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Medium-Voltage Cables in Nuclear Plant Applications – State of Industry and Conditioning Monitoring

This report describes research sponsored by EPRI and the U.S. Department of Energy under the Nuclear Energy Plant Optimization (NEPO) Program.

Technical Report

Medium-Voltage Cables in Nuclear Plant Applications – State of Industry and Condition Monitoring

1003664

Final Report, October 2003

Cosponsor
U.S. Department of Energy
Washington, D.C.

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This report describes research sponsored by EPRI and the U.S. Department of Energy under the Nuclear Energy Plant Optimization (NEPO) Program, Task FY01-3-8.11.

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

Medium-Voltage Cables in Nuclear Plant Applications – State of Industry and Condition Monitoring, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, D.C.: 2003. 1003664.

REPORT SUMMARY

This report reviews the types of medium-voltage (MV) cables in use in nuclear power plants and the techniques that are currently available to assess the condition of MV cable systems.

Background

Many MV cable systems have been in service in nuclear power plants for 25 years and more. Because cables are critical for plant safety and operation, it is essential for operating personnel to know the condition of their installed cables. The use of high-voltage direct-current (HVDC) withstand testing to assess the condition of aged extruded cables has been questioned by many utilities due to its insensitivity to detect some forms of degradation while causing additional damage to the insulation. As a result, other diagnostic techniques are under evaluation to detect localized damage or to assess the overall condition of the cable insulation.

Objectives

- To identify the types of MV cables in service
- To assess failure experience with MV cables and associated accessories
- To assess the techniques available for determining the condition of MV cable systems

Approach

The project identified the types of cable systems in nuclear plants and their operating conditions and then assessed the aging and failure mechanisms of these cables and suitable diagnostic test techniques. In addition, ways to alleviate conditions that cause the most severe aging were identified.

Results

A survey identified the main types and designs of the extruded cables presently in use in nuclear power plants. The majority of the cables were ethylene propylene rubber (EPR) insulated cables manufactured prior to the 1980s when the higher levels of contaminants in the insulation and shield materials made the cables prone to aging earlier than originally expected, particularly when operating under wet conditions. Although the number of reported in-service failures was not large, about one-third could be attributed to water tree degradation and about one third to unknown causes where water could have been a factor. The results indicate that the pre-1980

vintage cables operating under wet conditions will be susceptible to water-induced degradation and possible failures in service prior to the end of the original projected 40-year life. Early replacement may be necessary to preclude in-service failures. However, non-nuclear plant experience has shown that injecting wet cables with a silicone solution prolongs cable life. This may be considered as an alternative to full cable replacement.

The survey also identified that utilities were still using HVDC withstand testing of their cable systems. This practice is being discontinued by many utilities due to the possibility of the HVDC causing additional damage. Alternative diagnostic tests have been and continue to be developed to detect localized degradation by partial discharges (PD) and to measure the average condition of the insulation by dissipation factor or similar measurements. The measurement techniques themselves are reasonably well developed, but the interpretation of data to assess cable condition needs further improvement. Utilities have reported mixed results in their assessment of distribution circuits. Most of the experience in cable assessment, however, has been gathered for cross-linked polyethylene (XLPE) insulated cables. There is little experience with EPR cables so that significant work is necessary to develop cable assessment criteria for both pink and gray EPRs. A very low frequency (VLF) test guide has proposed standard test voltages for XLPE cables and should be considered as an alternative to direct current (dc) hipot testing.

EPRI Perspective

Although the amount of MV cable used in nuclear power plants is not great, the cables are used in applications that are critical to both safety and operations. Most of the MV cable in service was installed at the time of plant construction. Some of these cables are as much as 36 years old, and numerous cables are between 25 and 30 years old. The bulk of the cables in service were manufactured before the significance of contaminants and voids in the insulation was understood. With the passage of time, contaminants and voids can lead to electrical failure, especially when the cable is wet. This report was prepared to provide plant personnel with a concise description of the insulation materials in use and their characteristics, the degradation mechanisms and service conditions that increase the rate of degradation, and a summary of the state of the art in monitoring the degradation of insulation.

Keywords

Nuclear plant cables
Medium-voltage cable
Water treeing
Electrical treeing
Cable condition monitoring

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1 INTRODUCTION

Older medium-voltage (MV) cable systems installed in nuclear power plants are approaching or have exceeded 30 years of service, and some of the cable types have reached or are approaching the end of their expected lives. Accordingly, there are concerns regarding their reliability and how much longer they can operate. Because continuous operation of the MV cable systems is essential for plant safety and operation, plant operators need to know the condition of their installed cables so that a planned replacement program, if required, can be set up with a minimum effect on operations and cost.

The extruded insulation cables used in nuclear power plants were “designed” to have the same life span (approximately 40 years) as the paper-insulated lead-covered (PILC) cables that had previously been used in the power industry. This was long before water treeing of insulating polymers was identified as a concern. Water treeing reduced the life span to less than 40 years for some polymer insulations, particularly those manufactured in the 1970s and early 1980s. The experience of operating in wet or dry environments shows that generally dry cables, even those with significant levels of polymer contamination during manufacture (1970s and 1980s), will perform satisfactorily for at least 40 years. If the cables have been running near their maximum temperatures for all that time, then thermal aging could reduce their operating lives. Thermal aging may cause embrittlement of the insulation shield or jackets. It is expected that dry cables will operate for more than 40 years if they are not heavily loaded, because they do not experience a large decrease in alternating current (ac) breakdown strength with aging duration. However, all polymer insulations show significant decreases in breakdown strength over time when immersed in water while energized.

The success of dc testing to assess the condition of PILC cables made it an ideal candidate to assess extruded insulations also. However, dc testing is losing credibility as an effective assessment tool for cables with extruded insulations, and several alternative techniques have been proposed. These alternative tests range from potentially destructive withstand tests up to $3U_o$[1] to nondestructive tests that measure either bulk or localized properties of the insulation. Some of the techniques assess the aging and failure mechanisms in a specific insulation system operating in a particular environment more effectively than others. Some cable configurations (for example, those with shields) are more amenable to the assessment of degradation than others. The variation in cable constructions, operating environments, and failure mechanisms requires a full understanding of the cable population and operating conditions to allow the selection and implementation of an effective diagnostic test method for nuclear plant MV cables.

[1] U_o is line to ground voltage.

Presently, several MV cable types with different constructions and insulations are in use in nuclear power plants. MV cables may have one or three conductors, insulation with or without an insulation shield, and a jacket. Most MV plant cables in nuclear plants have extruded insulations, either ethylene propylene rubber (EPR) or cross-linked polyethylene (XLPE). EPR comes in different formulations, depending on the manufacturer's preference, and in different colors—black (older versions), pink, and gray. A limited number of the cables installed in the late 1960s or early 1970s were insulated with butyl rubber.

The insulation shield, if present, consists of an extruded semiconducting layer plus bare or tinned copper strands or tinned copper tapes. It is likely that, in early vintage cable, the insulation shield was a thermoplastic polymer, which could be susceptible to deformation and cracking when exposed to high temperatures for prolonged periods. Some cable engineers refer to the metallic tapes as the *concentric neutral*.

The jackets are usually made from polyvinyl chloride (PVC), chlorinated polyethylene (CPE), or chlorosulfonated polyethylene (CSPE).

Various types of accessories (splices, terminations, or potheads) are used to connect the cables to each other and associated equipment, depending on the type and insulation of the cable. Because of the higher voltages associated with MV cables, the design and installation of the insulation of connections is critical for proper operation, especially when shields are present.

The aging mechanisms are different for extruded cables when operating in dry or wet environments, and the rate of aging will depend on the specific type of insulation, that is, the type of EPR or XLPE, quality of manufacture, and operating voltage. In nuclear power plants, the majority of cable circuits operate in a normally dry environment; however, some circuits may be in wet underground ducts and experience more severe aging as a result. Care must be exercised in relating known failures to the insulation material, cable construction, and operating environment to avoid reaching an erroneous diagnostic conclusion and taking inappropriate actions, for example, unnecessary cable replacement.

This report reviews techniques to assess the condition of MV cable systems by:

- Identifying cable systems in nuclear plants, the conditions under which they operate, and their failure records
- Assessing the different aging and failure mechanisms in relation to diagnostic test techniques
- Identifying and alleviating the operating conditions that cause the most severe aging

2 CABLE SYSTEMS, PLANT ENVIRONMENTS, AND FAILURE RECORDS

The cable systems used in nuclear plants, their environments, and failure records were identified to the extent possible. The three key elements—cable, environment, and failure statistics—are intimately linked. The plant environment and operating stresses (electrical, thermal, and mechanical) directly affect the rate of aging of polymer-insulated cables. Failure rates also depend on the severity of the aging of the individual components of the cable system. To predict the performance of a cable system, the details of the cable system, its aging mechanisms, and failure records must be known.

To determine the necessary information, a questionnaire was prepared and distributed to EPRI member utilities with nuclear plants. The questionnaire, which is included in Appendix A, asked for details about the type of cable, accessories, installation, operating environment, and failure statistics.

The responses to the questionnaire represent 14 units from 8 stations. Full details regarding the lengths of cables installed were not given for four units. Failure statistics were received from about 45 units from 30 stations. This represents more than 40% of the units in operation in the United States.

Table 2-1 lists the general characteristics of MV cable systems obtained from the data.

The choice of single conductor or three conductor cables appears to depend on the utility. One utility has a small number of 35 kilovolt (kV) cables with pink EPR insulation.

