Plant Support Engineering: Life Cycle Management Planning Sourcebooks: Medium-Voltage (MV) Cables and Accessories (Terminations and Splices)

Technical Report

Plant Support Engineering: Life Cycle Management Planning Sourcebooks: Medium-Voltage (MV) Cables and Accessories (Terminations and Splices)

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REPORT SUMMARY

EPRI is producing a series of Life Cycle Management Planning Sourcebooks, each containing a compilation of industry experience information and data on aging degradation and historical performance for a specific type of system, structure, or component (SSC). This sourcebook provides information and guidance for implementing cost-effective life cycle management (LCM) planning for medium-voltage (MV) cables and accessories (terminations and field splices).

Background

As explained in the *LCM Sourcebook Overview Report* (1003058), the industry cost for producing LCM plans for many of the important SSCs in operating plants can be reduced if LCM planners have an LCM sourcebook of generic industry performance data for each SSC they address. The general objective of EPRI's LCM sourcebook effort is to provide system engineers with generic information, data, and guidance they can use to generate a long-term equipment reliability plan for the plant-specific SSC (aging and obsolescence management plan optimized in terms of plant performance and financial risk). The long-term equipment reliability plan, or LCM plan, for a plant SSC combines industry experience and plant-specific performance data to provide an optimum maintenance plan, schedule, and cost profile throughout the plant's remaining operating life.

Objective

- To provide plant engineers (or their expert consultants) with a compilation of the generic information, data, and guidance typically needed to produce a plant-specific LCM plan for MV cables and accessories

Approach

Experts in the maintenance and aging management of MV cables, terminations, and field splices followed the LCM process developed in EPRI's *LCM Implementation Demonstration Project* (1000806). The scope of the physical system and types of components included in the study was defined. Information and data on historical industry performance of components within this scope were compiled, and technical guidance for using this information is presented as a starting point for preparing a plant-specific LCM plan for MV cables and accessories.

Results

This sourcebook contains information on typical MV cables, terminations, and field splices (accessories) found in both boiling water reactor (BWR) and pressurized water reactor (PWR) nuclear power generating stations. Information compiled includes performance monitoring issues, component aging mechanisms, aging management / maintenance activities, equipment upgrades, replacements, and technical obsolescence assessments. Typical alternatives for LCM are delineated. The sourcebook includes an extensive list of references, many of which are EPRI reports related to the maintenance and reliability of MV cables and accessories.

EPRI Perspective

This report should enable the preparation of plant-specific LCM plans for MV cables and accessories with substantially less effort and cost than if planners had to start from scratch. The sourcebook captures both industry experience and the expertise of the sourcebook authors. Using this sourcebook, one needs only to add plant-specific data and information to complete an economic evaluation and LCM plan for the plant's MV cables, terminations, and field splices. The process of using sourcebooks as an aid in preparing LCM plans will improve as the industry gains experience. EPRI welcomes constructive feedback from users and plans to incorporate lessons learned in future revisions of LCM sourcebooks.

Keywords

Life cycle management
Nuclear asset management
System reliability
Component reliability
Medium-voltage (MV) cables
Component aging

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EXECUTIVE SUMMARY

This Life Cycle Management (LCM) Planning Sourcebook for medium-voltage (MV) cables and accessories will help plant engineers and/or expert consultants in preparing a life cycle management plan (a long-term reliability plan) for MV cables at their plant. The generic information and guidance presented in this document are expected to help plant engineers focus on areas where there may be significant opportunities for cost-effective improvements in long-term plans. Use of this sourcebook should reduce the cost of preparing a plant-specific LCM plan for MV cables and accessories (terminations and splices).

Guidance consists mainly of generic industry information, data, and references on MV cable systems. This sourcebook identifies component aging mechanisms together with the maintenance activities to manage them, as well as any applicable obsolescence issues and available management options. Guidance is provided on how to build alternative LCM plans, which can be considered for long-term planning for the critical components in the system. This sourcebook provides hypothetical LCM plan alternatives to serve as starting points for plant-specific applications.

This sourcebook also contains the lessons learned from the EPRI LCM planning process [1] by providing guidance in the evaluation of plant-specific data, selection of plant operating strategies, and feasible alternative LCM plans. A comprehensive reference listing is included to give the utility engineer additional resources for consultation.

In a companion document, the *LCM Planning Sourcebook Overview Report* (EPRI 1003058) [2], process-oriented LCM planning information is presented as well as additional generic guidance for the preparation of plant-specific LCM plans. This sourcebook and the overview report are meant to be used together, with the sourcebook addressing "what to evaluate" and the overview report addressing "how to evaluate."

The scope of this LCM sourcebook covers the most common components contained in MV electric cable systems for both BWRs and PWRs. The components included are cross-linked polyethylene (XLPE) and ethylene-propylene rubber (EPR) insulated cables and related terminations and field splices.

This report reviews the types of MV cables and accessories in use in nuclear power plants and the techniques that are currently available to assess the condition of these MV cable systems.

Many MV cable systems have been in service in nuclear power plants for more than 30 years. Because cables are critical for plant safety and operation, it is essential for plant personnel to know the condition of their installed cables. The use of high-voltage dc (HVDC) withstand testing to assess the condition of aged extruded cables has been questioned by many utilities due to its insensitivity in detecting some forms of degradation while causing additional damage to aged insulation. As a result, other diagnostic techniques are under evaluation to detect localized damage or to assess the overall condition of the cable insulation.

Surveys were conducted that identified the main types and designs of 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. Before the 1980s, manufacturers were less sensitive to the importance of controlling contaminants in the insulation and shield materials. Subsequently, they learned that contaminants and voids in the insulation 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 pre-1980 vintage cables operating under wet conditions are susceptible to water-induced degradation and possible failures in service before the end of the original projected 40-year life. Early replacement may be necessary to prevent in-service failures. However, non-nuclear plant experience has shown that injecting a silicone solution through the spaces between the strands of the conductors can prolong cable life, and this may be considered as an alternative to full cable replacement. To date, this technique has not been used on nuclear plant cables.

The surveys also identified that some utilities were still using HVDC withstand testing of their cable systems. This practice is being discontinued by many utilities due to the possibility of this testing causing additional damage. Alternative diagnostic tests have been and continue to be developed to detect localized degradation by partial discharges 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 crosslinked polyethylene (XLPE) insulated cables. There is much less assessment experience with EPR cables. Accordingly, significant work is needed to develop cable assessment criteria for both red and brown EPRs. A very low frequency (VLF) test guide has proposed standard test voltages for XLPE cables, and this should be considered as an alternative to DC high-potential (hi-pot) testing, which has been determined to be damaging to XLPE insulation systems.

The differences in the aging and failure mechanisms for the various types of cables and operating conditions require a full knowledge of the cable design, the cable applications, and the environment in which they are operating to be able to assess the condition of the cable systems. This information includes the type of cable, cable design, age, approximate length, number and type of accessories, dry or wet operating conditions, voltage rating versus operating voltage, duty cycle, current loading, location of possible hot spots, etc.

Diagnostic test methods can be divided into two broad groups, those that are sensitive to local defects (for example, partial discharge 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. However, state-of-the-art diagnostic testing and condition assessment is continuing to evolve, but it is not yet sufficiently advanced to give an accurate prediction of when a cable is going to fail, although in some instances it may be possible to determine that one cable circuit is worse than another. There has been a much greater effort 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. Thus, cable assessment techniques for red and brown EPR cables, which form a significant portion of the population of nuclear plant cables, need considerably more development. Improved diagnosis may be achieved by continuing to collect and analyze data, particularly from tests repeated regularly on selected circuits (that is, trending). 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 partial discharge (PD) testing or withstand testing, which is sensitive to localized defects, and visual inspections of accessible terminations. Use of a set of tests that cover bulk and local condition will give a more complete picture of the cable condition.

DC hi-pot testing of aged XLPE cables is not recommended due to charge remaining in the insulation when the test voltage is removed [3]. A 0.1 Hz, very low frequency (VLF) withstand test would be an adequate replacement test for XLPE cable. Although the effect of dc hi-pot testing on EPR cables has not been fully studied, the fact that water treeing occurs in EPR would suggest that water-tree-degraded EPR cables would also be susceptible to damage by dc hi-pot testing, and thus is not recommended. This is supported by failures in EPR cables that occurred at one utility during dc hi-pot testing.

Summary

- 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 be used to detect water treeing in XLPE and EPR cables. Although replacement criteria have been proposed for XLPE cables based on PD and dissipation factor measurements, success in their application has been mixed. No criteria have been proposed for EPR cables.
- An alternative to the HVDC hi-pot test that should be considered is the VLF hi-pot test. Test voltages for XLPE cables with different voltage ratings have been stated in an IEEE standard. No test voltages for EPR have been proposed.

- Repeat measurements every two to five years as diagnostic tests rather than a one-time measurement are recommended because trending information tends to yield more reliable and useful data.
- Rejuvenation of cables by injection of impregnants has proven to be a reliable technology in the power distribution industry, but it has not been used in the nuclear industry to date. 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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LCM SOURCEBOOK INTRODUCTION

1.1 Purpose of the LCM Sourcebook

As indicated in the *Life Cycle Management (LCM) Sourcebook Overview Report* [2], an LCM sourcebook is a compilation of generic information, data, and guidance an engineer typically needs to produce a plant-specific LCM plan for a system, structure, or component (SSC). This sourcebook will enable plant engineers or outside experts to develop a plant-specific LCM plan for medium-voltage (MV) cables and accessories, with substantially less effort than if they had to start from scratch. The engineer need add only plant-specific data and information to complete an economic evaluation and LCM plan for these MV components.

It must be recognized that not all generic information in a sourcebook applies to every plant. Some of the data can serve for comparison or benchmarking when preparing plant-specific LCM plans. Other data may show indicators or precursors to problems not yet experienced at a given plant. Therefore, caution and guidance is provided in the plant-specific guidance sections (Sections 5, 8, and 9 of the sourcebook) for the use and application of the generic information. These sections also contain useful tips and lessons learned from the EPRI LCM Plant Implementation Demonstration Program [4].

1.2 Relationship of Sourcebook to LCM Process

The process steps for LCM planning are described in detail in the EPRI LCM report [1]. The LCM planning flowchart in Figures 1-1, 1-2, and 1-3 of this Sourcebook is the same as Figure 1-1 of the LCM Sourcebook Overview Report [2] and Figure 2-2 of the LCM report [1]. The figures are segmented into the elements of the LCM planning process: SSC Categorization/Selection, Technical Evaluation, Economic Evaluation, and Implementation. Process step numbering has been maintained to be consistent with the prior LCM reports.

