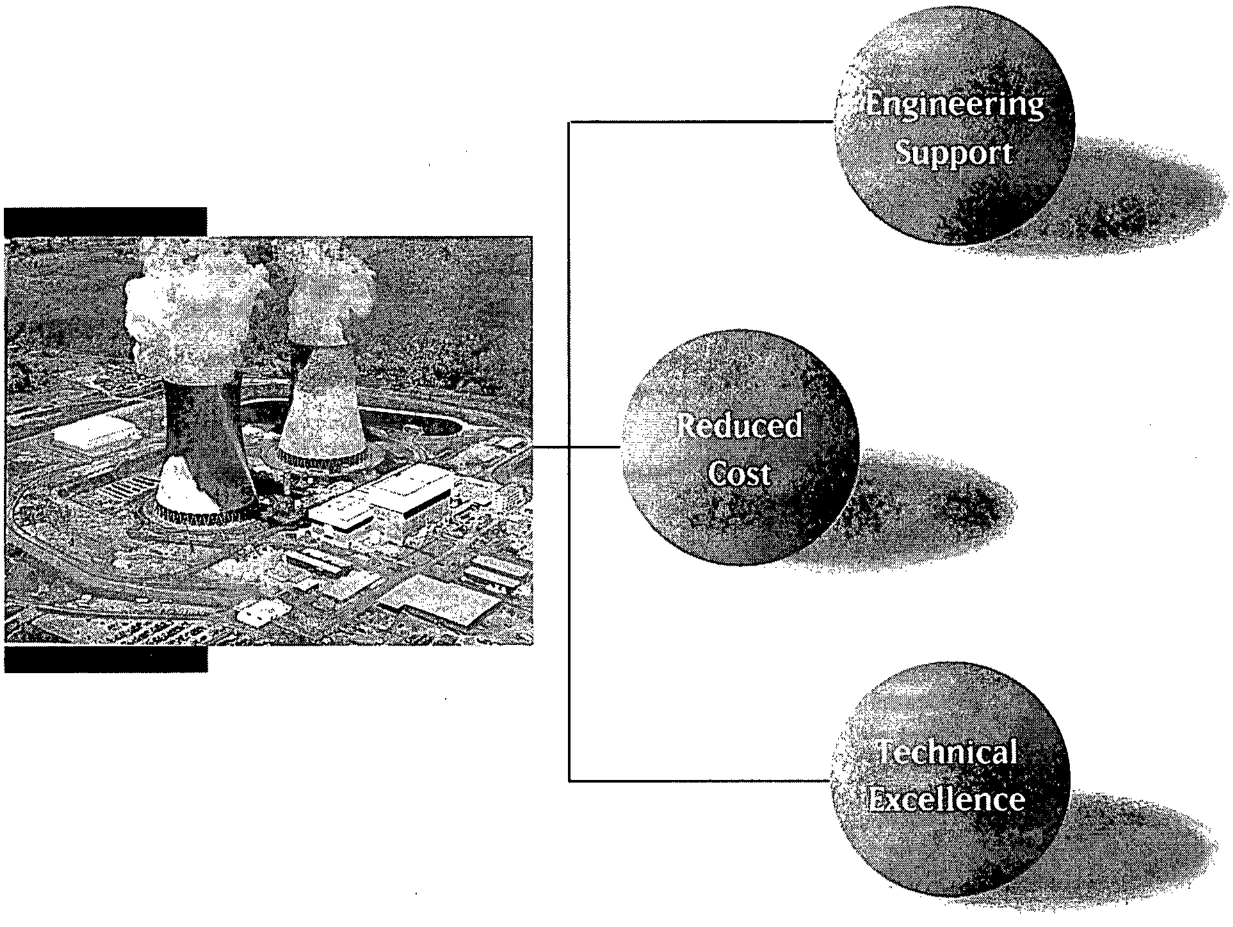
Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants



Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants

1020804

Final Report, June 2010

EPRI Project Manager
G. Toman

Work to develop this product was completed under the EPRI Nuclear Quality Assurance Program in compliance with 10 CFR 50, Appendix B and 10 CFR Part 21,
YES NO

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Principal Investigator
G. Toman

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The report is a corporate document that should be cited in the literature in the following manner:

Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants. EPRI, Palo Alto, CA: 2010. 1020804.

PRODUCT DESCRIPTION

Regulatory and management concern regarding the reliability of low-voltage power cable systems at nuclear plants has been increasing for the past 5–10 years. The staff of the United States Nuclear Regulatory Commission are concerned that wetted (up to and including submergence) low-voltage power cable circuits may be degrading to the point at which multiple cable circuits may fail when called on to perform functions affecting safety. Utility managers are concerned that cables may fail, causing adverse safety consequences and/or plant shutdowns. This document provides guidance for developing and implementing a cable aging management program for low-voltage power cable circuits in nuclear power plants.

Results and Findings

The report was developed by subjecting drafts to review and revision by a Technical Advisory Group formed of industry cable personnel from nuclear plant organizations, cable manufacturers, and cable test companies. This report describes the scope of the cable circuits to be evaluated, those conditions that are considered to be adverse environments, and the actions to be taken to assess the conditions of the cable circuits subjected to adverse conditions. Applicable test methodology is described, along with possible corrective actions that could be implemented.

Challenges and Objectives

This report was developed at the direction of utility management and in parallel with the Regulatory Issue Resolution Protocol for Inaccessible or Underground Cable Circuit Performance Issues at Nuclear Power Plants that occurred between the United States Nuclear Regulatory Commission and the industry (through the Nuclear Energy Institute) from mid-2009 into 2010. Implementation of this guide will form part of the closure process for the protocol. This report was developed to provide a consistent methodology for the industry to follow in developing an aging management program for low-voltage power cable circuits that are subjected to adverse environmental or service conditions that could lead to degradation of the insulation systems.

Application, Value, and Use

This guide describes a common approach for developing and implementing a low-voltage power cable system aging management program that will identify and resolve cable circuit aging concerns. The focus is on worst-case adverse environments and service conditions. Verifying that cables in such conditions are not aging significantly indicates that the remaining cables are in satisfactory condition. If not, the scope of assessment broadens, and further action is required.

EPRI Perspective

The need for a guide for developing cable system aging management programs has been increasing during the last few years. This report was developed with strong input from the industry and represents good practice for the foreseeable future. Cable aging management is an evolving process and an enhancement of the maintenance program for nuclear plants. As the implementation process matures and further research is performed on improving test technology and understanding degradation mechanisms, changes are expected to assessment criteria, the focus of the programs, and the methodologies used. This report will be revised as needed.

Approach

This guide provides a means of determining the scope of a cable aging management program and focuses the aging management process on cables in the worst-case adverse environment and service conditions. It describes testing and assessment criteria and potential corrective actions. The bases for program development are provided as a means of determining the health of the resulting aging management program.

Keywords

Cable aging management
Cable aging management program
Low-voltage cables

ACKNOWLEDGMENTS

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Donna Young	Progress Energy, Inc.

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1 INTRODUCTION

> ***Program Element 1***
>
> Each nuclear power plant should have an aging management program for low-voltage ac and dc power cables. A program plan and implementing procedures should be prepared. Documentation of program development and implementation should be prepared and retained. Program health should be monitored using established performance indicators.

Low-voltage power cables (those operating at less than 1000 V)[1] may age and fail due to a number of different mechanisms. Random causes such as installation damage or manufacturing defects do not affect a significant portion of the population of cables and therefore are not described in this report. This document pertains to long-term aging that, if neglected, could lead to in-service failures. A separate guide, the Electric Power Research Institute (EPRI) report *Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants* (1020805) has been prepared for medium-voltage power cables [1]. It is recognized that plants may choose to have one program cover all cable types. However, because different aging mechanisms and assessment activities apply to low- and medium-voltage power cables, the guidance has been generated separately.

In a few plants, the prime movers for safety systems are powered by low-voltage cable, and failure of these cables may have a significant effect on plant safety and reliability. However, in most plants, the prime movers are powered by medium-voltage cable; therefore, the failures of individual low-voltage power cables generally do not have a gross effect on plant operation and safety. Failure of an individual low-voltage power cable generally does not represent a significant risk due to electrical system redundancy and diversity. However, if the aging of cables subjected to adverse environments and service conditions is not controlled, multiple cables could age to the point at which safety and reliability could be impacted should a design basis event result in a steam or spray condition. An aging management process for low-voltage power cable systems is desirable to limit the number of in-service failures and to support high reliability of the low-voltage power system.

[1] Some specialty instrumentation cables may operate at 2 kV and would be considered low-voltage cables. Power cables operating at 2.4 kV to ground are medium-voltage cables.

An additional class of low-voltage cables exist that support instrument logic and control functions for both ac and dc circuits. These low-voltage cables, although they share many of the attributes of low-voltage power cables, have certain aspects and guidance that are best handled separately from low-voltage power cables. Therefore, the low-voltage instrument and control cables will be described in a separate guide.

Low-voltage power cables that are properly installed, supported, and kept cool and dry should have a long life. However, cables that are exposed to adverse conditions should be subject to aging management. The following are adverse conditions with respect to the longevity of low-voltage power cables:

- Adverse localized high-temperature or high-radiation ambient environments under normal operating conditions
- High conductor temperature from ohmic heating
- High-resistance connections at terminations or splices
- Long-term wetting (assumed to have adverse affects)[2]

The presence or absence of these conditions can be determined by inspection and analysis, environmental monitoring, or infrared thermography. If there are no adverse conditions, a long life can be expected for cable circuits. Accordingly, for applications in benign environments and service conditions, monitoring and maintenance are not necessary. Only if failures or degradation from very long service (that is, well beyond 60 years) occurs would further action be dictated. In that case, the need for maintenance and monitoring for benign environment and service condition applications should be determined in accordance with the Maintenance Rule, 10 CFR 50.65 [2].

If one or more adverse conditions are observed, then further assessment, testing, and/or corrective action will be necessary to ensure reliability, unless the cable has been designed for the conditions.

[2] Although numerous references for medium-voltage insulation indicate that wet, energized conditions result in water-related insulation degradation, no references indicating a general water-related insulation-degradation mechanism exist for low-voltage insulation systems. For the purposes of this guide, water-related effects have been assumed to occur. As further assessment and testing are implemented for nuclear plant low-voltage cable systems, the presence or absence of water-related degradation will be confirmed, and adjustments will be made to this guidance as appropriate.

Program Development

A program plan should be developed for aging management of low-voltage power cable. The plan should include the following elements:

- Management's objectives for the program (such as identification and management of aging caused by adverse localized environments and adverse service conditions)
- Interfaces with other inspection and integrity programs (for example, infrared thermography program or thermal insulation integrity program)
- A well-structured process including scoping, identification of adverse environments and service conditions, assessment of cables exposed to the adverse environments and conditions, and implementation of corrective action as appropriate
- Defined roles and responsibilities including program manager, supporting organizations for assessments, tests, and repair and replacement
- Training requirements
- Scope of cables to be included in the program (see Section 2, Scope of Aging Management for Low-Voltage Power Cable Systems)
- A schedule for completion of the scoping and determination of the cables potentially affected by adverse environments and service conditions (see Section 3, Approach to Implementation of Aging Management of Low-Voltage Power Cable) and development of the initial assessment plan and expected cost for adoption
- Management sponsorship of continued implementation
- Program health reporting and corresponding performance indicators
- Documentation to be retained, including scope determination, adverse service conditions, cables to be assessed,[3] condition and cable assessment methods, condition and cable assessment and test results, and corrective actions that have been implemented

[3] When the starting point for cable aging assessment is first to identify the adverse environments and then to determine whether the cable has aged, the cables to be assessed may be in terms of trays or conduits containing cables at a specific location, rather than in terms of individual cable circuits. Individual circuit identifications must be determined only when cable aging has been determined to be significant.

Implementing Procedures

Implementing procedures[4] should address the following:

- Roles and responsibilities
- Scoping methodology and documentation
- Determination of adverse conditions
- Consideration of susceptibility of the plant cables to adverse conditions
- Identification of cables requiring assessment
- Schedule of initial assessments and subsequent periodicity of assessment
- Methods to be used to assess cables subjected to adverse conditions
- Assessment of results related to cable condition
- Repair or replacement options (see Section 7, Actions for Failed or Deteriorated Cable)

Data and Information to Be Collected and Retained

The following data and information should be retained for use in continued assessment:

- Program plan
- Implementing procedures
- Scope of the program (cables subject to Maintenance Rule, additional License Renewal required scope, and so on)
- Cables within the program that are subjected to adverse localized environments and/or service conditions that require aging management

[4] Different utilities use the terms *guides*, *procedures*, and *plans* in different ways. The key issue is to have a documented process that includes the appropriate elements of a cable aging management program.

- Additional information that should be identified for these cables includes the following:
  - The nature and location of the adverse environment or service condition.
  - The cable circuits that are affected, including the subcomponent of concern (for example, termination, splice, or cable). Specific cable circuits may not have to be identified until the degradation is severe enough to affect function or accident capability. For example, an adverse environment, such as a pipe with elevated temperature, may be found to be having an effect on cables in an adjacent tray, but the effect may not yet warrant action. In this case, identification of the specific circuits is not yet necessary. The information to be recorded would be the location of the adverse environment and the tray of cables that is to be periodically assessed.[5]
  - Associated load of affected cable circuits (for example, specific motor, bus, or transformer).
  - Degradation mechanism of concern (for example, thermal damage or water degradation).
  - The method of assessing or monitoring the effect and the periodicity of assessment (for example, one-time assessment, periodic visual inspection, or periodic test [including initial planned assessment interval]).
  - The methodology of assessment and tests. (Given that periods between assessments and tests may be a number years, a complete description of the methods used will help to ensure the ability to compare and trend results, especially if changes to methods occur as technology improves.)
  - The results of assessments and tests.
  - Descriptions of repair and replacement.
- When credit is taken for maintaining dry conditions in ducts, manholes, and vaults, documentation showing that automatic drainage systems are effective and/or that cables are not found to be submerged when water is manually pumped from manholes and vaults.
- Program health report performance indicators.

Program Plan Milestones

The following are suggested program plan milestones:

- Program plan and technical procedures are in place, current, and being implemented.
- Program documentation is complete and current.
- Roles and responsibilities are defined, accepted, and owned by organizations and individuals for assessment, testing, repair, and replacement.
- The program manager and backup are identified and trained.

[5] When the starting point for cable aging assessment is first to identify the adverse environments and then to determine whether the cable has aged, the cables to be assessed may be in terms of trays or conduits containing cables at a specific location, rather than in terms of individual cable circuits. Individual circuit identifications must be determined only when cable aging has been determined to be significant.

- Program resources are adequate.
- The scope of the program is clearly defined.
- The cables within the scope of the program have been identified.
- The potentially adverse localized environments and adverse service conditions of concern have been defined.
- The cables within the program that are subjected to potentially adverse localized environments and/or adverse service conditions have been identified for further assessment.
- For cables requiring further assessment, a means of assessing the cable has been identified and scheduled.

Program Health Indicators

The following are possible program health indicators:

- The cable circuit and adverse environment assessments are being implemented according to schedule.
- Deferrals of cable circuit assessments are limited.
- Review of cable circuit assessment results is timely, and corrective actions are initiated.
- Implementation schedule of corrective actions is met.
- Control of cable submergence is satisfactory.
- Control of thermal insulation in the vicinity of power cable is adequate.
- Thermography of connections and high-current cables is being performed and acted on.
- Program self-assessments are being performed at a reasonable interval.
- The number of open findings or areas for improvement from external audits or assessments (such as those from the Nuclear Regulatory Commission or the Institute of Nuclear Power Operations) is limited and the findings are being resolved satisfactorily and in a timely manner.
- Forensic assessment of cables that fail in service is being conducted. If the findings indicate changes or improvements to the program, those changes or improvements are being planned or implemented.
- Applicable operating experience from other plant sites is being reviewed, assessed, and incorporated into the cable program by the program manager.

Definitions

Assessment. In this report, the word *assessment* is used to cover a broad range of activities regarding cable condition. These activities include evaluating the severity of environments and service conditions, evaluating the need for testing, and evaluating condition, including visual/tactile inspection and condition monitoring through activities such as electrical testing or *in situ* or laboratory physiochemical testing. Some assessments are expected to limit the scope of testing and evaluation (for example, the cable has benign service and environmental conditions); other assessments will include testing and condition monitoring, as appropriate, due to the presence of adverse service or environmental conditions.

Wet, Damp, and Dry Locations. Both Underwriters Laboratories, Inc., and the National Electrical Code define the terms *dry*, *damp*, and *wet* locations (see Table 1-1). The definitions indicate that the term *wet* means up to and including submerged, and not just *damp*, which has its own definition. The National Electrical Code definition of *wet location* indicates "...subject to saturation with water or other liquid... ." The Underwriters Laboratories definition indicates "...liquid can drip, splash, or flow on or against electrical equipment."

Table 1-1
National Electrical Code and Underwriters Laboratories Definitions of Dry, Damp, and Wet Locations

Term	National Electrical Code Definition [3]	Underwriters Laboratories Definition [4]
Dry Location	A location not normally subject to dampness or wetness. A location classified as dry may be temporarily subject to dampness or wetness, as in the case of a building under construction.	A location not normally subject to dampness, but may include a location subject to temporary dampness, as in the case of a building under construction, provided ventilation is adequate to prevent an accumulation of moisture.
Damp Location	Locations protected from weather and not subject to saturation with water or other liquids but subject to moderate degrees of moisture. Examples of such locations include partially protected locations under canopies, marquees, roofed open porches, and like locations, and interior locations subject to moderated degrees of moisture, such as basements, some barns, and some cold storage buildings.	An exterior or interior location that is normally or periodically subject to condensation of moisture in, on, or adjacent to, electrical equipment, and includes partially protected locations.
Wet Location	Installations underground or in concrete slabs or masonry in direct contact with the earth; in locations subject to saturation with water or other liquids, such as vehicle washing areas; and in unprotected locations exposed to weather.	A location in which water or other liquid can drip, splash, or flow on or against electrical equipment.

Inaccessible Cables. *Inaccessible cables* are those cables that have sections located below grade or embedded in the plant base mat; that are located in duct banks, buried conduits, cable trenches, cable troughs, underground vaults; or that are direct buried.[6]

The concept of inaccessibility for cables is related to the ability to determine the environment and physical condition of cable. For underground cable, inaccessibility makes identification of wetting and submergence more difficult. In dry plant areas, inaccessibility is less of a problem. Even when cables are inside conduits or contained in trays that are difficult to access, identification of heat sources that are close to the tray or conduit is relatively easy, and determining the need for further assessment of condition is possible. Inaccessibility is not a concern if adverse service and environments do not exist.

Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report:

ac	alternating current
dc	direct current
CSPE	chlorosulfonated polyethylene (commonly referred to by the DuPont trade name, Hypalon)
EPR	ethylene propylene rubber
Gy	Gray; a metric unit of radiation equal to 100 rad
hr	hour
LIRA	line resonance analysis (a cable condition monitoring method)
Mrd	megarad
PVC	polyvinyl chloride
rd	rad
XLPE	cross-linked polyethylene

[6] *NUREG-1801, Generic Aging Lessons Learned Report,* Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, states "...inaccessible (e.g., in conduit or direct buried) medium-voltage cables...." [5]. *NRC Generic Letter 2007-01* states "...in inaccessible locations such as buried conduits, cable trenches, cable troughs, above ground and underground duct banks, underground vaults, and direct-buried installations." [6].

2
SCOPE OF AGING MANAGEMENT FOR LOW-VOLTAGE POWER CABLE SYSTEMS

Program Element 2

The cables and associated connections and terminations that support the function of Maintenance Rule equipment should be within the scope of the low-voltage ac and dc power cable aging management program. It is recommended that additional cables associated with the scope of the License Renewal Program be included in the scope of the low-voltage ac and dc power cable aging management program. These cable circuits may be included in the initial scope or added to the program when implementation of License Renewal actions is required. Any commitments related to low-voltage ac and dc power cable aging management contained in plant-specific regulatory correspondence should also be included in the development of the program and its scope.

Cables required to support critical functions as defined in AP-913, *Equipment Reliability Process*, should be considered for inclusion in the scope of the low-voltage ac and dc power cable system aging management program. Low-voltage power cables critical to power generation may be added to the scope of the program at management option.

The development of the scope of the cable circuits to be within the low-voltage ac and dc power cable system aging management program should consider these sources:

- The Maintenance Rule, 10 CFR 50.65 [2]
- The License Renewal Rule, 10 CFR 54 [7]
- Updated final safety analysis report commitments (if any)
- Plant-specific licensing commitments
- License Renewal Aging Management Program commitments
- Critical components, as defined in AP-913, *Equipment Reliability Process* [8]
- Circuits critical to power generation (management option)

Table 2-1 provides a comparison of the equipment covered by the Maintenance Rule, 10 CFR 50.65, and the License Renewal Rule, 10 CFR 54. Paragraph 10 CFR 50.65(b)(1) and paragraph 10 CFR 54.4(a)(1) require that cables supporting safety-related functions be within scope of the respective activities. Paragraphs 10 CFR 50.65(b)(2) and 10 CFR 54.4(a)(2) both require that non-safety-related cables whose failure could prevent safety-related functions from being fulfilled be within scope. Paragraph 10 CFR 50.65 (b)(2) also requires that cables used to mitigate accidents or transients or to support emergency operating procedures, as well as cables whose failure could cause a reactor scram or actuation of a safety-related system, be in scope. Paragraph 10 CFR 54.4(a)(3) extends beyond the Maintenance Rule scope in that cables related to Station Blackout and Fire Protection are within scope.

Some plants may have cable monitoring commitments in their updated final safety analysis report. All plants will have cable aging management commitments in the License Renewal aging management program for cable and connections and terminations. There are likely to be separate aging management programs for cable and for connections and terminations that should be considered when developing the scope and content of the low-voltage ac and dc power cable system aging management program. Some plants may have cable-specific regulatory correspondence pertaining to cable that should be considered when setting the scope of the aging management program. Review of the plant-specific response to Generic Letter 2007-01 is appropriate to confirm the activities that the plant stated were in place to assess the condition of cables and to control wetting of cables [6]. As the plant's low-voltage ac and dc power cable system aging management program is developed and implemented, it is recommended that differences from and changes to methodologies from those in the Generic Letter 2007-01 response be documented.

The AP-913 equipment reliability process ranks components with respect to importance to reliability. Those cables required to support the function of critical components should be considered with respect to the scope of the low-voltage power cable aging management program.

Table 2-1
Scope Comparison for Maintenance Rule,10 CFR 50.65, and License Renewal Rule, 10 CFR 54 [2, 7]

Maintenance Rule Scope	License Renewal Scope	Differences
10 CFR 50.65(b)(1) Safety-related...systems and components that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure....	10 CFR 54.4(a)(1) Safety related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions— (i) The integrity of the reactor coolant pressure boundary; (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), in 10 CFR 50.67(b)(2) or 10 CFR 100.11 of this chapter as applicable.	None.
10 CFR 50.65(b)(2) Non-safety related...systems, or components: (i) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or (ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or (iii) Whose failure could cause a reactor scram or actuation of a safety-related system.	10 CFR 54.4(a)(2) All non-safety related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.	Agreement on non-safety-related components that could affect function of safety components. Maintenance Rule adds cables associated with emergency operating procedures and that could result in scrams or safety system actuation.