Most of the cables have been installed in trays or ducts, with a limited number of cables at a few stations installed in trenches. The cables in trays are usually spaced, but some are randomly laid. Some utilities attempt to keep their cables in ducts dry by periodically pumping out those ducts and manholes that fill with water.

Most utilities perform a dc hipot testing after installation, but none conducts any other diagnostic testing. Sometimes dc hipot is used after a repair or long outage. The test voltages used for post-installation tests range from 500 V for 1 minute to 2–3 U_o, where U_o is the phase-to-ground voltage, for 5–15 minutes for EPR. One utility reported carrying out post-installation dc hipot testing of XLPE cables at 1–2 U_o. One utility carries out post-installation ac hipot testing at voltages up to three U_o for up to five minutes.

Table 2-1
General Characteristics of Nuclear Power Plant Cables

Cable		
	4/5 kV	**8 kV**
Conductor material	Aluminum or Copper	Aluminum or Copper
Conductor size	2/0 to 1000 MCM[1]	2/0 to 1000 MCM[1]
Conductor number	Single or three	Single or three
Conductor shield	Extruded	Extruded
Insulation	EPR (different types)[2] Mostly133% thickness, some 100%	EPR (different types)[2] Mostly 133% thickness, some 100%
	XLPE[3] 133% thickness	XLPE[3] 133% thickness
Insulation shield	Unshielded (most EPR)[4]	Unshielded (some EPR)[4]
	Extruded (for XLPE)	Extruded (for XLPE)
Neutral (when present)	Concentric tinned copper tape	Concentric tinned copper tape
Jacket	CSPE or CPE or PVC[5]	CSPE or CPE or PVC[5]
Number of manufacturers[6]	8	5
Terminations		
	4/5 kV	8 kV
Type (number of manufacturers)	Heat shrink (1)	Heat shrink (1)
	Handmade (>2)	Handmade (>2)
Splices[7]		
Type (number of manufacturers)	Heat shrink (1)	Heat shrink (1)
	Handmade (2)	Handmade (2)

1 MCM = thousands of circular mils. A circular mil equals the area of a circle 0.001 inches in diameter (7.854e-7 in^2 [5.067e-4 mm^2]).

2 There are different types of EPR, for example black and pink, and compounds from different manufacturers can have significantly different properties. EPR appears to be the insulation that is mostly widely used for nuclear station MV application.

3 Most XLPE was installed prior to 1981. One utility mentioned that it is replacing cables with original XLPE with cables having a tree-retardant XLPE (TR-XLPE).

4 Many 5-kV and some 8-kV EPR cables did not have an insulation shield. All XLPE cables had an insulation shield.

5 All cables have jackets. XLPE cables tended to have PVC jackets. Newer EPR cables have CSPE jackets.

[6] Many of the cables were manufactured prior to 1985 when there were many more cable manufacturers than there are in 2003. Some of the original manufacturers have been acquired by other companies or have ceased to exist.

[7] The majority of utilities do not have splices in their cable systems at voltages above 4 kV. The installation of splices is restricted to long runs, so that the total number of splices on MV cables in nuclear power plants is small.

The above information represents the comments from fewer than half of the nuclear units in the United States. Even so, some of the trends are probably universal, for example, the use of jacketed cables and EPR insulation, the minimal use of splices, and post-installation dc hipot testing. It is important to know the extent to which utilities maintain their cables under dry conditions. Some of the failures described below have been attributed to moisture-induced degradation from extended immersion in water.

The accuracy of failure data depends on how well utilities record and maintain statistics. It is likely that recordkeeping before the middle to late 1980s is not as good as recordkeeping since that time. Table 2-2 lists the data of cables that have failed in service, and Table 2-3 gives details of other cable failures (for example, those that occurred during dc hipot testing during outages).

Table 2-2
Failures In-Service

Cable Failures				
Year	**Voltage/ Insulation**	**Years in Service**	**Cause**	**Comments**
1978	5 kV/XLPE	~5	Treeing/installation damage.	Three cables failed.
Mid-1980s	5 kV/XLPE	>10	Water trees.	Cable installed in tray (dry).
1988	8 kV/XLPE	~10	Physical damage.	No water trees found.
1989	8 kV/EPR	~8	Unknown cause.	No water trees found.
1993	5 kV/EPR	~21	Unknown cause.	Similar cable to those that failed due to manufacturing defect.
1995	5 kV/EPR	>9	Manufacturing defect.	Two failures within six months.
1995	5 kV/Not stated	Not stated	Unknown cause. Moisture in insulation.	Off-site power source.
1995	5 kV/EPR	~23	Unknown cause.	
1996	5 kV/EPR	7	Water treeing.	Voids and contaminants in EPR.
1996	5 kV/EPR	22	Unknown cause.	
1997	5 kV/XLPE	~24	Failed at contaminant introduced during manufacture.	No mention of water treeing.
1997	5 kV/XLPE	25	Water treeing suspected.	
1998	15 kV/PE	25	Cause not specified.	Water treeing possible.
1998	5 kV/EPR	Not stated	Crack due to overheating.	
1999	5 kV/EPR	25	Water in insulation.	
2000	5 kV/EPR	~20	Failed at excessive bend.	
2001	5 kV/EPR	~27	Defect in cable design.	
2001	5 kV/EPR	29	Unknown cause although jacket was split at failure site.	Water treeing possible.
2002	8 kV/XLPE	~22	Unknown cause.	
2002	15 kV/EPR	~20	Water in insulation. Delamination of shield.	PDs were identifiable when cable had dried.
2003	5 kV/EPR	~23	Unknown cause. Cable probably wet at failure site.	Other failures in unshielded cables of similar vintage.

Table 2-2
Failures In-Service (continued)

Accessory Failures				
Year	**Voltage/ Insulation**	**Years in Service**	**Cause**	**Comments**
1988	8 kV/XLPE splice	~8	Unknown cause.	No water treeing in cable.
1996	5 kV/XLPE	28	Unknown cause.	Two splice failures.
1998	35 kV/unknown splice	>30	Unknown cause.	

Eight additional failures were reported, but some details regarding construction or age are not known. The known details are:

- 2 failures probably due to lightning in 15 kV gray EPR; time in service unknown.
- 1 failure in 15 kV pink EPR cable in service less than 10 years; cause unknown.
- 2 failures in 15 kV pink EPR cable in service less than 10 years, cables operating dry; cause unknown, but damage during installation suspected.
- 1 failure in 15 kV pink EPR cable; cable age and cause unknown, but may have been exposed to water.
- 2 failures in 5 kV cables, insulation unknown; cause unknown.

Four cables failed due to mechanical damage caused when other work was performed nearby. Dig-ins and cables damaged during installation have not been included.

Table 2-3
Failures Identified During Outage Periods

Cable Failures				
Year	**Voltage/ Insulation**	**Years in Service**	**Cause**	**Comments**
1978	5 kV/XLPE	>5	Physical damage during installation. Treeing evident.	17 lengths failed hipot test.
Late 1970s	8 kV/XLPE	0	Physical damage during installation.	3 cable lengths. Failed acceptance test.
Late 1970s	8 kV/XLPE	>5	Damaged during outage.	
Mid-1980s	8 kV/XLPE	0	Physical damage during installation.	2 cable lengths damaged.
1992	8 kV/EPR	>10	Unknown cause. Failed hipot test after being out of service for a long time.	10 out of 54 cable lengths failed. No trees found.
1994	8 kV/XLPE	~14	Water tree at manufacturing defect.	Failed hipot test.
Mid-1990s	8 kV/XLPE	~15	Physical damage due to dig-in.	
Late 1990s	8 kV/XLPE	~18	Damaged during outage.	
Accessory Failures				
2000	Not stated/ termination	Not stated	Loose connection caused overheating of cable.	Detected during outage.
2000	Not stated/ leads	Not stated	Overheating due to inadequate connectors.	Detected during outage.

Table 2-4 summarizes the results from Table 2-2 and Table 2-3.

Table 2-4
Summary of the Cable Failure Data

In-Service Failures					
Damage	**Treeing**	**Unknown**	**Cable defects**	**Thermal**	**Total**
3	8	9	4	1	25
Other Cable Failures					
25	1	10	0	0	36
Accessories					
Unknown	**Connector Problems Causing Overheating**			**Total**	
3	2			5	

Of the 24 in-service cable failures reported, water treeing accounts for about one-third. The real number of water treeing-related failures is probably larger, as water was found in some of the failures having no specific cause listed, although no trees were observed during failure evaluations. Also, water treeing can initiate the failures from defects. Five of the water treeing failures were in XLPE and three in EPR; six of the failures with no known cause were in EPR and three in XLPE. As shown in Table 2-3, water treeing was evident in several XLPE cables that failed the dc hipot test. Although no water trees were found in the 10 (out of 54) EPR cables that failed the dc hipot test (see the 1992 EPR entry), the low withstand strength is indicative of severe electrical degradation. It must be noted that water trees are more difficult to detect in opaque materials such as EPR.

There was no information given about the manufacturers of the failed XLPE cables or the accessories. The cable insulation in two failures was not reported. Of the 14 in-service failures in EPR cables, eight were in Anaconda cables, some of which were black EPR; two were in Okonite cables; two were in black General Cable EPR cables; and one failure was reported in a Cablec Corp. cable. There were no failures reported in gray Kerite EPR cables. One Anaconda EPR cable failure was caused by excessive bending. Manufacturing defects and moisture were listed as the possible cause of failures in four cases, and unknown causes in another three of the Anaconda cables. One failure in each of the Okonite and General Cable cables was attributed to unknown causes and one each to moisture. The data indicate that EPR cables made more than 20 years ago are susceptible to degradation when operating under wet conditions. Although more failures are evident in cables made by Anaconda, to determine a failure rate per unit length of installed cable, the total installed lengths of cable from each manufacturer would be required and is not known as of this writing.