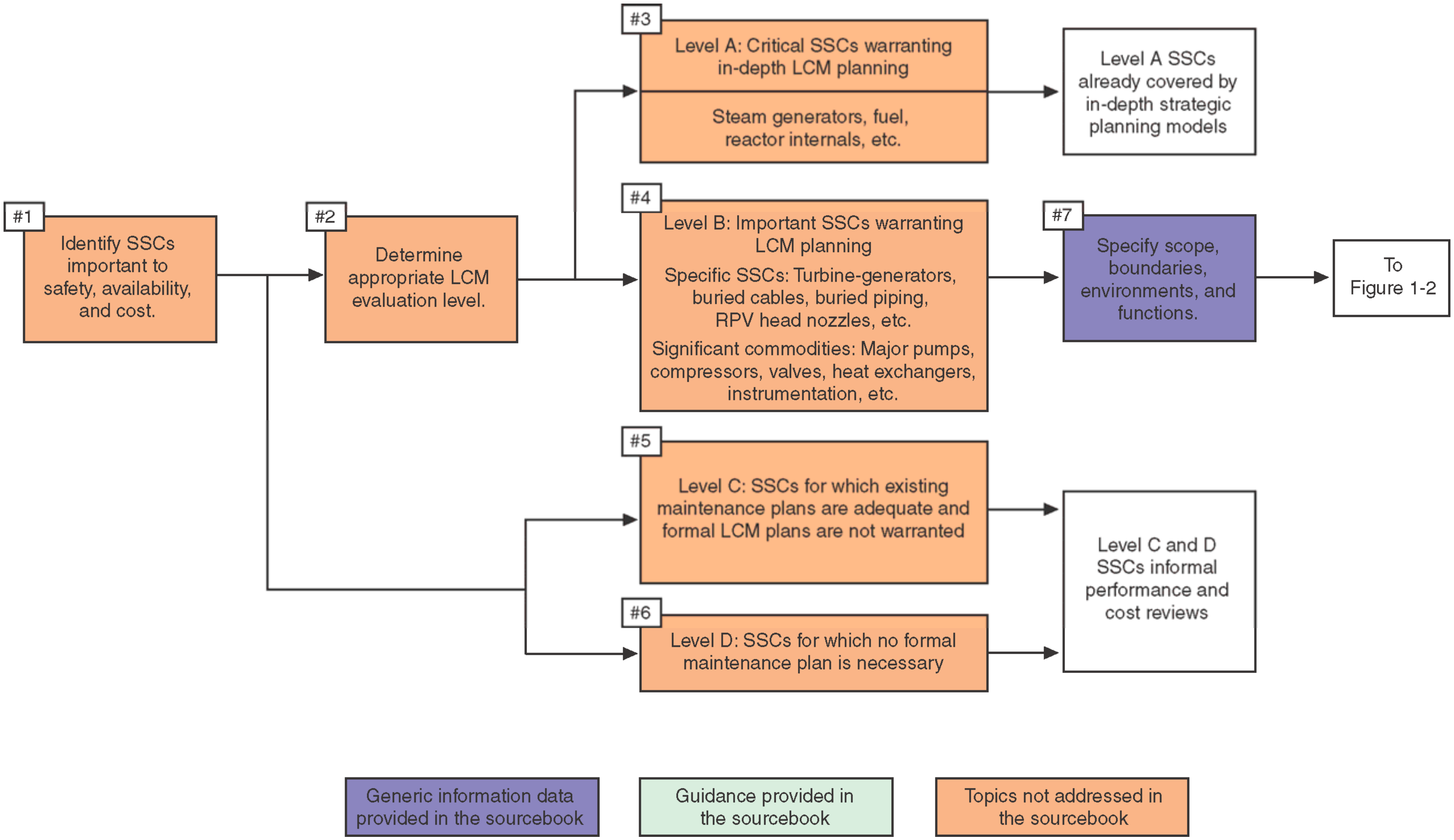

Figure 1-1
LCM Planning Flowchart – SSC Categorization and Selection

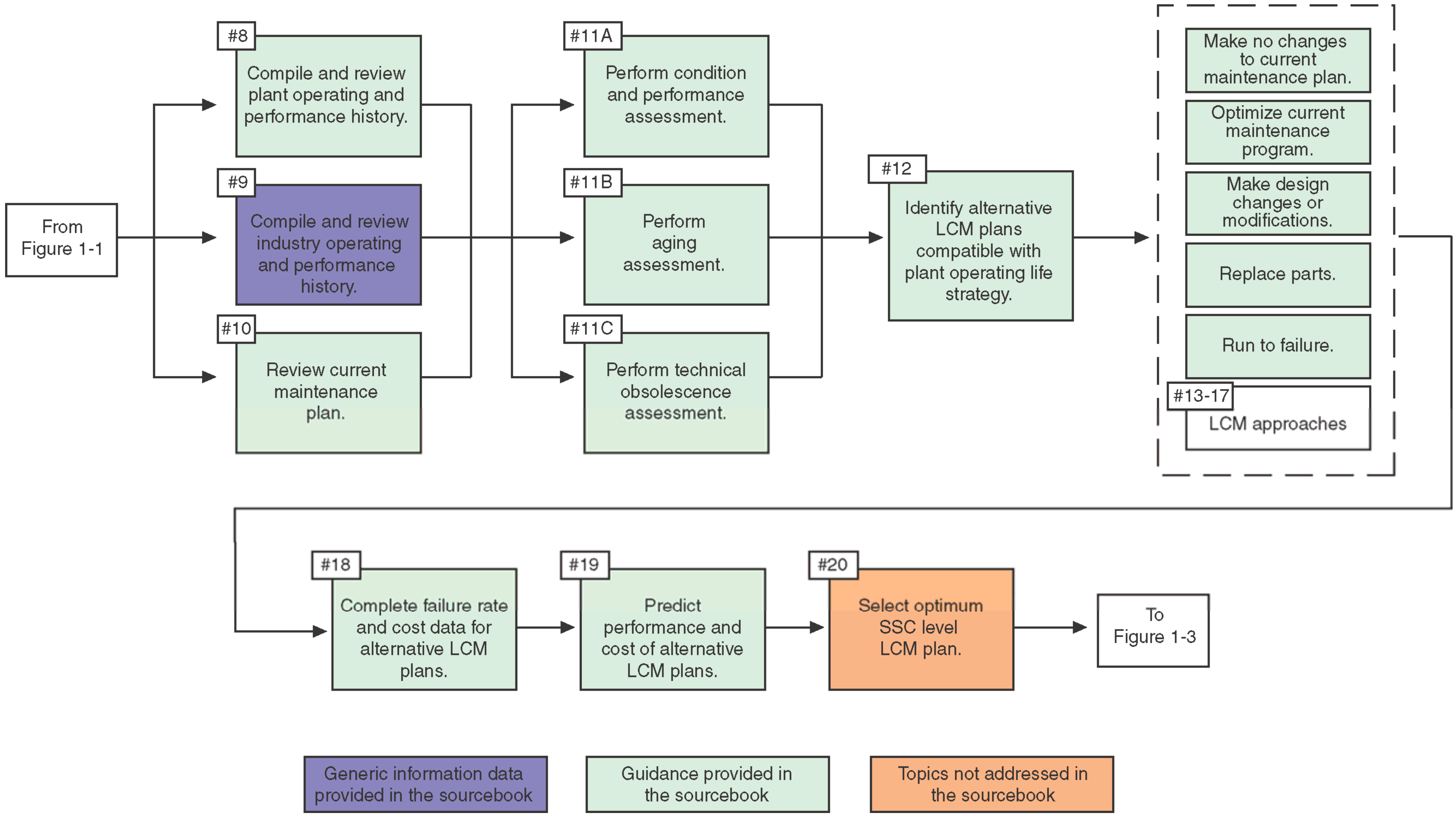

Figure 1-2
LCM Planning Flowchart – Technical and Economic Evaluation

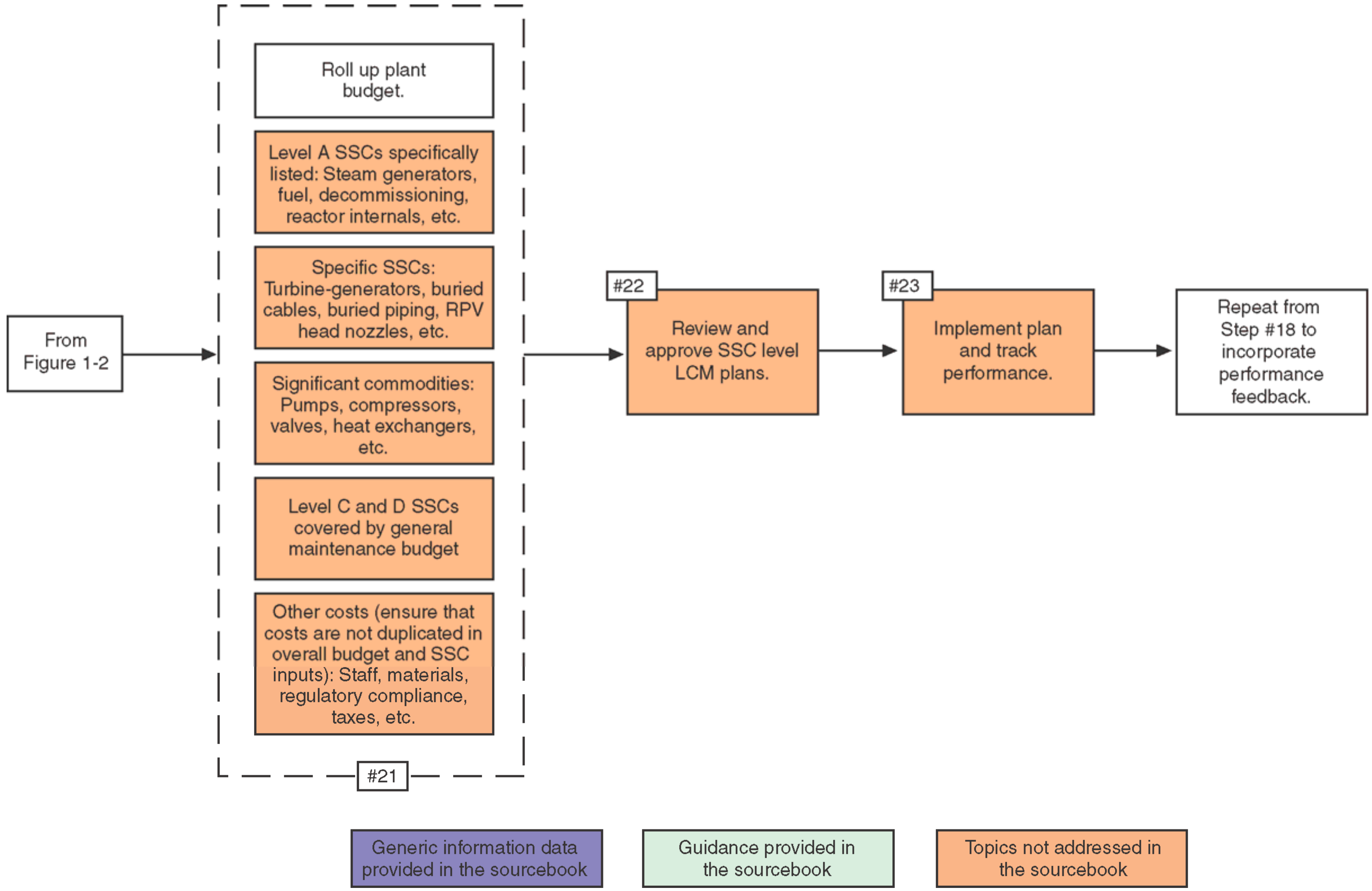

Figure 1-3
LCM Planning Flowchart – Implementation

1.3 Basis for Selection of the MV Cables/Accessories for LCM Sourcebook

MV cables and accessories were selected for preparation of a sourcebook by EPRI-member utility advisors. Using an initial listing of important SSCs, the sourcebook candidates were ranked in accordance with the priority given by LCM Advisory Committee members, SSC importance for power production and safety, potential for degradation and obsolescence, and concern for maintenance. The main reasons for the selection of each MV cable or accessory were:

- It is applicable to all plants, both BWRs and PWRs.
- It is important to power production and is safety significant.
- It is subject to degradation and age-related failure.

2 BASIC INFORMATION ON MV CABLES/ACCESSORIES

This section addresses Step 7 in Fig. 1-1. The function of MV cables and accessories is to carry power to the electrical equipment that needs it for operation. The MV cables and accessories must conduct the required current without overheating and must withstand the applied voltage between phase and ground, and, if high impedance grounding is used, phase-to-phase voltage if operation is allowed with a sustained ground fault condition present. Continuous operation of the MV cable system is essential for plant safety and operation. The MV cables and accessories can be divided into three major parts:

- Electric cables
- Terminations
- Splices

MV cables and accessories are required to function during any one of a number of normal and emergency plant operating modes. The critical components within this equipment are the same in design and function for both BWRs and PWRs and among the individual plants of each type. This sourcebook is therefore applicable to both BWRs and PWRs, in that the common design, operating conditions, and equipment problems can be addressed, to a large extent, by the same set of generic data.

2.1 Safety and Operational Significance

MV cables are critical to plant operation and safety. Station cables subject to adverse operating conditions may be nearing the end of their useful lives and may be near end of life and electrical failure. Adverse conditions include long-term wetting and high operating temperatures. Dry cables with moderate loads should have longer lives. Thus, it is very important that operators understand the condition of their installed cables to determine if and when replacement is needed to support acceptable reliability and optimize resources under their capital replacement programs. While determining the condition of cables is not always possible with today's technology, understanding the severity of operating conditions, and plant and industry failure trends for like cables will help support replacement considerations.

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

- Types of cable systems installed, including accessories
- Operating environment (wet or dry, high or low load, level of ambient temperature)
- Failure statistics

The important factors that affect the life of cable systems (that is, cables, terminations, and splices) are the construction and materials in the components, the quality of manufacture, the electrical stress on the insulation (which depends on the applied voltage), and insulation thickness. The quality of the installation and the service conditions can also greatly affect cable system life.

The MV cable components are generally included in the scope of systems reviewed for license renewal and are included in a plant's Maintenance Rule program. MV cables provide power to many of the critical components in both PWR and BWR plants, including feedwater pumps, condensate pumps, and circulating water pumps. The loss of a circulating pump, for example, could result in the need to reduce plant output, and the failure of MV cabling to a safety-related load could result in a limiting condition for operation (LCO), which, if not resolved, eventually leads to plant shutdown. Bus feeds are generally redundant, and most plant designs require a second failure (for example, a failure to fast transfer or a breaker failure) to cause a plant trip. While many MV loads are included in a probabilistic risk assessment (PRA), the MV cables themselves are not usually modeled.

2.2 Functions and Configurations of MV Cables/Accessories

The following information describes functions and configurations for MV cables, terminations, and splices. MV cables, terminations and splices are classified as passive components, and many circuits are considered to be critical for the continued safe operation of a nuclear power plant. Not all of the MV cable applications are safety related or important to operations; most plants have MV cables that feed general-use circuits (out buildings, office buildings, etc.) that will not affect safety or operations.

Presently, several MV cable types with different constructions and insulations are in use in nuclear power plants. The circuits may be composed of three individual cables, triplex individual cables, or three insulated conductors under a common jacket. Paralleling of cables in phases is used for some high-current applications. Nearly all 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), red, and brown. A limited number of cables installed in the late 1960s or early 1970s were insulated with butyl rubber, an early replacement for natural rubber.

