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Plant Engineering: Cable Aging Management Program Implementation Guidance

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Plant Engineering: Cable Aging Management Program Implementation Guidance

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Product Description

This report describes issues identified during the initial implementation of low- and medium-voltage cable aging management programs by utilities and presents possible resolutions and guidance.

Background

In September 2010, the Nuclear Energy Institute issued a letter to the U.S. Nuclear Regulatory Commission that committed the U.S. nuclear industry to implementing low- and medium-voltage cable aging management programs in accordance with Electric Power Research Institute (EPRI) guidance. U.S. nuclear plant operators are rapidly implementing cable aging management programs, including testing and assessment of cable systems. From time to time during that implementation process, issues and problems arise that have not been addressed in existing industry guidance. This report discusses those items that were brought to the attention of EPRI staff either in Cable Users Group meetings or through other communication paths.

Objectives

This report provides common solutions to issues identified during the implementation of cable system aging management programs in the nuclear industry. These solutions provide a path to understanding the issues and their correction. They are not necessarily meant to be the only path to resolution; others might exist.

Approach

The issues are described: some relate to problems encountered and how to resolve them. Some indicate the need for clarification of existing practices. The discussions provide clarifications on how to correct the issue or methodology for assessing its importance. In some cases, recommendations for precluding future problems are provided.

Results

This document covers six topics: manholes and ducts, sampling, effects of elevated voltage tests on cable, jacket material aging, proper use of insulation resistance, and removal of cable from ducts.

Applications, Value, and Use

The discussions in this report will help nuclear plant personnel—if they experience the same issues—to understand the ramifications and more readily resolve them.

Keywords

Cable aging
Insulation resistance
Manholes and ducts
Sampling for cable testing

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Section 1: Introduction

In 2010, three cable aging management program implementation guides were issued by the Electric Power Research Institute (EPRI) to support the industry:

- *Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants* [1]
- *Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants* [2]
- *Aging Management Program Development Guidance for Instrument and Control Cable Systems for Nuclear Power Plants*

These guides describe how to determine the scope of a cable aging management program, how to identify adverse environments with respect to cable longevity, and how to judge the acceptability of cable for continued service. Although these guides provide a reasonable level of detail for the development and implementation of a cable aging management program, issues and problems were expected to arise at plants—requiring the development of further guidance. This report is a compendium of issues that have been recognized from June 2010 through late October 2011 and the resolutions developed with the industry. The guidance provides a way to resolve an issue so that other plants that have not encountered the problem have a solution based on industry experience. Although these resolutions have been reviewed by knowledgeable industry representatives, other resolution paths might exist and be more pertinent to the conditions at a particular nuclear plant.

Section 2: Issues and Resolutions

2.1 Duct, Manhole, and Vault Issues

Most of this section is related to keeping ducts, manholes, and vaults containing cables dry. Although modern cables can operate for long durations under wet conditions, wet and submerged conditions can lead to shorter lives, especially if a cable has imperfections from manufacture or damage from or after installation. The basic assumption of this section is that actions have been or are being taken to drain water that has accumulated around cables and to keep the water drained. The nature of some duct, manhole, and vault systems allows them to be almost always dry, with wetting or submergence being an unusual condition. Other systems flood quickly if automatic sump pumps are not installed or not working. The following subsections describe actions that might be considered to resolve issues related to underground and inaccessible cable support systems.

Automatic Pumping Systems

Some nuclear plants have duct and manhole drainage systems with automatic sump pumps. When the water level in a manhole reaches a specific point, the sump pump is switched on, and the water is pumped out. Under the assumption that these systems have been either continuously maintained or their operation has been restored, periodic confirmation of operability is desired. The periodicity of evaluating the condition of the sump pumps is a plant-specific consideration related to the rates at which manholes flood and the consequences of the flooding in the manholes. For example, if a plant's manholes rarely fill, and no abnormal conditions such as heavy rains or flooding have occurred that would alter that fact, the importance of a sump pumping system is low—and verifying pump operation at 18-month to 2-year intervals is acceptable.

If the manholes reflood within short periods of time, and pre-1976 vintage cables are feeding critical circuits, verifying the operation of the sump pumps should be more frequent. Consideration should be given to having level alarms in the manholes that refill quickly. Such alarms would allow a reduction in the frequency of manual inspections of the sump pumps. Assuming that no alarm is in place, a review of the maintenance record for the sump pump system will provide insight on the length of the necessary interval. If the sump pumps fail occasionally after 2 to 3 years, a functional check at 18 months would be defendable. If a plant has a yearly rainy season, and sump pump failures are common, performing an inspection of the sump pumps each year before the start of the rainy season is recommended.

If a plant has a cascading drain system, evaluating the sump pump in the last manhole in the chain will be more important. However, the inspection interval should be based on each plant's maintenance history of issues that had to be resolved. For example, if the pumps tend to clog after a heavy rainfall because of debris that accumulates in the lowest sump, inspection after a heavy rainfall might be necessary. This does not mean that every manhole needs to be inspected. The recommendation is to review manholes that have a sump pump, are prone to filling rapidly and not draining, or have some known problem that occurs under a specific set of recognizable circumstances.

Maintenance of Sump Pumps

Several utilities have had difficulties in maintaining both automatic and manual sump pumping. Often the automatic sump pump equipment is assigned a low priority. This makes obtaining resources—or even the ability to create a work order—problematic. Sometimes the systems are not assigned to a system engineer, or the system engineer is not required to have a system health report because the sump pumping system is designated as noncritical. One path to resolution used by a utility was to have the corrective action process require a system health report for the pumping system. The system ended up being classified as severely degraded, and the subsequent system improvement plan called for repair of the automatic sumps with management sponsorship.

Generally, manual sump pumping is performed by maintenance or facilities personnel. At one plant, manual sump pumping was stopped for several months because of manpower issues and incorrect prioritization by the group supervisor. The program owner was involved in refuel activities and did not know for several months that the manhole work was at first deferred and then stopped completely. The supervisor made no attempt to inform the program owner, and the program owner had to write a corrective action item to "influence" the work group to resume pumping.

These two examples highlight the fact that establishing programmatic requirements is not the end of a successful cable program, rather, that ongoing efforts and oversight are required to maintain the functions needed for the long term.

Water Sampling Before Pumping

Pumping of manholes is not as simple as it sounds. For security reasons, some manholes are welded shut. Vault lids can weigh up to 11 tons (9979 kg) or more, constituting heavy lifts. Security concerns must be addressed when removing theses covers. In addition, the water in manholes might be contaminated with oil or even tritium or other radioactive contaminant. Many factors determine whether the quality of the water must be evaluated before it can be pumped out of a manhole. If the water is going to be pumped into a river, state or federal environmental discharge licenses may dictate that the water be tested for contaminants before being discharged. Automatic sump pumps can be equipped with monitors that will detect oil contamination so that environmental permit violations can be avoided.

Some plants have manholes with known problems such as those that were contaminated with diesel fuel, oil, or other chemicals or where groundwater contains tritium. The water from manholes with these known problems must be sampled and the level of contamination determined to know if the water can be released or must be subjected to storage and treatment before being released. Some plants routinely sample before pumping. Others sample the water from manholes only in the vicinity of tritium in groundwater or having known contaminations. Some with man-made cooling lakes that do not drain to a river can pump to them without sampling.

In summary, the need to sample is site specific and, in some cases, manhole specific.

Duct Sealing at Building Entries

If the plugged end of an underground duct is at the low point, there is almost a 100% certainty that water has accumulated at the low end of the duct. See Figure 2-1. For older medium-voltage cable (the transition to modern designs occurred between 1976 and 1978), a pool of water only a few inches to feet long is enough to cause degradation. The first failure in a population of wet, medium-voltage, black ethylene propylene rubber (EPR) or butyl rubber cables might be expected to first occur at 30 to 35 years. Failures have been noted at approximately 15 years when ducts were sealed at the low end 20 years into the service life of these cables. That is, if the ducts were sealed at the low end to prevent water from entering buildings 20 years into service, the medium-voltage cable in the duct failed about 15 years later. Similar cables that were submerged for their entire lives failed for the first time at about the same total life (30 to 35 years). Therefore, if sealing of ducts is to be performed well into plant life to preclude building flooding from external events, care should be taken that the seals are placed at the high point of the duct—not the low point—to prevent pooling of water above the plug.