Many of the cables installed in nuclear plants were manufactured before the mid-1980s. Prior to that time, the handling of materials for cable manufacture was done in the open air, which resulted in contamination of the insulating and semiconducting compounds. In addition, semiconducting compounds contained significant quantities of impurities and ions. Some impurities and contaminants became initiation sites for both electrical and water trees. By the mid-1980s, the cable industry began to realize that cleanliness of the materials and the control of contaminants during cable manufacture were very important to suppress electrical and water treeing in cables in service, particularly in XLPE cables. This discovery resulted in technological improvements in the way materials were produced and transported (in sealed containers), and the way cables were extruded (under "clean room" conditions). It is widely accepted that present-day cables, both XLPE and EPR, have higher quality insulation than those made prior to the mid-1980s. These newer cables have much lower levels of contaminants and impurities in the semiconducting and insulating materials, making them less susceptible to water treeing if allowed to operate under wet conditions.

When performing failure assessments, both electrical and water trees are easier to see in translucent XLPE than in EPR. The difficulty of seeing water trees in EPR, caused by its opacity, has led to the misconception that trees do not occur in EPR. Trees have been observed in pink EPR although they appear to grow at a slower rate than they do in XLPE. Because EPR is opaque, water trees can be seen only if the insulation is cut directly through a tree after the insulation has been dyed. Although some of the older black EPR cables have shown a decrease in breakdown strength with aging similar to, or even exceeding, pink EPR, it is not possible to see water trees with the "standard" dyeing methods used to detect trees. It is also not possible to see water trees in gray EPR. Because XLPE is translucent, it is possible to examine the volume of the insulation for trees, making them easier to see. Whether or not it is possible to see the trees in the material, any extruded insulation subjected to moisture is susceptible to water treeing.

An important observation is that there were a number of failures in one pink EPR cable design from one manufacturer. If water is allowed to enter the cable from this manufacturer, the water can accumulate in voids, particularly at the interface between the insulation shield and the insulation. This results in delamination between the semiconducting shield and the insulation. If the insulation dries out, the resulting air gap can be the site for partial discharges (PDs) that can lead to electrical treeing and failure. In laboratory tests, all insulations, XLPE, and black, pink, and gray EPRs show significant decreases in ac and impulse breakdown strengths during the 12 to 18 months of tests when immersed in water under voltage [1, 2]. Thereafter, the rates of decrease in breakdown strengths are much slower and tend to reach limiting values after 3–5 years. There has been considerable discussion in the industry regarding the magnitude of the decreases for the different materials and if water trees are solely responsible. There is also debate over the use of absolute values of breakdown strength or the percentage retention. The absolute values tend to favor TR-XLPE in that its breakdown strength is larger than that of any of the EPRs, whereas the percentage retention of breakdown strength favors the EPRs. The EPRs have a lower initial breakdown strength, but the initial rate of decrease with immersion time in water is less than that of TR-XLPE. Of the EPRs, the gray EPR has the lowest initial ac and impulse breakdown strengths but also the lowest rates of decrease with immersion in water. The data reported [1, 2] are for cables manufactured in the 1990s, which have cleaner insulations and improved manufacturing compared with those manufactured in the 1970s and 1980s. There are no published data comparing the wet performance of the three types of EPR cables manufactured in the 1970s and 1980s.

Field failures have been reported in the literature with all insulations except the gray EPR. However, there is little gray EPR installed in distribution systems. In addition, there are no published data from accelerated aging tests on gray EPR.

Another important concern relates to dc hipot testing performed on cables that have been in service for some time. Several studies have shown that MV cables that have been immersed in water for long periods and degraded by water trees have a low dc dielectric strength even though they may be satisfactory for further operation. As a result, many utilities have stopped dc hipot testing and are now performing other types of tests or dc tests at lower voltages to measure dc leakage currents.

The recommendations from the collected data are to:

- Continue collecting and analyzing to give an indication of important trends
- Operate cables under dry conditions to prolong cable life
- Stop dc hipot testing to verify the integrity of service aged cables or at least to lower test voltages

3

USEFULNESS OF EXISTING TEST METHODS FOR THE EVALUATION OF CABLE AGING

Aging and Failure Mechanisms

Aging is generally defined as the irreversible changes in the properties of materials or components over time. The type of aging (for example, electrical, thermal, or mechanical), aging rate, and failure mechanisms will differ according to the cable construction and insulation and the stresses (such as actual operating voltage, number and level of voltage surges, level of operating current, and physical stress such as pinching or wetting) cables are subjected to during operation.

The usual aging stress of extruded cable systems is electrical, although under abnormal conditions thermal aging may be significant, for example, if heavily loaded cable systems are located close to one another or if the cables are exposed to severe external heating or radiant energy. Electrical stress is controlled by the cable geometry and applied voltage. Thermal aging is determined by the conductor and ambient temperatures. Electrical aging is localized and occurs in regions where there are electrical stress concentrations or weaknesses in the insulation, for example, at defects that are unintentionally introduced into the cable system during material processing, cable/accessory manufacture, transportation, installation, or during operation. The main defects responsible for electrical aging are shown in Figure 3-1 and listed in Table 3-1.

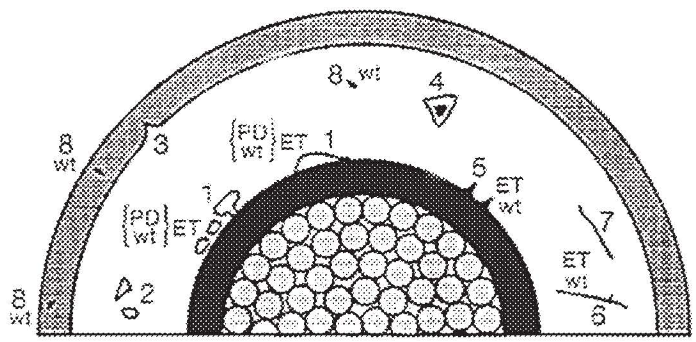


Figure 3-1
Section of Part of Extruded Cable Showing Possible Defects and Type of Aging Expected

PD partial discharge

wt water tree initiation site

ET electrical tree initiation site

Legend for Figure 3-1:

1 Cavities close to shields or flat voids caused by delamination between insulation and shields. Cavities are electrically weak (have low dielectric strength) compared to the solid insulation.

2 Cavities in insulation caused by shrinkage. They can be a source of PDs or bow-tie water trees, if filled with water.

3 Defects in the shield (insulation shield shown here, but can also occur in conductor shield).

4 Loosely-bound contaminant in the insulation. The contaminant may be conducting or insulating and is a likely source of PD due to the gas surrounding it. Soluble contaminants are a source of bow-tie water trees.

5 Protrusions from shield (can occur from either shield). Protrusions are stress enhancements.

6 Conducting splinter-shaped contaminant in the insulation. A stress enhancement.

7 Insulating fibrous contaminant in the insulation. A stress enhancement.

8 Conducting or soluble contaminants in the shields. Soluble contaminants can be a source of vented water trees.

Table 3-1
Defects in MV Extruded Cables

Type of Defect	Origin	Effect
Contaminant	• Metallic particle from extruder and/or mixer. • Fibers from insulating material transport container. • Particles from atmosphere during manufacture. • Particles in semiconducting shield from manufacturing process. • Residues from polymer compounding and mixing. • Impurities in compounds during manufacture. • Diffusion from outside, such as water or ions. • Particles introduced accidentally at interfaces during installation.	SE
Protrusions/skips	• Irregularities in semiconducting shield/insulation interfaces formed during cable extrusion. • Agglomeration of carbon particles from semiconducting shield at interface.	SE
Voids/cavities in insulation	• Formed during extrusion by shrinkage. • Formed around contaminant that does not fully adhere to the polymer. • Formed during cross-linking by steam-curing (halos of water-filled microvoids visible in steam-cured cables). • At interfaces between the insulations of a cable and its accessories due to thermal expansion or pressure. • Cuts at interfaces during installation of accessories.	WI
Voids/cavities due to delamination at semiconducting/insulation interface	• Separation of semiconducting shield layer from insulation to leave air gap. • Looseness of insulation shield over insulation due to repeated thermal expansion and contraction. • Water accumulation at interface causes separation at interface: leaves cavity if allowed to dry.	WI
Installation issues: Pinching (improper vertical support) Disruption of Shields from overbending		SE

SE electrical stress enhancement. Example: #5 in Figure 3-1.

WI weakness in insulation, a region of low dielectric strength. Example: #1 or #2 in Figure 3-1.