The insulation shield, if present, consists of an extruded semi-conducting layer plus bare or tinned copper strands or tinned copper tapes. In early vintage cables, the insulation shield was a thermoplastic polymer, which could be susceptible to deformation and cracking when exposed to high temperatures for prolonged periods. Older black EPR cables had either a carbonized cotton tape or a semiconducting polymer tape. It was not extruded because it would have been indistinguishable from the black insulation. When manufacturers changed to red EPR, extruded polymer shields became common, because the black semiconducting extruded polymer could be easily distinguished form the red extruded insulation. Insulation shields are always used on XLPE and on EPR rated above 5 kV. Insulation shields may or may not be present on EPR rated at or below 5 kV. The jackets are usually made from polyvinyl chloride (PVC), chlorinated polyethylene (CPE), or chloro-sulfonated polyethylene (CSPE [Hypalon]).

MV insulation systems present the same aging concerns as low-voltage cables. High operating temperatures and/or high radiation levels harden the polymers with the exception of butyl rubber that softens in high radiation conditions. Safety-related MV cables are not used inside containment, and radiation conditions in the remainder of the plant are below levels where significant damage would occur to insulation. Thermal damage is possible for MV cables if the local environment is hot or if cables have high ohmic heating. In general, safety-related MV cables are either lightly loaded or unloaded during normal operation, and there is little concern for ohmic heating. Operationally important cables tend to operate under heavier loads. Depending on plant design criteria, ohmic heating may or may not be an aging concern for operationally important cables. Balancing of magnetic fields is important on cables with multiple conductors per phase. It is recommended that plants confirm that loadings are reasonably balanced in cables with multiple conductors per phase and are not causing an overload of specific cables in each phase.

The insulation thicknesses of MV cable rated for 5–15 kV applications are large in proportion to the applied voltage. Under dry conditions, the voltage stress in MV cables of the type used in nuclear plants is below the threshold where electrical degradation will occur. Electrical degradation of dry MV cable occurs only where an additional stress enhancer, such as physical damage or elevated temperature, exists. However, under prolonged wetted conditions, electrically induced degradation of the insulation is expected to shorten the life of a cable. In XLPE, this degradation takes the form of water treeing, which reduces the dielectric strength. In 5-kV rated circuits, water treeing may take 20 to 25 years to become significant. Wetting-induced degradation occurs in black EPR as well; however, the exact nature of the degradation is not fully understood. The degree to which wetting increases aging depends on the amount of contaminants and voids in the insulation system. Cables with larger or numerous contaminants and voids will be more susceptible to long-term wetting-induced degradation.

2.2.1 MV Cable

The MV cables under discussion are used for systems rated from 5 to 15 kV and are used to provide electrical power to buses and connected loads. Typically, MV cable for a nuclear application consists of:

- A stranded conductor
- A conductor shield
- Organic insulation
- An insulation shield
- An outer jacket, also organic

For 5-kV rated EPR insulated cables, the insulation shield is optional. The cable conductors are sized so that operating current does not overheat the cable insulation.

The conductor shield is a nonmetallic, semiconducting material in direct contact with both the conductor and the inner surface of the insulation, which helps to maintain a uniform voltage stress in the cable insulation. Conductor shields are generally found only on cables rated at 5 kV and above.

The insulation is an insulating material applied over the conductors, usually either ethylene propylene rubber (EPR) or cross-linked polyethylene (XLPE).

Insulation shields are used on shielded cables and cause a uniform electrical stress within the insulation. Copper tape rather than strands has been used in the insulation shields in most manufacturers' designs. There is one compact cable design (Anaconda/General Cable Unishield) where copper strands are imbedded in the polymer shield, and the polymer shield doubles as the jacket.

Cable jackets are usually rubber or plastic material applied over the insulation to provide mechanical or corrosion protection.

Some MV cables are armored with a metallic sheath of steel or aluminum that consists of interlocking metal strips wound helically around the cable and provides an extra measure of mechanical protection for the cable. A limited number of plants used a lead sheath on cables located below grade. Cable construction may be single conductor (1/C), three conductor (3/C), or tri-plexed. A tri-plexed cable has three individual insulated conductors cabled together without an overall jacket.

Figures 2-1 and 2-2 show typical single-conductor unshielded and shielded MV cable constructions. Approximately 25% of the units providing information to the NEI 2005 Underground Medium Voltage Cable Survey [5] indicated the use of unshielded EPR cables.