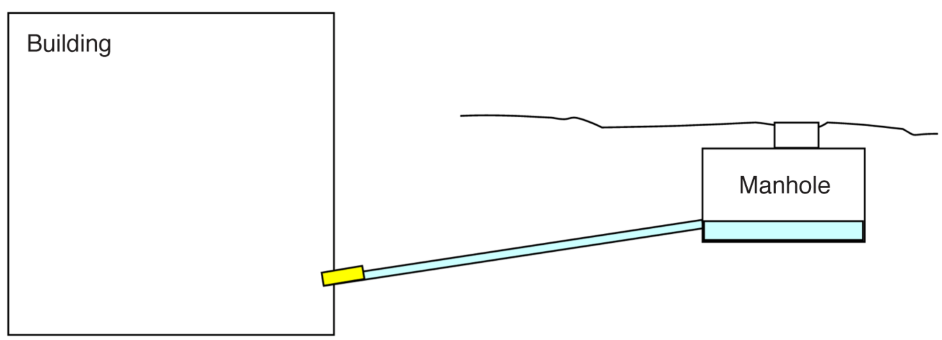

Figure 2-1
Effect of Sealing Ducts at the Low Point: Water Enters the Duct from the Manhole

Assuming that the duct is dry at the time of plugging of both ends, it is highly likely that groundwater will seep into the duct through the duct joints if the duct is below the water table at some time of the year. The ducts might drain again if the water table drops; however, the last segment of duct to the building cannot drain because the lowest point is sealed. Therefore, this segment will always be wet. It is unlikely that the ohmic heating of the circuit could ever evaporate the water sufficiently to cause the duct to dry. Moisture would evaporate at the top surface of the water only to condense on the walls at the upper portion of the duct and drain back down into the lower section of non-drainable duct. See Figure 2-2.

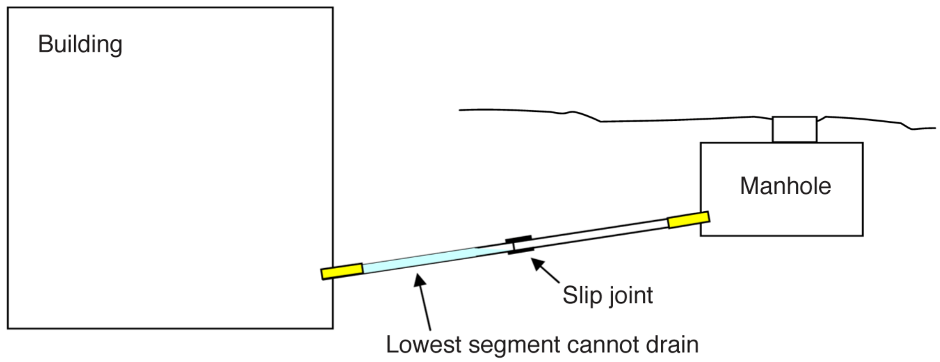

Figure 2-2
Last Segment of Duct Is Always Wet Once Water Enters

If at all possible, removal of any existing low-point seals is recommended. Finding an alternative way of keeping any residual in-leakage after a seal is placed at the high point of the duct is recommended. Upper point seals are satisfactory; they will keep water from draining into the duct from the manhole—especially from external flooding events. Lower point seals will almost guarantee water retention and submergence of a segment of the medium-voltage cable in the duct. Although modern (approximately post-1976) cable should be much less sensitive to aging under submerged conditions, sealing at the low ends of ducts is not recommended for any medium-voltage cable.

Non-Drained Ducts and Conduits Embedded in Floors

Embedded ducts and conduits are not unusual in nuclear plants and may be at any elevation in a concrete structure. Often these embedded ducts or conduits have no drain. They may run from an overhead cable system, down a wall, into the floor, under the floor to the base mat of a component such as a pump motor, and then re-emerge as shown in Figure 2-3. In some cases, water enters a duct during construction or a plant event or through condensation. The water remains in these ducts for long periods—if not forever—because there is little or no driving force to cause the water to evaporate.

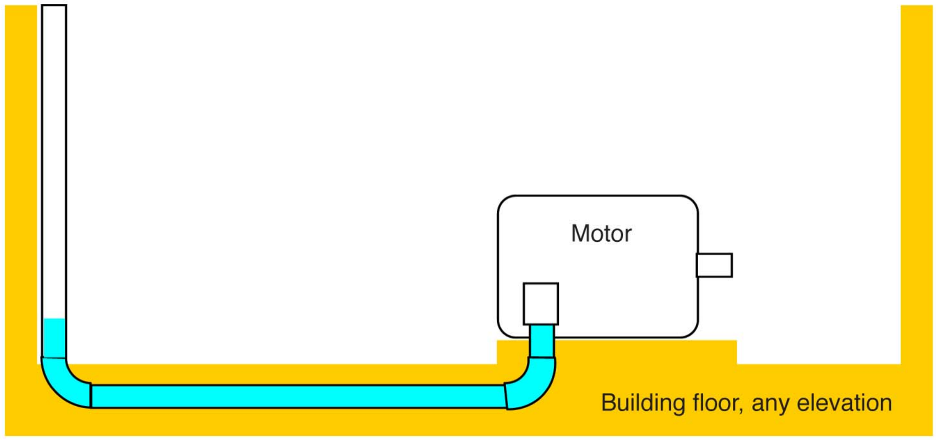

Figure 2-3
Embedded, Non-Drained Duct or Conduit

One way to determine whether this condition exists is to send a small video camera through the duct. If water is found, a flexible plastic tube may be inserted and the water sucked out of the duct. Blowing the water out with compressed air is another option. If the source of the water is unknown, a periodic assessment might be necessary until it is determined that there is no recurrence of wetting and submergence.

Manhole Water Depth Monitoring

One station has installed a manhole water depth system that reports the results via satellite and the web to the engineer's desk. This is a commercially available system that provides instantaneous levels with respect to cable elevation and has alarm points that may be used to determine when pumping is required. Reference [3] provides a discussion of the system and its use.

Solar Driven Manhole Pumps

A few plants have installed solar driven manhole sump pumps rather than running power to the manhole. The systems might need to be repaired or replaced due to wear-out after 3 to 5 years. These pumping systems may be found on the Internet.

Draining Upon Refilling

Manholes might refill rapidly with water if an on-site flood or heavy storm affects a plant site. If this occurs, the question is: "How soon must the manholes be pumped out?" Research indicates that for an unjacketed cable to be saturated with water, a period of months is required [4]. Adding a jacket slows the ingress of water, adding a few more months for saturation of the insulation. Degradation from water in the insulation in combination with voltage stress is a slow process, taking decades in most cases and requiring either a susceptible insulation or one with significant damage in order to proceed. The following discussions are based on the period of time to saturation of the polymers and the knowledge that water-related degradation is a slow process that takes much longer than a few months to significantly affect the condition of a cable's insulation system.

Obviously, ducts and manholes cannot be pumped manually during a flood, and pumping during a storm might not be possible. The following discussions are based on the assumption that manual or automatic pumping of manholes and vaults has been established for the particular nuclear plant but that reflooding has occurred due to failure of the automatic system or a severe storm or flood. Table 2-1 relates to the period after the end of the storm or flood and is separate from the period in which pumping is not possible. Naturally, if an extended period of submergence occurs when flooding is not possible, such as many months, a condition-specific analysis will be necessary to determine the actions to ensure that the period of submergence has not significantly affected the cables. The importance of returning a cable to a dry state after immersion from a period of rain or other source of in-leakage depends on many factors, including past history, cable type and materials, and knowledge of condition through periodic testing.

Table 2-1
Pumping Criteria Summary for Medium- and Low-Voltage Cable

Condition Prior to Pumping	No Previous Test Results Available		"Good" Condition Monitoring Result in Last 6 Years	"Further Study Required" Test Result
Acceptable action	Drain within 3 weeks	Drain within 1 to 2 months (see Note)	See text in box	Drain within 1 week
Always previously dry	OK	OK	Drain within 4 months	OK
Wet occasionally during life	OK	OK	Drain within 4 months	OK
Wet most of long service period prior to drying	OK	Not recommended	Drain within 1 to 2 months	OK

Note: See *Other Considerations* for newly installed cable.