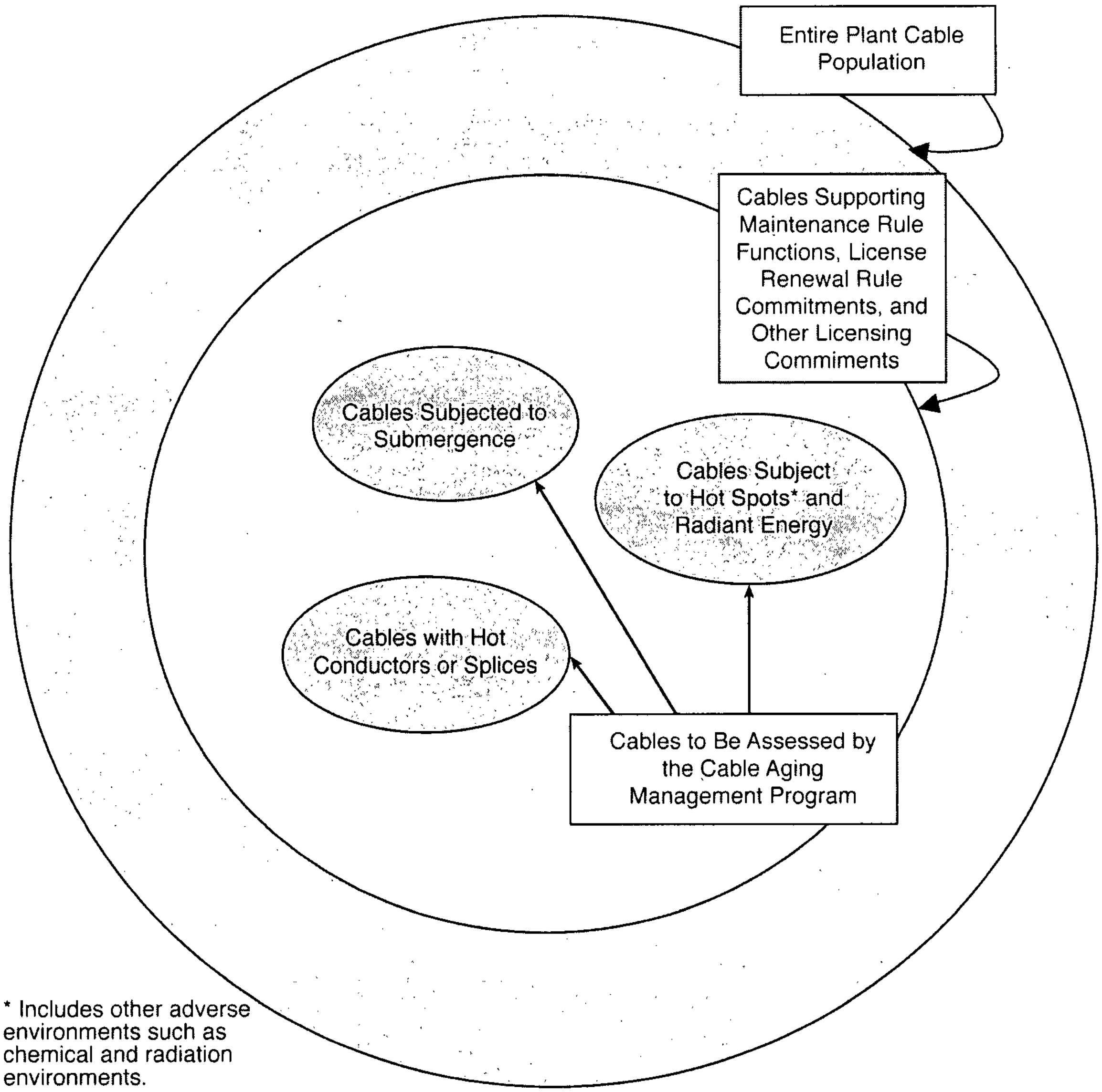
Table 2-1 (continued)
Scope Comparison for Maintenance Rule,10 CFR 50.65, and License Renewal Rule, 10 CFR 54 [2, 7]

Maintenance Rule Scope	License Renewal Scope	Differences
	10 CFR 54.4(a)(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63)	License Rule adds cables associated with fire protection, station blackout, and anticipated transients without scram. (Environmentally qualified cables would be in scope already; there are no cables associated with pressurized thermal shock.)

Program Scope Versus Cables Requiring Condition Monitoring or Assessment

The purpose of scoping is to identify the extent of cables that, if exposed to adverse environment or adverse operating conditions, will have their condition assessed or monitored. It is not the intent of the program to assess and monitor the condition of the entire program scope. Rather, this document requires assessment of cables and/or terminations and splices that are exposed to adverse environments or that have adverse service conditions. Accordingly, those cables that are within the scope, such as those supporting Maintenance Rule functions, *and* that are exposed to adverse environments or adverse service conditions will be assessed or monitored under the low-voltage ac and dc power cable system aging management program as appropriate.

For low-voltage power cables, plants may determine a list of cables to be assessed from single line diagrams or from a raceway routing database and then determine whether these cables are subjected to adverse conditions. Alternatively, they may determine the locations of adverse localized environments that could age the cables prematurely and then assess the affects of the adverse environments on the cables. Where significant degradation is detected, action should be taken either to correct the condition or to replace or repair the cable. Figure 2-1 illustrates the scoping concept. Although this document focuses on managing the aging of low-voltage cables that are subjected to recognized adverse effects, the Maintenance Rule process ensures that if a new failure cause is identified, it will be assessed, and corrective actions will be taken to control the effect. As appropriate, the low-voltage ac and dc power cable system aging management program should be revised to take new failure causes into account.



* Includes other adverse environments such as chemical and radiation environments.

Figure 2-1
Low-Voltage Cable Scoping Process

3
APPROACH TO IMPLEMENTATION OF AGING MANAGEMENT OF LOW-VOLTAGE POWER CABLE

> ***Program Element 3***
>
> The subset of cables within the scope requiring assessment should be determined either by identification of the adverse localized environments and then determining whether cables are aging prematurely in those areas or by identification of cables within the scope and then determining whether they are located in areas with adverse environments. Plants may use either or both methods

Although the number of in-scope inaccessible or underground low-voltage power cables is likely to be relatively small, the number of low-voltage power cables in dry conditions within the plant is likely to be a larger population. Accordingly, focusing on aging of cables in adverse localized environments and those with potentially adverse service conditions (such as elevated conductor temperature) is appropriate to limit aging management to those cables that are subjected to conditions that could cause premature aging. Focusing on worst-case applications and determining whether aging is occurring in those cables provides a basis for understanding the overall health of the low-voltage power cable system. If significant aging were found in the worst-case circuits, appropriate corrective action would be implemented, and the assessment of low-voltage power cables would be widened to take in the group of cables in less severe conditions.

This approach is conservative with respect to Maintenance Rule requirements and AP-913 equipment reliability goals in that cables that are not at risk of premature aging and, accordingly, not affecting system performance would not have to be assessed. Evaluation of worst-case cables, including past failures, if any, would support early identification of problems and broadening of the review if significant aging were identified, thus supporting system performance and reliability before it deteriorated.

Two approaches are possible depending on the nature of cable circuit information available: 1) identify the areas within the plant having adverse localized environments and then determine whether in-scope cables are affected by the adverse localized environments, or 2) identify cables in scope with their routings and then determine whether adverse localized environments exist along the runs.

In the first case, the areas with adverse environments would be identified, and then the areas would be evaluated—either physically, or through the use of plant raceway drawings, or both—to determine whether low-voltage power cables are in the vicinity of the adverse localized environments. Walkdowns could be used to determine whether low-voltage power cables are potentially affected and, if so, they would be evaluated through visual/tactile assessment or other appropriate means. If no or limited degradation is identified, identification of specific circuits would not be necessary. Instead, the location of the adverse localized environment would be documented, and periodic assessments of its affect would be made to verify that degradation has not had a significant effect. If significant degradation is identified, identification of specific circuits and appropriate corrective action would be necessary. Guidance on performing walkdowns for identification of adverse localized environments is contained in the EPRI report *Guideline for the Management of Adverse Localized Equipment Environments* (TR-109619) [9]. The need for periodic walkdowns is a plant-by-plant consideration.

In the second case, the cables within scope would be identified from single line diagrams or a cable database, and then a determination would be made as to whether potentially adverse environments existed along their lengths or whether they were subjected to adverse service conditions. Where cable runs were identified as being potentially affected by adverse environments, the power cables would be assessed for the effects of the environment through visual/tactile assessment or other appropriate means.

4
IDENTIFICATION OF ADVERSE ENVIRONMENTS AND CONDITIONS

Program Element 4

The program should identify those conditions that are considered to be adverse localized environments. This determination should consider elevated temperature, radiant energy from exposed process piping, radiation, water, chemical, and oil exposure.

In establishing the program, the severity of environmental parameters and the associated duration at which aging would become a concern should be established. For example, the temperature above which aging would be a concern for a 40- or 60-year life could be established, or the radiation dose for a given life could be established. It is recommended that conservative values be assumed initially, with revisions being allowed as experience is gained. The intent is not to require assessment of all cables exposed to the elevated stress levels, but rather to identify areas of potential concern within the plant. Evaluation of the population of worst-case applications will provide the insight necessary to determine when assessment of additional cables in less adverse environments is necessary.

The program should require a review of ohmic heating documentation to determine whether significant aging from ohmic heating for low-voltage power cables is a concern, especially if sections of the cable are located in areas with adverse localized environments.

The thermal insulation and barriers that protect cables from process heat damage should be maintained. If plants remove thermal insulation from piping and equipment adjacent to cable in preparation for an outage, the effects on adjacent cable should be addressed. Procedures for restoration of thermal insulation in the vicinity of cable circuits should be reviewed to ensure that the thermal insulation is inspected for acceptability and that the cable has adequate protection from thermal stresses.

Controls should exist to identify and correct splices and terminations having high resistance connections that could cause degradation or failure.

The EPRI report *Guideline for the Management of Adverse Localized Equipment Environments* (TR-109619) provides guidance on identifying adverse localized equipment environments [9]. The report defines an adverse localized equipment environment as an environmental[7] "condition in a limited plant area containing a piece or pieces of equipment that is significantly more severe

[7] The words *an environmental* were added for clarity in this report. They are not included in the original definition.

than the specified service conditions for the equipment, the room in which the equipment is located, or the surrounding plant area. The service conditions of interest include normal, abnormal, and error-induced conditions prior to the start of a design-basis accident or earthquake."

For low-voltage cable, adverse environmental conditions are the following:

- High temperature or dose rate environments under normal operating conditions
- Long-term wetting (assumed to have adverse affects)[8]
- Chemical or moist environments (a concern for unsealed terminations, such as at terminal blocks)
- Oil or hydraulic fluid contamination

Adverse service conditions are the following:

- High conductor temperature from ohmic heating
- High-resistance connections at terminations or splices

Identification of Adverse Environments

Temperature

Elevated temperature is likely to be the most common cause of long-term aging of cable insulations and jackets in dry areas. For most insulation types and jackets used in nuclear plants, thermal aging causes the materials to harden, lose elongation properties, and eventually, lose tensile properties.

For power cables, whether ac or dc, the combination of ohmic heating from load current and ambient environment temperature affects the rate of aging of the insulation and jacket systems. For low-voltage power cables, operational ratings are based on a maximum conductor temperature in an assumed 104°F (40°C) ambient environment. Most power cables have 90°C conductor temperature ratings. Power cable in areas with high ambient temperature (that is, in excess of 104°F [40°C]) will tend to thermally age more rapidly if operated close to ampacity if the elevated ambient temperature was not considered in the design.

[8] Although numerous references for medium-voltage insulation systems indicate that wet, energized conditions result in water-related insulation degradation, no references indicating a general water-related insulation-degradation mechanism exist for low-voltage insulation systems. For the purposes of this guide, water-related effects have been assumed to occur. As further assessment and testing are implemented for nuclear plant low-voltage cable systems, the presence or absence of water-related degradation will be confirmed, and adjustments will be made to this guidance as appropriate.

As ambient temperature increases above 122°F (50°C), the jacket materials of some power cables will begin to thermally age with or without the ohmic heating. Finding a hardened cable jacket would indicate that assessment of the aging of the cable is desirable to determine whether the insulation has hardened and may be susceptible to cracking and failure. Table 4-1 provides approximate times to the point at which jacket aging would be detectable through tactile assessment for various ambient temperatures. The values are given to show that elevated temperatures reduce life and to show that jacket materials age at differing rates. The table gives a rough indication of temperature sensitivity for identifying areas where cable condition should be assessed. Graphic presentations of life versus temperature are provided in Appendix A for neoprene and chlorosulfonated polyethylene (CSPE).

Table 4-1
Approximate Times at Which Jacket Aging Would Be Readily Detectable (Appreciably Hardened)

Material (See Note 1)	122°F (50°C)	140°F (60°C)	158°F (70°C)
Neoprene	16–20 years	2–3 years	Very short life
Chlorosulfonated Polyethylene (CSPE; often referred to as Hypalon)	Very long life	25–30 years	9–11 years
Polyvinyl Chloride (PVC; see note 2)	14–22 years	5–8 years	2–3 years

Notes:
1. Manufacturer-specific materials may age differently (for example, more slowly). The times listed were chosen as conservative for the generic material type.
2. There are many PVC formulations having different capabilities. The data presented are for the more susceptible formulations.

Although severe ohmic heating from high conductor currents may lead to more rapid insulation damage that may not be observed through jacket aging, conductor insulations tend to have ratings that are 15°C higher than the associated jacket systems (for example, 90°C versus 75°C). Accordingly, jacket aging is likely to proceed in parallel with insulation aging, and the jacket will still be a useful indicator of aging. Silicone rubber cables tend to be the exception because the jackets are generally braided glass or asbestos that does not degrade under thermal aging. However, the high temperature ratings of silicone rubber tend to make thermal aging a limited concern.

The Table 4-1 data provide an indication of the aging of materials based on air temperature. However, radiant heating can also greatly shorten the life of cable jackets and insulation. When cables are not shielded from direct exposure to hot process piping, the cables are also subjected to elevated radiant heating, which greatly increases the rate of aging. Verification that necessary thermal insulation is in place on process piping in the vicinity of low-voltage power cable is important. Leaving thermal insulation off process piping can cause significant cable jacket aging in as little as one operating cycle. Some plants have implemented temporary removal of thermal insulation from process piping and components well before the start of refueling outages to reduce workload during the outage and, similarly, reinstall the thermal insulation well after startup. Such actions must be precluded in the vicinity of cable assessed for the potential for causing early aging of the cable jacket and insulation. Maintaining the condition and control of thermal insulation on process piping in the vicinity of power cables is an important key to cable longevity.

Table 4-2 lists some of the areas where elevated temperatures could be expected within a plant. These are also indications of where control of thermal insulation on process piping is desirable.

Table 4-2
Plant Areas and Components with Potentially Adverse Thermal Conditions

Vicinity of main steam isolation valves
Main steam tunnel
Vicinity of PWR primary loop piping
Vicinity of PWR steam generator and main steam lines
Vicinity of PWR steam generator blowdown lines
PWR pressurizer room
Steam turbine rooms (high-pressure coolant injection, reactor core isolation cooling, feedwater, and auxiliary feedwater)
Feedwater heater bay rooms
BWR turbine bypass valve room
Cables beneath the reactor (BWRs, Mark I)
Motor-operated valves on primary piping
Adjacent to high-temperature lighting fixtures
Motor termination housings for continuous duty motors
Lagging area beneath the generator and turbine
Vicinity of auxiliary boiler room and associated piping

Radiation

With respect to radiation effects, most low-voltage cable will be in low-dose areas of the plant. However, some cables may be located in areas with appreciable doses. Sandia research showed that effects on physical properties are not observable at 1 Mrd (10 kGy) and that at least 5 Mrd (50 kGy) must be absorbed for effects to be observable [10]. Assuming a 60-year desired life for a low-voltage cable, no appreciable effect would be expected for average dose rates up to 10 rd/hr (0.1 Gy/hr).[9] Although minimal effects are expected at 10 rd/hr, the effects could be appreciable if the cables are simultaneously exposed to high temperature (for example, greater than 122°F [50°C] with conductor temperatures reaching ampacity limits).

[9] 10 rd/hr ≈ 5 Mrd ÷ (60 years × (365 days/year) × 24 hours/day)

The effects of radiation and temperature are to change the physical properties (loss of elongation and increased hardness) of the insulation and, after severe aging (such as after cracking), to eventually affect the electrical properties. If high-temperature conditions are recognized and radiation doses in excess of 5 Mrd (50 kGy) are expected, the low-voltage cables should be inspected periodically for degradation unless environmental qualification data exist that show the capability of the materials. Until the dose from the exposure reaches approximately 5 Mrd, radiation effects may not be observable. Inspections at the 30- or 40-year mark may identify radiation effects only if the dose rate is well above 10 rd/hr (that is, 15–20 rd/hr). Although most insulations will harden with exposure to elevated temperature and radiation, PVC hardens with elevated temperature exposure, but does not harden with radiation exposure. Rather, it generates hydrogen chloride (HCl) in its structure when highly irradiated (35–50 Mrd [350–500 kGy]) that becomes conductive when exposed to steam environments. Although PVC insulation is rarely used in power cable applications in the United States, some plants outside the United States have significant quantities of PVC insulated cable.

Many types of low-voltage power cable have been subjected to environmental qualification testing. These tests provide information on whether radiation doses up to 50 Mrd (500 kGy, or ~95 rd/hr for 60 years) are within the qualification limits for normal aging. The thicker insulation and jackets of low-voltage power cables makes them less susceptible to thermal and radiation aging than the typical qualification sample. The damage from irradiation does not appreciably reduce the electrical properties of the insulation; rather, it hardens the insulation and makes it more susceptible to physical damage and failure after severe degradation. The sole exception is PVC. Where radiation or thermal damage or both are a concern, initial evaluation should include visual/tactile assessment as described in Section 5, Actions for Dry Cables Having Adverse Environments.

Radiation zone maps and environmental reports should be reviewed to determine whether there are any additional zones where high radiation (>5 Mrd/plant life) may exist. In general, high radiation conditions are expected to be accompanied by elevated thermal conditions, and few additional areas needing assessment should be identified by this review. For cable types having an IEEE Std 323/383 environmental qualification, radiation qualification may be used to exempt cables from normal radiation exposure consideration for radiation doses within the bounds of the environmental qualification.

Wet Conditions

There are two concerns associated with wet conditions. One is moisture in the vicinity of open connections (that is, terminal blocks). Under moist conditions, corrosion of terminations is possible. Damp terminal blocks may also be subject to surface tracking that can lead to failure. Connections in damp areas, such as intake structures, should be included in assessments. The second concern is long-term wetting of cable as could occur in underground applications. Although manufacturers of cable perform water stability tests of their insulation systems, a concern still exists for very long-term wetting but only because there is little forensic information to determine whether water related degradation actually occurs. The duct/manhole system containing low-voltage power cable should be assessed to determine whether long-term wetting of the cable has occurred or is occurring. If so, the cables in these locations should be considered to be in an adverse condition.

Chemical and Oil Contamination

Most low-voltage cables are not subjected to contamination with oil or chemicals. Areas containing borates or other chemicals should be identified and evaluated for having cables. With respect to borates, deterioration of exposed terminations is more of a concern than jacket/insulation deterioration. For the insulation and jacket systems in use at nuclear plants, borates have little effect on the mechanical and electrical capability of the materials [11]. In general, contamination with oil or hydraulic fluid is related to a spill or leak. Cables subjected to oil or hydraulic fluid contamination should be cleaned and evaluated for any effects on longevity. The effect on the cable jacket and insulation is a factor of the insulation or jacket material, the duration of exposure, the temperature, and the nature of the oil or hydraulic fluid. Short exposures (days) at normal operating temperatures (that is, below 122°F [50°C]) before cleaning will generally not degrade the cable materials. However, short exposures to certain hydraulic fluids at temperatures of 176°F (80°C) or more could significantly plasticize (soften) insulations or jackets and lead to the potential for failure. Long exposure under less severe temperatures may lead to softening or swelling of jacket and insulation materials. If significant swelling or softening of a jacket is observed, removal of the jacket may be necessary to determine the effect on the insulation. If the insulation is not affected, and only a short section of jacket had to be removed, repair of the jacket with heat-shrink material may be possible. If the insulation is significantly degraded, the affected section cable should be replaced.

Literature searches may provide insights on the effects of chemicals, hydraulic fluid, or oils on specific cable insulation and jacketing systems. If limited or no significant effect is immediately identified after oil, hydraulic fluid, or chemicals are removed from a cable jacket, reinspection after an operating cycle is recommended to verify that no hidden damage has occurred.

Identification of Adverse Service Conditions

Ohmic Heating

The current in the conductors of power cable will cause temperature rise due to ohmic heating. The review of the effects of ohmic heating requires identification of the power circuits and evaluating the current with respect to the ampacities of the cables. If the normal conservatisms were applied during design, cables would be loaded to no more than 80% of ampacity. Given that temperature rise is proportional to the square of the current, 80% of ampacity should result in 64% of the allowed temperature rise. In the case of a 90°C rated cable in a 40°C environment, the rise at 80% ampacity should be approximately 32°C, so that the conductor temperature would be 72°C. Ohmic heating reviews may already exist at plants. If so, the existing data should be reviewed to determine the worst cases and whether these cases raise aging concerns. If aging concerns are identified, the cables should be assessed to determine whether premature aging is occurring.

Ohmic heating should be considered in conjunction with identified adverse thermal conditions in rooms, especially if ambient temperature coupled with the conductor rise result in temperatures approaching the rated temperature of the cable.

Periodicity of Review

Ohmic heating reviews need be performed only once unless plant modifications cause an increase to the loading of power cables.

High-Resistance Connections at Terminations or Splices

Properly made splices and terminations should not experience overheating. However, when terminations or splices are disassembled and reassembled or first installed, human performance errors or design deficiencies may occur that result in high-resistance connections, especially when connections involving aluminum conductor are being made. Accordingly, for non-intermittent, heavily loaded circuits, terminations and splices should be checked for elevated temperature conditions when operating at load after installation. This verification should be performed at some reasonable period following installation (one or two operating cycles). Identification of high-resistance connections may be through the use of infrared thermography or periodic visual inspection for signs of discoloration or deterioration of the splice or termination. If the adequacy of the connection was confirmed at the time of splice/termination preparation through the use of a micro-ohmmeter or other recognized method, periodic evaluation may be unnecessary for most connections, but it may be desirable for aluminum connections until stability is confirmed.

The program may take credit for the performance of periodic infrared thermography or inspection of terminations and splices that is covered by the station maintenance program. The EPRI *Preventive Maintenance Basis Database* provides frequencies for performing routine infrared surveys or inspections of terminations [12]. Frequencies vary based on the end load's component classification. Infrared thermography surveys should be scheduled to be performed when the equipment is energized and loaded to provide meaningful results.

Infrared thermography should also be scheduled as post-maintenance verification whenever terminations are disturbed for maintenance. This check should be done at least one hour after the equipment has been energized and loaded (to allow thermal stabilization) or at the earliest opportunity thereafter.

In many cases, access to terminations of low-voltage cable terminations (480 V or greater) may be limited due to equipment design or arc flash concerns. Generally, access to low-voltage power cables and their terminations can be performed by donning flash protection personal protective equipment and establishing an arc flash zone in accordance with National Fire Protection Association standards [13].

5
ACTIONS FOR DRY CABLES HAVING ADVERSE ENVIRONMENTS

Program Element 5

The low-voltage ac and dc power cable aging management program should include one or more methods of determining whether significant aging of the cable is occurring for cables located in dry adverse environments. The techniques that may be used include visual/tactile inspection, indenter modulus, near infrared spectroscopy, and acoustic assessment. If removal of samples is possible, numerous laboratory tests are available. The assessment technique should be applicable to the polymer under assessment.

The effects of adverse dry environment conditions are different from those caused by cables being energized in wet/submerged conditions because the failure mechanisms are not the same. Accordingly, different test and inspection methods will apply. This section addresses those tests that may be applied to cables in dry adverse environments. Low-voltage ac and dc power cables are typically not shielded, and aging under dry conditions generally does not cause a reduction in insulation resistance until cable polymers have aged to the point of cracking. Even then, dry air is a good insulator, and insulation resistance may remain acceptable. Accordingly, electrical assessment with commonly available techniques will generally be of little use. However, for low-voltage power cable used in nuclear plants, physical and chemical techniques can be used to assess cable condition. These include in-plant methodologies, such as visual/tactile assessment, indenter modulus, and acoustic velocity assessment; and numerous laboratory tests, including elongation-at-break, oxidation induction time and temperature, density change, and nuclear magnetic resonance shift. One electrical testing technique that may be used on multi-conductor cable is line resonance analysis (LIRA). This technique may be used to identify and locate thermal aging along the length of a cable. Although LIRA continues to be developed, research indicates that it readily identifies thermal damage [14]. Tables 5-1 and 5-2 describe the expected effects of thermal and radiation aging for various cable polymers.

The assessment of the effects of chemical and oil exposure is included in this section. The main concerns are borates and lubricating or hydraulic fluids.

Table 5-1
Effects of Thermal and Radiation Aging on Low-Voltage Cable Jackets

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation	Effect of Degradation
Neoprene	Hardening with spontaneous cracking and discoloration (turning greenish brown) (see note 1)	Hardening	Visual inspection can identify discoloration or cracking. Hardening can be manually or indenter evaluated.	Cracking exposes insulation to airborne moisture, causing limited effects on insulation.
CSPE (Hypalon)	Hardening with discoloration (turning greenish brown)	Hardening	Visual inspection can identify discoloration. Hardening can be manually or indenter evaluated.	Until extreme hardening occurs CSPE will remain intact. However, if a through fault occurs, the cable may crack due to motion from high magnetic fields.
PVC	Hardening, possible spontaneous cracking, weeping of plasticizer; darkening with age	Production of hydrogen chloride (HCl)	Hardening may be observed manually or through indenter. HCl production may be indicated by white powdering or corrosion of surrounding metal. Plasticizer may cause the surface of cable to be tacky or may weep from surface.	Cracking exposes the underlying insulation to more direct exposure to the stressor. HCl production could corrode surrounding metal components, as could weeping plasticizer.
Chlorinated Polyethylene (CPE)	Hardening, cracking, discoloration (turning greenish brown) (thermoplastic version only)	Hardening, cracking	Hardening may be observed manually or through indenter.	Material will be sensitive to manipulation. Some chlorine may be generated that could affect surrounding metals (generally associated with thermoplastic version).