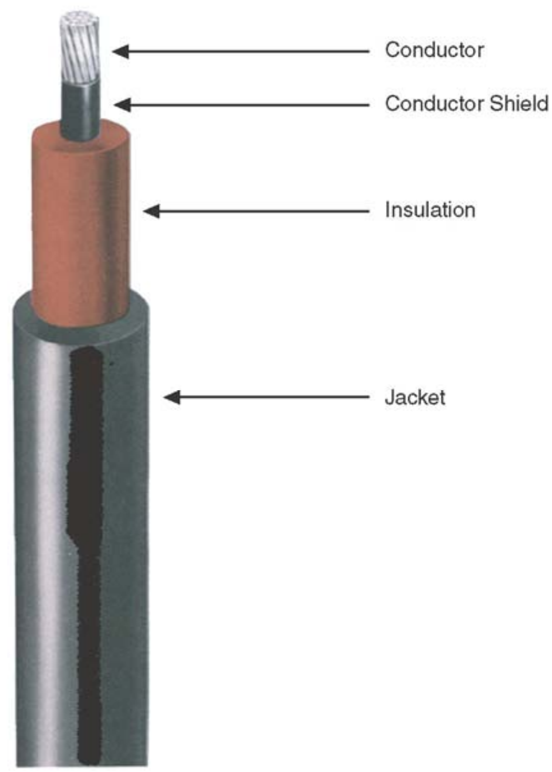

Figure 2-1
Typical Unshielded MV Cable

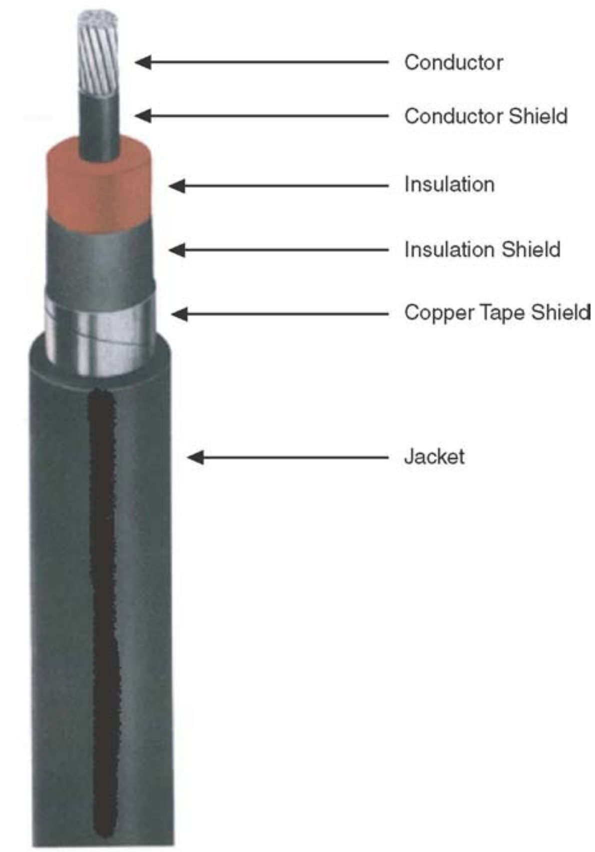

Figure 2-2
Typical Shielded MV Cable

Triplex, 1/C, and 3/C are typical power cable constructions. Triplex and 3/C cables are generally limited in size to 1000 thousand circular mils (MCM)[1] because of manufacturing and shipping limitations. The 1/C cable is used when the required size exceeds 1000 MCM or when the user prefers not to handle triplex and 3/C cables in the large conductor sizes. The 1/C and triplex cables are normally specified with jackets over the insulation to protect the insulation during installation. The 3/C cable, which has an overall jacket or armor, is sometimes specified instead of triplex when more mechanical protection or ease in cable pulling is desired.

Both 8- and 15-kV rated cables are usually shielded. Copper or aluminum conductors may be used in power cable, with copper prevalent in nuclear applications.

[1] 1000 thousand circular mils (MCM) conductor size is approximately 0.5 in (12.7 mm) in diameter.

2.2.2 MV Accessories

2.2.2.1 Cable Termination and Splicing

Various types of accessories (splices and terminations) 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 connection insulation is critical to ensuring proper operation, especially when shields are present. Cable termination consists of preparing the cable ends for proper connection to a terminal block, equipment pigtails, or busbars of a device or equipment. Splices may be used in the repair process when sections of a long cable are replaced instead of replacing the entire circuit.

2.2.2.1.1 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 metallic shield at the end of the cable. Figure 2-3 illustrates a typical MV cable termination. Terminations also increase the length of the electrical path 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. The potential gradient at the termination is very high by comparison to elsewhere in the cable where the insulation shield controls the stress in the insulation.

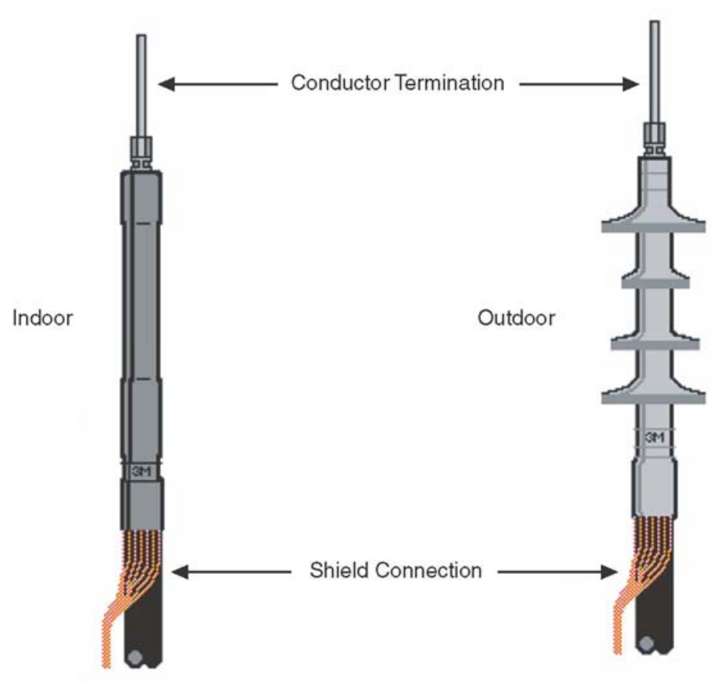

Figure 2-3
MV Cable Terminations (Courtesy 3M)

2.2.2.1.2 Splices

Splices are high-voltage connectors that join two cables together. Figure 2-4 illustrates a typical MV cable splice. Most MV cables in nuclear plants are short enough that splices are unnecessary; however, some plants have a few long runs that require the splicing of sections. 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 shields. As with terminations, the insulation shield must be removed for a significant distance along the cable surface to provide electrical separation from the conductor.

Cable splicing may be required because of the following reasons:

- The total circuit length is longer than the existing cable.
- Connections must be made to a segment of cable used to replace damaged or failed cable.
- The cable size is too large to fit into equipment, and a smaller size cable is spliced to the larger one.

Splices should preferably be made inside a metal enclosure or manhole, and the enclosures should be accessible.

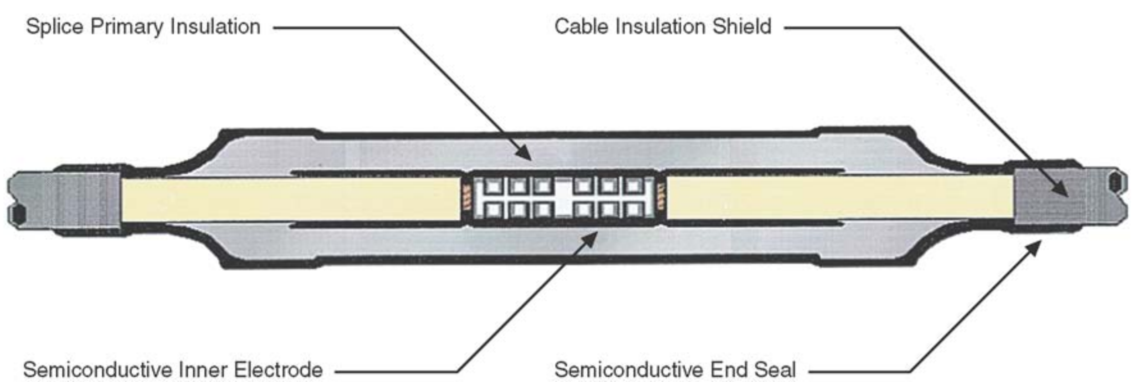

Figure 2-4
MV Cabling Splice (Courtesy 3M)

Great care is needed when installing terminations and splices to prevent contamination and de-lamination of the interfaces that may lead to increased surface leakage and/or partial discharges (PDs) that could eventually lead to failure.

Cable termination and splicing require one or more of the following:

- Mechanical connection of the conductor to another conductor
- Insulation and protection of the connection area
- Stress cones or other devices for relieving the voltage stress created by the splice of the MV cable
- Connection of shield to ground or adjacent cable section

2.2.2.2 Conductor Connection Methods

Two methods are used for cable terminations and splices: fusion connection and pressure connection. The former consists of soldering, welding, or brazing the cable conductor to another conductor or bus work. Pressure connections are used in most cases, and there are two basic types. In the compression method, the conductor is inserted into a lug, and a compression tool is used to clamp the lug onto the conductor. In the mechanical method, the bare conductor is joined mechanically by clamping down with a set screw or bolt.

2.3 MV Cables/Accessories Design and Operating Parameters

For MV cable components, the design and operating parameters are different from the component's rated voltage. Cable components will be rated for one voltage level, yet normally carry a lower maximum operating voltage. MV cables rated at 5 kV will normally carry 4.16 kV, those rated for 8 kV will carry 6.9 kV, and those rated at 15 kV will carry 13.8 kV [6].

The insulation thicknesses for cables are classified as 100%, 133%, or 173% insulation levels. The 100% level cables rely on relay protection to normally clear ground faults within approximately 1 minute. For cables with 133% insulation levels, the faulted cable is assumed to be de-energized within 1 hour. At the 173% insulation level, cables may remain in a ground fault condition indefinitely [6].

MV cable insulation is usually assigned one of three different temperature ratings: operating condition, emergency overload, and short circuit. The emergency overload temperature rating is for situations where load current is larger than normal but is not expected to last longer than 100 hours at a time or 500 hours for the life of the cable. The short circuit temperature rating is for fault current conditions lasting no longer than 150 cycles [7].

The operating environment for MV cables may vary significantly from plant to plant, from relatively dry cable trays within plant structure interiors, to exterior cable duct banks between plant structures, to (in some cases) cables completely submerged in water. The ideal operating environment would be a cool, dry location that allows for adequate ventilation flow to remove excess heat due to ohmic heating.

3
HISTORICAL PERFORMANCE DATA FROM INDUSTRY OPERATING EXPERIENCE

This section addresses Step 9 in the LCM planning flowchart (Figure 1-2). The information compiled in this section is to be used for a comparison or benchmark of plant-specific conditions and operating experience. The qualitative data allows potential conditions affecting plant-specific performance to be reviewed with respect to general industry experience, while the quantitative failure data may provide insight into the potential for plant-specific enhancements and may help identify where improvements can be made.