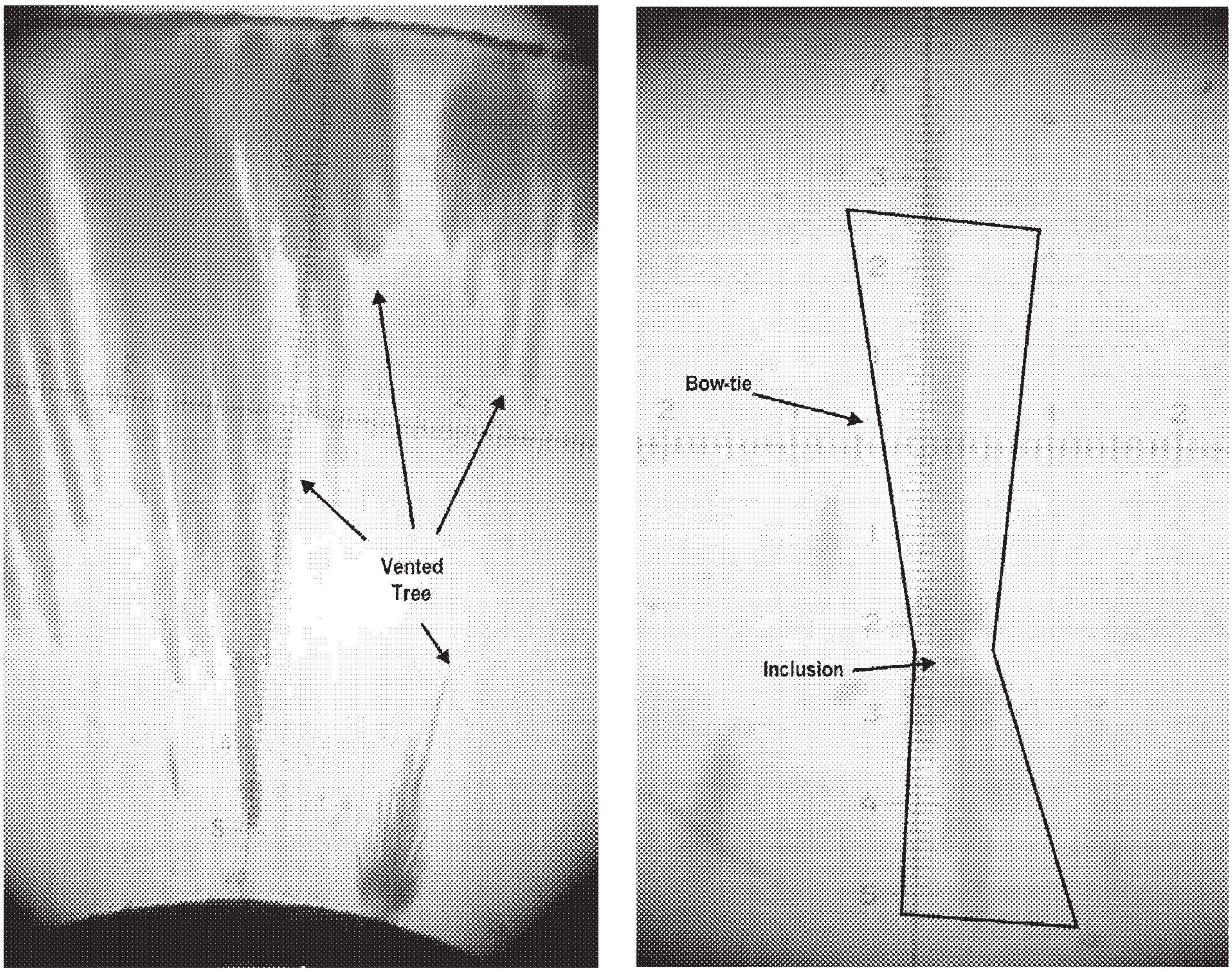
Table 3-1 indicates that two effects occur from defects: stress enhancement and weakness in the insulation. Stress enhancement increases the effect of the applied voltage across the insulation such that normal applied voltages have the effect of much higher voltages. Weaknesses in the insulation cause the insulation to be less capable of withstanding the applied voltage.

Two electrical aging mechanisms are 1) water treeing at contaminants, protrusions, and water-filled microvoids and 2) electrical treeing at stress enhancements due to contaminants and protrusions. Another electrical aging mechanism—PDs—can occur at gas-filled voids or cavities in the insulation. These aging mechanisms result in localized degradation at defects. Although there has been a concerted effort to reduce the types, numbers, and sizes of the defects, they cannot be eliminated completely from cable systems. As a general rule, as the intensity of the defects decreases, their influence on aging begins at higher electrical stresses and the rate of aging will be slower. The aging mechanisms can occur simultaneously and change with time. Accordingly, vastly different rates of aging will result for different cable insulations and operating conditions. To determine the condition of a cable system, tests that measure the degree of aging and the aging rates must be performed on the cable systems.

The data from the questionnaire showed that the majority of MV cables were installed in nuclear plants prior to the mid-1980s. The semiconducting and insulating compounds in use at that time had significantly higher levels of contaminants than those found in cables manufactured today, and, as a result, are more prone to aging. The higher level of contamination of the conductor shields will cause a higher rate of water treeing under wet conditions than will occur in cables produced after the mid-1980s.

Water Treeing

A *water tree* is a collection of water-filled microvoids that propagate over time in insulation in the direction of the electric field while energized. It is caused by contaminants and protrusions and occurs when the insulation is immersed in water. Under a microscope, water trees look like trees. Water trees cause a gradual reduction in the breakdown strength and can result in premature failures in service. Figure 3-2 shows typical water trees in XLPE insulation. The tree will grow more rapidly if the contaminant is soluble (for example, a salt particle) due to increased osmotic pressure created by the concentration of ions. If the contaminants are in the bulk of the extruded insulation, the water trees are referred to as *bow-tie trees* because they have a bow-tie shape (see Figure 3-2b). Bow-tie trees will also grow from water-filled microvoids in the insulation. If the contaminants or protrusions are at the interfaces between the insulation and the shield or in the shields themselves, the trees growing from them are referred to as *vented trees* or *streamer trees* (see Figure 3-2a). Water trees are generally non-conducting but, due to their high dielectric constant, can act as stress enhancements at their tips, thus increasing the effect of voltage on the remaining insulation. Mature vented water trees may be partially conducting near their base. The growth rate and lengths of water trees depend on several factors, the most important of which are type of ions at soluble contaminants and the applied voltage. Bow-tie trees from microvoids tend to reach a limiting length of several tens of microns independent of voltage; however, a bow-tie tree from a soluble contaminant can grow several millimeters at typical operating stresses (~2 kV/mm [~51V/mil]). If a cable is allowed to dry, water trees can dry out and often become invisible, causing an increase in electric breakdown strength. The trees reappear with a corresponding breakdown strength decrease when the cable is rewetted. The growth rate of water trees is slow; it usually takes several years for the trees to grow through the insulation thickness of 5 or 8 kV cables. The cable jacket will also retard the initiation of water trees because the water and soluble ions have to permeate the jacket to reach the insulation. Although voltage stress is necessary for water trees to grow in 5- to 8-kV cable insulation, the contamination of the insulation is more critical. The degree of contamination, the size of the contaminants, and their location are factors affecting the formation of trees and the rate of growth.



(a) (b)

Figure 3-2
Examples of Water Trees. (a) Vented trees can be seen growing from the conductor and insulation shields interfaces. A small bow-tie tree is also visible. Thickness of the insulation is 2.3 mm. (b) A bow-tie tree is growing from a contaminant or void. The length of the bow-tie tree is 1.6 mm.

As mentioned previously, the ac and impulse breakdown strengths decrease for XLPE and EPR insulation that operates immersed in water. The wet performance of black EPR is worse than that of pink EPR, and for this reason has been largely superseded by pink EPR. The reduction in breakdown strength is lowest for gray EPR. The reduction in breakdown strengths for black and gray EPR indicates there is water-induced damage even though no water trees are visible when conventional staining techniques are used.

The improvement in electrical properties if a cable is allowed to dry throughout makes it important to maintain wet cables in that condition if they are taken out of service for diagnostic testing, particularly if they have been removed for laboratory tests. Even if kept wet, cables should be tested as soon as it is convenient and not allowed to sit unenergized for longer than 2–3 weeks because the electrical characteristics of the water trees slowly revert with time.

Impact of Water Trees and the Transition to Electrical Treeing

Water treeing is a “silent” deterioration mechanism because there are no detectable PDs during water tree growth. A water tree usually causes failure by converting to an electrical tree, and this is when PDs may occur, for example, when one or more gas-filled channels appears shortly before failure. Often, a transient overvoltage (such as lightning or a switching surge) initiates the electrical tree adjacent to a mature water tree, and PDs result.

The change in dielectric constant in a water tree causes an increased stress at the tips of the tree. In more mature water trees, a higher density of water-filled microvoids exists, which increases the dielectric constant, with a corresponding increase in electrical stress in the insulation at the tree tip. As the tree tip approaches another stress enhancement in the insulation, or as it approaches the interface between the insulation and the conductor or insulation shield, the local field can become sufficiently large—particularly if the cable is subjected to a voltage transient—to initiate an electrical tree. The electrical tree is initiated either from the tip of the water tree, or from the stress enhancement in the insulation or at the interface. Once an electrical tree has initiated, PDs may occur every half-cycle of the applied voltage within the gas-filled electrical tree channels. The PDs cause the electrical tree to grow and propagate quickly through the insulation relative to the growth rate of water trees.

Individual water trees have small changes in the dielectric constant and conductivity, which make water trees difficult to detect. Large numbers of water trees will increase the loss current and change the dielectric constant that can be measured by power factor measurements or dielectric spectroscopy.