Notes:
1. *Spontaneous cracking* means that the material shrinks when significantly aged and cracks occur even though the cable has not been manipulated or physically disturbed.

Table 5-2
Effects of Thermal and Radiation Aging on Low-Voltage Cable Insulations

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation (See Note 1)	Effect of Degradation
Cross-Linked Polyethylene (XLPE)	Hardening	Hardening	Line resonance analysis (LIRA) may be used to determine whether significant aging has occurred. Jacket is a generally a leading indicator.	Ultimately (after an extremely long time) insulation could crack. Life still could be long, provided condition is corrected before severe degradation occurs.
Butyl Rubber	Hardening or softening	Softening	Jacket is a generally a leading indicator.	Softening may occur on advanced thermal aging. May also soften under irradiation.
Fire-Retardant Ethylene-Propylene Rubber (EPR-FR)	Hardening	Hardening	LIRA may be used to determine whether significant aging has occurred. Jacket is a leading indicator.	Extreme thermal aging can cause physical failure (embrittlement and cracking). Material will be susceptible to failure under manipulation.
Ethylene-Propylene Rubber with Bonded Chlorosulfonated Polyethylene (EPR/CSPE bonded) (see note 2)	Initial hardening of the CSPE layer, followed by hardening of the EPR layer. CSPE will discolor (turn greenish brown) with exposure to elevated temperature	Same as temperature	LIRA may be used to determine whether significant aging has occurred. Jacket is a leading indicator. Indenter or acoustic assessment may be used to evaluate hardening.	CSPE layer will become controlling when highly aged. Through cracking of CSPE and EPR may occur if manipulated or exposed to a high-pressure loss-of-coolant accident environment, although this effect will be less important for large conductor sizes (6 to 8 AWG and larger) where material thicknesses are larger.
Ethylene-Propylene Rubber/Neoprene (see note 3)	Early hardening and cracking of neoprene layer; eventual hardening of EPR layer	Same as temperature	LIRA may be used to determine whether significant aging has occurred. Jacket is a leading indicator. Indenter or acoustic assessment may be used to evaluate hardening.	Neoprene will spontaneously crack, but does not seem to cause through cracking of EPR.

Table 5-2 (continued)
Effects of Thermal and Radiation Aging on Low-Voltage Cable Insulations

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation (See Note 1)	Effect of Degradation
Chlorosulfonated Polyethylene (CSPE) (see note 4)	Hardening of CSPE insulation; CSPE will discolor (turn greenish brown) with exposure to elevated temperature	Same as temperature	LIRA may be used to determine whether significant aging has occurred. Outer jacket would age simultaneously from external environments, but a Indenter or acoustic assessment may be used to evaluate hardening,	Hardened CSPE may crack if manipulated or exposed to a high-pressure loss-of-coolant accident environment.
Silicone Rubber	Little effect unless temperatures are extreme, then hardening	Loss of tensile properties	Generally difficult to assess due to glass or asbestos braid coverings,	Loss of tensile properties would make insulation susceptible to manipulation and pressurized steam exposures.

Notes:
1. In most cases, cable jackets will be leading indicators of thermal/radiation damage in that jackets generally have ratings that are 59°F (15°C) lower than the insulation. The exceptions are jackets on silicone rubber cables that are constructed of glass or asbestos braids that do not provide indication of thermal/radiation damage.
2. EPR/CSPE is a composite insulation having EPR as the primary insulation with a layer of CSPE applied over the EPR to add fire retardancy. The CSPE layer may or may not be bonded to the EPR.
3. EPR/neoprene is a composite insulation having EPR as the primary insulation with a layer of neoprene applied over the EPR to add fire retardancy. The neoprene may or may not be bonded to the EPR.
4. CSPE was used as an insulation by a limited number of manufacturers. Boston Insulated Wire's Bostrad 7 had Hypalon insulation; Bostrad 7E had EPR insulation.

Visual/Tactile Assessment

Visual/tactile assessment is a key tool in the initial assessment of low-voltage power cable aging, especially if the aging is predominantly environmentally induced. For most of the cables in use in nuclear plants, the jackets will age and harden more readily than the insulation will. If the aging is caused by the external environment, the jacket will definitely age faster than the insulation. If the aging is caused by ohmic heating, the jacket will still tend to age more rapidly than the insulation, but it may not lead the aging of the insulation by a significant factor. Care should be taken in those cases in which the insulation and jacket material are the same (for example, cables with both the jacket and the insulation made of CSPE or both made of XLPE). The jacket aging will tend to cause the cable to stiffen and lose flexibility. The unaged condition for use in visual/tactile assessment can be identified by evaluating cable samples from the warehouse or cables located in benign environments. Most of the rubber jackets can also turn brownish green when exposed to severe thermal conditions. If the color remains like an unaged cable and the cable retains flexibility, significant thermal aging has not occurred. If the cable is stiffening, further assessment is necessary, with severe hardening requiring more immediate attention. The EPRI report *Training Aids for Visual/Tactile Inspection of Electrical Cables for Detection of Aging* (1001391) describes how visual/tactile training aids were developed and what can be deduced from visual/tactile inspection [15]. If visual/tactile assessment identifies aging of the cable, the cable may be repaired or replaced, or a more sophisticated assessment technique, such as the indenter or one of the other nondestructive test methods described in the following sections, may be applied. Alternatively, a sample could be removed for laboratory assessment.

Visual/tactile assessment may be used to evaluate the condition of cables in trays that are adjacent to heat sources or to assess the condition of cables in the vicinity of the end devices (for example, motors), where high temperatures may occur. The technique may be incorporated into specific area inspections or inspections done during routine maintenance of components connected to cables.

Indenter Testing

The indenter is a nondestructive, in-plant test device that measures *compressive modulus*, an indication of hardness, of a cable jacket or insulation. A small probe is pressed against the cable jacket or insulation at a constant velocity while the force is measured. The probe is retracted when a force limit is reached. The change in force is divided by the change in position during the compression to arrive at the modulus. Correlations between the indenter results and elongation at break are available for a number of materials. See the EPRI products *Cable Polymer Aging Database* (1011874) and *Initial Acceptance Criteria Concepts and Data for Assessing Longevity of Low-Voltage Cable Insulations and Jackets* (1008211) [16, 17]. Although tactile testing provides a rough indication of the degree of aging, the indenter provides a more precise indication of the degree of aging. The indenter may be applied to cable insulation or jacket wherever >4 in. (>10 cm) of cable length is exposed.

Ultrasonic Velocity Assessment

As polymers harden or soften with aging, the velocity of ultrasonic waves changes. The change in ultrasonic velocity can be correlated with the change in elongation at the break of the insulation or jacket of a cable and used for assessment of aging of the material. The test is nondestructive, and a portable test device has been developed [18]. Ultrasonic testing has been demonstrated in nuclear plant applications, but it remains under development.

Line Resonance Analysis

A line resonance analysis (LIRA) test set uses the cable under test to modulate a high-frequency white noise, low-energy electrical signal. The detector evaluates the modulated signal for amplitude and phase differences of the frequency-dependent resonances. The reflected resonances indicate the points of termination and any significant impedance changes along the length. Thermally damaged segments of the cable are indicated by such resonances. The LIRA system provides a relative severity of the damage and the location. The LIRA system may be used on the adjacent conductors of any multi-conductor cable; no shield is required. The system requires one end of the circuit to be de-terminated. The opposite end may be either open or closed. The EPRI report *Line Impedance Resonance Analysis for Detection of Cable Damage and Degradation* (1015209) describes the technique and its application. LIRA testing is useful to determine whether cables within a conduit or that are physically difficult to access have been damaged [14]. LIRA has been demonstrated in research and in limited plant use. It continues to be developed.

Near-Infrared Spectroscopy

For cables that are not loaded with carbon black (that is, cables with lighter colors such as red, orange, or white), near-infrared spectroscopy may be used to nondestructively identify the chemical composition of cable insulations found on control and power cables and to assess the aging of the materials. The technique measures the absorption of incident light by chemical groups in the polymer, providing a unique fingerprint for each cable insulation compound and its state of aging. Spectra collected by a portable spectrometer from field cables can be compared with results for insulation formulations contained in a near-infrared spectroscopy library for which thermal and radiation aging characteristics have been established [19].

Laboratory Tests

Numerous laboratory tests that assess the degree of aging of cable polymers are available. A number of tests have been developed based on very small samples on the order of 10 mg or less. With such tests, a small sample of jacket or insulation may be removed and a repair made so that the cable can remain in service while the assessment is being made. Descriptions of such techniques are provided in the EPRI report *Cable Polymer Aging and Condition Monitoring Research at Sandia National Laboratory Under the Nuclear Energy Plant Optimization (NEPO) Program* (1011873) [10].

If larger sections of cable (1.5 ft [≈0.5 m]) are available, numerous traditional physical and chemical tests—including elongation-at-break, swell-gel, density, and others,—may be applied to cable insulation and jacketing to evaluate the degree of aging.

Traditional Troubleshooting Techniques

Thermal and radiation exposure of cable polymers do not cause electrical indications of degradation that are observable by traditional means, such as insulation resistance or time-domain reflectometry, until the insulation system has failed. Thermal aging, in many cases, will improve insulation resistance by drying out the insulation system. Insulation resistance will degrade only after the insulation fails by cracking or powdering and moisture enters. Insulation resistance tests and time-domain reflectometry are not useful for trending the aging of dry cables. However, they remain useful troubleshooting tools when failure has occurred.

6

ACTIONS FOR LOW-VOLTAGE POWER CABLES IN WET ENVIRONMENTS

Program Element 6

Low-voltage ac and dc power cables subjected to wet conditions should be periodically tested by insulation resistance to ground and, as practicable, phase-to-phase or other recognized tests to determine whether degradation has occurred. Results should be trended to identify significant drops (for example, a decade or more) that are not associated with conditions at the time of the test. Acceptance criteria should be developed.

To the extent practicable, manholes, vaults, and ducts should be drained, so that cables are not in or covered by long-standing water.

The insulation of low-voltage power cable subjected to long-term wetting may deteriorate over time. Insulated Cable Engineers Association manufacturing standards required insulation stability testing to be performed by manufacturers to prove stability of cable insulation under wet conditions, so that no significant deterioration should occur for an extended period unless the conditions of the soil or water are particularly aggressive. In low-voltage cables, the thickness of insulation and jacketing that are used is driven by mechanical protection capabilities rather than by voltage withstand. Therefore, the voltage stress in the insulation is quite low by comparison to that of medium-voltage cable, and no electrically driven failure mechanism such as water treeing is expected to occur. Failures have occurred, possibly due to long-term chemical deterioration of jackets and insulations, but failures are more often due to installation or post-installation damage.

Deterioration of low-voltage power cable insulation from wetting can be detected through trending of insulation resistance. Often, dc systems have a continuous ground detector circuit that would also indicate whether the insulation failure on a leg of a circuit has occurred. Such grounds should be eliminated to preclude a pole-to-pole short should a ground occur on the opposite pole. Some ac systems may also have continuous ground detection to detect high-resistance grounds. Grounds on the ac system, when alarmed, should be identified and isolated before the insulation has completely failed.

For motor circuits, the insulation resistance to ground may be measured with the motor connected. Insulation resistance results will be affected by temperature and humidity, especially of the end device (for example, a motor). Accordingly, to the extent possible, the results should be compensated for the conditions at the time of the test.

Pumping of Manholes and Ducts

Removing water from around the cable will not reverse water-related degradation if any has occurred. However, removing water will remove the source of and transfer mechanism for ions that may lead to degradation. Instituting a pumping program, installing automatic sump pumps, or repairing failed automatic pumping systems is recommended.

It is recognized that not all systems can be pumped dry. Continued operation of cables under wetted conditions is allowable, but the condition of the cable insulation should be periodically assessed.

Rain and drain conditions will not adversely affect jacketed cables. Water takes a number of months to years to migrate into the jacket. Low-voltage power cables are not susceptible to water treeing because the voltage stresses in the insulation are too low to induce the electrochemical/electromechanical degradation mechanisms involved. Other water-related degradation mechanisms may exist; however, manufacturers' water stability tests indicate that water-related degradation should not occur.

Relative Importance of Low-Voltage Power Systems

For most plants, safety-related emergency power is generated at 4 kV or greater. For plants having safety-related power systems that operate at 4 kV or greater, the low-voltage power circuits have a lesser safety significance.[10] However, a few plants have safety-related emergency power generated and distributed at low voltage (such as 480 V). For this set of plants, assessment of low-voltage power cables, especially those that are wetted, is more important to verify that significant insulation deterioration has not occurred, and greater scrutiny of wetted circuits is desirable. In setting up the low-voltage power cable aging management program, the safety significance of the cable circuit, coupled with the severity of the adverse environment/service condition, may be used to determine those cable circuits that should receive the most attention and those that have little impact and/or no adverse conditions.

Continuously energized wetted (and potentially wetted) dc power distribution circuits supporting Maintenance Rule applications should be included in assessments. An instance of long-term water instability of insulation has occurred in one dc application and is suspected, but not yet proven, in another. The known failure was associated with extremely aggressive chemical conditions and elevated underground temperature. It is not clear whether the observed degradation was material and/or condition specific. Vigilance is recommended until more forensic data are available to make firm conclusions.

[10] There may be some low-voltage power loads that do have a significant effect on power production, such as service and instrument air, stator water cooling, electro-hydraulic control, and so on.

Test Methods

Although a number of tests are available for troubleshooting low-voltage power cable insulation problems, insulation resistance remains the main method for assessing degradation of wet low-voltage cable circuits. Capacitance tests may indicate that a cable has absorbed water and time-domain reflectometry may identify the location of a wetted portion of the cable. However, these tests do not indicate whether degradation has occurred.

Low insulation resistance or a significantly decreasing trend (for example, a decade or more) in insulation resistance is indicative of insulation degradation for low-voltage power circuits. Insulation measurements are affected by temperature and moisture conditions at the time of test. Care must be taken when making comparisons between tests performed at different times. Changes could be the result of different temperature or moisture conditions during the tests. However, large decreases in insulation resistance that are not from conditions at the time of the test are important, and a continuing decreasing trend of multiple decades should be investigated further. Although the use of an absolute limit for low insulation resistance provides a cutoff for continued use of a cable, or at a minimum indicates the need for further assessment, trending of insulation results will provide more information regarding the rate of change and an earlier indication that deterioration may be occurring.

Acceptance Criteria

Minimum insulation resistance values for return to service exist for cable and motor circuits. These values are not meant to indicate that the cable insulations or motors are in "good" condition if they just exceed these values; rather, they indicate that low-voltage circuits can function. The EPRI report *Power Plant Electrical Reference Series*: *Volume 4, Cables* (EL-5036) provides the following formula for a field acceptance limit[11] for cable [20]:

$$IR_{\min} = 1000 \times \left(\frac{kV + 1}{L} \right) \quad M\Omega$$

where:

kV is the insulated rated voltage, in kilovolts.

L is the cable length, in feet.

[11] This limit is recommended only for application to low-voltage cable for condition assessment. More sophisticated test methods and acceptance criteria are recommended for assessing medium-voltage cable.

For comparison, cable manufacturing standards, such as the Insulated Cable Engineers Association publication *Ethylene-Propylene-Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy* (S-68-516), require minimum insulation resistances for new cable based on the following formula [21]:

$$IR = 10{,}000 \log_{10} (D/d) \text{ M}\Omega\text{-1000 ft}$$

where:

D is the diameter over the insulation.

d is the diameter under the insulation.

To allow a comparison of the new cable requirement to the minimum acceptance criteria, assume a 500-ft (152-m) long cable with a 1/0 AWG conductor and an 80 mil (2 mm) thick, 600 V rated insulation. A representative cable of this type would have a 0.49 in. (12.4 mm) diameter. The field acceptance limit would be 1.6 MΩ. The new cable value would equal the following:

$$IR = 10{,}000 \log_{10} (0.49 \text{ in}/0.33 \text{ in}) \text{ M}\Omega * 1000 \text{ ft}/500 \text{ ft} = 3440 \text{ M}\Omega$$

If the circuit was 2000 ft (610 m) long, the new cable value would be 860 MΩ. The length of the circuit is a significant consideration related to expected insulation resistance values.

A newly installed cable should have a near-factory-value insulation resistance per 1000 ft (305 m). When evaluating insulation resistance results from cable testing, trending of results allows identification of deterioration. Some variations in results are natural due to difference in temperature and humidity at the time of test. However, a continuing decrease on the order of two decades is a strong indication of significant degradation. If no trend data exist, caution should be used if a value of less than 10 times the minimum field acceptance criteria is found. The period between tests should be reduced, or an assessment should be made to identify the cause of the low insulation resistance.

Because power cables may be connected to motors at the time of insulation resistance testing, the minimum acceptance criterion for motors should be considered. The EPRI report *Power Plant Electrical Reference Series: Volume 6, Motors* [20]) provides a formula for a minimum value for a motor [22]:

$$IR_{min} = ((\text{Rating in kV}) + 1) \text{ M}\Omega$$

The value of insulation resistance should be corrected to 104°F (40°C) to allow trending and comparison. The EPRI report EL-5036 states that this value does not provide a basis for considering a motor's insulation as good or to expect a long life when a motor's insulation resistance approaches this value. It also states that good motor insulation will normally read 200 MΩ to infinity.

IEEE Std 43-2000 states that the (rating in kV + 1) MΩ value applies to pre-1970 winding types and 100 MΩ is applicable to more modern form wound systems [23]. Although many plants transfer the limits for rotary equipment to cable, the 100 MΩ limit is more applicable to cable than the (rating in kV + 1) MΩ limit, and the length of the cable should also be considered.

The minimum acceptance criteria for both motors and cables are similar. Caution should be applied when the insulation resistance values approach these limits. Although the cable and motor may function for some period with these limiting values, they are likely to be significantly degraded when the point of minimum insulation resistance acceptance criteria has been reached. Separate testing of the motor and cable are recommended when insulation resistance values are within a decade of the minimum insulation resistances.

7
ACTIONS FOR FAILED OR DETERIORATED CABLE

Program Element 7

The low-voltage ac and dc power cable system aging management program should require that appropriate corrective action be taken if significant aging of cable insulation systems is identified or suspected due to adverse localized environments. Those actions may include assessment, testing, repair, or replacement, as appropriate. If the investigation of the failure or deterioration indicates a generic degradation mechanism, circuits with similar conditions should be reviewed to determine whether they, too, require corrective action.

Operability Concerns

Depending on the severity of the degradation identified, an operability concern may or may not exist. Severe physical degradation, such as cracked insulation, damaged conductors, extreme hardening or softening of insulation, or a "highly degraded" result from electrical testing, indicates an operability concern. However, lesser indications of degradation would constitute a need for further vigilance but not an immediate operability concern. Examples of these types of degradation include a limited stiffening of insulation and jacket or an electrical test result indicating "aged" insulation (for example, low insulation resistance but not less than minimum acceptable insulation resistance). The following subsections provide insights on verifying the condition and determining the course of further action. In-service failure of a cable requires an extent of condition assessment for cables subjected to like service conditions.

Corrective Actions

The corrective actions to be taken in response to cable degradation will depend on the nature of degradation and whether the degradation is localized or distributed over a significant length of the cable. Actions may be permanent or temporary, depending on the nature of the application and the licensing basis. The following text provides some possible considerations and resolutions. These considerations and resolutions are not all-inclusive. Plant-specific requirements and application-specific conditions may dictate different resolution paths.

Insulation Resistance Test Indicates Degraded Insulation on Wet Cable

If a low but acceptable insulation resistance is identified, separating the load from the cable and determining whether the cause is the load or the cable are recommended. If the cable is the cause, shortening the time between insulation resistance tests and trending the result is recommended. If continued deterioration is identified and the cause cannot be identified, replacement of the cable should be considered. If the cable is replaced, removal of the old cable and forensic assessment should be considered. If the degradation was caused by physical damage (such as cuts or gouges), laboratory assessment is unnecessary. However, if there are no obvious indications of the cause of failure, laboratory assessment is recommended to determine whether polymer degradation has occurred.

If unacceptable insulation resistance is identified, immediate replacement should be considered. Removal and forensic study is also recommended.

Cables Experiencing Localized Thermal Damage

Two concerns exist for localized thermal damage. The first is that the temperature of the insulation is so high as to cause the insulation system to fail due to thermal avalanche. In such a case, the local volumetric insulation resistance would decrease, causing higher leakage current and further elevating the insulation temperature. Eventually, the leakage current and insulation temperature are so high that insulation breaks down. This is not an aging phenomenon but a direct effect of excessive temperature. Given the thickness of insulation and jackets by comparison to operating voltage, leakage currents should be small, and thermal runaway should be unlikely.

The aging concern is that the temperature is not high enough to cause thermal avalanche but is high enough to cause hardening of jackets and insulations (softening of sulfur-cured butyl rubber) over time. Eventually, cracking of the insulation could occur from manipulation or from motion induced by a fault current surge. For sulfur-cured butyl rubber, long-term thermal aging could cause softening that could allow compression of the insulation, leading to high electrical stress and failure. Thermal degradation of environmentally qualified cables located in harsh environment areas can cause the cable to have a shortened qualified life.

Evaluation of the Degree of Damage

Environmentally induced degradation will generally be caused by an adjacent heat source that was not properly controlled (such as adjacent process pipe with inadequate or missing thermal insulation). The first assessment should be of the jacket to determine whether complete hardening has occurred or if some elasticity remains. If some elasticity remains, the likelihood of damage to the cable insulation is low, and the thermal insulation on the process component should be improved. Periodic inspection of the cable is recommended to verify that deterioration is not worsening significantly with time.

Evaluation of the severity of the jacket degradation may be performed through indenter modulus assessment [24]. The use of indenter testing allows quantification and trending of the hardening of the jacket to provide insights as to the relative hardness and the degree of continued aging.

LIRA may be used to determine whether an adverse localized thermal environment has affected the insulation [14]. If the effect was limited to the jacket on shielded cable, LIRA should identify no significant signal. If the insulation was affected, LIRA would give a relative indication of the severity of the effect. LIRA may be used on triplexed cable, but the jacket system would be within the boundary of the test, and the effects of aging on the insulation and jacket would not be separable. As of this writing, LIRA can provide only an indication of the relative degree of damage, not a precise indication of expended or remaining life.

Insulation resistance will not be a useful indicator of thermal degradation in that the insulation resistance will not degrade from thermal aging. (It is likely to improve from driving off any residual moisture from the cable.) Insulation resistance will indicate a problem only after the insulation has failed physically and moisture has entered through cracks. Insulation resistance is generally a lagging indicator of thermal damage to insulation and jacketing.

Correction of the Adverse Localized Thermal Environment

When an adverse localized thermal environment is identified, the thermal insulation on the source of the heat and radiant energy should be replaced, repaired, or upgraded. If this activity does not sufficiently reduce the effects on the cable, consideration should be given to rerouting the cable. If the cable must remain where it is, periodic assessment of the condition of the cable should be implemented to verify that the rate and severity of the cable degradation is known, so that condition-based corrective action may be taken at the appropriate time.

Replacement of Thermally Damaged Cable

Consideration should be given to replacing cables that have been thermally damaged to the point at which they are no longer flexible. Alternatively, a small sample of insulation can be removed and sent for laboratory tests to determine whether the degradation has proceeded to the point at which the insulation is susceptible to failure on manipulation or under a steam accident (if applicable).

If severe thermal aging of the insulation is identified, removal and replacement of the affected cable section is recommended. If the qualified life of a cable is shortened due to the adverse localized thermal environment, it must be replaced before the end of its qualified life. Replacement of a section through the use of appropriate splices or replacement of the entire circuit is permissible.

High-Resistance Connections

When inspection or infrared assessment of cable connections indicates significant heating of a connection (for example, for infrared thermography), the affected connection should be repaired or replaced. Early replacement is recommended to preclude significant damage to the cable insulation at the connection point. If the cable insulation has been damaged, repair or replacement of the cable or the affected section will be necessary, as well.

Cables Damaged by High Current

Damage to cable from ohmic heating due to high currents is likely to affect the entire length of the cable, with the worst effect in sections having elevated ambient temperature. The entire circuit generally will require replacement. Rectification of the cause of the high current is necessary, whether it is from lack of transpositions in multi-conductor per phase circuits or undersized conductors.