If significantly higher failure rates are identified for a plant, the plant failures must be examined to determine if other cables under the same conditions should be assessed and replaced as appropriate or if cable condition monitoring should be implemented. In general, if the reliability of an SSC falls below a certain level, replacement or other major maintenance efforts will be required to satisfy Maintenance Rule performance criteria. MV cable failure rates could affect the reliability of Maintenance Rule SSCs.

It should be noted that this section addresses failures and failure data rather than repair practices and data. Monitoring techniques are addressed in Section 4.

3.1 Nuclear Industry Experience

A comprehensive review of the available industry operating experience has been done to extract the salient information and to present the data that the plant engineer may use in assessing the plant-specific performance of MV cables and accessories. Several industry databases were reviewed to identify problems that have been reported with MV cables and accessories at nuclear plants.

The cable systems used in nuclear plants, their environments, and failure records were identified to the extent possible. The three key elements—cable type, environment (wet or dry), and failure statistics—are intimately linked to each other. 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. Thus, to predict the performance of a cable system, the details of the cable system, its aging mechanisms, and its failure history must be understood.

To gather the necessary information, a questionnaire was prepared and distributed by the Nuclear Energy Institute (NEI) to all U.S. nuclear plant owner/operators [5]. The questionnaire asked for details about the types of cable used, accessories, installation, operating environment, and failure statistics.

The responses to the questionnaire represent 81 units from 51 stations, with 74 units from 47 plants providing failure data. This represents more than 70% of the units in operation in the United States. According to the survey, 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 the water out of the ducts and manholes that fill up with water.

Forty-eight units (59%) report some form of electrical testing is performed on MV cable; 43 units (53%) report use of insulation resistance testing; 20 units (25%) report use of polarization index; 14 units (17%) report use of dc high-potential (hi-pot) testing; 13 units (16%) report use of leakage current testing; 6 units (7%) report use of tan δ; 2 units (2%) report use of off line PD testing; 5 units (6%) report use of on-line PD testing; 2 units (2%) report use of ac hi-pot testing; 4 units (5%) report use of VLF ac hi-pot testing; 1 plant performs Doble tests; and 1 plant uses time domain reflectometry (TDR). Some of the tests are associated with the connected load through the cable, some testing is performed at the time of installation, some is performed on a periodic basis, and some is done "as needed."

3.1.1 Evaluation of NEI Survey Results for MV Underground Cable

3.1.1.1 Introduction

Eighty-one units (51 plants) provided information to the general survey questions. Seventy-four units (47 plants) provided information on originally installed cables, failures, and replacement cables. The information from the survey provides a strong understanding of the cable types in use, their insulations and shielding systems, and generational differences [5].

3.1.1.2 Underground Circuit Information

All 81 responding units reported some underground cable. Sixty-five units (80%) reported use of underground conduits; 76 units (94%) reported underground ducts; and 23 units (28%) reported some direct buried circuits. Twenty-one units (28%) reported having enclosed trenches with cables supported within the trench.

The number of circuits per plant was quite variable and appears to relate to vintage and whether general service cables (those not important to safety or operation) were reported. For the 75 units providing data, the total number of circuits identified was 8509. This quantity is for wet and dry applications underground and in plant. The average number of circuits per unit was 113 circuits with a high of 376 per unit and a low of 4. Seventy-seven units provided data on the number of underground circuits with a total number of circuits for the 77 units of 2767. The average number of underground circuits per unit was 36 with a high of 214 and a low of 2 per unit. The ratio of underground circuits to total MV circuits was 0.32. Of the plants reporting underground circuits, 31% indicated that the circuits were dry, and 69% indicated that the circuits were wet.

3.1.1.3 Installed Cables

Most respondents indicated use of 5-kV rated cables in underground applications operating at 4.16 kV. Table 3-1 provides a listing of the 5-kV rated insulation types by number of units reporting the material. Butyl rubber is an insulation that was in use in the late 1960s and very early 1970s, but at just a few sites. The material was replaced by black EPR, XLPE, and brown EPR. In the late 1970s to early 1980s, EPR manufacturers recognized that improvements in longevity could be had by improving the coating of clay fillers to make them nonhydroscopic. The black pigment was replaced with red pigment to indicate the generational difference. It should be noted that EPR is a compound, and each manufacturer's formulation is somewhat different. Some variations in behavior may exist due to formulation and overall cable design differences.

Table 3-1
Originally Installed 5-kV Insulation Types in Use at Nuclear Plants

Insulation	Units	Percent of Reporting Units
Butyl Rubber	4	5
EPDM	1	1
Black EPR	48	65
Brown EPR	20	27
Red EPR	31	42
XLPE	23	31

Note: Some units reported more than one type of cable in use.

Figure 3-1 shows the distribution of manufacturers for the black EPR-insulated cables. Okonite and Anaconda are the dominant manufacturers. The brown EPR is manufactured only by Kerite. The red EPR was manufactured by either Anaconda (9 units reporting use) or Okonite (21 units reporting use). One unit reported having both Anaconda and Okonite red EPR.

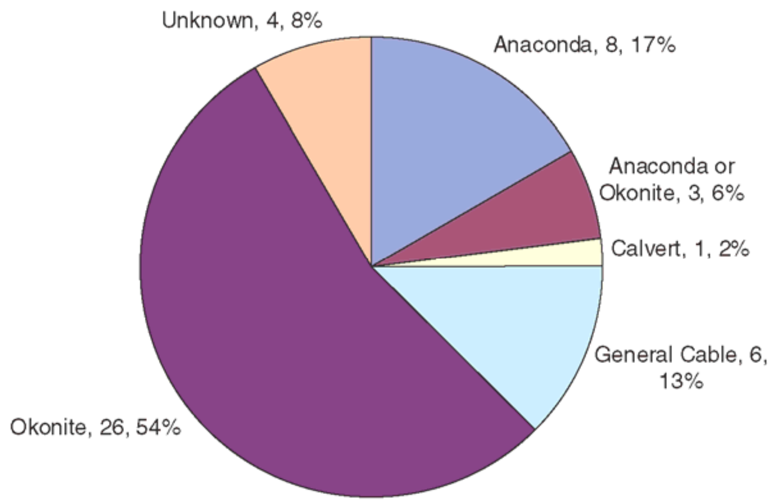

Figure 3-1
Distribution of Black EPR Manufacturers of 5-kV Cable

Twenty-four units reported having 8-kV rated cable in use on systems operating at 6.9 kV. Table 3-2 provides a breakdown of the insulation types in use. Plants with 6.9-kV systems tended to be constructed in the late 1970s and beyond so that a lower percentage of the plants had black EPR insulations for 8-kV rated cables than for the 5-kV rated population. In addition, 6.9-kV systems were not adopted by most utilities—even in later plants. Some later plants remained with 4160-V systems for the bulk of the plant and used 13.8-kV systems to supply large loads, such as the circulating water pumps.

Table 3-2
Insulation Materials for Plants Using 8-kV Cable

Insulation	Units	Percent of Reporting Units
Black EPR	8	11
Brown EPR	2	3
Red EPR	20	27
XLPE	7	9

Forty units reported having 15-kV rated cables operating at 12 to 13.8 kV. Table 4-7 provides the breakdown of the insulation types in use. As stated above, these cables are used for distribution to large loads and feeds to step-down transformers with 4-kV secondaries.

Table 3-3
Insulation Materials for Plants Using 15-kV Cables

Insulation	Units	Percent of Reporting Units
Butyl	1	1
Black EPR	21	28
Brown EPR	9	12
Red EPR	26	35
XLPE	9	12

Nineteen units reported use of cables rated at 25 and 35 kV. Table 3-4 provides the breakdown of the insulation materials on these cables. The 35-kV cables were used in 34.5-kV operating systems associated with off-site power feeds. The 25-kV cable was used in 22-kV circuits between the generator output and auxiliary transformers. A few units reported having PILC (paper insulated, lead jacketed) cable. Rather than having extruded polymer insulation, these cables are insulated by oil impregnated paper with an overall sheath of lead. Only a few plants reported using this type of cable and even at those plants, extruded polymer insulation was used on the bulk of the installed cables.

Table 3-4
Insulation Materials for Plants Using 25- to 35-kV Rated Cables

Insulation	Units	Percent of Reporting Units
EPR-black	7	9
EPR-brown	3	4
EPR-red	1	1
XLPE	2	3
PILC*	4	5
Unknown	2	3

* PILC is paper-insulated, lead-covered (jacketed) cable.

3.1.1.4 Shielding

Above 5 kV, some cables are manufactured with insulation shields. At 5 kV and above, XLPE cables have insulation shields. However, 5-kV EPR cables may be manufactured and purchased with or without shields. Excluding the general service cables, 22 units (30%) reported having a total of more than 271 circuits with unshielded EPR cables. (Two plants reported having unshielded cables, but they did not indicate the quantity.) These cables were used in safety, fire protection, operationally important, station black-out, and off-site feed cables. The lack of a shield on the EPR cables is not a reliability issue. Circuits without shields represent an electrical testing issue. Electrical testing at high voltage requires a uniform ground plane that an insulation shield provides. Circuits without a shield would not have a uniform ground plane, and electrical testing is unlikely to provide useful results.

Forty-two units reported having 5-kV cables with shields. This group included all of the XLPE cables and a portion of the EPR cables from most of the manufacturers and vintages.

3.1.1.5 Underground Wet Duty Failure Assessment

3.1.1.5.1 Plants with No Failures

Seventy-four units provided data regarding failure experience. Of the 74 units, 53 units (72% of reporting units) had no failures of MV wet underground cable to date. Figure 3-2 shows the distribution of ages of the plants that have not experienced a failure. The figure shows that 23 of the units with no failures are older than the average age of the fleet and 30 are younger than the average. Nineteen units with no failures are 30–35 years old.