Electrochemical degradation that causes water-related degradation requires the ingress of water into the insulation and/or shield interface layers. Nuclear plant cables have jackets—commonly made of neoprene, chlorosulfonated polyethylene (CSPE), or chloronated polyethylene (CPE)—that slow the ingress of water such that when immersed, the water takes weeks to months to permeate to the shield and insulation, depending on the jacket material and service conditions. When the water is through to the insulation, the slow process of electrochemical degradation begins, which takes decades to result in deterioration that could lead to failure. In the absence of condition monitoring data, the longer the cable was previously exposed to water, the more important it is to keep the cable dry to reduce the likelihood of additional degradation. However, even where little is known about the past and present condition, the effect of wetting or submergence on the process of degradation is obviously not instantaneous.

The medium-voltage cable criteria contained in Table 2-1 are based on previous history of the circuit with respect to wetting and whether recent condition monitoring data are available. For example, if a circuit was always dry in the past, a short period of wetting or submergence will have no real effect. A cable that was submerged for a long period in the past might have some degradation, and wetting it again for a significant period could cause additional degradation to occur. However, if cable test data indicate that the cable is in “good” condition following its long-term wetting, there would be less concern for that period of rewetting.

No Condition Monitoring Data Exist

If the cable has an advanced age (25 or more years), the more that is known about its condition, the more leeway exists with regard to draining the water from the ducts and manholes. If the manhole and duct system is known to have been dry for the cable’s entire service life, submergence for a few weeks to two months before drying will have no effect. If the system was occasionally wet for short periods (such as a week or two) during a year, wetting for a few weeks to two months before drying will have no significant effect. However, if the cable was submerged or wet for most of its life, some long-term deterioration might have occurred. An additional period of wetting might lead to additional long-term deterioration. If no data exist concerning the cable’s condition and the cable is rewet, draining the system within three weeks after the flood has receded or the storm has passed is recommended. Although floods might be in place for extended periods, the additional degradation from three weeks of exposure is minimal. Failure during the three-week period would occur only if the cable were already near the point of in-service failure.

“Good” Condition Monitoring Results Exist

If the cable circuit has been tested within the last six years, more latitude exists with how soon draining the system is needed. If the manhole and duct system has always been dry, no significant degradation will occur for a significant period, and draining within four months is acceptable. Similarly, if the cable has been wet occasionally over its life but has a “good” test result, draining within four months is recommended. If the cable had been wet or submerged for most of its life and had a “good” test result, draining within 1 to 2 months is recommended only because some degradation might have occurred, and resubmergence may add some degradation.

"Further Study Required" Result Exists

This result indicates that the cable circuit has suffered some water-related degradation. Draining the manhole and duct system as soon as practical (for example, within a week) following the termination of the cause of immersion (such as the end of a storm or flood) is recommended. Testing at the next outage is recommended if it is not already scheduled.

Other Considerations

If a recently manufactured cable has been installed in the last 5 to 10 years, the likelihood of significant degradation in that period is low. Accordingly, two to four months before draining is not critical, even if no condition monitoring tests have been performed.

If the cable supports a run-to-failure component or one that is noncritical and has no significant effect on the plant should it fail, the criticality of maintaining a dry condition is reduced. If the cable is normally deenergized, electrochemical degradation will not occur, and the criticality of maintaining the cable in dry condition is reduced.

Pumping Criteria: Low-Voltage Cable

Unlike medium-voltage cable insulation in which electrochemical degradation (for example, water trees in cross-linked polyethylene [XLPE] insulation) is a known degradation mechanism, there are no established failure mechanisms for low-voltage insulation. It is likely that manufacturing flaws or installation damage coupled with long-term wetting leads to failure. However, electrochemical degradation is not expected because the voltage stress in the insulation is low (>20 V/mil [>0.5 kV/mm]).

The remaining concern with respect to the insulation is the stability of the insulating polymer in water. Manufacturers' water stability tests have been performed, indicating that long-term stability should not be a problem. However, where no obvious indication of the cause of a low-voltage cable failure exists, more detailed forensics is recommended.

The use of the Table 2-1 pumping criteria is recommended as a conservative approach for low-voltage cables.

Instrumentation Cable

Although the insulation of low-voltage cable is not expected to deteriorate, jackets will allow water to permeate to the shields of instrumentation cable and might cause multiple grounds to occur. If multiple grounds have been experienced due to wetting of an instrument cable, the previously presented pumping criteria should be modified to maintain the operability of the associated instrument circuits.

2.2 Sampling

In assessing the aging of a cable system, populations of cables with like environments may be found that are too large to test during one or several refueling outages. If such populations exist, testing based on statistical sampling methods may be employed to provide a basis for establishing the overall acceptability of the population.

A sampling process is provided in Electric Power Research Institute (EPRI) TR-017218-R1, *Guideline for Sampling in Commercial-Grade Item Acceptance Process* [5], for the application of receipt inspection testing to determine the adequacy of a population of received components from a vendor. If the sample results are acceptable, there is reasonable assurance that the remainder of the lot (population) is acceptable. If some of the population is found to be deteriorated, the sample size will likely have to be increased to more fully characterize the population of cables. The process entails several considerations that affect the results and might cause the sample population size to change significantly. For cables, these considerations are as follows:

- Lot formation
- Safety function of the cables in the lot
- Test methodology to be used
- Plant and industry operating experience with cable type(s)

When these items have been determined, the samples to be tested from the lot should be chosen at random. This list is abridged from Reference [5]. Items not applicable to cable assessment have been eliminated.

The sampling process and the bases for the sampling plan selection should be adequately documented. The following describes the actions to be taken in developing and implementing the sampling program.

Lot Homogeneity

A perfectly homogeneous lot is not likely to be possible for a given population of cables. The size of the conductors, the loadings, and even the environments might be different. Lot homogeneity is typically a matter of degree and not an absolute. If a lot were truly homogenous, all attributes and variables for every cable in the lot would be identical, and only one cable would have to be tested to be representative of the lot. The cables in the lot should be of the same voltage rating and design (for example, shielding and insulation system). Low-voltage power, instrument, control, and medium-voltage cables should not be lumped together. For medium-voltage cable, inferences about the suitability of non-shielded cables based on the testing of shielded cables should be made cautiously if at all.

The first assumption is that the cables are subject to an adverse environment. Benign environment cables need not be assessed at this point. The suggested starting points for lot development are provided in Table 2-2.

Table 2-2
Suggested Lot Groupings for Underground and Inaccessible Cable

Cable Type	Environment	Loading Relative	Criticality
5-kV rated, shielded (Note: similar groupings may be employed for 15-kV rated cable)	Wet for a long period of its life (years +)	Energized for more than 25% of the time	High
5-kV rated, shielded	Wet for a long period of its life (years +)	Critical safety cables, such as diesel generator cables, in this grouping energized for less than 25% of the time	High (safety concern rather than degradation concern)
5-kV rated, shielded	Wet for a long period of its life (years +)	Energized only on test or less than 25% of life	Medium
5-kV rated, shielded	Underground but rarely wet	Energized for more than 25% of the time	Low
5-kV rated, shielded	Underground but rarely wet	Energized for less than 25% of the time	Very low
Low-voltage power cable (<1000 V rated)	Wet for a long period of its life (years +)	Stability is likely independent of energization	Medium to low
Low-voltage power cable (<1000 V rated)	Underground but rarely wet	Stability is likely independent of energization	Low to very low
Low-voltage control cable (<1000 V rated)	Wet for a long period of its life (years +)	Stability is likely independent of energization	Medium to low
Low-voltage control cable (<1000 V rated)	Underground but rarely wet	Stability is likely independent of energization	Low to very low
Twisted, shielded instrument cables	Wet for a long period of its life (years +)	Jacket deterioration could lead to shield grounds	Medium to low
Twisted, shielded instrument cables	Underground but rarely wet	Jacket deterioration or damage unlikely	Low to very low
Coaxial/triaxial cables	Wet for a long period of its life (years +)	Jacket deterioration or damage could lead to shield grounds	Medium to low
Coaxial/triaxial cables	Underground but rarely wet	Jacket deterioration unlikely; damage is still a concern, but grounds are less likely due to the absence of water	Low to very low

The population of wet medium-voltage cables might have to be broken into separate groups to provide reasonable uniformity in a particular lot. The underground temperature is likely to be relatively uniform and not greatly affect degradation. The key difference between lots—assuming that some section is wet and the cable is energized most of the time—is the thickness of the insulation with respect to the applied voltage. Accordingly, 5-kV shielded cables with the same insulation system could be in one group but should not be grouped with 15-kV rated cables operated at 5 kV or with non-shielded 5-kV rated cables because the voltage stresses in these other sets are much lower. Making decisions on 5-kV rated shielded cables based on testing of the thicker insulations with lower operating stress would be nonconservative.