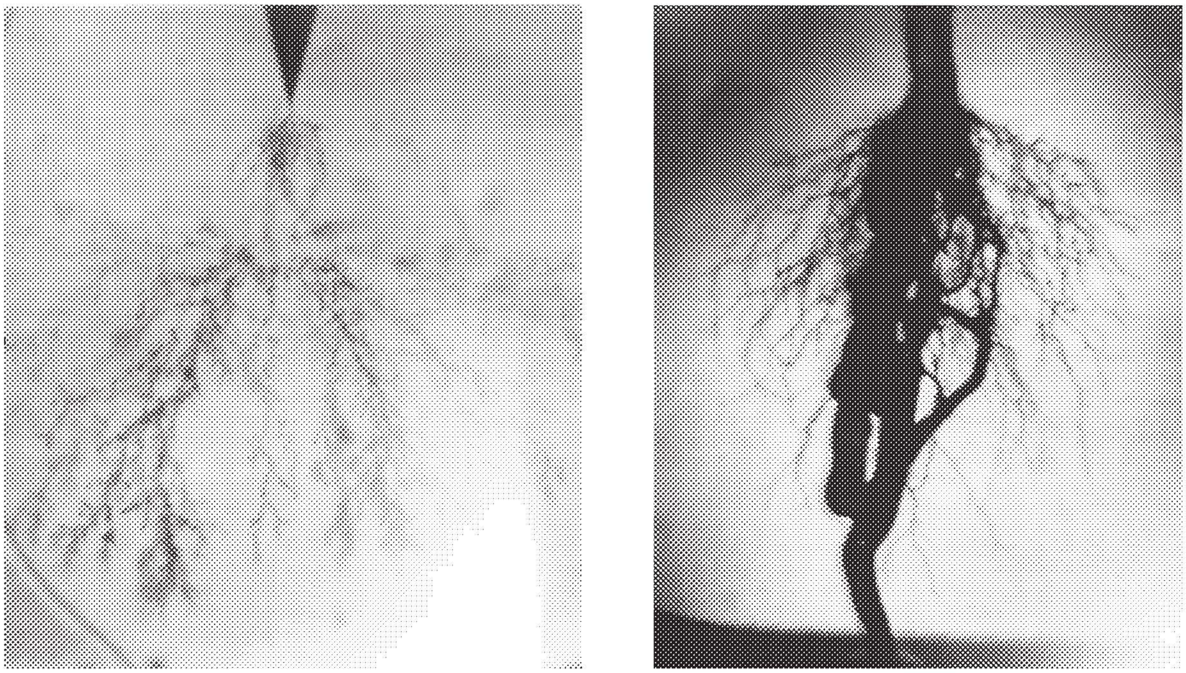
An issue that is often raised related to water tree-degraded insulation concerns the condition of cables that are periodically submerged in water and then dried. Repeated arguments have been made that submergence and drying are more harmful than continuous submergence because the wet microvoids in a water tree could be initiation sites of PDs when allowed to dry. However, there is no experimental evidence to support this argument. In addition, the PD inception stress in gas-filled microvoids of the sizes typically found in water trees is at least an order of magnitude greater than at operating stress. The water tree growth rate in cables that are submerged in water only part of the time would be slower than that in continuously submerged cables.

The severity of the degradation caused by water treeing will depend on the material, as well as the number and the lengths of the water trees. Long water trees will significantly increase the probability of failure. Even one failure of a cable installed in a duct means that the cable would have to be replaced. However, numerous small bow-tie trees from water-filled microvoids will reduce the breakdown strength, but usually not sufficiently to cause failure under typical operating conditions. As a result, large soluble contaminants, either in the insulation or in the shields, are particularly harmful because they may be the initiation sites for long water trees. These long water trees may take several years to penetrate the insulation. These large soluble contaminants are relatively benign if the cable is operated under dry conditions and would have little effect on the long-term performance of the cable. From a practical viewpoint, it would take only one large soluble contaminant per cable length to cause failure under wet conditions, and it would be very difficult to detect such a contaminant by any of the presently available diagnostic test techniques.

A large soluble contaminant in EPR immersed in water will absorb water to form a pressurized water bubble in the insulation. Under the action of the electrical field, the water bubble will become elliptical in shape, which will further enhance the electrical field along the major axis. This stress enhancement, even in the absence of a water tree, will cause a reduction in ac and impulse breakdown strengths.

Electrical Trees

If the stress at the tip of a protrusion or contaminant is sufficiently high (typically greater than 150 to 200 kV/mm [3.8 to 5.1 kV/mil]), charge injection and extraction takes place every half cycle of the applied voltage. This charge motion eventually causes breakage of polymer bonds, localized fatigue, and a small crack to appear in the insulation. When this crack reaches a critical size, PDs occur, which cause the crack to grow and form a channel. Additional channels may form at the tip by the action of PDs. This results in a network of gas-filled channels that resemble a tree, referred to as an *electrical tree*. Typical electrical trees are shown in Figure 3-3. Failure results when one or more of the channels penetrates the complete insulation. Electrical trees usually grow due to the action of PDs within the gas-filled channels and can be recognized by conventional PD detection equipment if the PD characteristics of electrical trees are known. Once an electrical tree has initiated and the gas-filled tree channels have grown to several tens of micrometers, the electrical stress required to sustain PDs to cause the electrical tree to grow is that required to cause breakdown of the gas in the cavity, typically 2 to 5kV/mm (0.051 to 0.127 kV/mil), which is a fraction of the electrical tree initiation stress. The electrical tree growth rate depends on the average electrical stress and the temperature of the insulation and in laboratory experiments has varied from ~0.4 mils/h to >2 in/h (~0.01 mm/h to >50 mm/h) for XLPE [3]. Electrical trees can initiate and grow in dry or wet insulation, depending on the severity of the defects and the applied voltage the magnitude of the local electrical stress. Electrical trees grow more rapidly in XLPE than in pink, black, or gray EPR. Gray EPR is particularly resistant to PD and presumably is resistant to growth of electrical trees.



(a) (b)

Figure 3-3
Examples of Electrical Trees in XLPE. (a) Electrical trees grown from a needle tip. (b) Breakdown path through an electrical tree.

Electrical trees, unlike water trees, require PDs to grow. Also, unlike the water-filled microvoids of a water tree that can disappear if the insulation dries out, the gas-filled channels of an electrical tree are permanent. The stress to initiate an electrical tree is about two orders of magnitude larger than that required to initiate a water tree. An electrical tree is usually the failure mechanism resulting from water tree degradation.

Partial Discharges

Partial discharges (PDs) are electrical discharges that can take place in gaseous inclusions, which may accidentally occur in solid insulation, as listed in Table 2-1. PDs do not bridge the whole insulation (that is, do not extend from conductor to ground) but can lead to ultimate failure. A PD takes place in nanoseconds and causes high frequency currents, measurable by PD detection equipment, to flow in the external circuit. After a discharge, both positive and negative charges are deposited on the surfaces of the voids or tree channels. These charges change the localized electrical field. As a result, these charges control, along with the change in field due to the sinusoidal voltage applied, the time when the next PD will take place. The net result is that a pattern of PDs of various magnitudes, repetition rates, and phase angles relative to the applied voltage can be seen. During testing in which the voltage is slowly raised, the voltage at which discharges are observed in each cycle is known as the *PD inception voltage*. On decreasing the voltage slowly from above the PD inception voltage value, the voltage at which PD ceases is referred to as the *PD extinction voltage*. PD will often become intermittent before complete extinction occurs. Due to the deposition of charges on the surfaces of the voids caused by PD, the PD extinction voltage can theoretically be as low as 50% of the inception voltage. In practice, the difference is between 10 and 25%. To ensure that a cable is discharge-free at operating voltage, it is necessary to test for PD at levels up to twice the operating voltage. A cable that has PD at operating voltage or within one and one-half times operating voltage is generally significantly deteriorated and may fail in the near future. Cables that have no significant PD at levels up to twice operating voltage have no immediate expectation of failure from PD and will operate satisfactorily for a significant period of time. Not all PD is indicative of imminent failure. For example, gray EPR is resistant to PD.

There are several sources of PDs in cable systems. These are in:

- Voids in the cable or accessory insulation
- Voids at interfaces between the insulation and the shields
- Voids or gaps at the interfaces between the cable insulation and accessories, for example, tracking
- Electrical trees initiated from protrusions, voids, or water trees

Some examples of PDs are shown in Figure 3-1.

The shape and location of the void are important because they control the electrical stress. For example, if the void is located close to the conductor shield rather than close to the insulation shield, a lower voltage will be needed to reach the PD inception stress. At any particular voltage, the stress at the conductor shield, which is inversely proportional to the radius of the conductor shield, will be greater than that at the insulation shield, which is inversely proportional to the radius of the insulation shield. The electrical stress in a spherical void in EPR with a dielectric constant of 3.5 will be ~30% greater than the stress in the insulation. However, the stress in a flat cavity will be ~250% greater than the stress in the insulation, so that the PD inception voltage for a flat cavity will only be ~40% of that for a spherical void of the same depth and location. When PDs occur in a void, they change the composition and pressure of the gas in the void, and thereby the PD inception and extinction voltages, and also the conductivity of the void surfaces, which can affect the electrical stress in the void. If the surface conductivity in a void increases sufficiently, its PD can extinguish. This is more likely to happen in a spherical void than in a flat void. As a result, flat cavities pose a greater risk of degradation than spherical ones. Prolonged PD activity in a void will lead to gradual erosion of the void surfaces and the eventual formation of pits. Electrical trees will form from these pits and cause failure.