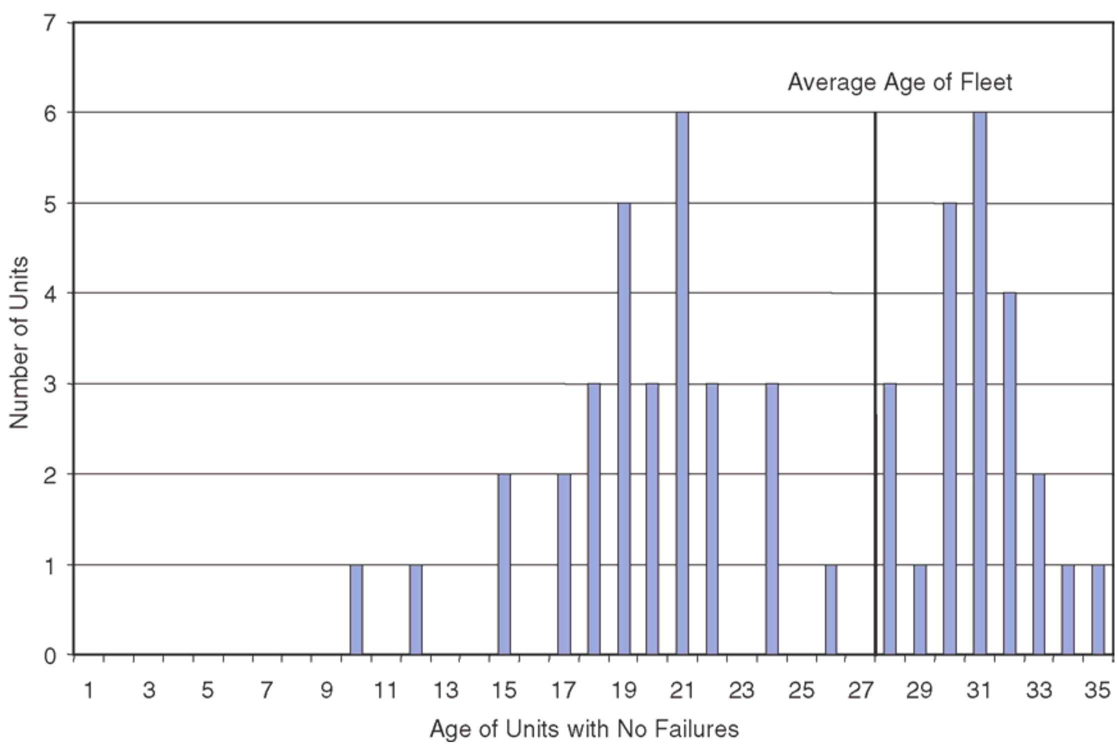

Figure 3-2
Distribution of Age of Plants with No Failures

3.1.1.5.2 Plants with Failures

Of the 74 reporting units, 21 units (15 plants) experienced failures of MV, wet, or possibly wet underground cable. The 21 units experienced a total of 50 failures in underground circuits that were safety-related, fire protection, off-site power, station blackout, or operationally important. General-service cables were generally excluded because these circuits are not related to safety or power production and are typically treated differently, with respect to installation and operational practices. Events not related to the wet section of the cable were excluded from the analysis. Cables that were replaced on the basis of test results or that were replaced as an extended corrective action resulting from failure of a similar circuit were also excluded because they had been replaced prior to failure. The 21 units having failures represent 28% of the reporting units.

Table 3-5 summarizes the number of events per plant that reported failures. The table indicates that the six plants with three or more failures account for 75% of the failures. (**Note:** A parallel evaluation of related Equipment Performance & Information Exchange (EPIX) and Nuclear Plant Reliability Data System (NPRDS) data indicates that the failures reported by the 74 units responding to the survey appear to cover all of the failures of wet MV cable that have occurred.)

Table 3-5
Failures per Plant (Unit) of 15 Plants Experiencing Events

Number of Failures	Number of Plants with Failures	Number of Units with Failures
1	4	5
2	5	7
3	1	1
4	2	3
5	1	2
10	2	3

Figure 3-3 shows the distribution of the age of cables at time of failure for all cable types. The distribution of age at time of failure is quite broad with as little as 5 years and as many as 30 years of service before failure.

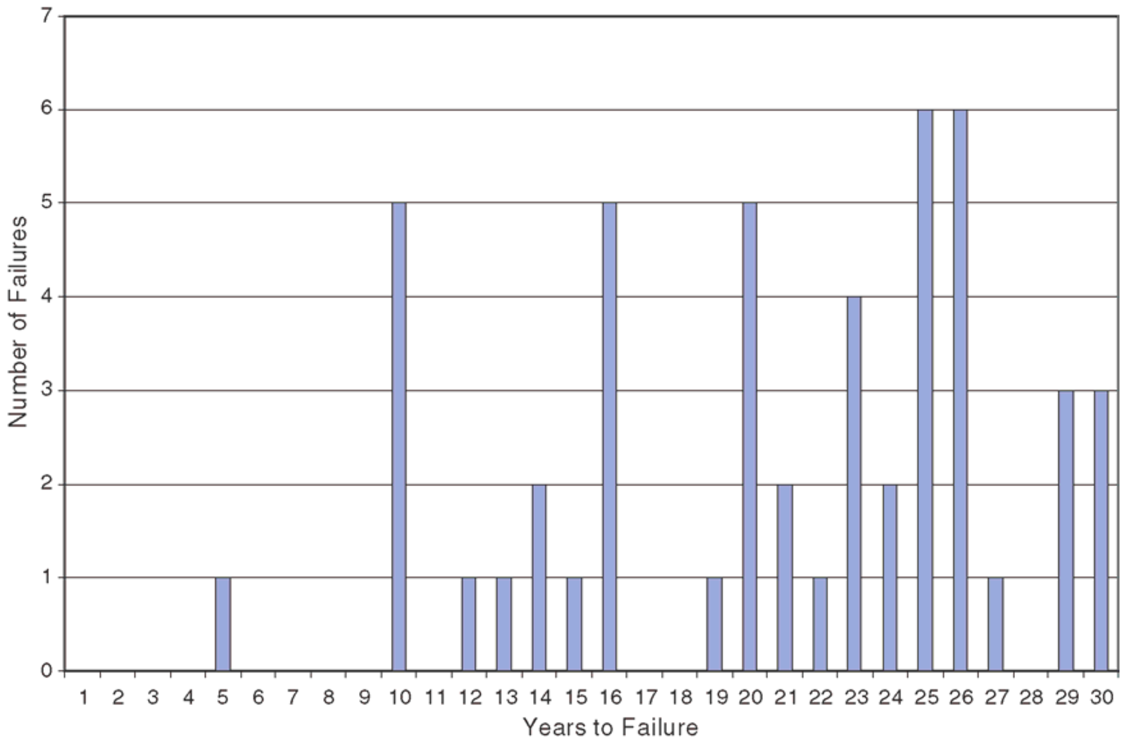

Figure 3-3
Age of Cables at Time of Failure

Figure 3-4 shows how the XLPE cable failures relate to all failures. The total distribution of failures is shown as striped bars with the XLPE failures shown in color. Twelve XLPE failures occurred at four plants. Eight of the failures occurred at one plant in a specific type of filled XLPE that was used only at that plant. These eight failures represent 16% of the total wet, underground cable failures.

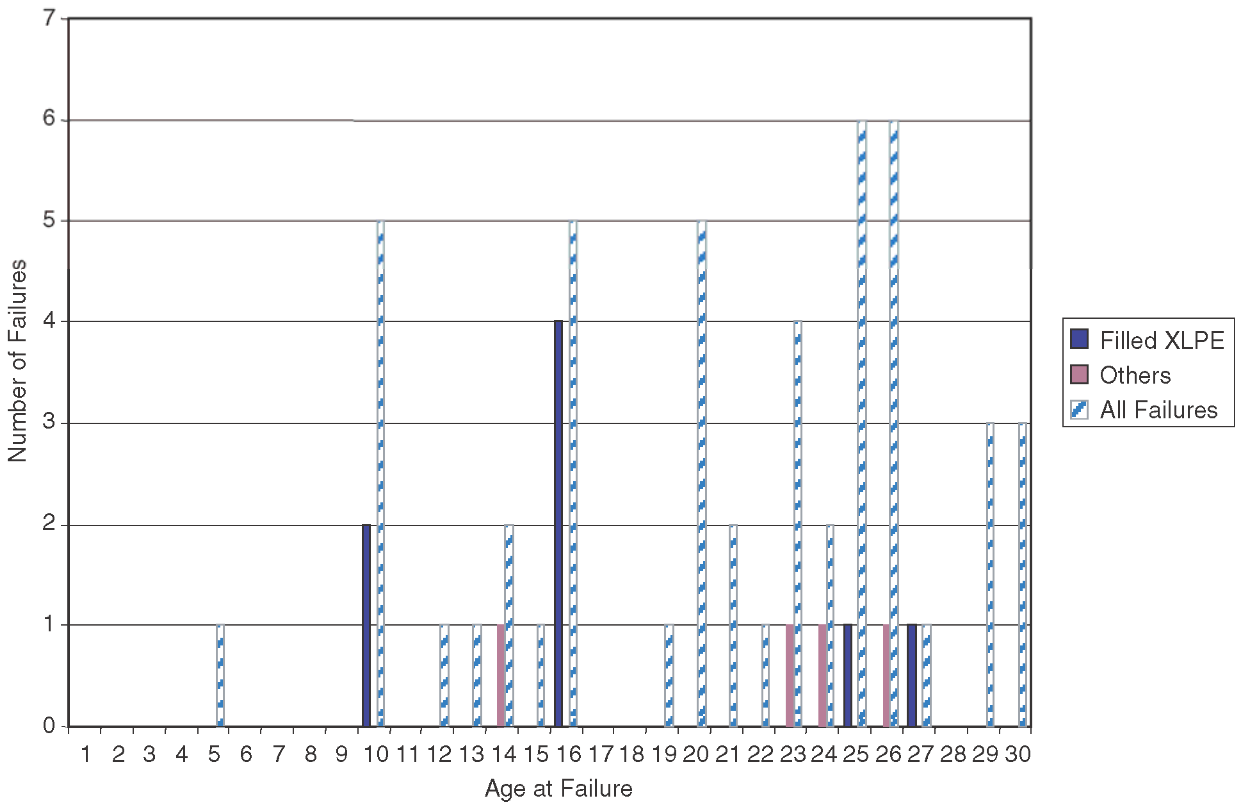

Figure 3-4
XLPE Failures in Relation to All Failures of Wet Underground Cable

Figure 3-5 shows the distribution of EPR failures in relation to all failures. Black EPR is the dominant insulation in the industry (88% of units reported usage), with red EPR installed in units that became commercial in the 1980s and beyond and then becoming the dominant replacement insulation. The failure of the red EPR at five years was determined to be related to manufacturing flaws, causing a large contaminant at the failure site. The three red EPR failures at 10 years occurred at one plant; however, the cause of failure was not given.