Manufacturers' insulation system and designs should not be mixed in the samples. Test results from Kerite HTK cannot be used as a basis for acceptability of Okonite Okoguard and vice versa. Test results from Anaconda cables with standard shield designs cannot be used as bases for Anaconda UniShield designs and vice versa. Given that wet deterioration of medium-voltage insulation systems is caused by electrochemical and electromechanical degradation, degradation, if any, is proportional to the period of energization. Results for continuously energized cable would be conservative to rarely energized cables, and results from rarely energized cables would be nonconservative for continuously energized cables. Longer periods of energization times should lead to higher levels of degradation if continuously or frequently wet. Therefore, separating groups of continuously energized cables from cables that are rarely energized is recommended. Combining the lots might be possible as long as the makeup of the lot and the ramifications are understood. Assessment of the characteristics of the applications might allow identification of segments of the population at higher and lower risk such that the lot at the highest risk of significant degradation can be the focus of attention.

The quality and nature of the test or assessment method that will be used to judge the adequacy of the lot of cable for continued service will affect test sample size considerations. If a test is highly indicative of the degree of degradation and will detect that degradation well before it is severe enough to cause a failure, small test sample sizes are possible. If the test is less sensitive and there is less margin between the point of detectability and the point of possible in-service failure, a larger test set is indicated. For wet, shielded medium-voltage cable, currently available tan δ and dielectric spectroscopy test methods provide a reasonable margin between the detectability of aging and the point of possible failure. The "normal" plan sample sizes are shown in Table 2-3.

Table 2-3
Sample Size for Cable Test Lots [5]

Normal Plan		Reduced Plan		Tightened Plan	
Lot Size	Sample	Lot Size	Sample	Lot Size	Sample
1	1	1–5	1	1	1
2–4	2	6–13	2	2	2
5–6	3	14–24	3	3–4	3
7–11	4	25–41	4	5–6	4
12–20	5	42–50	5	7–8	5
21–24	6	51–63	6	9–10	6
25–28	7	64–76	7	11	7
29–32	8	77–90	8	12–13	8
33–41	9	91–102	9	14–15	9
42–50	10	103–104	10	12–20	10

If all of the samples from a lot test acceptably, the conclusion may be reached that the lot as a whole is acceptable. The current state of the art in cable testing results in three categories: *acceptable*, *further study required*, and *action required*. If a cable in the sample set has a valid (not resolved through correction of a testing issue such as cleaning terminations) *further study required* result, the periodicity of testing should be reduced for that cable and that cable followed over time rather than being randomly selected in the next round of testing. Given that the *further study required* result is an indication of the possible onset of aging, increasing the lot size is desirable to determine if the potential problem is isolated or more widespread. According to Reference [5], an additional sample from the remainder of the lot could be selected to determine if the nonconformance is an isolated case or a systematic problem. The additional sample size should be larger than the original sample size. An engineering evaluation can be performed to disposition the degraded cable(s). A cable that is just over the boundary from *acceptable* would require a small increase in sampling. A cable that is at the boundary of *action required* would require a much larger increase to the sample, possibly as much as if a test had an *action required* result. Knowledge of the component of the circuit that failed could change the need for or the type of sample. For example, if the failure of a medium-voltage circuit occurred in a splice, further sampling of circuits with similar splicing would be necessary. Additional testing of circuits without splices would not be necessary. If the cable insulation failed, additional samples of cable with the same insulation system would be tested.

If forensics assessments are done before the additional tests can be performed (for example, additional testing had to be postponed until the next convenient outage), the results of the forensics should be considered in determining the increase in sample size. If the forensics assessment found that the failure was caused by a singular random manufacturing defect and not related to widespread flaws or distributed degradation, a limited increase in sample size would be allowed. If widespread flaws or degradation were detected, a much larger sample set would be needed to confirm that widespread degradation has not affected the rest of the cable population.

Table 2-3 provides lot sizes and sample sizes depending on whether a normal, tightened, or reduced sampling plan has been chosen. For high-criticality lots of cables, the *tightened* plan should be used. For low-criticality lots of cables, the *reduced* plan may be used. Similar reasoning would be used for low-voltage power and control cable as well as instrumentation cable. For underground and inaccessible low-voltage cable, insulation resistance testing is most useful: the wet conditions should help identify significant degradation from aging, manufacturing flaws, or installation or post-installation damage.

Assuming that the sampling plan chosen is based on *normal* plan sampling from Table 2-2, identification of problems would drive the user toward the *tightened* plan. Conversely, if the entire set of *normal* plan samples were successfully tested and found acceptable, further testing campaigns might be based on the *reduced* plan until a cable circuit problem was identified. If one started out with a *tightened* plan for critical circuits, dropping back to a *normal* plan would be possible after completion of a testing campaign in which all cable circuits were found acceptable.

For dry cables that have been subjected to adverse thermal conditions with or without adverse radiation conditions, the identification of damage is most likely going to be through visual/tactile assessment. If a large group of cables in a tray or conduit has been affected, statistical sampling might or might not be useful. The nature of the degradation and the severity of the accident environment, if any, must be considered along with whether in-service testing of the cables would provide useful information. *In situ* or laboratory tests of representative worst-case cables will generally provide an answer regarding the surrounding cables of the same type. Statistical sampling might not be needed in that case.

Even using sampling, testing all of the cables in a set might not be possible in one outage, and implementation of statistical sampling might require more than one refueling outage to complete. Sampling assumes random selection of items in the *homogeneous* lot. Outage limitations might not allow testing of some of the cables in the lot. If the cables in the sample cannot be selected randomly, larger sample sizes are called for to support the conclusions.

2.3 Effects of Elevated AC Test Voltages on Good Insulation

When plants first perform elevated voltage tests, whether using 60-Hz or 0.1-Hz excitation, and the test result indicates that the cable is deteriorated, plant managers often ask: "Why was a damaging voltage applied to the cable?" The elevated voltage tests are generally performed at approximately twice the line-to-ground voltage (V_0) for medium-voltage cable. Guidance on test methods and voltage levels is contained in Reference [6]. A value of 2 V_0 is generally the limit of the test voltage for dissipation factor (tan δ) testing with the test voltage being applied for a few minutes, and up to 3 V_0 is used for withstand testing with durations between 15 minutes and 1 hour—with 30 minutes being the industry-recommended standard. Reducing the test duration for a cable that has a gross type defect will reduce the likelihood that it will fail during a withstand test and could also increase the likelihood that the cable will fail during normal operation when the cable is returned to service. Duration, like applied voltage, is a key part of the withstand test; the reduction of either can compromise the effectiveness and intended purpose of the test.

These elevated test voltages sound as though they might be damaging to a cable with "good" insulation, but they are not. They are intended to identify significantly weakened insulation and/or cause a severe localized degradation or defect to fail during the test. Good insulation will be unaffected.

Laboratory and field research [4] attempted to cause the accelerated aging of five types of modern EPR insulation, including the brown Kerite and pink Okonite used in nuclear plants. In the laboratory, 2.5 V_0 was applied to submerged cable specimens also having water in the conductor strands. The 15-kV field cables were in an underground application serving customer load. They were operated at 35 kV, which is also 2.5 times the rated voltage. The cables were purchased from the manufacturers anonymously; they did not know that the cables would be used for a research program. The cables had the same conductors, shields, and insulations as those used in nuclear plants. Concentric neutrals rather than a tape shield were used, and there was no jacket. See Figure 2-4.