8
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A

THERMAL AGING OF NEOPRENE AND CHLOROSULFONATED POLYETHYLENE

The jackets for cables have a lower temperature rating than that of the insulation system and generally age more rapidly than the underlying insulation, given the same temperature. The two most common jackets in use are neoprene and chlorosulfonated polyethylene (CSPE, commonly referred to by the DuPont brand name, Hypalon). Because they typically age faster than the underlying ethylene-propylene rubber and cross-linked polyethylene insulations, they will be leading indicators of thermal degradation. Figures A-1 and A-2 provide temperatures at which common neoprene and CSPE jackets will reach 50% remaining absolute elongation. The figures show that the more modern CSPE material ages more slowly than the older neoprene. These figures do not represent an end of life for the cables but rather conditions at which aging can begin to be detectable and provide an indication of the temperatures at which a boundary for adverse conditions can be set, depending on the age of the plant and the type of cables that are installed. The concept of using a jacket as a leading indicator of thermal/radiation degradation is that if the jacket remains flexible and resilient and shows no sign of discoloration, the underlying insulation will likewise be sound. If the jacket is brittle or highly discolored, the condition of the insulation will be questionable and further assessment is needed. Although ohmic heating could adversely affect the insulation, the high temperature in the core of the cable is likely to cause the jackets to age as quickly as the insulation, and observable hardening would be detectable and indicative of a condition that needed to be assessed.

Figures A-1 and A-2 indicate that a 40-year-old plant with neoprene jackets would have a lower cutoff temperature for adverse environments than a plant with Hypalon jackets would. This does not mean that the underlying insulations would behave significantly differently but rather that thermal damage to the jackets would be observable sooner on the neoprene and that further assessment of the cable insulation by other means would likely be necessary sooner. Figure A-2 indicates that temperatures as low as 92°F (33°C) could lead to identifiable thermal aging of neoprene after 40 years. It must be recognized that a large portion of most plants do not experience a year-round temperature as high as 92°F (33°C).

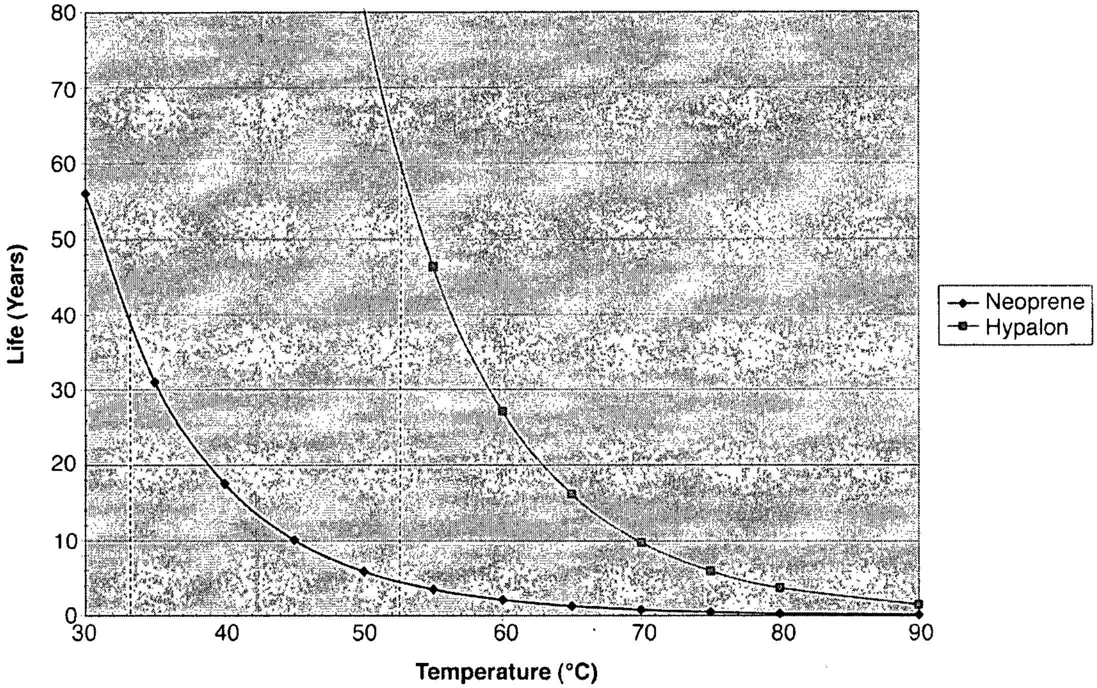

Figure A-1
Age at Which Typical Neoprene and Chlorosulfonated Polyethylene Will Reach 50% Absolute Elongation (Temperature in °C) [16]

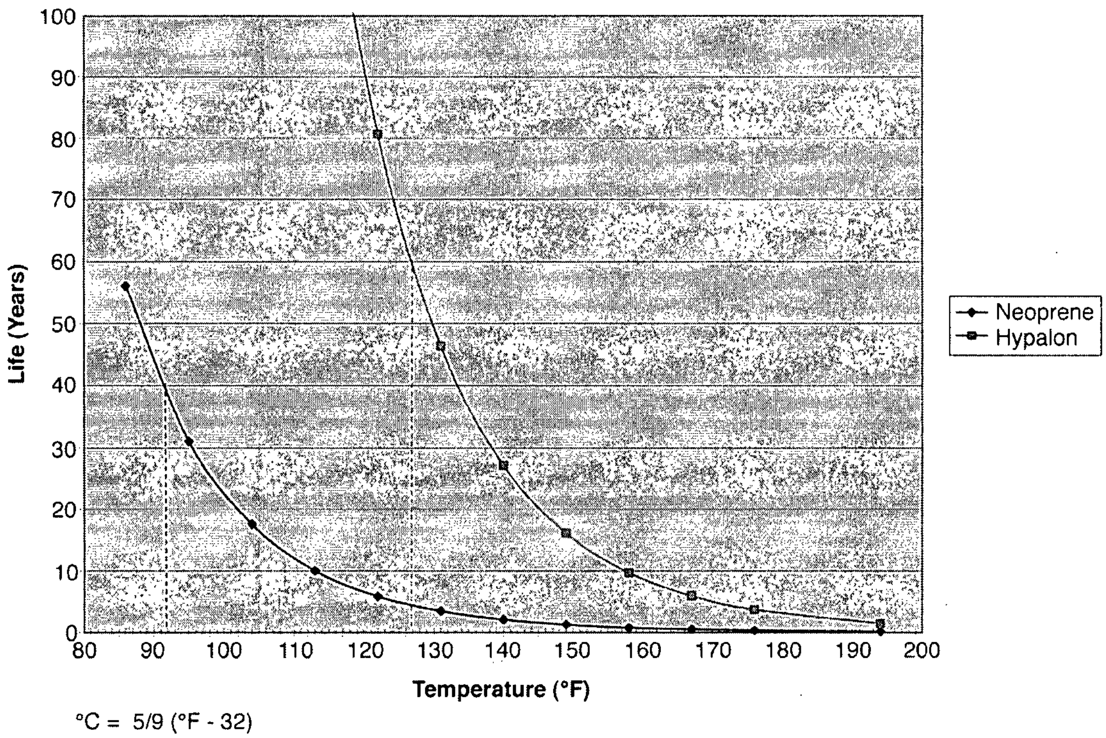

Figure A-2
Age at Which Typical Neoprene and Chlorosulfonated Polyethylene Will Reach 50% Absolute Elongation (Temperature in °F) [16]

Programs:

Nuclear Power

Plant Support Engineering

1020804

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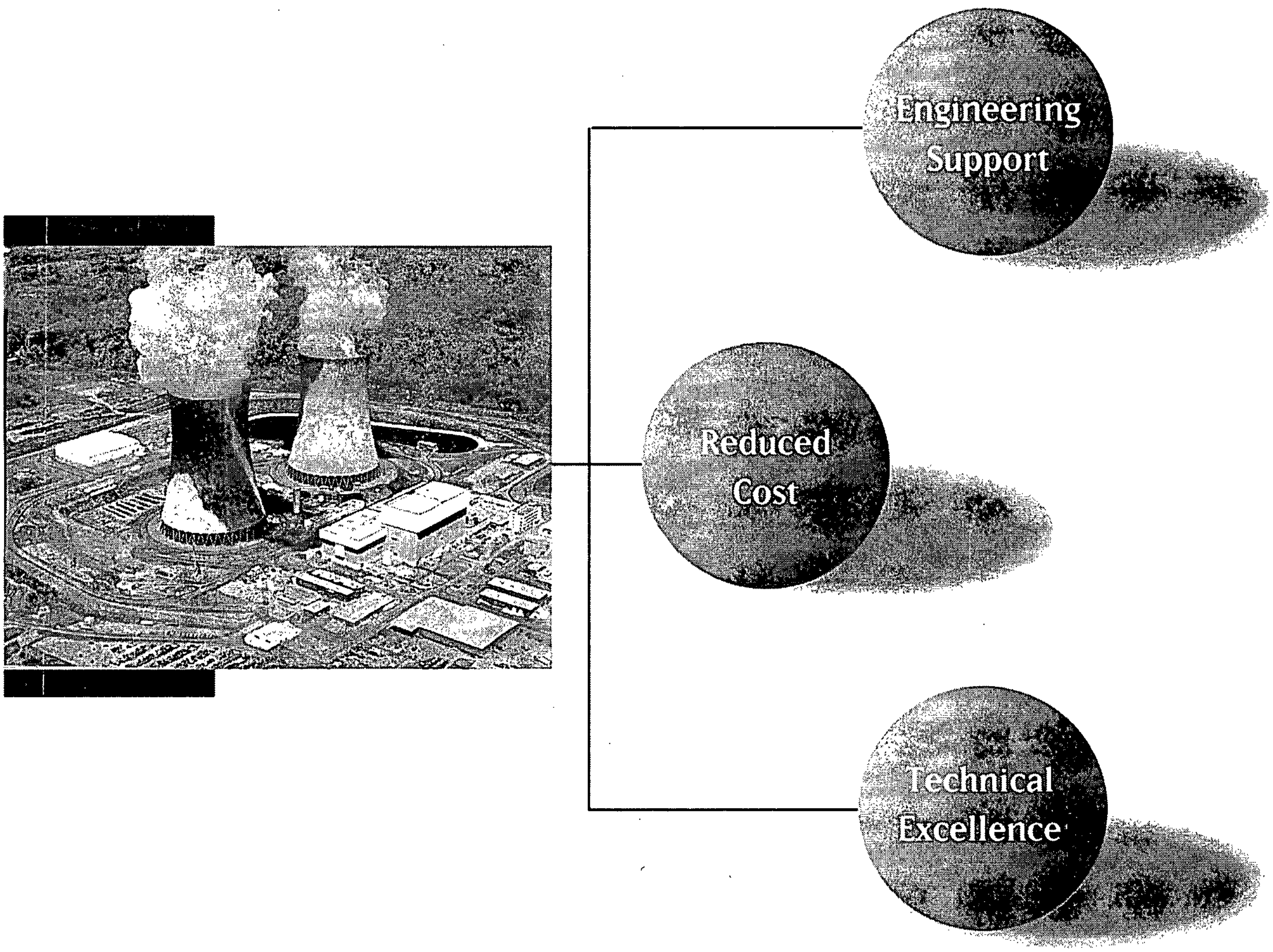
Plant Support Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants



Plant Support Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants

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Final Report, June 2010

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PRODUCT DESCRIPTION

Regulatory and management concern regarding the reliability of medium-voltage cable systems at nuclear plants has been increasing for 5–10 years. The staff of the U.S. Nuclear Regulatory Commission (NRC) are concerned that wetted (up to and including submergence) medium-voltage cable circuits may be degrading to the point at which multiple cable circuits may fail when called on to perform functions affecting safety. Utility managers are concerned that cables may fail, causing adverse safety consequences and/or plant shutdowns. This report provides guidance for developing and implementing a cable aging management program for medium-voltage cable circuits in nuclear power plants.

Results and Findings

The report was developed by subjecting drafts to review and revision by a Technical Advisory Group formed of industry cable personnel from nuclear plant organizations, cable manufacturers, and cable test companies. This report describes the scope of the cable circuits to be evaluated, those conditions that are considered to be adverse environments, and the actions to be taken to assess the conditions of the cable circuits subject to adverse conditions. For key test methodology, assessment criteria are described, along with possible corrective actions that could be implemented.

Challenges and Objectives

This report was developed at the direction of utility management and in parallel with the Regulatory Issue Resolution Protocol for Inaccessible or Underground Cable Circuit Performance Issues at Nuclear Power Plants that occurred between the NRC and the industry (through the Nuclear Energy Institute) from mid-2009 into 2010. Implementation of this guide will form part of the closure process for the protocol. This guide was developed to provide a consistent methodology for the industry to follow in developing an aging management program for medium-voltage cable circuits that are subjected to adverse environmental or service conditions that could lead to degradation of the insulation systems.

Applications, Value, and Use

This guide describes a common approach for developing and implementing a medium-voltage cable system aging management program. Techniques applicable to shielded and nonshielded cable are provided. Because the nuclear industry generally uses different cable types and designs from those used in the power distribution industry, initial assessment criteria and guidance pertinent to the cable applications in the nuclear industry are provided.

EPRI Perspective

The need for a guide for developing cable system aging management programs has been increasing over the last few years. This report was developed with strong input from the industry and represents good practice for the foreseeable future. Cable aging management is an evolving process and an enhancement of the maintenance program for nuclear plants. As the implementation process matures and further research is performed on improving test technology and understanding degradation mechanisms, changes are expected to assessment criteria, the focus of the programs, and the methodologies used. This report will be revised as needed.

Approach

This guide provides a way of determining the scope of a cable aging management program and focuses the aging management process on cables in the worst-case adverse environment and service conditions. It describes testing and assessment criteria and potential corrective actions. The bases for program development are provided as a way of determining the health of the resulting aging management program.

Keywords

Cable aging management
Cable aging management program
Medium-voltage cables

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1 INTRODUCTION

This report provides guidance for the development of an aging management program for medium-voltage cable circuits in nuclear power plants to ensure high reliability. The program is intended to identify adverse localized environments and adverse service conditions that could lead to early failure of medium-voltage cable circuits and to manage significant aging effects to preclude in-service failure. Low-voltage power cables have been addressed in a separate EPRI report *Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants* (1020804) [1]. It is recognized that plants may choose to have one program cover all cable types. However, because different aging mechanisms and assessment activities apply to low- and medium-voltage power cable, the guidance is being generated separately.

Medium-voltage cables (rated 5 kV to 46 kV[1] and generally having operating voltages between 2.3 kV and 34 kV) may age and fail because of several mechanisms. Table 2-2 of EPRI report *Equipment Failure Model and Data for Underground Distribution Cables: A PM Basis Application* (1008560) lists the potential failure mechanisms and whether they are random or age related [2]. The random causes such as installation damage or manufacturing defects do not affect any significant portion of the population of cables and, as such, are not addressed in this report. This document pertains to long-term aging from adverse service conditions that, if neglected, could lead to in-service failures. The effect of a medium-voltage cable failure can cause the loss of a train of a safety system or remove an offsite feed from service. Accordingly, an aging management process for medium-voltage cable systems is desirable to limit the number of in-service failures and support high reliability of the medium-voltage cable system.

Medium-voltage cables and accessories that are properly installed, supported, and kept cool and dry should have a long life. However, cables or accessories that are subject to adverse conditions should be governed by an aging management program. The following are recognized adverse conditions with respect to the longevity of medium-voltage cable circuits:

- Adverse localized high-temperature and/or high-radiation ambient environments under normal operating conditions
- High conductor temperature from ohmic heating
- High-resistance connections at terminations or splices
- Long-term submergence (partial or full submergence)

[1] This definition of *medium voltage ratings* is from the Insulated Cable Engineers Association Standards. NUREG-1801 XI.E3 defines *medium voltage* as 2 kV to 35 kV (assumed to be the range of operating voltages).

The presence or absence of these conditions can be determined by inspection and analysis, environmental monitoring, or infrared thermography. If there are no adverse conditions, a long life can be expected for the cable circuits. Accordingly, for benign environments and service conditions, monitoring and maintenance are not expected to be necessary. Further action would be required only if failures occur or degradation from very long service is recognized. In that case, the need for maintenance and monitoring for benign environment and service condition applications should be determined in accordance with the Maintenance Rule, 10 CFR 50.65 [3] and plant corrective action programs.

If one or more adverse conditions are observed, further assessment, testing, and/or corrective action will be necessary to ensure reliability, unless the cable and/or its accessories have been designed for the conditions.

Program Development

Program Element 1

Each nuclear power plant should have an aging management program for medium-voltage cable systems. A program plan and implementing procedures should be prepared. Documentation of program development and implementation should be prepared and retained. Program health should be monitored using appropriate performance indicators.

A program plan should be developed for aging management of medium-voltage cable circuits. The plan should include the following elements:

- Management's objectives for the program (that is, identification and management of aging caused by adverse localized environments and adverse service conditions)
- Interfaces with other inspection and integrity programs (for example, infrared thermography program or thermal insulation integrity program)
- A well-structured process including scoping, identification of adverse environments and service conditions, assessment of cable circuits exposed to the adverse environments and conditions, and implementation of corrective action as appropriate
- Defined roles and responsibilities including those for the program manager and supporting organizations for assessments, tests, and repair or replacement
- Training requirements
- Determination of the scope of cable circuits to be in the program (see Section 2)
- A schedule for completion of the scoping, determination of the cable circuits potentially affected by adverse environments and service conditions (see Section 3) and the development of the initial assessment plan and expected cost for adoption
- Management sponsorship of continued implementation
- Program health reporting and corresponding performance indicators

- Documentation to be retained, including scope determination, adverse service conditions, cable circuits to be assessed, condition and cable assessment methods, condition and cable assessment and test results, and corrective actions that have been implemented
- Periodic review of plant conditions to determine whether there are any changes to adverse conditions (additions or deletions)

Implementing Procedures

Implementing procedures[2] should address the following:

- Roles and responsibilities
- Scoping methodology and documentation
- Determination of adverse conditions
- Consideration of susceptibility of the plant cables to adverse conditions and identification of cable circuits needing assessment
- Schedule of initial assessments and periodicity of subsequent assessments
- Methods to be used to assess cable circuits subject to adverse conditions
- Assessment of results related to cable condition
- Repair or replacement options (see Section 7)

Data and Information to Be Collected and Retained

The following data and information should be retained for use in continued assessment:

- Program plan
- Implementing procedures
- Scope of the program (for example, cable circuits subject to Maintenance Rule and additional License Renewal required scope)
- Cable circuits within the program that are subject to adverse localized environments and/or service conditions that require aging management

[2] Different utilities use the terms *guides, procedures, and plans* in different ways. The key issue is to have a documented process that includes the appropriate elements of a cable aging management program.

- Additional information that should be identified for these cable circuits includes the following:
  - The nature and location of the adverse environment or service condition.
  - Cable circuits that are affected, including the subcomponent of concern (for example, termination, splice, or cable).
  - Associated load of affected cable circuits (for example, specific motor, bus, or transformer).
  - Degradation mechanism of concern (for example, thermal damage or voltage/water degradation).
  - Method of assessing or monitoring the effect and the periodicity of assessment (for example, one-time assessment, periodic visual inspection, or periodic test [including initial assessment interval]).
  - Methodology of assessment and tests. (Given that periods between assessments and tests may be several years, a complete description of the methods used will help to ensure the ability to compare and trend results, especially if changes to methods occur as technology improves.)
  - Results of assessments and tests.
  - Repair and replacement descriptions.
- Where credit is taken for maintaining dry conditions in ducts, manholes, and vaults, documentation showing that automatic drainage systems are effective and/or that cables are not found to be submerged when water is manually pumped from manholes and vaults.
- Program health report performance indicators.

Program Plan Milestones

The following are suggested program plan milestones:

- Program plan and technical procedures are in place, current, and being implemented.
- Program documentation is complete and current.
- Roles and responsibilities are defined, accepted, and owned by organizations and individuals for assessment, testing, repair, and replacement.
- The program manager and backup are identified and trained.
- Program resources are adequate.
- The scope of the program is clearly defined.
- The adverse localized environments and adverse service conditions of concern have been defined.

- The cable circuits within the program that are subject to adverse localized environments and/or adverse service conditions have been identified for further aging management activities.
- For cable circuits requiring further aging management activities, a method of assessing the cable has been identified and scheduled.

Program Health Indicators

The following are suggested program health indicators:

- The cable circuit/adverse environment assessments are being implemented according to schedule.
- Deferral of cable circuit assessments is limited.
- Review of cable circuit assessment results is timely, and corrective actions are initiated.
- Implementation schedule of corrective actions is met.
- Control of cable submergence is satisfactory.
- Control of thermal insulation in the vicinity of power cables is adequate.
- Thermography of connections and high-current cables is being performed and acted on.
- Program self-assessments are being performed at a reasonable interval.
- The number of age-related cable circuit failures during a defined period is within prescribed limits.
- The number of open findings or areas for improvement from external audits or assessments (for example, U.S. Nuclear Regulatory Commission [NRC] and Institute of Nuclear Power Operations [INPO]) is limited, and they have been resolved in a timely manner.
- Forensic assessment of cables that fail in service is performed, and the findings are incorporated into changes or improvements to the program.
- Applicable operating experience of other sites is being reviewed, assessed, and incorporated into the cable program by the program manager.

Definitions

Assessment. In the context of this report, *assessment* is used to cover a broad range of activities regarding cable condition. These activities include evaluating the severity of environments and service conditions, evaluating the need for testing, and evaluating condition, including visual/tactile inspection and condition monitoring through activities such as electrical testing or *in situ* or laboratory physio-chemical testing. Some assessments are expected to limit the scope of testing and evaluation (for example, the cable has benign service and environmental conditions); other assessments will include testing and condition monitoring, as appropriate, because of the presence of adverse service or environmental conditions.

Delta Tan δ. Delta tan δ is the value yielded from the difference between the tan δ readings at 0.5 V_0 and 1.5 V_0. It can also be the difference in tan δ readings between V_0 and 2 V_0.

Impervious Coverings. Some utilities have and continue to purchase and install cables with impervious coverings, which are designed to prevent penetration of water into the insulation system. Earlier cables used continuous lead or aluminum coverings tightly formed over the core of the insulation, including cable shields.[3] These continuous layers preclude water ingress, and the result is a dry insulation that is not subjected to wetting even if the cable is completely submerged.

Impervious coverings are optional and not required for submerged applications. They are most often chosen when particularly aggressive soil or water conditions exist.

Inaccessible Cable. Inaccessible cables are those cables that have sections located below grade or are imbedded in the plant base mat that are located in duct banks, buried conduits, cable trenches, cable troughs, underground vaults, or that are direct buried.[4]

The concept of inaccessibility for cables is related to the ability to determine the environment and physical condition of cable. For underground cable, inaccessibility makes identification of wetting and submergence more difficult. In dry plant areas, inaccessibility is less of a problem. Even when cables are inside conduits or contained in trays that are difficult to access, heat sources that are close to the tray or conduit are relatively easy to identify and further assessment of condition is possible. Inaccessibility is not a concern if adverse service and environments do not exist.

Submergence, Wet, Damp, and Dry Locations. Both the Underwriters Laboratories, Inc. (UL) and the National Electric Code (NEC) define the terms *dry*, *damp*, and *wet locations* (see Table 1-1). The definitions indicate that the term *wet* means up to and including submerged and not just *damp*, which has its own definition. The NEC definition indicates "saturation with water or other liquid," and the UL definition indicates "flow on or against electrical equipment."

[3] For example, a 1-in. (25.4-mm) diameter core, the required lead layer was 80 mils (2.03 mm), and the required aluminum layer was 55 mils (1.4 mm). A more modern design of water-impervious cable uses a continuous linearly corrugated copper tape system that is wrapped around the cable core with the overlap glued shut (See IEEE Std 400-2001, Section 4 [14]).

[4] NUREG-1801, Generic Aging Lessons Learned Report, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, states "...inaccessible (e.g., in conduit or direct buried) medium-voltage cables...." [4]. NRC Generic Letter 2007-01 states "...in inaccessible locations such as buried conduits, cable trenches, cable troughs, above ground and underground duct banks, underground vaults, and direct-buried installations." [5].

Table 1-1
National Electric Code and Underwriters Laboratories, Inc. Definitions of Dry, Damp, and Wet Locations

Term	National Electric Code Definition [6]	Underwriters Laboratories Definition [7]
Dry location	A location not normally subject to dampness or wetness. A location classified as dry may be temporarily subject to dampness or wetness, as in the case of a building under construction.	A location not normally subject to dampness, but may include a location subject to temporary dampness, as in the case of a building under construction, provided ventilation is adequate to prevent an accumulation of moisture.
Damp location	Locations protected from weather and not subject to saturation with water or other liquids but subject to moderate degrees of moisture. Examples of such locations include partially protected locations beneath canopies, marquees, roofed open porches, and like locations, and interior locations subject to moderated degrees of moisture, such as basements, some barns, and some cold storage buildings.	An exterior or interior location that is normally or periodically subject to condensation of moisture in, on, or adjacent to, electrical equipment, and includes partially protected locations.
Wet location	Installations underground or in concrete slabs or masonry in direct contact with the earth; in locations subject to saturation with water or other liquids, such as vehicle washing areas; and in unprotected locations exposed to weather.	A location in which water or other liquid can drip, splash, or flow on or against electrical equipment.

Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report:

ac alternating current

CPE chlorinated polyethylene (thermoset or thermoplastic)

CSPE chlorosulfonated polyethylene (commonly referred to by the DuPont trade name Hypalon)

dc direct current

EOP emergency operating procedure

EPR ethylene propylene rubber
Black EPR is the earliest generation of EPR used as cable insulation. Later generations were either gray (substantially reduced levels of carbon black), pink (red) EPR (most manufacturers), or brown EPR (Kerite). The color differences were to allow visual distinction between black semi-conducting or high permittivity shields and the insulation and also to demark the transition to improved coatings of the filler clay to improve its bonding to the base insulation material and preclude absorption of water.

GALL Generic Aging Lessons Learned report

Gy Gray; a metric unit of radiation equal to 100 rad

HCl hydrogen chloride

hi-pot high potential

hr hour

INPO Institute of Nuclear Power Operations

kV kilovolt(s)

LIRA line resonance analysis (a cable condition monitoring technique)

Mrd megarad

NEI Nuclear Energy Institute

NEC National Electric Code

NRC U.S. Nuclear Regulatory Commission

PM preventive maintenance

PVC polyvinyl chloride

rd rad

rms root mean square

tan δ An ac dielectric test of insulation that measures the ratio of resistive leakage current to the capacitive current across the insulation (radians, often given in terms of 10^{-3})

TDR time domain reflectometry

UL Underwriters Laboratories, Inc.

VLF very low frequency

V_0 line-to-ground rms voltage on a three-phase system, also referred to as U_0

XLPE cross-linked polyethylene

2
SCOPE OF THE AGING MANAGEMENT PROGRAM FOR MEDIUM-VOLTAGE CABLE SYSTEMS

> ***Program Element 2***
>
> The cables and associated connections and terminations that support the function of Maintenance Rule equipment should be within the scope of the medium-voltage cable system aging management program. It is recommended that additional cable circuits associated within the scope of the License Renewal program be included in the scope of the medium-voltage cable system aging management program. These cable circuits may be included in the initial scope or added to the program when implementation of License Renewal actions is required. Any commitments related to medium-voltage cable aging management contained in plant-specific regulatory correspondence should also be included in the development of the program and its scope.
>
> Cable circuits required to support AP-913 critical functions should be considered for inclusion in the scope of the medium-voltage cable system aging management program. Medium-voltage cable circuits critical to power generation, or that may result in outage length extension should they fail, may be added to the scope of the program at management option.

The development of the scope of the cable circuits to be within the medium-voltage cable system aging management program should consider these sources:

- The Maintenance Rule (10 CFR 50.65) scope requirements [3]
- The License Renewal Rule (10 CFR 54) scope requirements [8]
- Updated Final Safety Analysis Report commitments (if any)
- License Renewal aging management program commitments
- Plant-specific regulatory correspondence pertaining to cable
- Critical components as defined in INPO AP-913, *Equipment Reliability Process* [9]
- Circuits critical to power generation (management option)

Table 2-1 provides a comparison of the equipment covered by the Maintenance Rule and the License Renewal Rule. Paragraphs 10 CFR 50.65 (b)(1) and Paragraph 10 CFR 54.4(a)(1) require that cable circuits supporting safety-related functions be within scope of the respective activities. Paragraphs 10 CFR 50.65 (b)(2) and 10 CFR 54.4(a)(2) both require that nonsafety-related cable circuits whose failure could prevent safety-related functions from being fulfilled be within scope. Paragraph 10 CFR 50.65 (b)(2) also requires that cable circuits used to mitigate accidents or transients or to support emergency operating procedures, as well as cable circuits whose failure could cause a reactor scram or actuation of a safety-related system, be in scope. Paragraph 10 CFR 54.4(a)(3) extends beyond the Maintenance Rule scope in that cable circuits related to Station Blackout and Fire Protection are within scope.

Some plants may have cable monitoring commitments in their Updated Final Safety Analysis Report. All plants that pursue License Renewal will have cable aging management commitments in the License Renewal aging management program for cable and connections and terminations. Under the License Renewal process, there is likely to be separate aging management programs for cable and for connections and terminations that should be considered when developing the scope and content of the medium-voltage cable system aging management program. Some plants may have cable-specific regulatory correspondence pertaining to cable. Review of the plant-specific response to Generic Letter 2007-01 is appropriate to confirm the activities that the plant stated were in place to assess the condition of cables and to control wetting of cables [5]. As the plant's medium-voltage cable system aging management program is developed and implemented, it is recommended that differences from and changes to methodologies from those in the Generic Letter 2007-01 response be documented.

The AP-913 equipment reliability process ranks components with respect to importance to reliability. Those cables required to support the function of components should be considered with respect to the scope of the medium-voltage cable system aging management program.

Medium-voltage cable circuits that supply outage power whose failure may adversely affect outage duration should also be considered for inclusion in the scope of the program. Other cables may be identified for scope inclusion based on plant-specific experiences.

Table 2-1
Scope Comparison for Maintenance Rule, 10 CFR 50.65, and License Renewal Rule, 10 CFR 54 [3, 8]

Maintenance Rule	License Renewal	Differences
10 CFR 50.65 (b)(1) Safety-related...systems and components that are relied on to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure...	10 CFR 54.4(a)(1) Safety-related systems, structures, and components which are those relied on to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions: (i) The integrity of the reactor coolant pressure boundary; (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), in 10 CFR 50.67(b)(2) or 10 CFR 100.11 of this chapter as applicable.	None
10 CFR 50.65 (b)(2) nonsafety-related...systems, or components: (i) That are relied on to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or (ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or (iii) Whose failure could cause a reactor scram or actuation of a safety-related system.	10 CFR 54.4(a)(2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1) (i), (ii), or (iii) of this section.	Agreement on nonsafety components that could affect function of safety components. Maintenance Rule adds cables associated with EOPs and that could result in scrams or safety system actuation.

Table 2-1 (continued)
Scope Comparison for Maintenance Rule, 10 CFR 50.65, and License Renewal Rule, 10 CFR 54 [3, 8]

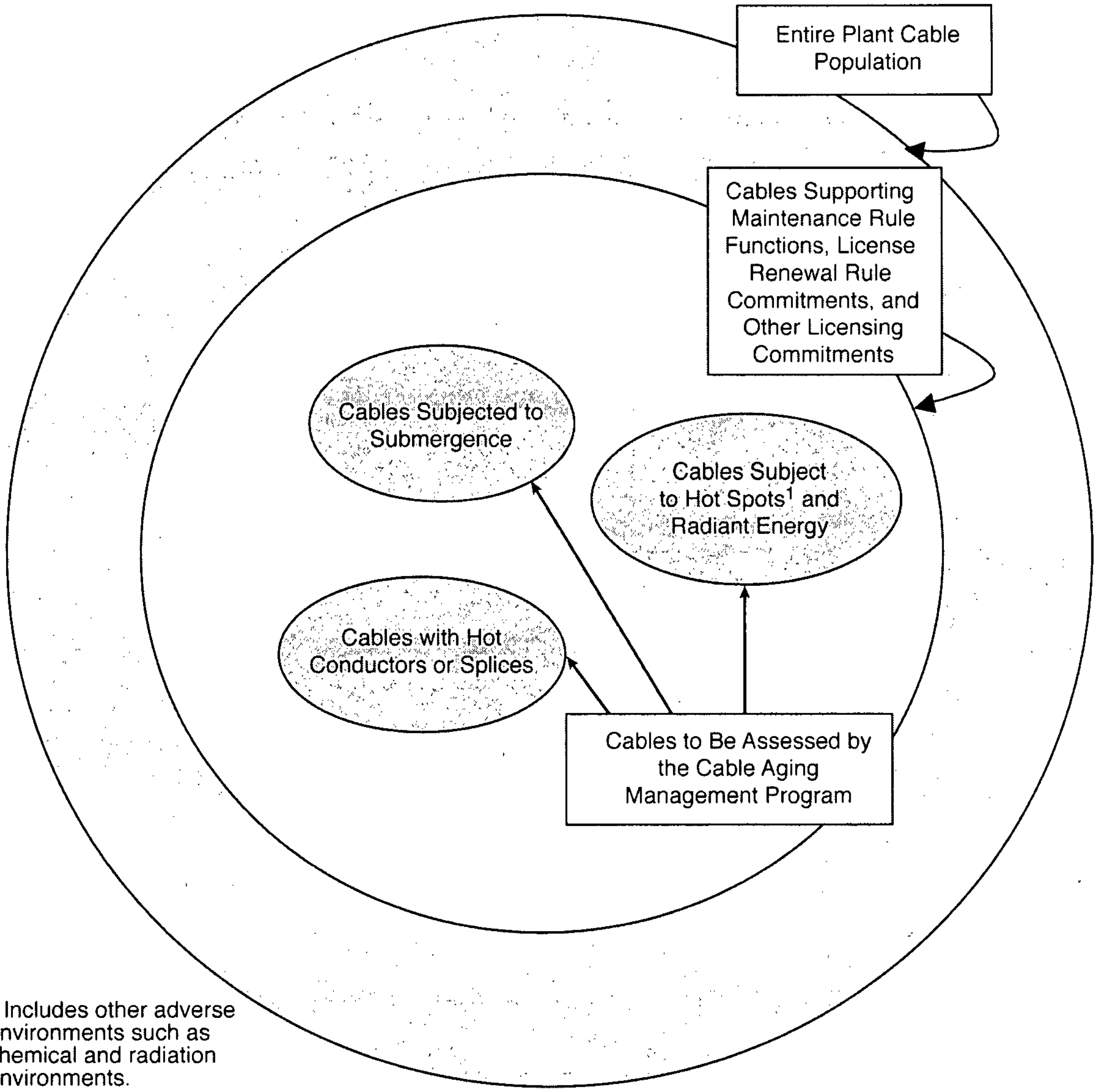
Maintenance Rule	License Renewal	Differences
	10 CFR 54.4(a)(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).	License Rule adds cables associated with fire protection, station blackout, and anticipated transient without scram. Environmentally qualified cables would be in scope already; there are no cables associated with pressurized thermal shock.)

Program Scope Versus Cable Circuits Requiring Condition Monitoring or Assessment

The purpose of scoping is to consider the extent of cables that would need condition assessment or monitoring if they were exposed to adverse environments or have adverse operating conditions. It is not the intent of the program to assess and monitor the condition of the entire program scope. Rather, this document requires assessment of cables and/or accessories[5] exposed to adverse environments or have adverse service conditions. Accordingly, those cable circuits that are within scope, such as those supporting Maintenance Rule functions, **and** that are exposed to adverse environments or adverse service conditions will be assessed or monitored under the medium-voltage cable system aging management program as appropriate.

For medium-voltage cables, the list of cable circuits under consideration will likely be determined by review of medium-voltage bus loads and offsite power sources and then by a determination of whether the individual circuits have elements that are subject to adverse environments or service conditions. This technique works because of the limited number of circuits involved. Figure 2-1 illustrates the scoping concept. Although this document focuses on managing the aging of medium-voltage cable circuits that are subject to recognized adverse effects, the Maintenance Rule and corrective action processes ensure that if a new failure cause is identified, it will be assessed and corrective actions taken to control the effect. As appropriate, the medium-voltage cable system aging management program should be revised to take new failure causes into account.

[5] Cable accessories are splices (joints) and terminations.



[1] Includes other adverse environments such as chemical and radiation environments.

Figure 2-1
Medium-Voltage Cable Circuit Scoping Process

3 IDENTIFICATION OF ADVERSE ENVIRONMENTS AND CONDITIONS

Program Element 3

The determination of cable circuits that are subject to adverse environments or cable circuits subject to adverse service conditions will be assessed as follows: Program Element 3.1 describes wetted cables subject to adverse conditions, and Program Element 3.2 describes cables in dry environments subject to adverse conditions.

After the cable circuits within the scope of the medium-voltage cable system aging management program have been identified, the nature of the cable layout and application must be identified to determine whether aging management activities are required for particular cables. If cable circuits are subject to benign conditions, there are no aging management concerns at this time.

The first effort will be to separate cables that are located in completely dry conditions from circuits potentially wet or known to contain wet sections. Cables having wet or potentially wet environments include cables that are inaccessible, underground and/or substructure segments whether installed in ducts, in trenches, or direct buried. Cables located in dry accessible cable tunnels may be excluded from consideration for wetting. For cables determined to be totally in dry environments or having an impervious design, skip to "Activities for Dry Environment Cables." For cables having mixed dry and wet segments, the "Activities for Dry Environment Cables" applies to the dry sections, and the "Activities for Wet and Potentially Wet Environment Cables" applies to the wet section.

Activities for Wet and Potentially Wet Environment Cables

> ***Program Element 3.1***
>
> Cable circuits subjected to long-term wetting should be identified.
>
> If cables are subjected to wetting or have been subjected to wetting for long periods in the past, aging management should be implemented starting with the assessment of the susceptibility of the insulation to wet conditions described in Section 4.
>
> The condition of vaults and manholes subject to wet conditions and the cable support structures within them should be evaluated at least once to determine the condition. Appropriate repairs should be made. The need and interval for further evaluations should be determined based on the conditions that are identified.

A conservative approach to medium-voltage cable aging management is to assume that all underground cables are wet and to develop the program on that premise. This approach eliminates the need to assess the design and perform verifications that there are no wetted sections in cable circuits.

However, some underground systems have been designed to be dry or drained automatically. If the cables in such systems can be shown to be dry (for example, by verifying that water does not exist in duct work between manholes), the concern for long-term wetting can be eliminated. This premise may be difficult to defend unless some sort of inspection evidence (for example, umbilical video inspection) can be provided to support the supposition that the conduits are water free.

"Rain and drain" applications in which a duct or manhole may be wet for a short period until natural or automated draining (for example, sump pump) occurs is not considered adverse with respect to the life of a medium-voltage cable. Systems in which ducts slope toward manholes or other structures that are drained so that cables neither sit in nor are submerged in water for any significant period may be treated as dry with respect to cable longevity. Cables mounted on the walls of trenches and not subject to wetting along their length may be considered dry.

Water permeation into cable insulation takes a significant period. For this report, *long-term wetting* is defined as a condition in which the cable sits in or is covered by water for a continuous period of months or longer. A jacket over the insulation will significantly slow the effect, but the exact degree has not been determined. After water has permeated the jacket, water is known to be drawn to the highest voltage stress concentration within the insulation, which is near the conductor surface. When the water is drained from the vicinity of the cable, the ohmic heating of the conductor may drive off some of the moisture from the insulation, but how much and how fast is not readily identifiable. Certainly, further water and the additional chemical contamination (for example, salts) in the water are no longer available to permeate into the cable. However, any degradation that may have occurred does not reverse. Rather, the rate of further degradation is assumed to be slowed by draining the ducts and manholes and keeping them drained. With respect to direct buried cables, an assumption must be made that the cables are always wetted, because observation cannot be made to show that they are above the water table and that there are no subterranean pockets of water surrounding sections of the cable.

If credit is being taken for a cable system being self- or naturally draining or manually pumped often enough to ensure that cables are not wetted, at least a one-time inspection of the system to confirm its nature should be made. If automatic sump pumps are being credited for maintaining a dry cable system, an appropriate inspection and maintenance program should be in place for the pumping system so that long-term wetting of the cables will not occur. If manual pumping is used as an alternative, the pumping must be performed frequently enough to preclude long-term wetting or manholes must be inspected after significant rainstorms, winter thaws, or flooding events to determine whether pumping is necessary and action taken accordingly.

Both water and voltage must be present for water-related deterioration to occur in medium-voltage cables. Accordingly, cables that are rarely energized will suffer minimal water-related degradation even if exposed to long-term wetting. However, given that the most important safety cables are likely to be de-energized for most of their service life and less well understood failure mechanisms could be possible in wet environments, assessment and testing of these cables is important. These cables should be evaluated early in the implementation process of the cable system aging management program. If these cables are found to be in satisfactory (that is, "good") condition after an extended period, consideration may be given to extending the period between tests with respect to continuously energized cables.

Nondrained Conduits and Ducts Within Plant Structures

In some cases, medium-voltage cable ducts within plant structures are embedded in the floor with both end points exiting the floor above the duct. If such ducts exist and there is no drain for the below floor section, moisture may accumulate and condense in the duct, or the duct may fill from spills or other water-related events. To the extent practical, such duct arrangements should be evaluated to determine whether they are dry. If not, the condition of the cable should be assessed, and if practical, the duct should be drained.

Condition of Vaults, Manholes, and Related Cable Support Structures

In addition to concerns for aging of cables under wet conditions, support structures for cables in trenches, manholes, and vaults may degrade with time, resulting in inadequate support of cables or physical damage to the cables. The physical structure of the manhole or vault may also degrade. Accordingly, the condition of support structures (for example, brackets and trays) and the overall manholes and vaults should be evaluated to confirm that no significant deterioration has occurred. It is recommended that ladders and platforms for personnel be included in these evaluations.

Activities for Dry Cable Circuits

> ***Program Element 3.2***
>
> Medium-voltage cables in the scope of the program that are located in dry environments should be reviewed to determine whether they are exposed to adverse localized environments, subjected to elevated operating temperature from circuit currents, or have high-resistance splices or terminations. Where other programs exist that will control and identify these conditions, credit may be taken for them, and additional controls need not be added.
>
> The thermal insulation and barriers that protect cables from process heat damage must be maintained. If plants remove thermal insulation from piping and equipment adjacent to cable in preparation for an outage, the effects on adjacent cable should be addressed. Procedures for restoration of thermal insulation in the vicinity of cable circuits should be reviewed to ensure that the thermal insulation is inspected for acceptability and that adequate protection from thermal stresses is given to the cable. The actions for cable found to be in adverse thermal and radiation environments are described in Section 6.

The adverse conditions and environments that can shorten the life of medium-voltage cables under dry conditions are as follows:

- High-temperature or dose-rate environments under normal operating conditions
- High conductor temperature from ohmic heating
- High-resistance connections at terminations or splices

The following subsections address these items and the assessment of their importance with respect to cable longevity.

High-Temperature- or High-Dose-Rate Ambient Environments

Thermal Aging

Elevated temperatures cause thermal aging and may also limit the allowable ampacity of the cable. Cable thermal ratings are based on conductor temperature in a free air 40°C environment. Most cables in nuclear plants have been derated so that conductor temperatures are well below the rated temperature and a long thermal life in a 40–50°C environment would be expected. However, care must be taken in environments that exceed 50°C and for cables operating near their ampacity limit in ambient environments of 40°C or more because the combination of ambient and ohmic heating may cause higher rates of thermal aging.

In general, bulk area temperatures are not expected to significantly affect the aging of medium-voltage cable. However, localized hot spots are a key concern, especially if the cable is adjacent to hot process piping. NRC Information Notice 86-49 identified a 4-kV cable failure from exposure to a hot process pipe [10]. If medium-voltage cable is adjacent to an uninsulated, hot process component (for example, pump, pipe, or valve) the cable polymer will be affected by both the local temperature and the radiant heating from the component. The circuit routing should be reviewed and/or walked down to determine whether hot process equipment is in the vicinity of the cable. If so, the condition of the thermal insulation on the hot components should be confirmed as adequate for the protection of the cable. Maintenance procedures should also be confirmed as requiring restoration of thermal insulation before the process component is returned to service if the thermal insulation must be removed to allow maintenance of the process component. If the process component must operate without insulation for any significant period, the effect on the medium-voltage cable should be evaluated. If a significant effect is expected, temporary thermal shielding should be placed between the hot process pipe and the cable.

Radiation-Related Aging

With respect to radiation effects, most medium-voltage cable will be in low-dose areas of the plant. However, some cables may be located in areas with appreciable doses. Sandia research on low-voltage cables with similar compounds to those in medium-voltage cables showed that effects on physical properties are not observable at 1 Mrd (10 kGy) and that at least 5 Mrd (50 kGy) must be absorbed for effects to be observed [11]. Assuming a 60-year desired life for a medium-voltage cable, no appreciable effect would be expected for average dose rates up to 10 rd/hr (0.1 Gy/hr)[6]. Although minimal effects are expected at 10 rd/hr (0.1 Gy/hr), the effects could be appreciable if the cables are simultaneously exposed to high temperature (for example, greater than 122°F (50°C) with conductor temperatures reaching ampacity limits).

The effects of radiation and temperature are to change the physical properties (such as loss of elongation and increased hardness) of the insulation and, after severe aging, to eventually affect the electrical properties. If high temperature conditions are recognized and radiation doses greater than 5 Mrd (50 kGy) are expected, the medium-voltage cables should be inspected for degradation unless environmental qualification data exist that shows the capability of the materials. Note that until the dose from the exposure reaches approximately 5 Mrd (50 kGy), radiation effects may not be observable. Inspections at the 30- or 40-year mark may only identify radiation effects if the dose rate is well above 10 rd/hr (0.1 Gy/hr) (that is, 15 to 20 rd/hr [0.15–0.2 Gy/hr]).

Several types of medium-voltage cable have been subjected to environmental qualification testing. These tests provide information on whether radiation doses up to 50 Mrd (500 kGy) (~95 rd/hr [0.95 Gy/hr] for 60 years) are within the qualification limits. The thicker insulation and jackets of medium-voltage cables makes them less susceptible to thermal and radiation aging. The damage from irradiation does not reduce the electrical properties appreciably of the insulation; rather, it hardens the insulation and makes it more susceptible to physical damage and failure after severe degradation. Where radiation or thermal damage or both are a concern, initial evaluation should include visual/tactile assessment as described in later sections of this guide.

[6] 1.9 rd/hr = 5 Mrd ÷ (60 years × (365 days/year) × 24 hours/day)

Periodicity of Review of Condition

The initial review of adverse conditions will identify areas, if any, with elevated thermal or radiation conditions. The need for action will be governed by the severity of the condition. Modifications and changes to plant operating conditions that could significantly worsen thermal or radiation conditions in the vicinity of medium-voltage cable should be reviewed for their effect.

The review should identify where medium-voltage cables are in close proximity to hot process piping. Programmatic controls should be put in place to verify that thermal insulation remains intact and effective so that the medium-voltage cables are not adversely affected as could occur if the thermal insulation is taken off and left off for a significant period.

High Conductor Temperature from Ohmic Heating

Ohmic heating of medium-voltage cable from load currents can cause appreciable aging of the insulation system if cable currents cause the cables to operate at or above rated temperature, especially if ambient temperatures are elevated. Normal design practices result in operating cables at currents significantly below their ampacity. Design practices or ohmic heating calculations should be reviewed to confirm that elevated conductor temperatures (for example, >90°C, a common cable thermal rating) should not occur.

One special case should be considered that can occur with multicable-per-phase circuits. When multiple cables are used in each phase, the magnetic fields must be balanced so that equal currents occur in each phase. This can be done by running three separate phase cables triplexed or in the same duct. However, if the individual conductors are laid flat in trays, the positions of the conductors may need to be transposed along the run to balance the magnetic circuits. If the magnetic fields are not balanced, some cables in each phase will run with lower currents and others will have high currents. Conditions have occurred in which the high-current cables were operating beyond ampacity and thermal aging caused severe hardening of the insulation and jacket. When a fault occurred on a connected transformer, the cables thrashed and one's insulation cracked to the conductor. Accordingly, the current balance on multiconductor-per-phase cables should be verified. This verification could be performed through the use of infrared thermography if cables are accessible or through measurements of current on individual conductors.

Periodicity of Review

The review of ohmic heating of medium-voltage cables and current balance on multiconductor-per-phase circuits needs to occur only once. Re-review would be necessary only at the time of circuit repair or replacement.

High-Resistance Connections at Terminations or Splices

Properly made splices and terminations should not experience overheating. However, when terminations or splices are disassembled and reassembled or first installed, human performance errors or design deficiencies can occur, resulting in high-resistance connections, especially when connections involving aluminum conductor are being made. Accordingly, terminations and splices should be checked for elevated temperature conditions when operating at load after installation. This verification should be performed at some reasonable period following installation (one or two operating cycles). Identification of high-resistance connections may be through the use of infrared thermography or periodic visual inspection for signs of discoloration or deterioration of the splice or termination. If the adequacy of the connection was confirmed at the time of splice or termination preparation through the use of a micro-ohmmeter or other recognized method, periodic evaluation may be unnecessary for most connections, but it may be desirable for aluminum connections until stability is confirmed.