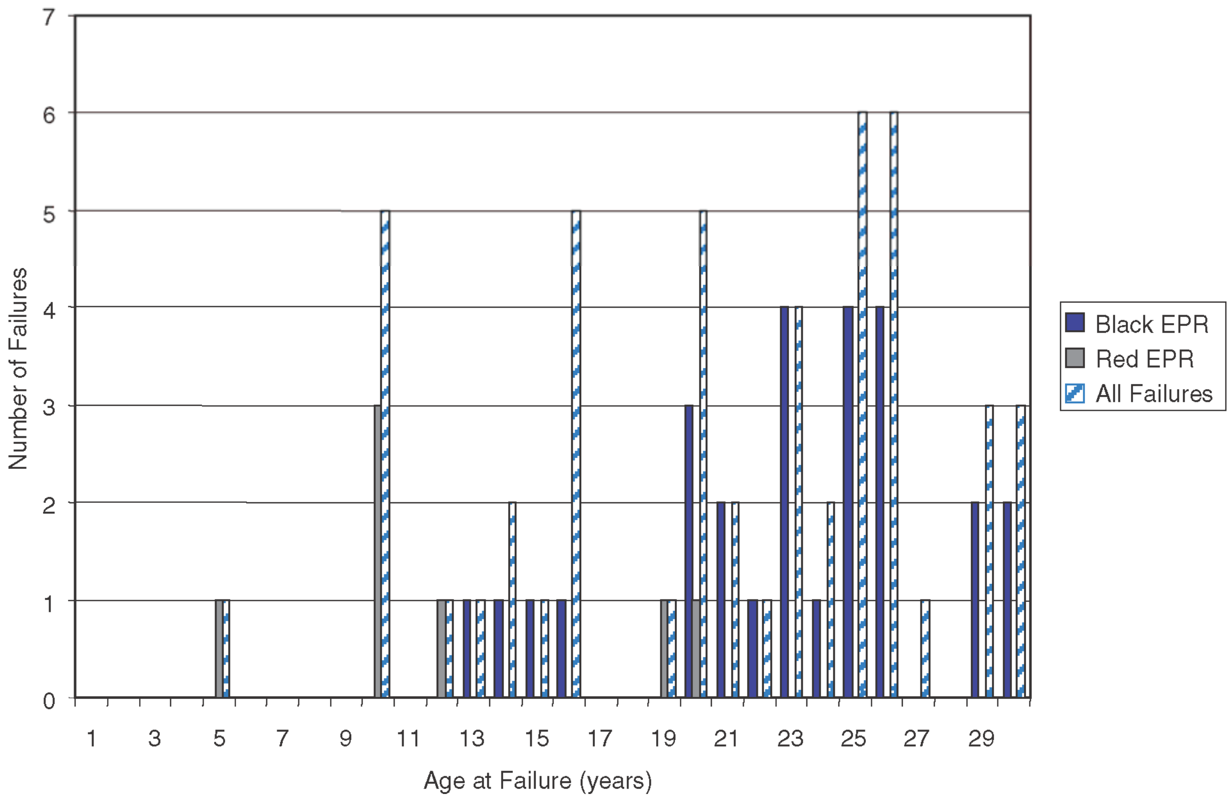

Figure 3-5
EPR Failures in Relation to All Failures of Wet Underground Cables

Figure 3-6 shows the relationship of the butyl rubber failures to the overall distribution of failures. The number of butyl rubber failures is small because only four of the reporting units indicated use of butyl rubber.

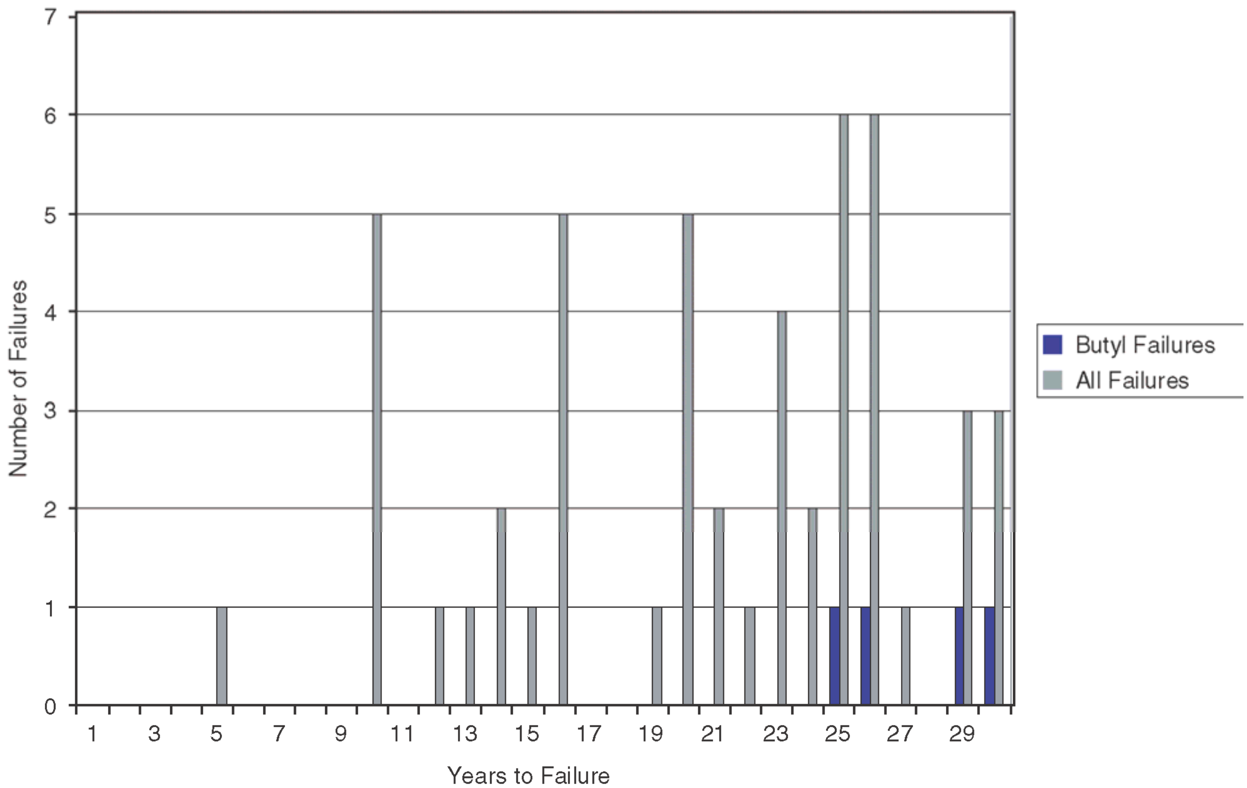

Figure 3-6
Butyl Rubber Failures in Relation to All Failures of Wet Underground Cable

Figure 3-7 shows the age of the cables at the time of their failure. The general trend in the age at failure is increasing. The trend in the number of failures at a given age is relatively stable but is showing a slight increase with time.

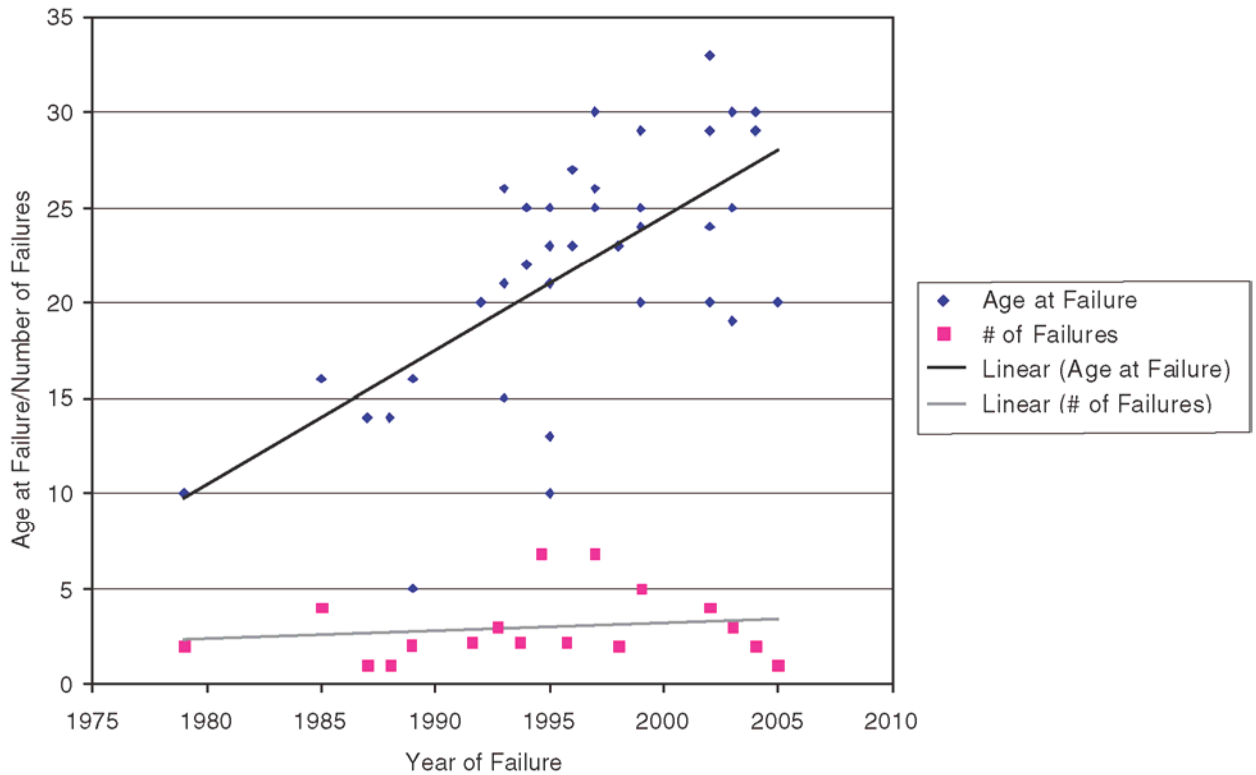

Figure 3-7
Age at Failure Versus Year of Failure

3.1.1.5.3 Plant Actions in Response to Cable Failures

A few of the 15 plants reporting failures had a significant number of failures. Each of these plants has taken action to manage the issue:

- The plant with 10 failures of Okonite black EPR determined that the bulk of the problem was associated with manufacturing defects (contaminants or voids in the insulation) and severe operating conditions, and has implemented a program of replacing the underground cables over a period of refueling outages.
- Another plant, having observed multiple failures of non-safety as well as safety-related black EPR Anaconda Unishield cables, has implemented replacement of underground cables.