The interfaces between the cable and accessory insulations may be sources of PD. If interfacial pressure is not sufficient to maintain firm contact between the surfaces, voids can form, and PDs can initiate and eventually form carbonized tracks along the interface. PDs can also occur in the channels of electrical trees, as discussed in the previous section.

Modern PD detection equipment can provide three-dimensional plots showing the phase, magnitude, and number of the PDs. From the characteristics of these three-dimensional plots, it may be possible to identify the source of the PD, for example, from spherical or flat cavities or voids, electrical trees, or interfaces. Commercial PD detection equipment is now available to identify PD sources. This technology is new and has yet to be fully proven in extensive field trials. In addition, it is possible to locate PDs by measuring the time intervals of PD signals at two different points along a cable circuit or the time intervals between the main pulse and the reflected pulse at the same point.

PDs do not occur in water trees. They can be observed if an electrical tree has initiated from a water tree, which can occur, for example, if the insulation is subjected to surges from switching operations or lightning, or if the tree has extended to at least 70% of the insulation thickness.

Although extruded insulations have excellent electrical properties, they do not have a high resistance to electrical discharges striking their surfaces. Pink EPR is more resistant to PDs than XLPE. The gray EPR is very resistant to PD due presumably to some of the more than 20 fillers and additives that make up the EPR compound.

Diagnostic Tests

According to [4], the purpose of a diagnostic test is "to evaluate and locate degradation phenomena that will cause cable or accessory failure." Any destructive or nondestructive tests carried out on-site or in the laboratory are *diagnostic tests*. Cables exposed to moisture will experience water treeing or other water-induced degradation from contaminants, water-filled microvoids, and protrusions. The final breakdown mechanism is likely to be an electrical tree from the tip of the water tree or other stress enhancement close to the tip of the water tree. A voltage transient (such as lightning) or a switching transient could initiate the electrical tree. Cables operating under dry conditions may experience PDs from voids that may occur due to failure of or damage to the lamination between the shield and the insulation. Another source of voids may be the poor surface contact between the interfaces of the cable and its accessories. The PDs will erode the void surfaces and eventually form electrical trees to complete the failure. Tracking along interfaces, if it occurs, will also lead to failure.

The questionnaire conducted as part of this project indicated that dc hipot testing is used as an after installation test and also by some utilities as a test after repairs or routine maintenance. An EPRI study [5] confirmed what many utilities had also realized: that dc hipot testing can further damage aged cables and so should be avoided. HVDC creates charge in the insulation that remains in the insulation after the voltage is removed. This charge can create high electrical stresses in the insulation when the service voltage is applied. As a result of the inadequacy of dc hipot testing, several other diagnostic test techniques have been developed. Table 3-2 lists the diagnostic tests for extruded cable systems. The table also shows the main advantages and disadvantages of the tests and also gives some critical values that cable insulation parameters should meet to continue in service. Not all the tests listed can be carried out *in situ,* and very few can be performed on-line. The presence of external noise affects the sensitivity of all *in situ* electrical measurements so that care must be taken to minimize the noise and avoid stray signals from entering the measuring system.

In addition to careful diagnostic measurements, proper interpretation of the data is essential to assess any cable circuit. To accomplish that, it is essential to know the type of cable and insulation (XLPE or EPR), the type and number of accessories being tested, and whether terminations are handmade or heat shrink. The different materials have different characteristics and will respond differently to the diagnostic tests that are currently in use. As an example, the dissipation factors are significantly different for new and aged XLPE, black, pink, and gray EPR. As a result, it is essential to know what type of insulation is being tested.

Partial Discharge Diagnostics

PD measurements detect localized defects such as voids or electrical trees. A significant effort is going on throughout the world to correlate the characteristics of three-dimensional plots of the phase, magnitude, and number of the PDs with the nature and size of the defects, for example, the size, shape, and location of the voids as well as the size and location of protrusions and electrical trees. To date, limited success has occurred in laboratory tests under ideal measuring conditions when the sources of noise and the number and types of defects are known. Artificial intelligence and fuzzy logic techniques are being applied to help identify noise and PD sites. Even for the same type of defect, considerable variation in the data from each repetition of a test occurs, which further complicates identification of the defect.

A PD source will send short duration pulses in both directions along a cable. The pulses are attenuated in amplitude and lose some of their high-frequency components as they travel along the cable. This limits the sensitivity of PD measurements and controls the frequency bandwidth that can be used to detect PD. By measuring the times at which pulses reach chosen points along the cable, it is possible to estimate the location of the PD site, and, if the attenuation characteristics of the cable are known, to determine the true magnitude of the PD. In the presence of noise, it is difficult to detect PD pulses. If there are multiple PD sources, locating individual PD sites also becomes a problem.

Measurements in the Field

PD measurements are far more difficult to make in the field and in a noisy environment. For example, radio stations broadcast in the same frequency spectrum as that of PDs, and some plant electrical equipment can give stationary pulses on the applied voltage waveform that could be mistaken for PD. Sources of noise need to be recognized and located and remedial action taken to minimize the effects of these signals on measurements. In the field, the number and types of defects are largely unknown, which greatly increases the difficulty of identifying and locating them.

Several organizations perform PD measurements for utilities on a commercial basis. Each organization has its own criteria to assess the condition of a cable circuit, and these are continuing to evolve. The vast majority of the tests are done on XLPE cables, and very little data have been reported for EPR cables. The tests can be carried out either on-line or off-line; the advantages and disadvantages are listed below:

On-line measurements – Advantages:

- Measurements can be made without taking an outage
- Measurements can be made at operating temperature of the cable system

On-line measurements – Disadvantages:

- Cannot vary applied voltage
- If no PDs are measured, tests cannot predict when they will start

Off-line measurements – Advantages:

- Measurements can be over a range of voltages
- Measurements can be made with different voltage waveforms (60 Hz, 0.1 Hz, oscillating wave, pulse) to minimize the effect of ambient electrical noise
- PD-free at 1.5 to 2 U_o ensures PD-free at operating voltage (U_o)

Off-line measurements – Disadvantages:

- Cable can be damaged if the test voltage is too high
- Cables must be removed from service, and disconnection from equipment may be necessary

At the present time, diagnostic service companies use the frequency domain method for on-line PD testing and time-domain methods for off-line PD testing. The frequency domain method has greater noise rejection so that more sensitive measurements can be made. Care must be taken that switching pulses (for example, from electronic power supplies and that are stationary on the voltage waveform) are not mistaken for PD pulses using the frequency domain method.

Off-line PD tests can be performed at power frequency or by a damped oscillating wave. The frequency of the oscillations can vary between hundreds of hertz to a few kilohertz, very low frequency (VLF), usually 0.1 Hz, or a single cycle of the power frequency. Each method has advantages and disadvantages and its own criteria to assess the condition of the cable being tested. These criteria have been developed mainly for XLPE cables because of the limited numbers of EPR cables tested. Criteria would have to be developed for EPR cables.

A panel discussion was held at the Fall 2000 meeting of the Institute of Electrical and Electronic Engineers (IEEE) Insulated Conductors Committee on the utility experience with PD measurements on MV XLPE cable systems. The panel discussion followed earlier presentations by organizations that performed PD diagnostic tests, both on-line and off-line. Six utilities presented their experiences. The general conclusions for extruded XLPE cables were:

- Off-line tests indicated that more than 80% of the PD sites were located at accessories. On-line tests produced the opposite result, with more than 80% of the PD sites observed in the cables and less than 20% in the accessories.
- There was mixed success in predicting and locating future failure sites.
- There were significant numbers of false positive and false negative results from PD testing.
- Not all PD is life threatening to the cable system. For example, some discharges between the metallic shield and the insulation shield may persist for many years without damage to the cable.
- Testing should be limited to $\leq 2\ U_o$.
- Improvements in the interpretation of the data are needed, particularly for all types of EPR cable systems.
- Greater success may be achieved if PD testing is carried out in conjunction with other diagnostic tests, such as dissipation factor tests or dielectric spectroscopy.
- Although the utilities had mixed success, the general feeling was to continue testing to accumulate data and to improve interpretation.
- No specific PD technique variation appeared to be superior to the others.

Water Tree Diagnostics

As previously mentioned, the detection of individual water trees with electrical test techniques is very difficult and almost impossible in long lengths of cable. However, a large number of water trees can increase to measurable levels the ac (capacitive) and dc leakage currents, the *dissipation factor* (sometimes referred to as the tangent delta, dielectric loss, or power factor), and the harmonic content of the loss current. The dissipation factor is a measure of the resistive (loss) current flowing through the insulation. The resistive current flowing through heavily treed insulation will be a nonlinear function of the instantaneous applied voltage; that is, harmonic currents will be generated that can be analyzed by measuring the loss current waveform. Measurements of these parameters are being used to detect water treeing in insulation, particularly with XLPE cables. Water-saturated insulation, without the presence of water trees, will also increase the leakage and loss currents, so that an increased tangent delta does not automatically signify water treeing.

Water treed XLPE insulation tends to have larger changes in dissipation factor with voltage (when the voltage is varied in steps), or with time (when the voltage is held constant for periods up to thirty minutes). For insulation without trees, the dissipation factor remains constant as the voltage is increased, as long as the PD inception voltage is not exceeded for unshielded cables.

Heavily-treed insulation will yield an increasing dissipation factor with increasing voltage. If the voltage is held constant on a heavily-treed insulation, the dissipation factor will gradually increase with time, will only reach a stable value after at least 1 hour, and will also have higher harmonic content in the loss currents than water-saturated insulation. As a result, monitoring these changes is a better indicator of water tree degradation and is used by some companies that carry out diagnostic tests. When measuring these properties on installed cables, care must be taken to prevent stray and surface-leakage currents from adversely affecting the data. Little test data is available to allow conclusions to be drawn for EPR cables.