The program may take credit for the performance of periodic infrared thermography or inspection of terminations and splices that is covered by the station maintenance program. The EPRI Preventive Maintenance Basis Database provides frequencies for performing routine infrared surveys or inspections of terminations. Frequencies vary based on the end load's criticality. Infrared thermography surveys should be scheduled to be performed when the equipment is energized and loaded to provide meaningful results.

In many cases, access to terminations of medium-voltage cable terminations is limited because of equipment design, arc flash concerns, and so on. One relatively inexpensive way to improve access is using infrared windows or infrared ports on switchgear doors and cable termination boxes. Both types of access covers are available with UL ratings equal to that of most electrical enclosures. Infrared windows are made from special materials that are transmissive (transmissive materials can pass radiant energy that glass and Plexiglas cannot), and they are more expensive than a port. In addition, they have 40–60% transmissivity, requiring calculating hot spot temperature by multiplying the measured value by the inverse of the transmissivity for the window, and they do not hold up well when exposed to outside environments. Infrared ports, on the other hand, are relatively inexpensive, simple to install, and allow direct viewing (no transmissive losses) of the target.

Infrared thermography should also be scheduled as post-maintenance verification whenever splices are installed or when splices or terminations are disturbed for maintenance. This check should be done at least 1 hour after the equipment has been energized and loaded (to allow thermal stabilization) or at the earliest opportunity thereafter.

Another diagnostic tool that can be applied to higher voltage terminations (6.9 kV and above) is ultrasonic partial discharge detectors that can be used to pick up arcing or other discharges within the connection.

Periodicity of Review

The plant maintenance program should be reviewed to verify that splices and terminations are evaluated on a periodic basis. Thereafter, the plant maintenance program may be credited for covering this subject.

4
SUSCEPTIBILITY OF CABLES TO WATER-RELATED DEGRADATION BY TYPE

> *Program Element 4*
>
> The cables in the scope of the program subjected to long-term wetting should be identified and their susceptibility to wet aging reviewed. It is recommended that cables that are older than the periods stated in Table 4-2 and subject to long-term wetting be assessed for the effects of long-term aging in accordance with Section 5 of this report.

Differences exist in the susceptibility of various cable insulation types and vintages to water-related degradation under energized conditions. Table 4-1 indicates the differences in degree of expected susceptibility and the operating experience to date by insulation type and vintage. The older insulations are cross-linked polyethylene (XLPE), butyl rubber, and black ethylene propylene rubber (EPR). XLPE was extensively used in the distribution industry and found to degrade under wet energized conditions, especially in nonjacketed cables used in power distribution applications. (Nuclear plant cables are jacketed.) The EPRI report *Equipment Failure Model and Data for Underground Distribution Cables: A PM Basis Application* (1008560) is based on an evaluation cable in distribution system service and developed onset of failure expectations based on expert opinion [2]. The result was that 30% through-wall water trees could be expected in XLPE in approximately 10–12 years of wet service. A 30% through-wall water tree was identified as the point at which the cable could be susceptible to a surge from a lightning strike that would convert the water tree to an electrical tree with relatively rapid failure thereafter. In nuclear service, cables are generally protected from lightning strikes, and the cables have lower voltage stresses, which tends to make the onset of failure later than the distribution industry operating experience. Nuclear industry operating experience indicates that the onset of XLPE failures traceable to wet aging occurred after 24 years of service.

Table 4-1
Cable Susceptibility Under Wet Conditions (population data are from the Nuclear Energy Institute [NEI] 2005 Survey on Underground Cables)

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Population of Installed Cables at Nuclear Plants	Oldest Nuclear Plant Cables as of 2009	Earliest Expected Onset of Water Degradation in Distribution Industry [2]	Nuclear Industry Actual Experience Discussion
XLPE	Reynolds, Cyprus, and others	1975–1980	Moderate	34 years	10–12 years	Water degradation failures have been observed in the nuclear industry starting at 24 years of service.
Filled XLPE	GE	1968	Single plant	No longer in service in wet conditions	10–12 years[7]	Failures were observed starting at 10 years of service, with many failures between 10 and 25 years.
Butyl rubber	GE, Collyer, and Okonite	1967–1972	Small	42 years	20–25 years	Water degradation failures have been observed in the nuclear industry starting at 25 years of service.
Black EPR	Okonite, Anaconda, and General Cable	Bulk 1971–1979, last 1986	Large	38 years	20–25 years[7]	There have been 26 failures to date in the nuclear industry with 20–30 years of service.
Brown EPR	Kerite	Bulk 1972–1985, some 1990–2003	Moderate	37 years	20–25 years	No water-related failures have been observed to date in the nuclear industry.
Pink EPR	Okonite	1978 to present	Newer plants and replacements	31 years	20–25 years	No water-related failures have been observed to date in the nuclear industry; one manufacturing defect-related failure has been observed.

[7] This material is not covered in EPRI report Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants, (1020804) [1]. The onset of significant water degradation may be somewhat earlier than listed.

Table 4-1 (continued)
Cable Susceptibility Under Wet Conditions (population data are from the Nuclear Energy Institute [NEI] 2005 Survey on Underground Cables)

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Population of Installed Cables at Nuclear Plants	Oldest Nuclear Plant Cables as of 2009	Earliest Expected Onset of Water Degradation in Distribution Industry [2]	Nuclear Industry Actual Experience Discussion
Pink EPR	Anaconda/Cablec/ BICC and General Cable	1978 to present	Newer plants and replacements	31 years	20–25 years	Some early failures with water combined with manufacturing defect have been observed; there have been no water degradation alone failures reported in the nuclear industry.
TR-XLPE	Not known	2004	Rare replacement	5 years	20–25 years	There is an insufficient population and period of service to make inferences.

For the other insulations commonly used in nuclear plants, EPRI Report 1008560 indicates that earliest expected onset of significant water-related degradation occurs in approximately 20–25 years of wet service [2]. Butyl-rubber-insulated cables were the first type of rubber-insulated cables used in nuclear plants. Only a few plants purchased these cables before the rubber-insulated cable industry converted to black EPR. At 25 years of service, water-related failures were identified in the nuclear industry.

Black EPR replaced butyl rubber in the early 1970s and is the insulation with the largest population of cables with approximately 48% of nuclear plants reporting its use. The first water-related failures occurred at approximately 20 years of service, and more than 26 failures[8] have occurred in the nuclear industry as of this writing.

Brown EPR insulation, while being available to the early nuclear plants, continues to be produced. Approximately 20% of plants report its use. No water-related failures have been reported in the nuclear industry to date.

Pink EPR replaced black EPR in the cable industry in the mid- to late 1970s, and approximately 30% of nuclear plants report its use. To date, the only failures related to water degradation have been associated with manufacturing defects or highly localized degradation likely associated with a local flaw. No bulk water-related degradation and failure has been reported in the nuclear industry.

Recommendations Based on Susceptibility Assessment

Table 4-2 provides the recommendations concerning the timing of cable aging management programs for wet medium-voltage cable based on insulation type. See Sections 6 and 7 for guidance.

Table 4-2
Aging Management Recommendations Based on Insulation Material Type

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Recommendation for Wetted Cable Circuits
XLPE	Reynolds, GE, Cyprus, and others	1975–1980	Implement aging management program.
Filled XLPE	No longer in use in wet circuits		
Butyl rubber	GE, Collyer, and Okonite	1967–1972	Implement aging management program.
Black EPR	Okonite, Anaconda, and General Cable	Bulk 1971–1979, last 1986	Implement aging management program.

[8] From the 2005 NEI industry survey of underground cable installed and failure information, approximately 1400 black EPR cables were originally installed underground in potentially wet conditions.

Table 4-2 (continued)
Aging Management Recommendations Based on Insulation Material Type

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Recommendation for Wetted Cable Circuits
Brown EPR	Kerite	Bulk 1972–1985, some 1990–2003	Implement aging management program for cables with more than 30 years of service.
Pink EPR	Okonite	1978 to present	Implement aging management program for cables with more than 30 years of service.
Pink EPR	Anaconda/Cablec/BICC, and General Cable	1978 to present	Implement aging management program for cables with more than 30 years of service.
TR-XLPE	Not known	2004	Implement aging management program for cables with more than 30 years of service.

Note: The timing of the recommendations in this table is based on the actual nuclear plant experience for the cable type described in Table 4-1.

Susceptibility of Splices to Wetting

Most plants have short enough on-site runs of medium-voltage cable that no splices exist. Other plants have some long runs, generally to intake structures or ultimate heat sinks, that require splices to complete the circuits. Offsite medium-voltage feeds to the plants likely have splices and also may be distribution-type cables with concentric neutral wires rather than helical tape shields. Some plants may have splices in circuits where wetted sections have been replaced while the dry portion of the circuit was retained. Splices in dry sections of cables should be long lived provided they are reasonably well made. However, splices in wetted sections of cables will be more susceptible to water-related degradation if there were errors in assembly. Cables having splices in wetted sections should be included in the scope of the program, no matter what type of insulation is present.[9] Only a limited number of circuits will have splices, and an even smaller set of these is expected to be subject to wet conditions. For these splices, local assessment through Lemke partial discharge probe or an ultrasonic acoustic probe may be most useful given that attenuation of partial discharge by the helical shield may preclude assessment of the splice from the circuit terminations. In some cases, splice deterioration from internal tracking or discharging may be observable through careful assessment of infrared thermographs.

[9] Cables with wetted splices that are subject to lightning strikes (that is, aerial sections or aboveground outdoor terminations) and that do not have lightning arrestors or surge suppressors may need additional assessment or testing. Cables with wetted splices that are not subject to lightning strikes (that is, terminated inside grounded structures) should be assessed starting at the point listed in Table 4-2 for the particular cable type unless adverse plant or industry operating experience dictates that a problem may exist with the splices.

5 ACTIONS FOR CABLES HAVING WET ENVIRONMENTS

Program Element 5

If practicable, manholes and vaults should be kept clear of water that could submerge cables and cable accessories.

Cables within the scope of the medium-voltage cable aging management program that are or have been subjected to long-term wet environments should be assessed for condition.

Wet environment cables with insulation shields should be assessed using an off-line ac test. Very low frequency tan δ is recommended for cables commonly used in nuclear plants; however, the test type should be applicable to the nature of the degradation expected and the design of the cable. Very low frequency withstand testing may be used in addition to very low frequency tan δ. Alternate tests, such as dielectric spectroscopy, may be used. Partial discharge testing may be used if the metallic shield configuration and insulation do not lead to excessive attenuation of partial discharge signals.

For medium-voltage cables within the scope of the medium-voltage cable aging management program that do **not** have insulation shields, plants should require a full forensic analysis of any failure that is potentially water related with corrective action appropriate to the findings. These plants should follow research on related cables to gain insights on the water-related aging. Laboratory testing of abandoned cable or cable removed from service that was subject to long-term water exposure may be of benefit in assessing the condition of similar cables exposed to similar environments. Cable failure and aging experience from other plants having nonshielded cables and insights from research on aging and assessment of nonshielded cables should be taken into consideration to determine whether corrective action is necessary.

Long-term wetting of energized medium-voltage cables can cause water-related degradation of the insulation. Earlier vintages (late 1960s through late 1970s) are more susceptible than modern cables, especially if small imperfections existed in the insulation or at its boundaries. Cables that have either been continuously wet or wet for an extended period, whether one long wetting or several shorter but significant length periods, may have experienced degradation and should be evaluated. Electrical testing of the cable will allow assessment to determine whether significant degradation has occurred. An alternative to implementing a test program would be to replace cables based on duration of wetting and expected susceptibility to wetting. A cable shield is required to do off-line testing. Actions for nonshielded cable are covered separately at the end of this section. The testing discussions in this section assume the presence of an insulation shield.

Pumping of Manholes and Ducts

Removing water from around the cable will not reverse degradation that has occurred. However, it may reduce the rate at which further degradation takes place, and some moisture may be expelled from the cable if there is ohmic heating during operation. The rate of deterioration in breakdown strength should slow and a small improvement may occur. Accordingly, instituting a pumping program, installing automatic sump pumps, or repairing failed automatic pumping systems is recommended.

It is recognized that not all systems can be pumped dry. Continued operation of cables under wetted conditions is allowable, but condition of the cable insulation should be proved through periodic assessment.

Rain and drain conditions should not adversely affect jacketed cables as long as wetting does not last for more than a few days on average. Water takes several months to years to migrate into the jacket and then a similar period to migrate into the insulation under wetted conditions and migrates out much more slowly when ducts are dried.

Assessment of Condition of Shielded Cables

Three practical tests[10] are currently available for shielded extruded polymer medium-voltage cable: partial discharge, tan δ,[11] and power frequency or very low frequency (VLF) withstand.[12] Depending on the nature of the cable design and the cable or accessory (termination or splice) concern, one or more of these tests would be recommended and others would be unsuitable. These test methods may be performed at line frequency or VLF (for example, 0.1 Hz). VLF test sets are frequently favored because they are readily portable and compact in comparison to line frequency systems that often must be truck mounted because of their size and weight. It should be noted that these tests assess the insulation of the terminations and splices if they are included in the test circuit. These tests are often performed off-line with elevated voltage. When elevated voltage testing is performed, whether during plant operation or during a refueling outage, it should be done with consideration of the time, materials, and personnel required to repair or replace the cable. This is not meant to be a reason not to test cables, but to ensure that due

[10] Other tests are available but are not commonly performed in the United States: oscillating wave partial discharge assessment, return current assessment, and return voltage assessment.

[11] Dielectric spectroscopy is a related test in which the insulation is subjected to dielectric assessment at multiple frequencies and voltage levels.

[12] The informal term for "withstand" testing is hi-pot. In this document, *withstand testing* is synonymous with high-potential (hi-pot) testing.

consideration is given to the impact of a cable replacement because a cable is found to be severely degraded or fails during a test. Testing during a refueling outage should be performed near the start of the outage to preclude extension of the outage.

Partial discharge tests are used to detect discharges that occur in gas voids within the insulation system. The discharges occur when the electric stress across the void is high enough to cause a breakdown of the gas void. The voltage is then distributed across the remaining intact insulation. Partial discharge can also occur along a surface interface or between a floating conductor and an energized electrode. For example, a partial discharge can occur on the outside of the insulation shield between the shield and a corroded tape or wire. Each discharge causes a small amount of damage to the surface of the insulation in the void causing a carbonized path to develop through the insulation, which can eventually lead to cable failures. Partial discharges result in high-frequency, low-energy signals that can be attenuated. Partial discharges in the insulation at operating voltage create electrical trees, which can propagate through the insulation relatively rapidly (for example, days to months). It should be noted that surface discharges are not as harmful and do not cause rapid damage. Accordingly, understanding the nature of the discharge involved is important and part of the art of interpreting partial discharge results.

Offline partial discharge testing is an elevated voltage test that can be performed at line frequency or VLF. Partial discharge testing can locate the site of the discharge along the length of the cable. Partial discharge testing may be most useful in detecting termination and splice problems, especially on off-site cable feeds and is useful for commissioning tests of new installations. However, water-related degradation, such as water treeing, does not produce partial discharge signals. In addition, in the case of helical tapes, corrosion of the tapes from long-term wetting is likely to severely attenuate partial discharge signals and impede their detection. Accordingly, partial discharge testing is likely to be unsuitable for evaluation of most of the wetted medium-voltage cables in use in nuclear plants.

Tan δ testing (also called dissipation factor testing) determines the ratio of the resistive leakage current through the insulation divided by the capacitive current and provides a figure of merit relating to the condition of the insulation. It is, therefore, also independent of the length of cable. Tan delta has no units[13] and is generally a small number given in terms of 10^{-3}. Tan δ is a bulk test and does not provide specific location information for identified degradation. It can be performed at line frequency or VLF and is generally performed at discrete voltage levels of 0.5, 1.0, 1.5, and 2 times line-to-ground voltage (V_0) (but no greater than the withstand voltage level derived from IEEE Std 400.2 [12][14]). Tan δ values that are elevated or unstable at a particular test voltage level or values that increase or decrease significantly with increase in voltage are indicative of deteriorated insulation. This test can identify insulation systems with distributed water-related degradation. However, if a cable insulation system has only a single but significant

[13] Technically, tan δ is the measurement of an angle in radians but is rarely expressed that way.

[14] IEEE Std 400.2 provides withstand test voltages that are applicable to all of the extruded insulation systems in use in nuclear plants.

flaw, tan δ may not necessarily detect it. In addition, the test does not discriminate between many widespread limited degradations and a smaller number of more severe degradations. VLF withstand testing may be used to identify severe localized conditions as described next.

Dielectric spectroscopy is a related test that performs tan δ measurement at several frequencies and voltages.

VLF withstand testing applies an elevated voltage for a significant period in an attempt to purposely cause a significantly weakened location in the insulation to break down during the test. The test is generally a go/no-go test. The concept is that if the cable does not breakdown during the test, it will perform satisfactorily for a reasonable period. The test would be applicable to the detection of localized, significant degradations, but it would provide no information concerning wide spread, low-level water degradation. VLF test voltage withstand levels and durations are defined in IEEE Std 400.2 [12]. Some testers are evaluating longer duration, lower level tests. Some VLF units measure the real part of the complex current providing the insulation resistance or "megohm" value. (Note: 60 Hz testing is acceptable. In general, practical limitations of portability of the test equipment and limited space within the power plant may preclude its use.)

Effects of Shield Design and Insulation on Long-Term Testability and Test Selection

Wet aging of medium-voltage cables affects two components of the cable: the metallic components of the shield and the insulation. When water migrates through the jacket, it causes a light corrosion of the metallic shield. Although light corrosion does not adversely affect the main functions of the shield, it can adversely affect its testability when attempting to use high-frequency measurement techniques such as time domain reflectometry (TDR) or partial discharge techniques [13]. The following four basic types of metallic shield are in use in nuclear power plant cables:

- Helically wound tapes
- Distributed drain wires
- Longitudinally corrugated copper shield
- Concentric neutral wires

Helically wrapped copper[15] tapes are the most common type of metallic shield. These are used in most XLPE and EPR nuclear plant cables. The helical tape allows reasonable flexibility by comparison to large conductor, concentric neutral wire systems. The next most common shield is used in the UniShield® compact design and uses six drain wires that parallel the conductor. The least commonly used design in nuclear plants is the concentric neutral design, in which large strands of wire or straps are arranged around the entire surface of the semiconducting shield. This design is common in distribution systems and can be found in offsite feeds. The newest shield design is the longitudinally corrugated copper shield, which is made by forming a

[15] A limited number of cables have used zinc tapes instead of copper.

longitudinally corrugated copper sheet around the polymer shield and sealing the overlap. This type of shield provides a continuous barrier to keep moisture from entering the insulation system and should improve the ability to test for partial discharge because the tube presents low impedance to high-frequency signals even if light surface corrosion occurs.

Corrosion of a helical copper tape shield is the most problematic for high-frequency diagnostic techniques such as time domain reflectometry and partial discharge testing. When the copper tape is new, the tape shield acts as a tube providing a good conducting path for high-frequency signals. If partial discharge were present, the new tape shield would present little attenuation. However, with a light corrosion on the surface of the tape, the lapping of the tape becomes insulated from one wrap to the next. At this point, the helical tape acts as an inductor, especially to high-frequency signals such as partial discharge. Accordingly, deteriorated tape shields are likely to occur at the same time as the potential for deteriorated insulation. In cases in which the attenuation resulting from metallic shield corrosion prevents a reflection of the test signal from the far end of the cable, it prevents the detectability of partial discharge signals that may occur in or near the wet section. To a lesser extent, the insulation also attenuates the high-frequency signals with XLPE having the least attenuation, EPR having higher attenuation, and butyl rubber having the highest. If partial discharge testing is to be used on wet cables having tape shields, a pulse should be injected, and using TDR techniques, the sensitivity and high-frequency transmission characteristics of the cable should be determined to verify whether the shield condition is adequate to support partial discharge testing. Light corrosion on the distributed wire, concentric neutral, and longitudinally corrugated copper-type shields should not cause excessive partial discharge test signal attenuation. Although this phenomenon affects the ability of certain diagnostic techniques to assess the condition of the cable, there is no evidence that it is detrimental to normal operation or reliability of the cable.

The choice of test depends on the nature of the problem that is of concern. In most cases, the concern for wetted cable is water-related insulation degradation (for example, water treeing). However, in cases in which splices have been used in the system, partial discharging or tracking within the splices could lead to failure. Most cables in nuclear plants do not have underground splices. However, in cases in which underground splices do exist and attenuation resulting from metallic shield corrosion is not a concern, partial discharge testing may be appropriate and useful.

Water-related degradation of the insulation does not in itself generate electrical discharge signals. Only when the water-related degradation (for example, a water tree) is so severe that the electric field in the surrounding good insulation is excessive (that is, high enough to cause a water tree to convert to an electrical tree) and partial discharge begins does the degradation generate electrical discharge signals. Water-related degradation is a long, slow process; partial discharges that would lead to failure occur and are detectable only late in the degradation cycle. However, as the water-related degradation progresses, the electrical leakage current through the insulation increases and tan δ testing, which measures this loss, should detect the degradation.

Combined Testing

The foregoing description indicates that tan δ measurement is most likely to be useful for detection of water-related degradation for the cable designs commonly used in nuclear plants (for example, lossy insulations with or without helical tape shields). Tan δ could be complemented with VLF withstand testing. Passing a withstand test after a successful tan δ test indicates that there is no significant distributed or local degradation in the insulation system. Tan δ testing would evaluate the cable for water-related degradation, and the VLF withstand test would determine whether severe localized degradation existed. The tan δ test is a global assessment that identifies more widespread deteriorations in the insulation system. Because it provides more of an "average" result over the length of the insulation, it might not be as sensitive to a single local defect. The VLF withstand test, on the other hand, does not provide an indication of the overall aging of the insulation but is designed to force a significant local degradation to failure.

The use of a VLF withstand test following a VLF tan δ test is an engineering decision. For cables having a tan δ result that is "good," a VLF withstand test is optional. However, consideration should be given to performing a VLF withstand test should a "further study required" or "action required" result occur (see next subsection).

One concern regarding the VLF withstand test is that the test may cause an already severe defect to progress toward failure, but that the duration of the test is not sufficient to bring the defect to failure during the test. As a result, failure could occur during the next period of operation. One way of gaining insight about whether the cable insulation is free of significant defects and that "partial completion" of a failure has not occurred is to perform the VLF withstand while measuring tan δ. If the cable passes the withstand test and the tan δ value is stable throughout the withstand period, partial completion of a degradation is unlikely to have occurred. If the cable passes the withstand and the tan δ is increasing or decreasing during the application of voltage, partial completion is likely, and further investigation or extension of the test period is recommended.

An alternative to coupling tan δ testing with VLF withstand would be to couple tan δ testing with partial discharge testing. The tan δ test would assess the cable for distributed water-related degradation, and the partial discharge test would assess for localized, severely degraded conditions. The use of partial discharge testing would be predicated on the cable having acceptable attenuation levels for detection of the high-frequency signals related to partial discharge. Similarly, dielectric spectroscopy could be coupled with partial discharge testing.

Tan δ Methodology and Assessment Criteria

Tables 5-1 through 5-4 provide preliminary criteria for assessing cable insulation degradation through tan δ testing. IEEE Std 400 should be consulted for assessment criteria for XLPE insulation [14]. Tan δ testing is typically performed in steps from 0.5 V_0 (V_0 is the phase-to-ground rms operating voltage), V_0, 1.5 V_0, and 2 V_0. (Note: The IEEE Std 400.2 standards group is expected to reduce the upper test voltage to 1.5 V_0 in the next revision of the standard. [12]) The tan δ value should change very little as voltage is raised and should remain stable during the application of voltage at each step. If the tan δ value is elevated or if there is a significant increase in value as voltage is increased, the cable is considered to be in aged condition and likely in a deteriorated state. Evidence that elevated standard deviations during the hold at each voltage level also indicates degradation in the insulation system is building. A separate description of its use follows this section.

Table 5-1
Preliminary Tan δ Assessment Criteria for Butyl Rubber (in terms of x 10^{-3}; 0.1 Hz test frequency) (Note 1)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 (Notes 2 and 3)
Good	≤12	and	≤3
Further study required	12< tan δ ≤50	or	3+ to 10
Action required	>50	or	>10+

Notes:
1. This is based on Figure C-13 in EPRI report *Plant Support Engineering: Medium-Voltage Cable Aging Management Guide* (1016689) [15] and in-plant test results and consultation with tan δ testers.
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See text preceding this table.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and may indicate a problem with a test or an indication of the presence of a significant defect.

Table 5-2
Preliminary Tan δ Assessment Criteria for Black EPR (in terms of x 10^{-3}; 0.1 Hz test frequency) (Note 1)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 (Notes 2 and 3)
Good	≤12	and	≤3
Further study required	12< tan δ ≤50	or	3+ to 10
Action required	>50	or	>10+

Notes:
1. This is based on Figure C-1 in EPRI Report 1016689 [15] and associated in plant results and consultation with tan δ testers.
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See text preceding these tables.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and may indicate a problem with a test or an indication of the presence of a significant defect.