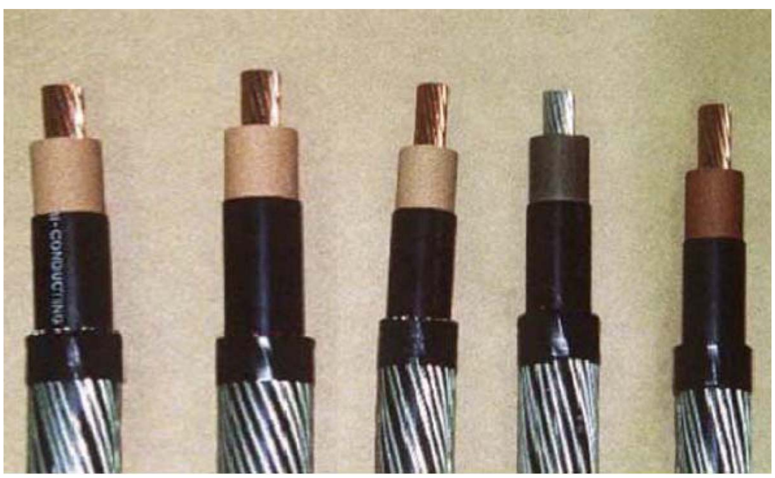

Figure 2-4
Five EPR Cable Types Subjected to Laboratory and Field Aging Research [4]

The research continued for 6.8 years. Only one cable, which is not used in nuclear applications, had failures related to the interface between the shield and the insulation rather than water-related degradation of the insulation. The Okonite and Kerite specimens had no failures. Figure 2-5 shows the breakdown strength of the insulations with respect to time under test. The breakdown strength of EPR drops to approximately one half of its dry value upon wetting. However, as indicated in Figure 2-5, the retained breakdown strength is approximately 7 times the operating voltage.

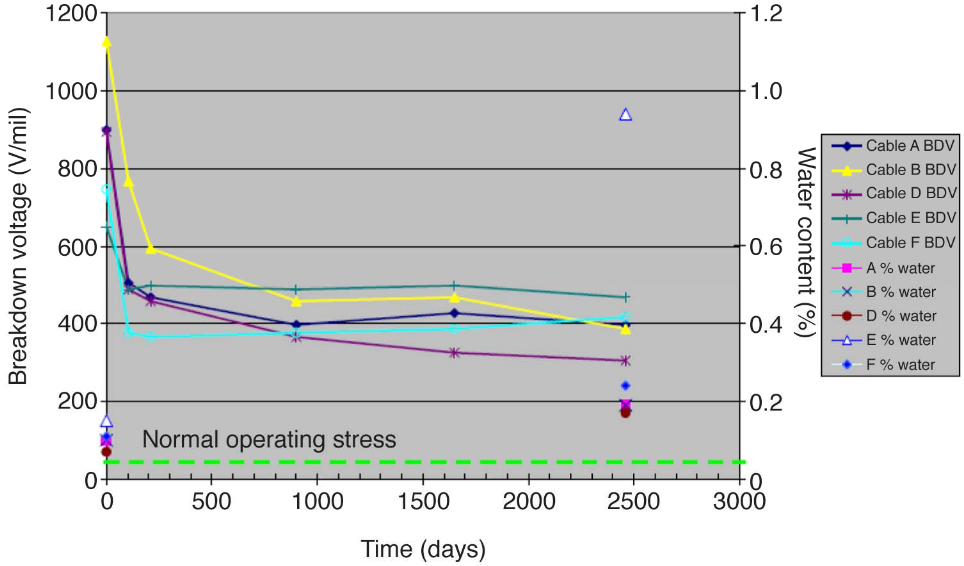

Figure 2-5
Retained Breakdown Strength versus Days of Laboratory Aging Under Submerged Conditions and at 2.5 V_0

The stress under normal operations of these 15-kV rated cables would be under 50 V/mil (8.7 kV across the insulation). A 2-V_0 test would apply 100 V/mil (17.4 kV across the insulation). A 3-V_0 test would apply 150 V/mil. It is obvious from the 6.8-year application of 2.5 V_0, both in the field and laboratory, that a 2-V_0 test with a duration of minutes would have no effect on a "good" cable. The breakdown voltage of 7 V_0 indicates that a 3-V_0 application also will not cause the failure of a "good" cable.

With regard to the effects of testing on in-service aged cables, Figure 2-6 provides 60-Hz tan δ results versus breakdown strength for a degraded 5-kV rated black EPR cable. The cable was 33 years old when it failed in service and had been submerged in brackish water for the entire period. The data show that as the breakdown strength deteriorates below 8 times V_0, the 60-Hz tan δ measurement begins to increase. The figure shows that increasing tan δ is indicative of dropping breakdown strength and that a "good" tan δ result is indicative of a cable with a breakdown strength on the order of 10 times the operating voltage and—if it is dry—well above 20 times the operating voltage. Generally, when 60-Hz tan δ testing is performed, the measurements tend to be approximately one half those of measurements made at 0.1 Hz.

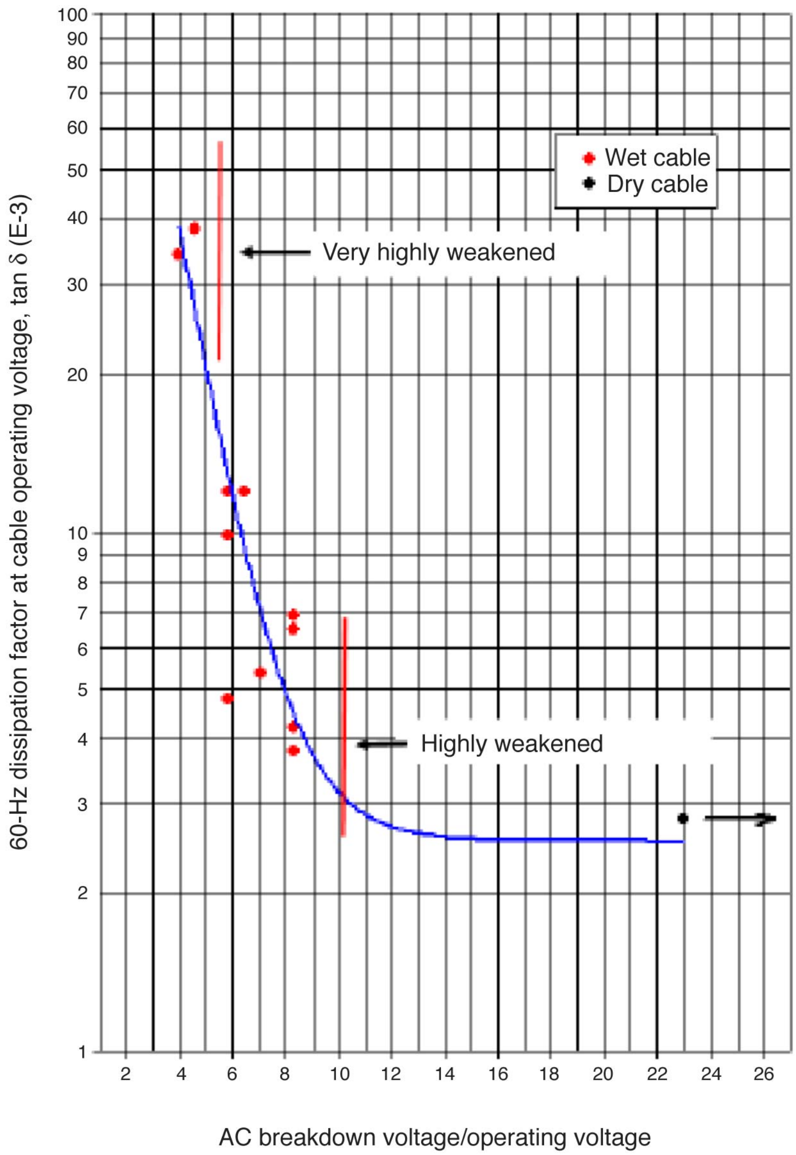

Figure 2-6
AC Breakdown Strength versus 60-Hz Tan δ Results [7]

Conclusions

The application of 2 to 3 times line-to-ground ac test voltage to an EPR insulated cable with good insulation has no adverse effect. If a cable circuit fails under test or has unacceptable test results, the cable, its terminations, or its splice(s) are degraded or defective. The test voltage does not cause the condition; rather, the test voltage allows the condition to be identified. Although XLPE data have not been presented here, the same arguments and similar data are available for XLPE insulation. If a 2-V_0 test voltage causes XLPE insulation to fail, the insulation was highly degraded prior to the start of the test. Although a short period of operation could have been possible for an XLPE or EPR insulated cable that fails during a test, there is a significant probability that the cable would have failed within the next one to two refueling periods for the plant.