Measurements of dc loss current (either polarization or depolarization), ac leakage and loss (dissipation factor) current measurements, and dielectric spectroscopy determine the average properties of the total volume of insulation under test. If only a short length of a cable system is wet and has water trees, the leakage and loss currents of only that affected region will be larger while the rest of the insulation will have normal values. As an example, suppose only 10% of the insulation is heavily water-treed and has a dielectric loss 10 times the value of the remaining healthy insulation. Then, the measured dissipation factor will be slightly less than twice the value of the healthy insulation so that it could be assumed that the insulation is not severely degraded. Conversely, if the terminations have high surface leakage current, the measurements could have artificially high loss currents so that the cable would be assumed to be more degraded than it actually is.

When making dissipation factor (tan delta or power factor) measurements, it is also important to note the value of the capacitance of the cable under test. The dissipation factor is the loss current divided by the capacitive current. If the capacitance, and thus the capacitive current, is increasing along with the loss current, the dissipation factor may not change appreciably. Some measurements (for example, dielectric spectroscopy) give separate plots of the actual loss and capacitive currents rather than dissipation factor, so that changes in the loss and capacitive current with voltage or frequency can be seen. If the capacitive current does not change very much, then the change in dissipation factor will be the same as the change in loss current.

Although dc hipot testing is not recommended for aged XLPE cables, lower-voltage dc tests that measure the charging and/or discharging current have been proposed. One European company has developed test equipment and software to analyze the data. However, there is very little experience with the technique in North America. Also, the experience is limited to XLPE and not EPR cables. The significant amount of interfacial polarization that will occur in EPR cables due to the fillers will probably mask the effects due to water treeing. A complementary test to the short-circuit discharge (depolarization) current test is to measure the recovery voltage. After charging the cable for a specified time, the cable is short-circuited for a short time to discharge the capacitive current, and then open-circuited. The polarization charges remaining in the insulation due to aging will create a voltage across the open-circuited cable, which will increase to a maximum and then slowly decrease. The recovery voltage method has been applied to paper/oil insulation systems with some success, but the data for XLPE is limited and no testing has been done on EPR cables. As a result, recovery voltage and polarization/depolarization current measurements on extruded cables are very new and unproven.

An alternative to dc hipot testing of extruded cables is the VLF hipot test, usually 0.1 Hz. As the voltage changes polarity every 5 seconds, the harmful buildup of space charge that can occur under dc voltage is prevented. A draft standard is under preparation that specifies test voltages for cables of different voltage ratings [6]. The test voltages have been derived from tests on XLPE cables. There has been limited VLF testing of EPR cables, so it is not known if the test values listed in [6] are applicable to EPR cables.

It should be noted that there has been a considerable effort to develop diagnostic tests and assessment criteria for XLPE cables, and this work is continuing. As already discussed, there has been mixed success. The technology is continuing to evolve, and the measurement techniques are reasonably well established, but the interpretation of data needs improvement. These improvements will come with more data and experience. However, there has been far less effort in the diagnostic testing of EPR cables, either for pink or gray EPRs. It is unlikely that the criteria applied to XLPE could be directly applied to EPR cables. The change in dissipation factor with voltage is a possible approach, but values have to be determined. Also, EPRs, particularly gray EPR, are more resistant to PD than XLPE, so that adopting the same criteria may be underestimating the ability of EPR to perform satisfactorily in service. As a result, it will be necessary to collect significant amounts of data to be able to assess the condition of EPR cables from any diagnostic testing.

Other Diagnostic Tests

In addition to assessing the condition of the insulation of the extruded cable, it is also important to determine the integrity of the cable’s metallic shields, which may corrode over time, depending on the operating environment. Corrosion can occur in both EPR and XLPE cables. Corroded concentric neutral tapes of extruded cables can lead to breaks in the electrical circuit that could cause arcing between isolated sections of the neutral; the inability of the neutral to carry its specified fault current; and also compromised safety due to the possible isolation of part of the neutral from ground. If the neutral is completely corroded in one or more sections, the isolated sections will be free to float to some potential depending on the inductive and capacitive coupling to the other conductors. As a result, periodic checks and tests should be made to verify continuity of the neutral.

A periodic visual inspection of the cable system is also useful to check for abnormal features, such as tracking or erosion of cable accessories that could eventually lead to flashover or failure, corrosion of the metallic components, or cracking of jackets. Tracking along insulated surfaces will be greater in polluted areas or in regions where salt is used or salt air is present. Aggressive chemicals, such as wood preservatives or oils, can also induce corrosion or malfunction of the cable components.

Table 3-2
Diagnostic Tests for Extruded Cable Systems

Electrical Tests					
Destructive	**Comments**	***In Situ***	**Critical Value for XLPE**	**Advantages**	**Limitations**
dc/ac Withstand or Maintenance	60 Hz, 0.1 Hz TSA*	Yes	2.5 to $3U_0$ for 15 min	Simple test	Could cause damage
ac Breakdown	Laboratory test	No	≥ 10 kV/mm	Simple test	Many samples needed
Impulse BD	Laboratory test	No		Simple test	Many samples needed
Nondestructive	**Comments**	***In Situ***	**Critical Value**	**Advantages**	**Limitations**
Oscillating Wave	Damped oscillation, TSA	Yes	Needed	Simulates surge	Equipment needed Could cause damage
Dielectric Spectroscopy	$10^{-3} - 10^{+2}$ Hz TSA	Yes	Needed	Test at or below operating voltage	Stray currents a possible problem
Capacitance Dissipation Factor (Tan Delta)	60 Hz, 0.1 Hz TSA	Yes	Needed	Test at or below operating voltage	Power supply needed for 60 Hz Stray currents a possible problem
ac Loss Current Waveform	60 Hz, 0.1 Hz TSA	Yes	Needed	Test at or below operating voltage	Power supply needed for 60 Hz Stray currents a possible problem
dc Leakage Current/ Residual/ Recovery voltage	Low dc voltages applied TSA	Yes	Needed	Test at or below operating voltage	Stray currents a possible problem
PD	60 Hz, on-line TSA	Yes	Companies have own rules	No need to take outage	Can only test at operating voltage
PD	60 Hz, 0.1 Hz, TSA	Yes	Companies have own rules	Can test at different voltages	Needs PD-free source Interference affects sensitivity

* Test sets commercially available

Conclusions

The differences in the aging and failure mechanisms for different types of cables requires a full knowledge of the cable, the cable circuit applications, and the operating environment to assess the condition of the cable systems. The required information includes the type of cable, cable design, age, approximate length, number and type of accessories, dry or wet operating conditions, current loading, and location of possible hot spots.

Diagnostic test methods can be divided into two broad groups: those that are sensitive to local defects (for example, PD tests and withstand tests) and those that measure average quantities of the bulk of the insulation (for example, capacitance, dissipation factor at power or other frequencies, polarization/depolarization currents, and recovery voltage measurements). A better assessment of the insulation of the cable system is obtained if a measurement from both groups is made, to give an indication of possible localized damage and an average value. The state-of-the-art of diagnostic testing and condition assessment is continuing to evolve; however, it is not yet sufficiently advanced to be able to give an accurate prediction of when a cable is going to fail. In some instances it may be possible to determine that one cable circuit is worse than another. A much greater effort has been concentrated on the condition assessment of XLPE cables relative to that for EPR cables due to the much larger quantities of XLPE cables installed in distribution systems in the 1970s and 1980s. As a result, cable assessment techniques for pink and gray EPR cables, which form a significant portion of the nuclear plant cable population, need considerably more development. Improved diagnosis may be achieved by continuing to collect, analyze, and trend data, particularly from tests repeated regularly on selected circuits. In this way, a data bank can be established that can be used to assess cable condition.

Periodic tests that determine the average condition of a cable (for example, dissipation factor, dielectric spectroscopy) should be combined with PD testing, which is sensitive to localized defects, and visual inspections. This gives a more complete picture of the cable condition.

Due to a charge remaining in the insulation when the test voltage is removed, dc hipot testing of aged XLPE cables is not recommended. A 0.1 Hz (VLF) withstand test would be an adequate replacement test for XLPE cable. Although the effect of dc hipot testing on EPR cables has not been fully studied, the fact that water treeing occurs in EPR suggests that water tree-degraded EPR cables would also be susceptible to damage by dc hipot testing; consequently, it is not recommended. This is supported by the 10 failures in EPR cables experienced by one utility during dc hipot testing.

4 IDENTIFICATION OF WETNESS AND WATER REMOVAL FROM CONDUITS AND DUCTS

This section identifies techniques to assist in recognizing wet areas in ducts and conduits and methods for removal of water.

Previous sections indicated that the aging of MV cable systems is more severe when they are immersed in water. Experience has shown that cables made before the mid-1980s, which comprise the majority of the cables in nuclear plants, contain contaminants in the shield materials and the insulation that could be initiation sites for water treeing if the cables are immersed in water during operation.