Table 5-3
Preliminary Tan δ Assessment Criteria for Pink EPR (Note 1) (in terms of x 10^{-3}; 0.1 Hz test frequency) (Note 2)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 (Notes 3 and 4)
Good	≤15	and	≤3
Further study required	15< tan δ ≤30	or	3+ to 8
Action required	>30	or	>8+

Notes:
1. This may also be used for "Gray" UniBlend® EPR (approximate time of manufacture from late 1970s on).
2. This is based on Figures C-3 and C-4 in EPRI Report 1016689 [15] and consultation with tan δ testers.
3. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See text preceding these tables.
4. The difference in tan δ is normally positive. Negative differences should be treated as very significant and may indicate a problem with a test or an indication of the presence of a significant defect.

Table 5-4
Preliminary Tan δ Assessment Criteria for Brown EPR (in terms of x 10^{-3}; 0.1 Hz test frequency) (Note 1)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 (Notes 2 and 3)
Good	≤50	and	≤5
Further study required	50< tan δ ≤60	or	5+ to 15
Action required	>60	or	>15+

Notes:
1. This is based on Figures C-3 and C-4 in EPRI Report 1016689 [15] and consultation with tan δ testers.
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See text preceding these tables.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and may indicate a problem with a test or an indication of the presence of a significant defect.

Starting with 0.5 V_0 allows the tester to determine whether the cable is significantly deteriorated at or before applying more than line-to-ground voltage. If deterioration is observed at the lower test voltages, the test can be terminated to avoid a severely deteriorated cable from failing under the higher test voltages and allow limited continued use of the cable. The assessment criteria for EPR and butyl rubber systems are based on limited field feedback and laboratory test information and consultation with tan δ test engineers. Confirmation or adjustments to these values will occur as further application of the test and correlation of test data to cable condition is developed in the nuclear industry or other data related to the cable designs in nuclear plants becomes available. The XLPE criteria from IEEE Std 400 are based on results from the distribution industry where XLPE is a commonly used insulation [14].

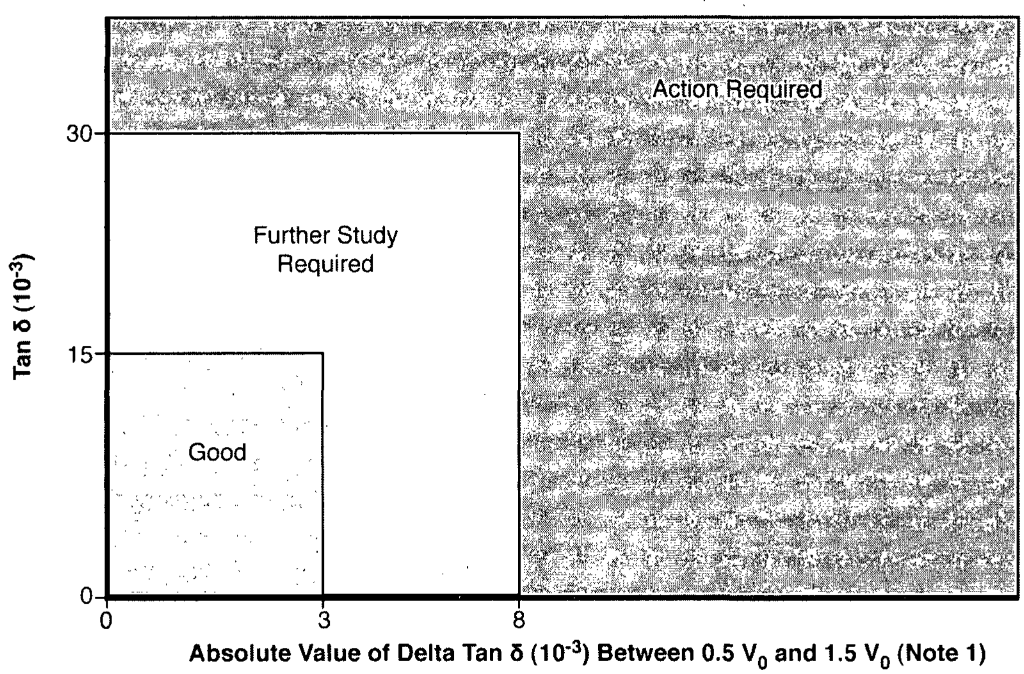
A minimum of eight tan δ measurements should be performed at each voltage step during a tan δ test. Careful attention should be paid to the trend of the tan δ values with time, particularly at applied voltages above the normal phase-to-ground operating voltage. Significant increases and decreases in tan δ with increasing voltage and/or instability during a voltage step are indicative of deterioration in the insulation or accessories. Poor grounding and/or significant corrosion of the ground shield of the cable will also contribute to elevating the tan δ values.

Tables 5-1 through 5-4 give ranges of "good," "further study required," and "action required." However, the absolute value of tan δ is somewhat less important than the stability of the value with increasing voltage. A significant increase or decrease in tan δ value as the voltage is increased during the test indicates that the leakage current through the insulation is changing. An increase in leakage current with increasing voltage indicates that the material is discharging at higher voltages and is not stable. A decrease in tan δ or a tan δ that alternately increases and decreases with increasing test voltage is unusual and indicates either a problem with the test process or a significant problem with the cable that should be evaluated further. Very high tan δ measurements indicate large leakage currents and could be indicative of many water-related degradation sites or a smaller number of highly deteriorated sites.

Anecdotal information indicates that deteriorated cables that had been installed before the mid-1970s tend to have many degradation sites and cables manufactured later will fail less frequently but from a single, large manufacturing flaw (that is, manufacturing and design improvements reduced the likelihood of overall insulation degradation of the insulation from wet conditions, but occasional manufacturing flaws still exist). Accordingly, for very early cables, elevated tan δ may be a strong indication of degradation, but for later cables, the differential value between 0.5 V_0 and 1.5 V_0 is likely to be a better indicator. The criteria provided in Tables 5-1 through 5-4 are preliminary values based on data from research and in-plant testing. The values have been chosen to identify degradation of concern. The criteria for considering "action required" have been chosen to be reasonably conservative. Corrections to these values are expected as plants implement assessment and further data are generated and as IEEE Std 400 and 400.2 are revised [14, 12].

Cables with results in the "further study required" range should be subjected to more frequent testing (for example, once per refueling cycle) to determine whether the condition is stable or worsening. Cables with results indicating "action required" should be replaced as soon as is practicable or additional testing (see VLF hi-pot in "Failure of Cable Under Test" later in this section) performed to verify serviceability. Section 7 addresses options for repair and replacement of cable. Consideration should be given to performing a VLF withstand test should a "further study required" or "action required" result occur. In the case of an "action required" result, a successful VLF withstand test would provide a basis for waiting until a more convenient time for repair or replacement of the circuit.

Figure 5-1 provides a pictorial version of the assessment criteria shown in Table 5-3 for pink EPR to help in understanding how the criteria work. The tan δ values are shown on the vertical axis, and the change in tan δ values between the points of 0.5 V_0 and 1.5 V_0 are shown on the horizontal axis. Staying within the limits of the green box for tan δ and delta tan δ means that the cable is in good condition. If the tan δ exceeds 15 x 10^{-3} but is less than 30 x 10^{-3}, further assessment is needed. At a minimum, the period between tests should be shortened, and the potential cause of the elevated value sought. Similarly, a delta tan δ greater than 3, whether increasing or decreasing, would be a cause for shortened periods between tests and a review to determine the cause. If the tan δ exceeded 30 or the delta tan δ exceeded 8, action should be taken to repair or replace the cable.



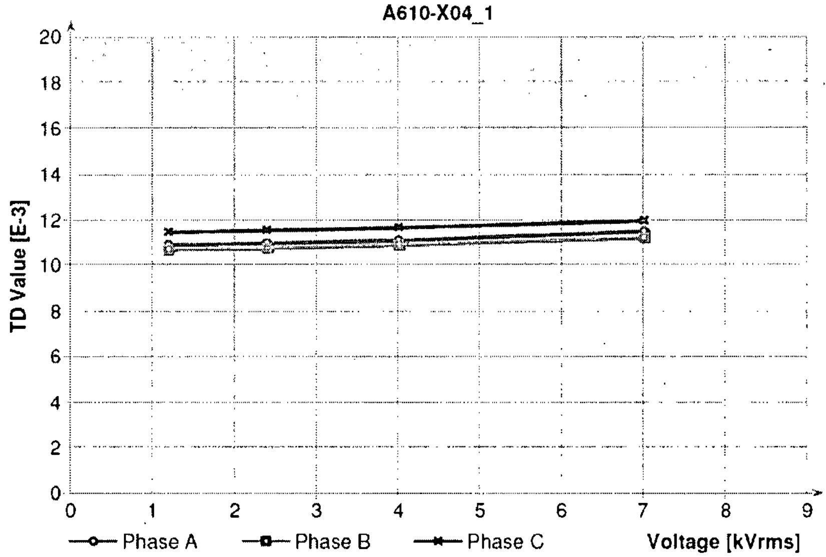
Note 1 The difference in tan δ is normally positive. Negative differences should be treated as very significant and might indicate a problem with a test or the presence of a significant defect.

Figure 5-1
Pictorial Representation of Tan δ Assessment Criteria for Pink Ethylene Propylene Rubber

Figure 5-2 shows a typical tan δ plot for a shielded EPR-insulated three-phase cable. For each of the three phases, the tan δ is stable through the range of test voltage, showing a very small increase with each step in voltage. The standard deviation at each step was very small during the period of voltage application for the step. It should be noted that this test combined VLF tan δ with a VLF withstand test. The last voltage step for this test was at 7 kV, the withstand test value. The duration of the 7 kV step was 30 minutes.

Phase C Summary: 0.1 Hz, 58.1 nF

Voltage [kVrms]	1.2	2.4	4.0	7.0			
TD Value [E-3]	11.5	11.5	11.7	12.0			
Std. Dev. [%]	0.00	0.00	0.00	0.00			



Std. Dev. = Standard Deviation

Figure 5-2
Typical "Good" Tan δ Result for a Shielded Cable with Pink Ethylene Propylene Rubber Insulation

Figure 5-3 shows a tan δ plot for a UniShield 13.8 kV pink EPR cable having degradation on the B phase. The plots for the A and C phases have acceptable tan δ values that are stable through the four steps in applied voltage and had very small standard deviations at each voltage step. The B phase had good measurements at the first two voltage steps but began an upward trend at the third step with a very significant increase at the fourth step. The tip up at higher voltage indicates instability in the insulation that indicates a weakness requiring further study.

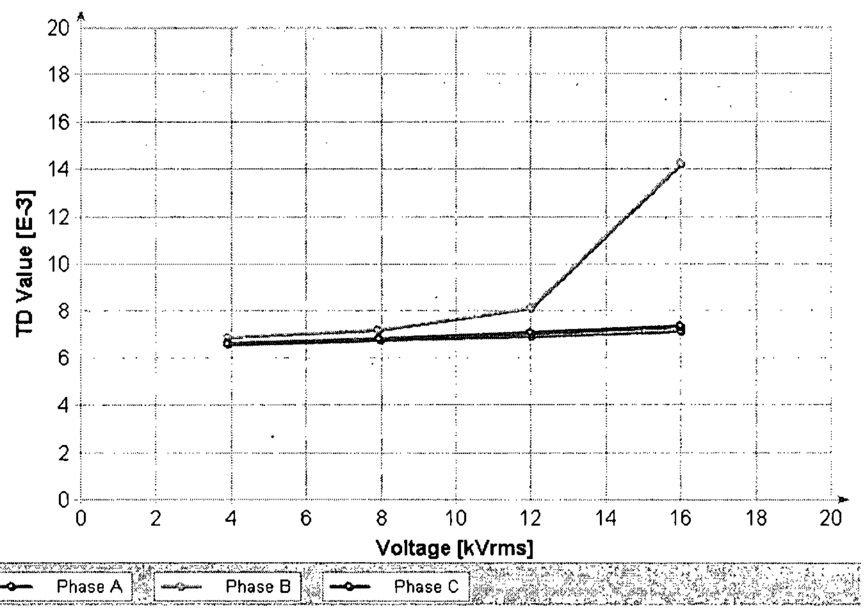


Figure 5-3
Tan δ Plots for a 13.8 kV UniShield Cable with a Degraded B Phase

Use of Standard Deviation in Assessing Tan δ Results

The standard deviation of a set of tan δ measurements at a particular test voltage may provide additional information relating the onset of degradation. The standard deviation of the tan δ measurements identifies whether the value is stable or changing during the voltage step. The standard deviation is an additional indicator of instability in the insulation, especially at lower test voltages, even when the tan δ and delta tan δ values may still be within acceptable limits. Some test sets automatically calculate the percent standard deviation (standard deviation times 100 [for example, for a standard deviation of 1.5×10^{-3}, the percent standard deviation would be 0.15]). Other test sets would require the individual measurement to be placed in an electronic spreadsheet to calculate the standard deviation. The formula for determining the percent standard deviation and an example of the data are contained in Appendix A. The consideration of percent standard deviation appears especially important for tests that may be limited to 1.0 V_0 as may occur when replacement cable is not immediately available. The suggested accepted criteria are shown in Table 5-5. Although the use of percent standard deviation is in its infancy, it appears to provide additional insight into degradation that may not be obvious from review of absolute and delta tan δ results.

Table 5-5
Preliminary Percent Tan δ Standard Deviation Assessment Criteria for Rubber Insulated Cables (Note 1)

Condition	Percent Standard Deviation of Tan δ Measurements at a Particular Test Voltage
Good	≤0.02
Further study required	0.02+<standard deviation [%]<0.04
Action required	>0.04

Notes:
1. Insufficient information exists to provide different criteria for different rubber polymers.

Figure 5-4 provides an example of a case in which a 15 kV cable was subjected to tan δ test. Had the test been stopped at 1 V_0 (8 kV) and only the absolute value of tan δ and delta tan δ been considered, all three phases of the cable would have been deemed acceptable. However, evaluation of the percent standard deviation at 8 kV finds the B phase acceptable, a small shift for the A phase (0.01), and a concern for the C phase (0.02). Evaluation of the test at 1.5 V_0 shows that all figures of merit are indicating that problems exist for the A and C phases, with 2 V_0 showing that the cable is highly degraded. At the higher voltages, the percent standard deviation is extremely high by comparison to the assessment criteria. In this case, the C phase cable failed after 30 seconds at 2 V_0, indicating that percent standard deviation as well as absolute tan δ and delta tan δ were strong indicators of deterioration of the C phase cable insulation. The B phase had acceptable tan δ, delta tan δ, and percent standard deviation values through all test voltages.

Phase A Summary: 0.1 Hz, 331.6 nF

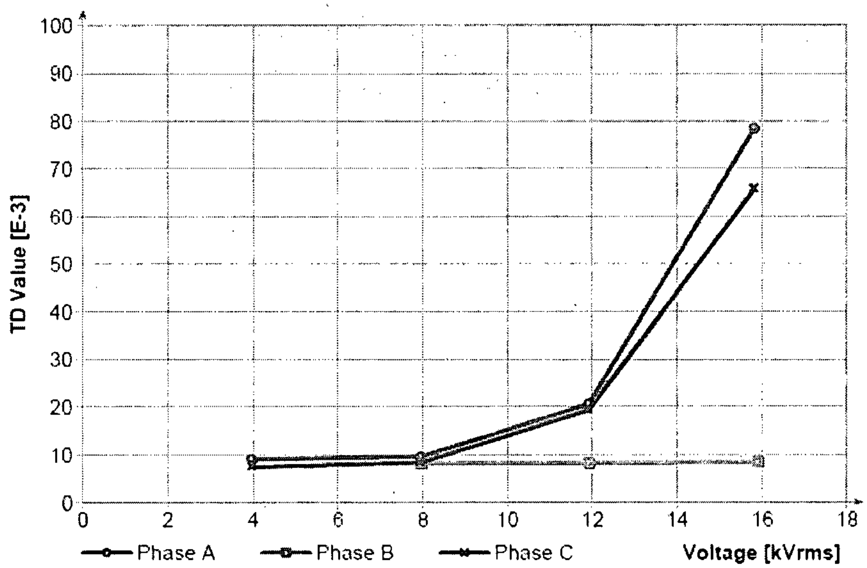
Voltage [kVrms]	4.0	8.0	11.9	15.8			
TD Value [E-3]	9.1	9.8	20.6	78.7			
Std. Dev. [%]	0.00	0.01	0.25	0.98			

Phase B Summary: 0.1 Hz, 330.1 nF

Voltage [kVrms]	7.9	11.9	15.9				
TD Value [E-3]	8.2	8.3	8.5				
Std. Dev. [%]	0.00	0.00	0.00				

Phase C Summary: 0.1 Hz, 330.5 nF

Voltage [kVrms]	4.0	7.9	11.9	15.8			
TD Value [E-3]	7.5	8.5	19.4	65.9			
Std. Dev. [%]	0.00	0.02	0.23	0.45			



Std. Dev. = Standard Deviation

Figure 5-4
Tan δ Example Including Percent Standard Deviation Data

Very Low Frequency Withstand Testing in Conjunction with Tan δ Testing

VLF withstand testing may be performed in conjunction with tan δ testing as described previously. If single severe local degradations are present, the VLF withstand test is designed to cause them to fail at the time of the test.

If a cable has indications that it is degraded based on tan δ results, a VLF withstand test could be used to determine whether the cable has localized highly degraded segments (that is, fails the withstand test) or lesser, more distributed degradation based on it passing the withstand test. If the cable passed the test, there is a reasonable likelihood of functioning until a more convenient time for repair or replacement of the cable.

The methodology for VLF withstand testing, including discussions of test voltages and durations, are contained in IEEE Std 400.2 [12]. The assessment criterion is simple. If the cable does not fail during the test, it is judged adequate for continued use. An improvement to a standard VLF withstand testing is to monitor tan δ for stability during the withstand test. A successful withstand test with tan δ stability indicates that there were no significant defects and that none were in the process of breaking down. Tan δ instability during the withstand test likely indicates that a significant degradation site exists and is in the process of going to failure.

Test Methodology and Assessment Criteria for Other Tests

Descriptions of off-line dielectric spectroscopy and partial discharge testing are beyond the scope of this report. When such tests are used to assess the condition of cable, the testers and interpreters of the test data must have the requisite skills and related experience to apply the test and to perform the interpretation of the results. Experience with the specific cable type (insulation and design) is recommended. EPRI report *Plant Support Engineering: Medium-Voltage Cable Aging Management Guide* (1016689) provides additional information on these testing techniques [15].

Test Preparation and Concerns

To allow testing of cable circuits with either off-line partial discharge testing, tan δ, or withstand testing, the connected load (for example, a transformer, motor drive, or motor) must be disconnected and the terminations isolated. All surge and lightning arrestors and voltage transducers must also be disconnected from the circuit under test. In some cases, testing may be performed through the backplane of the associated breaker cubicle; but before this is attempted, it is recommended that initial testing be performed with a cable connected to and then isolated from the cubicle to determine the effect of the cubicle backplane. If there is a significant influence from the breaker backplane, the cables should be disconnected from the breaker backplane. Testing of XLPE cables is likely to require separation of the cable from the breaker backplane to reduce inaccuracies.

Testing must be performed with a prepared termination at each end of the cable to control voltage stresses. For 4.16–6.9 kV applications, removal of the metal shield and insulation semiconducting layer in preparation for installation of a termination will suffice to allow testing to 2 V_0. However, the length of insulation after removal of the semiconducting layer will be too short when a splice is being prepared, and stress control will be necessary. Testing of 12 kV and higher circuits will require stress control to prevent flashover. Under no circumstance should testing be performed with the insulation shield in place to the end of the insulation at either end of the circuit; doing so will cause a flashover. Suitable stress cones must be used at each termination. The cable's metallic shield must remain grounded during testing. In addition, before testing, terminations should be inspected for cleanliness and general condition. Cleaning and/or repair may be necessary before cable testing occurs. In addition, the terminations must be located well away from the terminations of adjacent phases and the termination cabinet/box to reduce corona effects during the test. In confined spaces, use of insulating sheets (for example, Mylar) may help to ensure adequate separation between phases and from phase to ground.

In tan δ testing, cables of different types (for example, XLPE, butyl rubber, and EPR) ideally should be tested separately if spliced together. Otherwise, the material having higher losses will mask problems in the less lossy material. For example, severe deterioration in XLPE would likely be masked by the natural lossiness of EPR or butyl rubber, and butyl rubber could mask problems in EPR. In addition, if splices are used in circuits having the same cable materials, nonlinearity of the insulation resistance of some splice types may cause abnormal tan δ results that are not indicative of the condition of the cable insulation (see EPRI report *Plant Support Engineering: Medium-Voltage Cable Aging Management Guide* [1016689] Appendix C) [15].

When testing cables with multiple conductors per phase, tan δ testing of the individual conductors in each phase will provide the best results. It is understood that separating the conductors can be difficult and time consuming. If the insulations of each of the conductors deteriorated simultaneously, the tan δ measurement of the joined conductors would obviously indicate insulation condition. However, if only one conductor of a multiconductor-per-phase circuit were deteriorated, testing of the joined set could mask the deterioration. Accordingly, if joined-set testing is being performed, careful scrutiny of the results is recommended to determine whether further testing of the separate cables is warranted.

Regarding testing of motor and transformer circuits, if tests are to be performed periodically, separable connectors and disconnects should be considered so that the motor connections can be easily broken and remade. Use of separable disconnects will be advantageous to the testing of the motor or transformer and the cable. (Note: As of this writing, separable connectors having a manufacturer's environmental qualification do not exist.) Motor testing frequently entails use of high-voltage dc, which is not recommended for cables because it has been linked to damage of the cables' extruded polymer insulation. Separation of the motor from the cables is recommended when dc or surge testing is performed on the motor. Testing of cables with off-line ac tests would provide no useful information about the cable if the motor remained connected to the cable.

Failure of Cable Under Test

Concern exists that a "good" cable may fail under a test using elevated voltage. The tests recommended herein have elevated rms test voltages of 1.5 to 2 times line-to-ground voltage in accordance with IEEE Std 400.2 [12]. These ac tests are performed with either line frequency (for example, 60 Hz) or VLF (for example, 0.1 Hz).

The insulation of a new cable can withstand 30 times line-to-ground voltage or more before breaking down. Cable insulation that cannot withstand twice line-to-ground voltage for the duration of an off-line test is highly degraded and is not in a condition considered satisfactory for continued service. When performing tan δ or partial discharge testing, test operators can generally identify when cables have inadequate insulation properties and stop testing before failure. Occasionally, a failure will occur during test. In these cases, the cable failed because it was degraded, not because the test caused rapid deterioration.

Ac withstand tests may be used to cause weakened cable to purposely fail by applying elevated voltage for an extended period. The cable users industry continues to refine withstand testing methodology to ensure that significant degradations are brought to failure during test and that no lesser degradation is aggravated so that failure occurs shortly after return to service.

Dc withstand testing is not recommended. Although it was effective for evaluating paper-insulated lead-covered cables, it has been found on some cable designs to worsen end-of-life degradation of polymer insulations but not necessarily cause cable failure at the time of test. The cables fail in dc withstand testing only if very severely aged. Under conditions in which the cable is slightly less aged, the application of a dc test can cause an existing flaw to convert to electrical discharge so that the cable fails a short period after the return to service [16]. Because passing a dc withstand test may cause a false sense of security and because the dc testing may shorten the remaining limited life, dc withstand testing is not recommended for the purposes of ensuring continued functionality of polymer insulated cable.

Assessment of Nonshielded Cables

Nonshield cables, those cables without an insulation shield, represent a significant problem regarding off-line electrical testing. To allow an electrical test of the insulation, a uniform ground plane is needed, but such a ground plane does not exist in a nonshielded cable. Testing of nonshielded cable from phase to ground may only provide rough data at the random grounding points along the surface of the cable. Testing phase to phase may only provide information concerning the points where the phases touch one another. (Better results could be expected from a test of a triplexed cable than from three separate cables pulled together.) This limitation could cause variable results if water levels vary and make trending and assessment of results difficult. One way to effect a ground plane would be to full flood the ducts and verify that the water was grounded. Surrounding the cable with water is used in laboratory assessments, but it has not been attempted in a power plant.

Given that off-line electrical testing of nonshielded cables is not practical, other alternatives must be selected, which are the following:

- Full forensic analysis of cables if failure occurs
- Applying lessons learned from operating experience from related cables under similar conditions
- Applying lessons learned from forensic analysis of shielded cables with the same insulations from other plants
- Removal and testing of abandoned nonshielded cable
- Removal and testing of cable removed from service

The nonshielded cables in use in the nuclear industry almost always have EPR insulation and are limited to those rated 5 kV. The insulations are the same types as were used in shielded cables. The differences from the shielded cable are the absence of the insulation shield and a somewhat thicker insulation on the nonshielded cables.