2.4 Jacket Materials and Aging

Several different materials have been used as cable jackets for nuclear power plant cables. The dominant jacket materials change with plant vintage and country where the plant is located. Different jacket materials have different properties, and the thermal ratings of the jackets differ from one another and from the insulations they cover. The following provides a discussion of jacket and jacket aging with respect to cable type (medium-voltage, low-voltage power, and instrument and control). The commonly used jackets were polyvinyl chloride (PVC) (limited use in the United States but common in many other places), neoprene (chloroprene), Hypalon (CSPE), and CPE. These are generic names; there are different grades and vintages for each of these materials that can affect service life.

PVC Jackets

PVC has various ratings, but older versions were rated for 65°C. In the United States, PVC was used only as a conductor insulation covering over butyl rubber or as a cable jacket. It was not used as insulation as it was in other countries. The use of PVC was discouraged in the United States after a fire at Browns Ferry Unit 1 in March 1975 propagated along the PVC jacketed cables in containment. The toxicity and chlorine content in the smoke was high. Plants with non-fire-retardant PVC jackets either replaced the cable or covered it with fire-retardant coatings. PVC is a hard plastic by nature and would be unacceptable as cable insulation if it did not contain plasticizers that make it flexible and pliable at low temperatures. Early plasticizers for PVC were not stable and would weep from the cable surface, making the jacket sticky—in some cases, weeping would occur from the ends of the jacket or insulation. Two problems result: The PVC becomes stiff and inflexible, and the plasticizer carries chlorine that corrodes surrounding metals. Modern nuclear plant specifications preclude the use of PVC materials in containment and in high-pressure piping areas because of the concern for stress corrosion cracking of high-temperature/-pressure stainless steel piping. In the high temperature and under exposure to radiant energy, PVC jackets and insulations will harden and crack when exposed for a significant period. PVC jackets that do not contain carbon black (that is, are gray or colored) will crack if exposed to ultraviolet (UV) radiation from a nearby fluorescent fixture.

Plants having fire-retardant coatings on their PVC cables have a difficult time performing visual inspections because the cable jackets are not visible. Inspections are possible only within junction and termination boxes. Electrical housings where PVC cables are terminated should be inspected for signs of corrosion of metal surfaces, contacts, and connections—especially in high-temperature areas and areas having elevated radiation conditions (> a few Mrd [a few tens kGy]).

Neoprene Jackets

Neoprene was a common medium- and low-voltage jacket during the 1970s and, in some cases, into the 1980s. Although neoprene has a long life at temperatures below 40°C (122°F), it hardens and ages rapidly at elevated temperatures. Neoprene turns from black to brown when aged and will exhibit wide axial and longitudinal cracks when highly thermally aged. The change in color is called *bloom* and results from excess processing sulfur moving to the service due to high-temperature aging. Because it ages faster than the insulations it covers under thermal aging, the underlying insulation is likely to still be acceptable when evaluated. When highly thermally aged, neoprene gives off chlorine that will corrode surrounding metals. *Neoprene* is a generic title; some neoprenes are more resilient to thermal aging than others. Manufacturers use different compounding to obtain the set of properties they think best in the cables—from mechanical, chemical, and electrical properties to cost.

Neoprene jackets on medium- and low-voltage cables that have been removed from wet-underground service after 30 or more years generally exhibit deterioration that includes swelling and looseness, tearing, and/or blisters containing water. Although neoprene protects the cable during installation and initially slows the entry of water into the cable core, it will not stop water penetration in the long run. It is not clear whether the material splits during cable removal or if it occurs in the duct system before removal. However, the physical strength of the neoprene that has been subjected to wet aging for decades is greatly reduced from its as-manufactured state.

Chlorosulfonated Polyethylene

Until recently, more of the CSPE was manufactured in the United States by DuPont under the trade name *Hypalon*, with other countries such as Japan and China producing smaller quantities. Recently, DuPont ceased manufacturing Hypalon. U.S. cable manufacturers have chosen to find other manufacturers of CSPE or alternative materials for their jackets.

CSPE is a rubber material that was the jacket of choice for most cables from the early 1980s through approximately 2008, when it became less available. It was used as insulation to a limited degree by Boston Insulation Wire under the trade name *Bostrad 7* and by some European companies as well. It was surpassed as a common insulation by the mid- to late-1970s. CSPE has also been applied over non-fire-retardant EPR insulations for fire retardancy. In this type of composite insulation, the CSPE may or may not be bonded to the EPR. Most manufacturers having EPR/CSPE insulation (for example, 30 mils [0.76 mm]) of EPR with 15 mils [0.38 mm] CSPE covering it) bonded the two together so that the CSPE could not be stripped from the EPR singles. The CSPE layer is more sensitive to thermal aging than the EPR layer and hardens first. Even though the EPR is still resilient, the CSPE layer is controlling in manipulation and when exposed to high-pressure steam conditions as occur in a loss-of-coolant accident. If the CSPE layer in the EPR/CSPE composite insulation hardens significantly, it will crack when bent. Continued bending causes the elongation of the EPR to concentrate in the crack. A small further extension of the EPR in the bend causes it to rupture and fail. See Figure 2-7. In a pressurized steam event, the steam infuses the CSPE/EPR during the high-pressure (50-psig [450-kPa]) condition. When the temperature and pressure drop suddenly, as would occur when the sprays are operated, the CSPE tries to restrain the swelling of the EPR and inner layer of CSPE and fails. The crack propagates to the conductor as shown in Figure 2-8.

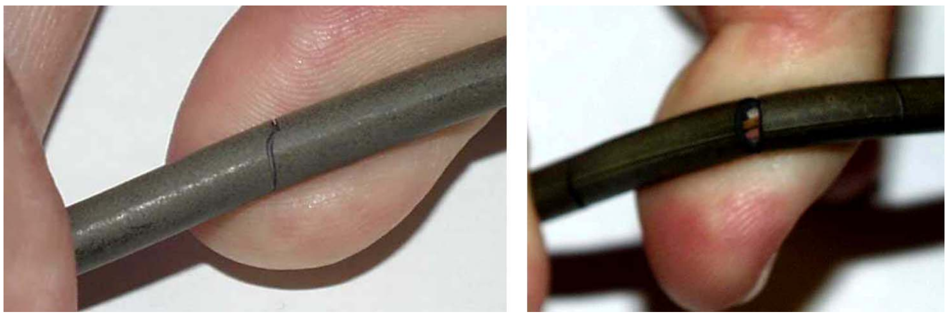

Figure 2-7
Crack in CSPE Layer with EPR Layer Intact (left); Slight Further Bending Causes Over-Extension of EPR, Which Fails (right)

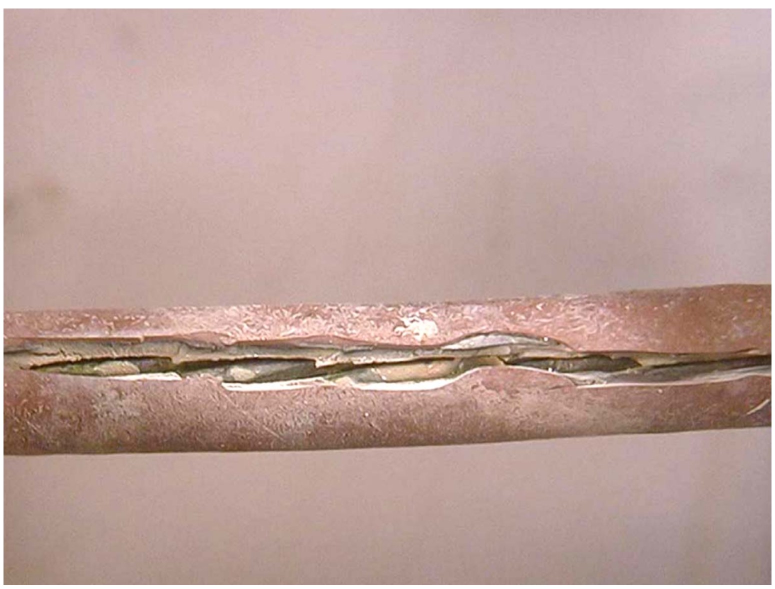

Figure 2-8
Crack in an EPR/CSPE Insulation from Loss-of Coolant Accident Steam Conditions (Insulation Diameter is ¼-in. [6.4-mm])

CSPE, like neoprene, hardens and turns brown. It hardens much more slowly than neoprene in the same conditions and does not crack until extremely over-aged. Figure 2-9 shows neoprene and CSPE jacketed cables in the same tray. The neoprene jackets are brown and have cracked. The CSPE jackets are still their original black color and might just be starting to turn brown. An additional early indicator of aging might be obtained from evaluating the condition of the tie wraps. Tie wraps start out a translucent white. When they age, they turn brown and crack. This can be seen in the upper right-hand corner of Figure 2-9.