There are several publications in the literature giving evidence that it is possible to detect water trees in extruded XLPE insulation by detecting changes in bulk properties such as capacitance, dissipation factor, dc leakage currents and dielectric spectroscopy, particularly in 5 and 8 kV rated cables. There are limited data on similar measurements on shielded EPR cables. One study of 15- and 35-kV cables showed that the dissipation factor of EPR cables taken from service after 2 to 22 years increased with the years in service [7]. However, changes in the formulation of the EPR might have contributed to the observed increases. As a result, changes in the electrical properties can give an indication of the presence of water and water trees in shielded XLPE and EPR cables, if at least 25% of the cable length has been submerged in water for some time. However, such measurements give an average value for the whole length of cable and will not give an indication of how much cable is affected if only part of the cable is submerged in water. It is recommended that tests that detect changes in the bulk properties of the insulation be repeated every 2–5 years to establish a trend in the data, rather than relying on one measurement. It must be remembered that the bulk properties of the insulation are usually temperature sensitive, so that high temperatures could be responsible for larger values of dielectric loss when measurements taken at different times are compared. Some diagnostic service companies are suggesting critical levels of dielectric loss to consider replacing XLPE cables, but no such values have been proposed for EPR cables.

Diagnostic tests are usually carried out on shielded cables so the electric field is confined to the cable insulation. Several utilities have used unshielded EPR single-phase and/or three-phase cables in nuclear plants. In both types of cables, it will be difficult to carry out diagnostic tests, because the field is no longer confined to the insulation by a shield. However, the uniformity of the three-phase cable should enable some dielectric measurements. If part of this cable is immersed in water, it will alter the field and also the characteristic impedance of the cable. A reflected pulse from a wetted insulation section surface in a time domain reflectometry (TDR) measurement should occur if part of the cable length is totally submerged. There should also be differences in phase-to-phase capacitances between the dry and submerged cables. Tests have not been carried out to confirm this. If the spacing between phases of single-phase unshielded cables in ducts is fairly constant, this should give a reproducible capacitance that will change if the ducts are filled, or partially filled, with water.

Rejuvenation of Cable with Water Tree Damage

With regard to remedial action, the rejuvenation of XLPE cables with water trees has been successfully performed and documented [8]. The cables are impregnated with a silicone fluid that chemically reacts with the water and improves the dielectric strength of the degraded insulation. The silicone fluid is forced into the gaps between the strands of the conductor from an end of the cable and fills the gaps and fissures on the conductor side of the insulation. Impregnation of water tree-degraded black and pink EPR insulation with silicone fluid shows similar improvements [9]. As a result, the injection of both XLPE and EPR cables to improve their electrical performance appears to be viable. A major problem with cable injection is the replacement of splices to allow the flow of the impregnant. Because the majority of cables in nuclear plants do not have splices, the cable injection process should be significantly simplified. Prior to impregnation with silicone, the conductor is flushed with dry nitrogen gas under pressure to drive out water from the conductor. When the moisture content of the gas has reached a particular level, the silicone fluid is injected into the conductor under pressure/vacuum.

5 CONCLUSIONS

- The majority of MV cables in nuclear plants are EPR cables and of a vintage that has shown susceptibility to water-induced degradation if they operate in a wet environment.
- Measurements of bulk properties of the insulation—such as capacitance, dissipation factor (0.1 Hz, 60 Hz), dielectric spectroscopy, and polarization and depolarization currents—can been used to detect water treeing in XLPE and EPR cables. However, although there have been replacement criteria proposed from XLPE cables based on PD and dissipation factor measurements, the success has been mixed. No criteria have been proposed for EPR cables.
- An alternative to the HVDC hipot test that should be considered is the VLF hipot test. Test voltages for XLPE cables with different voltage ratings have been proposed in an IEEE standard under preparation. No test voltages for EPR have been proposed.
- Repeating measurements every 2–5 years is recommended for diagnostic testing because this tends to yield more reliable and useful data than a one-time measurement.
- It may be possible to detect water in unshielded three-conductor cables by TDR techniques.
- Rejuvenation of cables by injection of impregnants has proven to be a reliable technology. The process of injection is simplified if there are no splices in the cable runs, as is the case in the majority of nuclear plant installations.

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A
QUESTIONNAIRE – MEDIUM-VOLTAGE CABLES IN STATIONS

Note

The information contained in this questionnaire will be treated as confidential. Reports will not contain the names of stations nor utilities, and data will be presented using generic terms, for example, by letters (A, B, C, and so on) or by numbers (1, 2, 3, and so on).

Introduction

Medium-voltage (MV) cables are critical to plant operation and safety. Many station cables, however, may be nearing the end of their useful lives and may become increasingly unreliable. It is very important that operators know the condition of their installed cables to determine if and when replacement is needed in order to optimize resources in their capital replacement programs within an acceptable reliability envelope.

To aid in the decision-making process, experience has shown that data on three issues are required:

- Types of cable systems installed
- Operating environment
- Failure statistics

The purpose of this questionnaire is to collect information as part of an EPRI project to evaluate techniques for assessing the condition of MV cable systems.

Some columns in the tables below have pull down lists. Click on the cell to bring up the list and then make a selection. Use as many rows as necessary in each table.

Name:

Company:

Phone:

E-Mail:

Cable Systems

The important factors that affect the life of cable systems, for example, cables, terminations, and splices, are the construction and materials in the components, and the electric stress in the insulation, which depends on the applied voltage and insulation thickness.

System Operating Voltage level (kV)

<5	4.16/5	8	15	25/28	35
☐	☐	☐	☐	☐	☐

Cables

Manuf.	Year of Manuf.	Year of Install.	Voltage Rating[1]	Cond. Shield	Insulation	Insulation Thickness[2]	Insulation Shield	Neutral/ Metallic Shield	Jacket
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE
ACW	<1970	<1970	<5	Taped	Pink EPR	100% level	Taped	None	CPE

[1] Rated voltage of cable (could be operating at lower voltage, that is, 15 kV rated voltage operating at 8 kV)

[2] As defined in AEIC CS5-94

Comments

Cable Terminations

Cable terminations are fitted at both ends of a cable, and their primary purpose is to reduce the electrical stresses that occur at the concentric neutral/metallic shield at the end of the cable. Terminations also increase the length over the surface at each end of a cable. This reduces the surface leakage current and increases the flashover voltage, factors that are particularly important in outdoor applications, when the terminations may become wet.

Manuf.	Type	Number Installed	Year Installed	Number Replaced	Year Replaced
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				

Comments

Splices

Splices are high voltage connectors that connect two or more cables. They usually consist of a metallic connector to join the high voltage conductors, an insulated housing to isolate the conductor from ground, and an outer conductor to connect the cable concentric neutrals/metallic shields.

Great care is required when installing terminations and splices to prevent contamination and delamination of the interfaces that may lead to increased surface leakage, PDs and eventual failure.

Manuf.	Type	Number Installed	Year Installed	Number Replaced	Year Replaced
Elastimold	Handmade (tapes)				

Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				
Elastimold	Handmade (tapes)				

Comments

Operating Environment

The aging mechanisms of a cable system depend to a great extent on its operating conditions. For example, extruded cables immersed in water are susceptible to water tree degradation and may fail prematurely. Heavily loaded cable systems may be subjected to thermal aging or overheating.

Cable System Conditions

Installation:	ducts	trays	direct buried	tunnels	trench	overhead
	☐	☐	☐	☐	☐	☐

If in trays: Maintained spacing between cables Yes ☐ No ☐

Random arrangement of cables Yes ☐ No ☐

Fire retardant covering Yes ☐ No ☐

Tests on Installed Cables: Yes ☐ No ☐

If Yes:

Voltage Rating	Insulation	Type of Test	Type of Measurement	Test Voltage	How Often (Routine/Maint. Tests Only)	Time Voltage Applied
<5	Pink EPR	Post installation	AC Hipot	V<Vo		t<5min
<5	Pink EPR	Post installation	AC Hipot	V<Vo		t<5min
<5	Pink EPR	Post installation	AC Hipot	V<Vo		t<5min
<5	Pink EPR	Post installation	AC Hipot	V<Vo		t<5min
<5	Pink EPR	Post installation	AC Hipot	V<Vo		t<5min

Environment

dry ☐ % of total cable lengths

water (100% of time) ☐ % of total cable lengths

water (part time % of time) ☐ % of total cable lengths

Comments

Failure Statistics

Failure includes a failure in service, during a condition assessment test, or a component replacement even though there was no failure in service.

Cables

How many:

Failure reports attached: Yes ☐ No ☐

If failure reports attached, go to part on terminations/splices.

Details:

Manuf	Years in Service	Year of Failure	Insulation	Cause of failure
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline
ACW			Pink EPR	Chemcials-gasoline

Comments

Termination/Splice Failures

Terminations: How Many

Splices: How Many

Failure reports attached: Yes ☐ No ☐

If failure reports attached, go to end.

Details of Failures

Manuf.	Years in Service	Year of Failure	Type	Cause of failure
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline
Elastimold			Handmade (tapes)	Chemicals-gasoline

Comments

B
LIST OF ACRONYMS USED IN THIS REPORT

ac
Alternating Current

CPE
Chlorinated Polyethylene

CSPE
Chlorosulfonated Polyethylene

dc
Direct Current

EPR
Ethylene Propylene Rubber

EPRI
Electric Power Research Institute

HVDC
High Voltage Direct Current

IEEE
Institute of Electrical and Electronic Engineers

MV
Medium-Voltage

PD
Partial Discharge

PILC
Paper-Insulated Lead-Covered

PVC
Polyvinyl Chloride

TDR
Time Domain Reflectometry

TR-XLPE
Tree-Retardant Cross-Linked Polyethylene

VLF
Very Low Frequency

XLPE
Cross-Linked Polyethylene

Program:
Nuclear Power

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EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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