A review of installed nonshielded cable data from the NEI 2005 industry survey [17] indicates that 31 of the responding units had some nonshielded medium-voltage circuits. The dominant manufacturers were Kerite and Okonite, with one plant reporting General Cable and another reporting Anaconda. Kerite has used brown EPR throughout the period, while Okonite used black EPR through the mid-1970s and then switched to pink EPR thereafter. Review of the failures of nuclear plant cables revealed only three failures. Only one failure report directly stated that wetting of the cable was involved and also indicated that thermal overload contributed to the degradation.

Although these data do not eliminate wet aging as a concern, they indicate that the lack of a shield on these cables does not lead to more frequent failure than for those cables having a shield.

Removal of abandoned cables that have experienced long service under wet conditions is a valuable input to the understanding the degree of electrically induced wet aging that can occur. Currently, two sets of Kerite cables that experienced 30 years of service before being abandoned are being evaluated by EPRI. Laboratory testing of these cables will give insights regarding wet degradation of nonshielded cables. The laboratory analysis may also give insights on whether in-service electrical testing is practicable (that is, using water as a ground shield).

For plants having nonshielded cables, the recommended path is as follows:

1. Require full forensics testing of any failure of nonshielded medium-voltage cable with appropriate action taken for other nonshielded cables in similar operating conditions (for example, if failures are wet aging related, replace similar circuits).
2. Maintain awareness of results of research performed on abandoned cables or those removed from service.
3. Maintain awareness of results of failure assessment and mechanism research for related shielded medium-voltage cable. For example, findings on the same manufacturer's material (for example, black, brown, or pink EPR) from a shielded cable may give insights on expected aging of a nonshielded cable.
4. Carefully assess operating experience for nonshielded cables of the same type and material for applicability and any indication of additional concern.
5. When industry insights indicate that nonshielded wetted cable may be entering an end-of-life state, either remove a "worst case" cable from service and perform laboratory testing or schedule replacement of wetted circuits.

6 ACTIONS FOR CABLES HAVING DRY ADVERSE ENVIRONMENTS

> ***Program Element 6***
>
> When the review of medium-voltage cables circuits within the scope of the program determines that cables are subject to dry adverse localized environments, actions should be taken to determine the effect on condition of the cables.
>
> Where hot process equipment is sufficiently close so that medium-voltage cable could be affected by thermal damage, visual assessment of the condition of the cable should be performed, and appropriate actions taken based on the identified condition. Physical and chemical tests of the insulation system can be performed to further define condition and the need to repair or replace the cable circuit. As applicable, the source of the thermal damage should be mitigated or rerouting of the cable should be considered.
>
> For circuits in which elevated conductor temperature from operating currents is determined to be a concern, visual assessment of the condition of the cable should be performed and documented, and appropriate actions taken based on the identified condition. Physical and chemical tests of the jacket and/or insulation system can be performed to further define condition and the need to repair or replace the cable circuit.
>
> When inspection or infrared thermography indicates that connections are overheating, the degree of damage should be assessed and the connection repaired or replaced as appropriate.

The effects of adverse dry environment conditions will be different from those caused by cables being energized in wet or submerged conditions because the failure mechanisms are not the same. Accordingly, different assessment methods apply. This section addresses those assessments that can be applied to cables in dry adverse environments.

High-Temperature or High-Dose-Rate Ambient Environments

Different dry environment aging effects can occur, depending on the insulation type and jacket type in use. Table 6-1 describes the degradation mechanisms that are expected for common types of medium-voltage cable jackets.

Table 6-1
Thermal and Radiation Degradation Mechanisms Expected for Medium-Voltage Cable Jacket Materials

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation	Effect of Degradation
Neoprene	Hardening with spontaneous cracking and discoloration (turning greenish brown)	Hardening	Visual inspection can identify discoloration or cracking. Hardening can be manually or indenter evaluated with cable de-energized.	Cracking exposes shield and insulation to airborne moisture. Released chlorine will corrode the shield and cause limited effects on insulation. Loss of jacket will adversely affect flame propagation.
Hypalon (chlorosulfonated polyethylene [CSPE])	Hardening and discoloration (turning greenish brown)	Hardening	Visual inspection can identify discoloration. Hardening can be manually or indenter evaluated with cable de-energized.	Until extreme hardening occurs, Hypalon will remain intact. However, if a through fault occurs, the cable may crack because of motion from high magnetic fields.
Polyvinyl chloride (PVC)	Hardening, possible spontaneous cracking	Production of hydrogen chloride (HCl)	With cable de-energized, hardening can be observed manually or through indenter. HCl production may be indicated by white powdering or corrosion of surrounding metal.	Cracking exposes shield and insulation to airborne moisture. Released chlorine will corrode the shield, causing limited effects on insulation.
Chlorinated polyethylene (CPE)	Hardening, cracking (thermoplastic only)	Hardening	With cable de-energized, hardening can be observed manually or through indenter.	Extreme hardening may cause failure. Cracking of thermoplastic versions would be expected with significant thermal aging.

In the case of thermal damage from the environment rather than from ohmic heating, the jacket will deteriorate before the insulation system. If the damage is from the environment, the deterioration of PVC and neoprene is likely to be of most concern because these jackets tend to crack spontaneously on severe aging. Figure 6-1 shows cracking of a neoprene jacket from an elevated thermal environment. One concern for both neoprene and PVC when highly thermally aged is that they will generate chlorine, which will affect the shield and surrounding metal materials, such as trays, conduits, and possibly piping. Under dry conditions, environmentally induced deterioration of PVC or neoprene might not cause an immediate concern for the aging of the insulation because the insulation will tend to age more slowly. Hypalon will age more slowly than neoprene and early PVCs and have a much lower tendency to crack spontaneously. Early thermoplastic chlorinated polyethylene (CPE) can crack when it ages and if highly stressed (for example, at bends). Modern thermoset CPE will not tend to crack with aging. If Hypalon and modern thermoset CPE are found to be aged, there is a higher likelihood of thermal damage to the insulation; but again, the insulation should age more slowly than the jacket from environmentally induced aging.

Note: Corrosion of tray and shield are likely from chlorine released by the aging of the neoprene. Jacket has turned brown from original black and is very hard. Brown color of the jacket is a strong indication of exposure to elevated temperature.

Figure 6-1
Spontaneous Cracking of Neoprene Jacket

Depending on the application and severity of the cable jacket cracking, different actions may be warranted. Jackets are important to keep moisture out of cables and to prevent fire propagation. If medium-voltage cables require environmental qualification for steam accident, cracking in a location with a potential steam environment would be unacceptable without further assessment. All cables are required to limit flame propagation; therefore, if cracking is severe enough that the jacket is in danger of or has fallen off, the flame retardancy provided by the jacket has been lost and corrective action is needed. For shielded cable, loss of jacket integrity could allow additional grounding points on the shield. Only a few plants have safety-related medium-voltage cables within containment. Accordingly, very few plants take credit for medium-voltage cable jackets acting as beta shields. Severe cracking of jackets on medium-voltage cable within containment could add to sump loadings in the event of an accident.

Severe jacket aging indicates that insulation damage may have occurred as well and that electrical assessment of the cable, as indicated for insulation damage in Table 6-2, should be implemented.

A tan δ or partial discharge test, as appropriate to the concern, will indicate whether the thermal damage has been severe enough to adversely affect the insulation properties. These tests can be performed only on shielded cables.

Line resonance analysis (LIRA) can be used on shielded and nonshielded triplexed cable to detect the effects of localized thermal damage. For shielded cables, it assesses only the insulation system. For triplexed cable, the jackets are included in the assessed material. If LIRA does not produce a signal at the site of the adverse localized thermal environment, the damage is not significant. If LIRA does produce a signal, the strength of the signal is proportional to the severity of the damage and a relative effect could be determined. LIRA is not useful on nonshielded cables that are pulled individually rather than triplexed. LIRA requires a uniform geometry along the length of cable under assessment. It should also be recognized that if the elevated temperature condition exists at the time of testing, LIRA is likely to identify the effects of the elevated temperature and not necessarily identify thermal damage. (Thermal expansion of the cable in the heat affected zone can cause a LIRA signal.) Accordingly, LIRA testing should be performed when the localized heat source is not producing heat.

Table 6-2
Thermal and Radiation Degradation Mechanisms Expected for Medium-Voltage Cable Insulation Materials

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation	Effect of Degradation
XLPE	Hardening	Hardening	Electrical tests required to determine whether leakage current is increasing because of damage. LIRA testing would identify whether thermal damage has occurred. Consider tan δ measurement to determine whether insulating capability has been adversely affected (see note 1).	Ultimately, insulation could crack (after a very long time). Life still could be long provided the condition is corrected before severe degradation occurs.
Butyl rubber	Hardening or softening	Softening	Electrical tests required to determine whether leakage current is increasing because of damage. LIRA testing would identify whether thermal damage or compression of softened insulation has occurred. Consider tan δ measurement. If softening has occurred, partial discharge may occur if components drift with respect to original position.	Softening failures have occurred on sulfur-cured butyl rubber insulation from advanced thermal aging. The shield drifted through the softened insulation toward conductor, leading to failure.
EPR	Hardening	Hardening	Electrical tests required to determine whether leakage current is increasing because of damage. LIRA testing would identify whether thermal damage had occurred. Consider tan δ measurement to determine whether insulating capability has been adversely affected (see note 1).	Extreme thermal aging has caused failure (embrittlement or thermal runaway).

Note:
1: Early polymeric shields may be more age sensitive than modern extruded shields. If they crack, partial discharge would be expected and partial discharge testing may be a useful test method.

Table 6-2 describes the degradation mechanisms that are expected for common types of medium-voltage cable insulations. The various insulation types behave differently from one another. Butyl rubbers that have been cured using sulfur will soften, rather than harden, to the point where the shield can drift toward the conductor,[16] causing very high electrical stress and subsequent insulation failure. EPRs and XLPEs harden under elevated temperature and dose conditions. The likelihood is that any of these conditions will eventually cause leakage current to increase. Accordingly, tan δ measurement should be a useful assessment method for thermally damaged cable. However, a very localized effect may be difficult to detect with tan δ. Damage affecting a significant portion of the cable run will be more easily identified. An exception to the use of tan δ as the preferred diagnostic tool is that if the components shift when sulfur cured butyl rubber softens with severe thermal aging, discharging in any gaps that may occur would allow partial discharge testing to be a method of assessment as well. High-intensity partial discharging, even if of low amplitude, will add to the dielectric loss of the insulation and will be detected, but not located, by a tan δ measurement.

For cables produced from the late 1970s forward, the thermal aging rate of polymer shields should be approximately the same as the insulation. However, early polymer shields from the early 1970s may age more rapidly than the insulation. Cables with early polymer shield designs may be more age sensitive than the later vintage cables when exposed to elevated temperature. If cracking occurred within the insulation or conductor extruded shield, partial discharge would be expected.

High Conductor Temperature from Ohmic Heating

Depending on the severity of the ohmic heating, the insulation may be damaged and the jacket may or may not be damaged. Should the jacket be found to be discolored and/or cracked and the environmental conditions are not severe enough to have caused the damage, ohmic heating is likely the cause and the insulation is likely to have suffered significant thermal damage because of the temperature being significantly higher at the conductor than at the exterior surface.

As described previously for ambient-induced damage, tan δ testing is likely to detect the effects of severe thermal degradation, whether caused by unbalanced magnetic circuits in multiconductor-per-phase circuits or by high, continuous currents. Significant softening of butyl rubber may cause gaps to open and allow the use of partial discharge testing as well.

High-Resistance Connections at Terminations or Splices

There are two considerations for thermal heating of connections, terminations, and splices. The first consideration is a difference in temperature between two connections with identical loadings. Guidance exists in various EPRI infrared thermography reports [18, 19, 20], such as that provided in Table 6-3. Any temperature difference above reference (the difference between two similar targets under similar loading) is a concern. Small temperature differences can be risk

[16] Note: To date, drifting of the shield towards the conductor has only been noted for failure from high ohmic heating situations rather than from environmentally induced conditions.

managed to allow time to make preparations for repairs, but anomalies caused by high-resistance connections do not necessarily increase linearly, therefore, uncertainty always exists in predicting time to failure. Increased monitoring should be performed to the extent that a rate of degradation can be estimated until the condition is repaired. Table 6-3 provides suggested severity ranges for evaluating indoor electrical power connections.

Table 6-3
EPRI-Suggested Severity Ranges for Indoor Electrical Power Connections [18]

Status	Range
Advisory	1°F to 15°F (0.5°C to 8°C) rise above reference
Intermediate	16°F to 50°F (9°C to 28°C) rise above reference
Serious	51°F to 100°F (29°C to 56°C) rise above reference
Critical	>100°F (56°C) rise above reference

The second consideration for high-resistance connections is the absolute thermal limitations of the materials involved. If the components of a cable, termination, or splice exceed the limits at which their physical and/or electrical properties are compromised and the immediate or long-term ability to function are compromised, the condition should be evaluated and corrected accordingly.

As described previously, routine thermographic inspections should be performed on all accessible connections, terminations, and splices based on the application and during postmaintenance testing if they have been disturbed.

7 ACTIONS FOR FAILED OR DETERIORATED CABLE

Program Element 7

The medium-voltage cable system aging management program should require that appropriate corrective action be taken if significant aging that results from adverse localized environments is identified or suspected. Those actions may include assessment, testing, repair, or replacement as appropriate. If the investigation of a failure or deterioration indicates a generic degradation mechanism, circuits with similar conditions should be reviewed to determine whether they, too, require corrective action.

Operability Concerns

Depending on the severity of the degradation identified, an operability concern may or may not exist. Severe physical degradation, such as cracked insulation, damaged conductors, extreme hardening or softening of insulation, or a "highly degraded" result from electrical testing indicates an operability concern. However, lesser indications of degradation would constitute a need for further vigilance but not an immediate operability concern. Examples of these types of degradation include a limited stiffening of insulation and jacket or an electrical test result indicating "further study required" insulation. The following subsections provide insights about verifying the condition and determining the course of further actions. In-service failure of a cable requires an extent of condition assessment for cables subject to like service conditions.

Corrective Actions

The corrective actions to be taken in response to cable degradation depend on the nature of degradation and whether the degradation is localized or distributed over a significant length of the cable. Actions may be permanent or temporary, based on the nature of the application and licensing basis. Some possible considerations and resolutions, which are not all inclusive, are described next. Plant-specific and application-specific conditions can dictate different resolution paths.

Cable Test Indicates "Further Study Required" Insulation System

As described in Section 5, the results of tan δ tests can indicate that a cable insulation system has aged but is not yet in a highly deteriorated state. An aged condition indicates a need for heightened awareness.

Eliminate Obvious Problems

Inspect the terminations for accumulated dirt, moisture, and tracking or other surface problems. Clean and repair as needed. In addition, verify that the terminations of the cable under test were well isolated from adjacent phase terminations and the cabinet/ termination box to eliminate corona at the termination as a cause of the adverse results. If termination issues appear to be the cause of the questionable results, retest and determine whether the "further study required" indication still persists.

Perform Very Low Frequency Withstand Test

If a VLF withstand test was not part of testing process, perform a VLF withstand test to confirm that a single, severe degradation site is not the cause of the "aged" indication.

Increase Frequency of Testing

Decrease the period between tests to one refueling cycle. Compare test results to determine whether the condition is stable or worsening. If it is worsening significantly (for example, approaching the "action required" state), schedule for replacement at a convenient time.

Prepare Contingency Plan

Although a "further study required" cable is likely to function for a significant period, a contingency plan should be prepared in case of failure. The plan should cover the availability of replacement cables and accessories, pulling procedures, pulling tools, and the required qualifications of craft.

Perform Polymer Injection

Silicone polymer injection has been shown to improve the breakdown strength of cable insulation for an extended period [21]. If injection is to be used, it is best to perform it when the cable is in the "further study required" but not in the "action required" state. At the point at which tests indicate "action required," electrical degradation may be severe enough that injection will not be able to overcome the degradation. In the case of butyl rubber that may soften with age depending on manufacturing cure issues, polymer injection will not correct the softening issue and would not be recommended.

Begin Replacement Program for Multiple Cables with "Further Study Required" Insulation

If multiple cables within a plant's population of cables have indications of "further study required" insulation, the need to begin an orderly replacement program should be considered.

Cable Test Indicates "Action Required" Insulation System

Eliminate Obvious Problems

Inspect the terminations for accumulated dirt, moisture, and tracking or other surface problems. Clean and repair as needed. Also, verify that the terminations of the cable circuit under test were well isolated from adjacent phase terminations and the cabinet/termination box to eliminate corona at the termination as a cause of the adverse results. If the termination issues appear to be cause of the questionable results, retest and determine whether the "action required" indication persists.

Perform Very Low Frequency High-Potential Tests

If a VLF hi-pot was not part of testing process, perform a VLF hi-pot to determine whether the cable's condition is sufficiently stable to establish an interim period of operation to allow orderly staging for replacement. Note: The purpose of a VLF hi-pot is to fail a highly weakened cable. If immediate replacement is being performed, there is no need to perform a VLF hi-pot.

Identify and Replace Degraded Section

The degraded section of cable is likely to be the section with the adverse localized environment (for example, wetted section). Accordingly, the section with the adverse localized environment may be cut from the section with the benign environment, and retesting of the segments performed to identify the deteriorated section. The appropriate section(s) would be replaced and spliced to the good section(s). If the deteriorated section is dry and the metallic shield is not corroded, partial discharge testing may be appropriate to identify the location of the degradation. Note that shielded splice designs should be qualified in accordance with IEEE Std 404 [22]. (This standard does not apply to nonshielded designs.). When splicing dissimilar cable types, the use of separable connectors should be considered to allow isolating of dissimilar cables for ease of future testing. In no case should a splice be pulled into an inaccessible location (that is, duct or conduit). Utility-specific limitations on location of splices should be observed.

Conduct Forensic Testing of "Action Required" Cable

Forensic testing of the "action required" cable segment is recommended to gain insight into the nature of the degradation and whether it is related to the adverse environment or another cause. The forensic information will provide insights into the overall effects of adverse environment aging on the cable system and the potential extent of condition.

Use Impervious Cable for Wetted Environments

If the cable degradation is related to a wetted environment, and long-term wetting cannot be eliminated, consideration should be given to using an impervious cable design for the replacement cable. Impervious cable designs incorporate a lead sheath or a longitudinally corrugated copper sheath that provides a barrier against water ingress.

Cables Experiencing Localized Thermal Damage

Two concerns exist for localized thermal damage. The first is that the temperature of the insulation is so high as to cause the insulation system to fail because of thermal avalanche. In such a case, the local volumetric insulation resistance would decrease causing higher leakage current further elevating the insulation temperature. Eventually, the leakage current and insulation temperature are so high that the insulation breaks down through thermal avalanche. This is not an aging phenomenon but a direct effect of excessive temperature. The aging concern is that the temperature is not high enough to cause thermal avalanche but is high enough to cause hardening of jackets and insulations (softening of sulfur-cured butyl rubber) over time. Eventually, cracking of the insulation could occur from manipulation or from motion induced by fault current surge. For sulfur-cured butyl rubber, long-term thermal aging could cause softening that could allow compression of the insulation leading to high electrical stress and failure. Thermal degradation of environmentally qualified cables located in harsh environment areas can cause the cable to have a shortened qualified life.

Evaluate the Degree of Damage

Environmentally induced degradation is generally caused by an adjacent heat source that was not properly controlled (for example, adjacent process pipe with inadequate or missing thermal insulation). The first assessment should be of the jacket to see if complete hardening has occurred or if some elasticity remains. If some elasticity remains, the likelihood of damage to the insulation is low, and the thermal insulation on the hot process component should be improved. Periodic inspection of the cable is recommended to verify that further deterioration is not worsening significantly.

Evaluation of the severity of the jacket degradation may be performed through indenter modulus assessment [23]. The use of indenter testing allows quantification and trending of the hardening of the jacket to provide insights as to the relative hardness and the degree of continued aging.

The ultimate effect of the thermal degradation on insulation can be evaluated with tan δ testing. Partial discharge testing may be appropriate for butyl rubber insulated cables in which softening and compression of the insulation are potential problems, although signal attenuation caused by corroded metallic shields could be a problem.

Line resonance assessment (LIRA) can be used for cables located in dry environments to determine whether an adverse localized thermal environment has affected the insulation [24]. If the effect was limited to the jacket on shielded cable, LIRA should identify no significant signal. If the insulation was affected, LIRA would give a relative indication of the severity of the effect. LIRA can be used on triplexed cable, but the jacket system would be within the boundary of the test and the effects of aging on the insulation and jacket would not be separable. LIRA is a test method under development. Although results to date show the ability to identify thermally damaged segments, research that indicates that LIRA can identify water-related damage or electrical trees has not been completed.

Correct the Adverse Localized Thermal Environment

When an adverse localized thermal environment is identified, the thermal insulation on the source of the heat and radiant energy should be repaired, replaced, or upgraded. If radiant energy is the source of the aging, shielding should be installed to reduce the effect to the point practical. If this activity does not sufficiently reduce the effects on the cable, consideration should be given to rerouting the cable. If the cable must remain where it is, periodic assessment of the condition of the cable should be implemented to verify that the rate and severity of the cable degradation is known so that corrective action can be taken at the appropriate time.

Replace Thermally Damaged Cable

If severe thermal aging of the insulation is identified or suspected and cannot be eliminated by evaluation, removal and replacement of the affected cable section is recommended. If the qualified life of a cable is shortened because of the adverse localized thermal environment, it must be replaced before the end of its qualified life. Replacement of a section by using appropriate splices or replacement of the entire circuit is permissible.

High-Resistance Connections

When inspection or infrared assessment of cable connections indicates significant heating of a connection (for example, for infrared thermography: upper "intermediate" through "critical" status in Table 6-3), the effected connection should be repaired or replaced. If replacement cannot be performed immediately, increased monitoring should be performed until replacement occurs. Early replacement is recommended to preclude significant damage to the cable insulation at the connection point. If the cable insulation has been damaged, replacement of the cable or the affected section will be necessary as well.

Cables Damaged by High Current

Damage to cable from ohmic heating resulting from high currents is likely to affect the entire length of the cable with the worst effect in sections having elevated ambient temperature. The entire circuit generally will require replacement. Rectification of the cause of the high current is necessary whether it is from lack of transpositions in multiconductor-per-phase circuits or undersized conductors.

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Additional Resources

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2. IEEE Std 400.3-2006, *IEEE Guide for Partial Discharge Testing of Shielded Power Cable Systems in a Field Environment,* Institute of Electrical and Electronics Engineers, Inc., New York, NY.

A
ASSESSMENT OF PERCENT STANDARD DEVIATION OF TAN δ MEASUREMENTS

Section 5 describes the use of percent standard deviation as a means of evaluating tan δ results. The following is a description of the mathematical determination of the percent standard deviation and an example of its calculation, including the equation used in the determination. This equation may be used in electronic spreadsheets such as Microsoft Excel.

$$\%STDEV = 100 * \sqrt{\frac{\sum (x - \bar{x})^2}{(n-1)}}$$

Where:

$\%STDEV$	is percent standard deviation.
X	is each individual tan δ measurement.
$\bar{x}$	is the mean (arithmetical average) of the tan δ measurements.
n	is the number of measurements.

A minimum of six measurements is recommended.

The percent standard deviation of the tan δ measurements provides a way to assess small but significant changes in tan δ at a particular voltage level. The following is an example from the C phase 8 kV (1 V_0) result from Figure 5-4. The following 14 measurements were taken over the course of 2 minutes:

8.2, 8.3, 8.3, 8.4, 8.4, 8.5, 8.5, 8.6, 8.6, 8.7, 8.7, 8.7, 8.7, and 8.8

A casual inspection might indicate no specific problem; however, under constant voltage, the tan δ measurements are increasing rather that staying stable. The mean of these results is 8.5. The rounded percent standard deviation is 0.02, placing the cable in a "further study required" state at 1 V_0 test level. Evaluating the percent standard deviation provided a clearer indication of a problem.

For the 1.5 V_0 test level (11.9 kV), the following 15 measurements were also taken:

15.0, 16.0, 16.8, 17.6, 18.2, 18.8, 19.3, 19.8, 20.2, 20.6, 21.0, 21.4, 21.7, 22.0, and 22.3

Scanning these data more easily indicates an ever-increasing tan δ measurement. The mean of these results is 22.3. The percent standard deviation is 0.23, which is nearly six times the "action required" level and is a strong indication of a significant degradation.

Programs:

Nuclear Power

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