Figure 2-9
Neoprene and CSPE Jacketed Cables in the Same Tray

In wet conditions, CSPE behaves differently depending on whether it is black or colored. Black EPR gets its color from carbon and is cured using sulfur. Colored CSPE is cured using magnesium dioxide, which is used to ensure color stability. The difference in cure processes affect water uptake and swelling. The colored CSPE takes up to 20 times as much water as the black version. In a submerged condition, it will swell and allow water accumulation inside the jacket. If a colored section of CSPE jacketed EPR cable is removed from service, the jacket will easily slide off the core. Corrosion of the shield from the large amount of water is possible. The jacket does not split nor is it physically degraded beyond the swollen condition.

Chlorinated Polyethylene

Chlorinated polyethylene jackets were used on a few Anaconda low-voltage cables and are being used on some medium-voltage cables as a replacement for CSPE. Chlorinated polyethylene is a rubber but is somewhat harder than CSPE and neoprene. It is produced by the random chlorination of high-density polyethylene. No information is available concerning in-plant problems. It is not known whether this is due to the small population of cables in which it is employed or to satisfactory behavior under the environments of the nuclear applications.

2.5 Insulation Resistance Measurements and Acceptance Criteria

Insulation resistance measurements and acceptance criteria are treated in the EPRI cable aging management program implementation guides [1, 2, 8] and the medium-voltage cable aging management guide [7]. However, confusion still exists on when insulation resistance is useful for aging management and what acceptance criteria should be used.

Many plants use 1 megohm plus 1 megohm per kV of applied voltage as the criteria for acceptance of cables for return to service. This criterion is discussed in IEEE Std 43 [9] and IEEE Std 422 [10]. Although this criterion might be useful for determining whether equipment and cables may be safely energized, it is not useful for aging management purposes or predicting whether cable will provide satisfactory service for a foreseeable period. IEEE Std 690 [11] on design and installation of cable in nuclear plants references IEEE Std 336 [12] for acceptance testing. However, IEEE Std 336 provides no acceptance criteria.

The IEEE Std 43 discussion relates to the energization of rotating electrical equipment [9]. The value applies to motors with winding systems that pre-date 1970 that were relatively porous and could have very low insulation resistances when damp. The acceptance value was related to whether it was safe to test the winding at elevated voltages and was never meant to be used as a cable condition acceptance criterion. It should be noted that IEEE Std 43-2000 requires 100 megohms for modern form-wound systems.

The discussion in IEEE Std 422-1986, which has been withdrawn by IEEE even though a revision is in progress, does apply to cable. Section 11.2 (2) states that for low-voltage power cable, the minimum acceptable insulation resistance using a 500-Vdc insulation resistance meter is as follows:

$$R \text{ in } \mathrm{M\Omega} = (\text{rated voltage in } \mathbf{kV} + 1) - 1000 \text{ ft}$$

Users are directed to IEEE Std 400 [13] for testing of medium-voltage cable. There is no doubt that a low-voltage power cable will function with a 2-megohm insulation resistance. However, if such a low value is found on test, there is something grossly wrong with the insulation system for the cable. IEEE Std 422 does require that the insulation resistance for a low-voltage power cable be related to cable length. IEEE Std 43, which relates to rotating electrical equipment, naturally does not have a criterion related to cable length.

There are two problems with the 1-megohm plus 1-megohm per kV approach without correcting for length. First, the value is much too low and represents an essentially failed cable insulation system; second, it does not account for cable length. Insulation resistance of cable insulation is inversely proportional to length. A low insulation resistance in a short length is much worse than a low insulation resistance in a long length if the results are not compensated for length. Common practice is to provide insulation resistance in terms of 1000-ft or 1-km lengths. The reading is multiplied by the length divided by 1000 ft or 1 km to give the corrected value to compare to the acceptance criteria.

New cable insulation—whether low or medium voltage—has an insulation resistance of gigohms-1000 ft, if not tens of gigohms-1000 ft. Therefore, if the insulation resistance is only 100 megohms-1000 ft (30.5 megohm-km), a dramatic decrease in insulation resistance has occurred. Something is wrong with the insulation of the cable that needs to be understood. To determine the insulation resistance of the cable, the cable must be disconnected from the associated end device such as a motor or transformer. Given that plant owners are reticent to disconnect a motor and reconnect it for testing of a cable, there are two options:

1. Install separable disconnects such as gel-based splices that reduce the time, effort, and likelihood of error when separate testing of the motor and cable is desirable. (As of this writing, environmentally qualified separable connectors are not available for safety systems. However, EPRI has an active project to develop an outside-containment environmental qualification.)
2. Adopt 100 megohms as the combined insulation resistance where the motor and cable must be separated to determine whether the motor (or other connected device) or the cable is the source of low insulation resistance.

Caution:
Hypalon insulation systems have lower insulation resistances than XLPE and EPR insulation systems. The as-manufactured insulation resistance of these Hypalon systems is on the order of 50 megohms-1000 ft (15 megohms-km). The action point for such Hypalon insulations should be 5 megohms-1000 ft (1.5 megohms-km). Kerite "FR" insulation used in 600-V applications is a Hypalon insulation having this characteristic.
Note: Kerite "FR2," "FR3," and "FR4" are EPR based insulations, and the 100 megohms-1000 ft (30.5 megohms-km) action point applies to them.

Separating the motor from the cable for motor testing will provide better results for the motor and is highly recommended if motor surge tests are to be performed. If a motor surge test is performed through the cable, the motor is not being tested properly because the capacitance of the cable will absorb most of the surge voltage before it reaches the motor terminations. When the motor is separated from its cable, insulation testing (tan δ testing for medium-voltage cables) should be performed on the cable.

Insulation resistance is a valuable troubleshooting test but has limited value as a condition monitoring test for cables. Table 2-4 summarizes when and how insulation resistance testing might be of value. Insulation resistance is not recommended as the primary test for assessing shielded medium-voltage cable insulation. It might identify severely degraded wet insulation in the nearly failed state, but it is not expected to detect light to very severe conditions that can be detected by tan δ and dielectric spectroscopy testing. For dry cables, insulation resistance will provide no indication of deteriorated insulation. In other words, insulation resistance is likely to give little warning of the onset of severe aging in medium-voltage cables and in many cases might erroneously indicate that the insulation is satisfactory for long-term service. For non-shielded cables, insulation resistance testing is essentially testing with respect to the contact point between adjacent phases and from phase to random grounds. The results are nearly useless. The only exception is for testing wet, non-shielded, medium-voltage cable. In this case, a bad test result would have to be believed, but an "acceptable" value (gigohms) would not provide confidence that the circuit is or is not in good condition. The result would be better than no data but not an absolute indication of acceptability.

Table 2-4
Applicability of Insulation Resistance Testing to Cable Aging Management

Cable Type and Environment	Condition Monitoring Discussion	Troubleshooting Discussion
Medium-voltage shielded cable: dry environment	Dry insulation will have high insulation resistance whether thermally aged or not. No useful trending data would be expected.	Insulation resistance is useful for troubleshooting failed circuits and can identify the phase that has failed.
Medium-voltage shielded cable: wet environment	If an insulation resistance test is performed and the result does not meet 100 megohms-1000 ft, the phase is severely degraded and should be either replaced or tested with an off-line elevated voltage test such as tan δ to determine condition accurately. Values of a gigohm or more do not indicate that insulation is in satisfactory condition. Only off-line elevated voltage tests can truly indicate insulation condition.	Insulation resistance is useful for troubleshooting failed circuits and can identify the phase that has failed. Values as high as tens of megohms might occur even on a failed phase because faults often blow out the shield, leaving a long surface resistance between the conductor and the remainder of the shield system.
Medium-voltage non-shielded cable: dry environment	Dry insulation will have high insulation resistance whether thermally aged or not. No useful trending data would be expected. The lack of a ground plane for testing compounds the problem.	If a fault occurs and the ground remains electrically close (such as a carbon path and not dry air) to the conductor, insulation resistance might be useful.
Medium-voltage non-shielded cable: wet environment	Insulation resistance will not produce useful data for trending, but it might provide some indication if severe degradation exists under the premise of “some information is better than none.”	If a fault occurs and the ground remains electrically close, insulation resistance might be useful.
Low-voltage power cable (multiconductor or triplexed): dry environment	Dry insulation will have high insulation resistance whether thermally aged or not. No useful trending data would be expected.	If a failure occurs and the failure from conductor to conductor or conductor to ground has a low enough resistance, insulation resistance might be useful.

Table 2-4 (continued)
Applicability of Insulation Resistance Testing to Cable Aging Management

Cable Type and Environment	Condition Monitoring Discussion	Troubleshooting Discussion
Low-voltage power cable (multiconductor or triplexed): wet environment	Insulation resistance from the conductor and to the remaining conductors grounded is the recommended way to assess the integrity of wet, low-voltage power cables.	If a fault occurs, insulation resistance should be useful for determining if the conductors have failed insulation.
Control cable (multiconductor): dry environment	Dry insulation will have high insulation resistance whether thermally aged or not. No useful trending data would be expected.	If a failure occurs and the failure from conductor to conductor or conductor to ground remains electrically close, insulation resistance might be useful.
Control cable (multiconductor): wet environment	Insulation resistance from the conductor and to the remaining conductors grounded is the recommended way to assess the integrity of wet, low-voltage power cables.	If a fault occurs, insulation resistance should be useful for determining if the conductors have failed insulation.
Coaxial and triaxial cable: dry environment	Insulation resistance is unlikely to provide useful condition monitoring data. 1000-V and higher insulation testers might leave a space charge in the insulation that could damage sensors or receivers.	Insulation resistance might be useful to assess a failed circuit. 1000-V and higher insulation testers might leave a space charge in the insulation that could damage sensors or receivers.
Coaxial and triaxial cable: wet environment	Insulation resistance would detect water-related degradation of the insulation system.	If noise is occurring in the circuit, insulation resistance could be used to evaluate the quality of the jacket to determine if multiple shield grounds exist, indicating jacket failure and water ingress.

Summary

Insulation resistance is not recommended as a condition monitoring technique for cables under most conditions, with the exception of wet, low-voltage cable. However, if a value of less than 100 megohms-1000 ft (305 megohms-km) is measured on medium-voltage cable between the shield and the conductor or on low-voltage cable between conductors or conductors and ground, it is a strong indication that the insulation is flawed, deteriorated, or failed—and the cause of the low measurement should be investigated and dispositioned. The insulation resistance of a cable must be adjusted for the circuit length to be of any practical use. Insulation resistance is a valuable troubleshooting tool when cable insulation failure has occurred.

For wet, low-voltage power and control cable, insulation resistance from a conductor to all other conductors grounded is the recommended test for determining if water-related degradation has occurred. For dry, low-voltage power and control cable, insulation resistance is not expected to be a useful condition assessment technique with respect to thermal or radiation aging. The types of insulation in use maintain their insulating properties even when highly thermally aged. Shorting can occur only upon complete physical breakdown of the materials, where the insulation powders or cracks. Even then, if no moisture or chemical contamination exists, electrical failure might not occur.

2.6 Cable Removal from Ducts

When a cable must be removed from a duct for replacement, care must be taken to extract the cable without causing it to jam and become immobile and to preclude damage to the duct system. Although some duct systems have spare ducts, most cable replacements will require removal of the cable from the duct to allow the duct to be reused. Distribution system experience is that cables being extracted jam approximately 20% of the time. Jams are possible on any cable type but are of higher consequence on power cable circuits—especially those with multiple cables per phase, where all of the ducts associated with the cable must be available to obtain the ampacity required to support the load.

Jamming is possible because of the dimensions of the duct and cables at turns, accumulation of debris in the duct, and deterioration of jackets that might dislodge and interfere with the remainder of the cable being removed. Figure 2-10 shows one possible cause of jamming during removal. If the cable is installed as three separate cables rather than triplexed, the three cables will tend to run parallel at a bend rather than in a triangular formation.

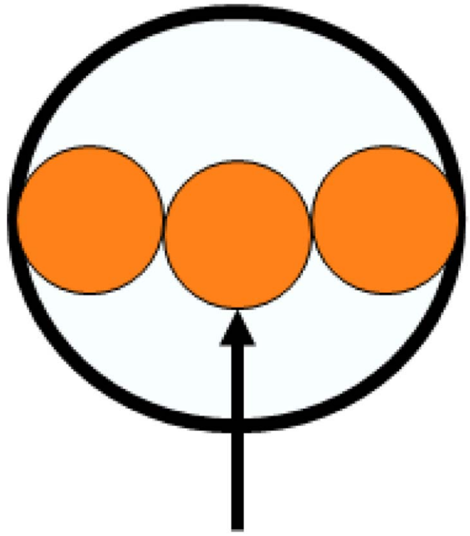

Figure 2-10
Cause of Jamming: Middle Cable Moves Between the Other Two and Acts as a Brake at a Bend

During installation, jamming is a concern when

$$J_r = 1.05 \text{ x } D_d / D_c$$

Where:

D_d = inside diameter of the duct

D_c = outer diameter of one cable

During installation, ratios between 2.8 and 3.1 should be avoided to preclude jams. Similarly, care must be taken on removal, especially if the cable diameters are in this range. To complicate matters, dried pulling compounds, mud, and construction debris might be in the duct along with the cable. If the jacket has deteriorated, as has been seen on old neoprene jackets that were in submerged conditions, the neoprene might be swollen and highly weakened such that it could tear free—adding to the possibility of a jam.

To start a cable moving during removal, the pulling force is likely to be much higher than the allowed pulling force required to limit sidewall bearing pressure during installation. The higher force is needed to free the cable from dried pulling compounds and possible mud or debris in the conduit. If the cable moves, jamming is still possible. The team removing the cable is likely to have a preference for a removal pull point based on conditions at each end of the segment being removed. However, regardless of which end is chosen as the pull point, a pull loop should be attached to the far end to provide an option to pull from the opposite end should the cable jam. See Figure 2-11. Although the trailing pull rope provides no guarantee that the jam can be freed, loosening a jam is not likely without being able to pull the cable from the opposite direction.

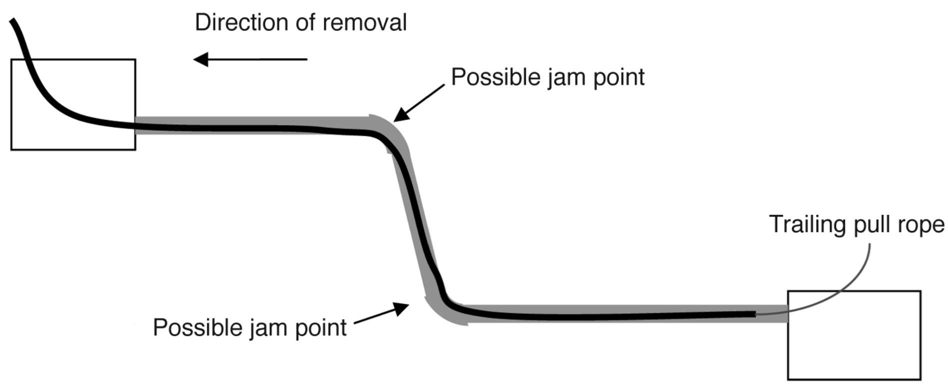

Figure 2-11
Potential Jamming Points During Cable Removal and Training Pull Rope in Case of a Jam

IEEE Std 422 [10] provides further guidance on pulling and installation of cables at power plants.

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