- The plant with nine failures of filled XLPE replaced the cable with a black EPR-insulated cable. The replacement cable had manufacturing problems, and the plant chose to replace all of that cable with modern red EPR-insulated cable.
- One of the plants that had XLPE failures performed laboratory failure assessments. Upon finding that a cable had degraded from water-treeing (previous failures were determined to be manufacturing defects), the plant implemented electrical testing (tan δ and hi-pot testing) to determine when other circuits needed to be replaced.

3.1.1.5.4 Inferred Failure Rate

As stated above, the average number of underground circuits per unit is 36 for the 81 units reporting. The population of units has been stable since 1990 at approximately 101. Forty of the failures have occurred since that time. The approximate failure rate for wet underground cables during the period from 1990 to 2005 is 40 failures/(101 units x 36 circuits/unit x 15 years) or 0.00073 failures per year per circuit. Thirty-one percent of respondents indicated that their underground cables were dry. If the failures were considered to be associated with wetting only (that is, making the assumption that dry circuits do not fail), then the failure rate for wet circuits would rise to 0.0011 failures per year per circuit (0.00073/0.69 [fraction of plants with wet cables]). These failure rates are approximate at best and include a mixed population of safety, fire protection, off-site power, station black out, and operationally important cables.

To date, no wetting-related failures of brown EPR-insulated cables has occurred, indicating that their failure rate is much lower than the average and the failure rate for other cable types is somewhat higher. Insufficient information concerning installed insulation types is available for all plants to readily identify the failure rates for wetted cable by specific insulation type.

3.1.1.5.5 Replacement Cables

Thirty units provided information on replacement cables in use. Nearly all of the remaining plants did not have failures and did not report on a replacement cable type. Table 3-6 summarizes the insulation types being used. Manufacturers have stopped making black EPR. Although some replacements may have occurred from black EPR that was on site, all future EPR replacements are likely to be either red or brown EPR. The dominant replacement material is red EPR, with a few plants using brown EPR or modern tree-retardant (TR) XLPE insulation.

Table 3-6
Replacement Cable Insulations

Insulation	Units
EPR (Type not indicated)	2
EPR-Black	3
EPR-Brown	5
EPR-Red	25
TR-XLPE	4

3.1.1.6 Failures of Circuits Related to Causes Other Than Wetting

3.1.1.6.1 Failures of Dry Circuits

Figure 3-8 shows the age distribution of failures of dry cables by insulation type. The data are from combined EPIX and NPRDS databases. The data indicate that far fewer failures of dry cable occur. A total of 10 failures were identified in the period from 1985 through 2005. The number of failures of dry circuits is one-fifth of that of wet or potentially wet underground circuits. Figure 3-9 shows the failures in relation to year of failure.

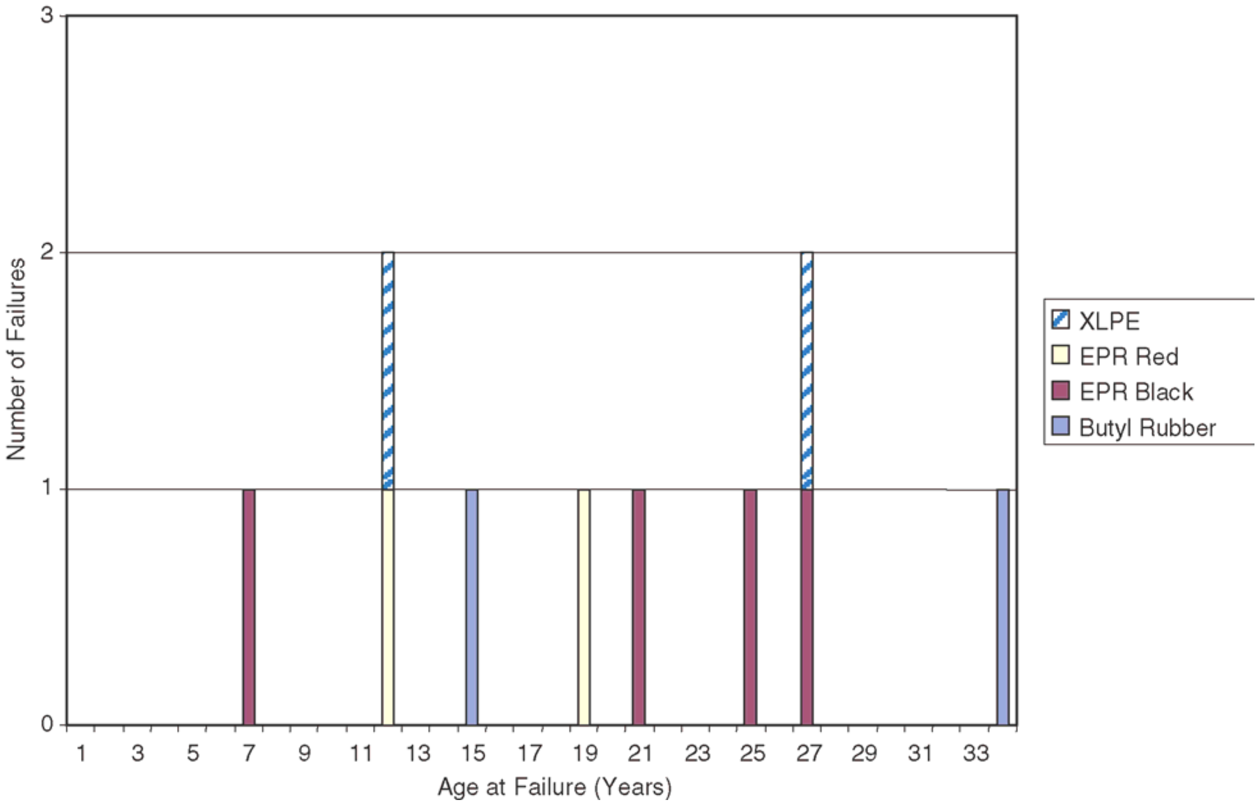

Figure 3-8
Failures of Dry MV Cables by Insulation Type

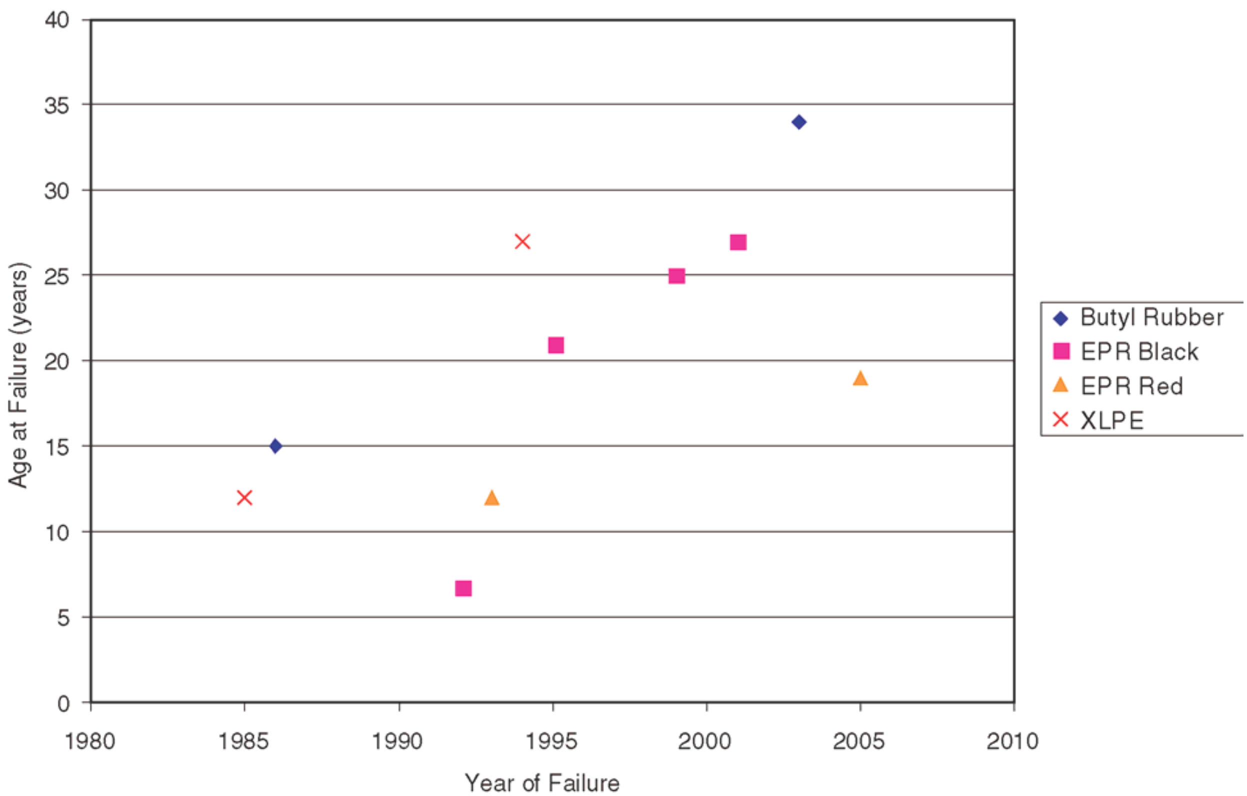

Figure 3-9
Dry Cable Time of Failure and Age

Eight of the failures occurred during the period from 1990 to 2005. During this period, 101 units were in operation. According to the NEI Survey data, there is an average of 77 dry MV circuits per plant. For the period, the approximate failure rate was 8 failures/(101 units x 77 circuits per unit x 15 years) or 0.000069 failures per circuit per year.

3.1.1.6.2 Deteriorated Cables Found on Test

Not all cables that have been replaced failed in service. Some were identified through electrical testing either of the cable or an associated motor. Figure 3-10 shows the distribution of age at time of test failure for cables. The data are from five plants. The 10 test failures of red EPR cable at eight years of age occurred at one plant. The cable system had been out of service for an extended period to allow replacement of a transformer. The plant decided to perform dc testing on 54 cables. Ten failed the tests. Neither the manufacturers nor an independent assessment at a university could find the cause of the test failures. Water treeing was eliminated as a cause in these assessments.

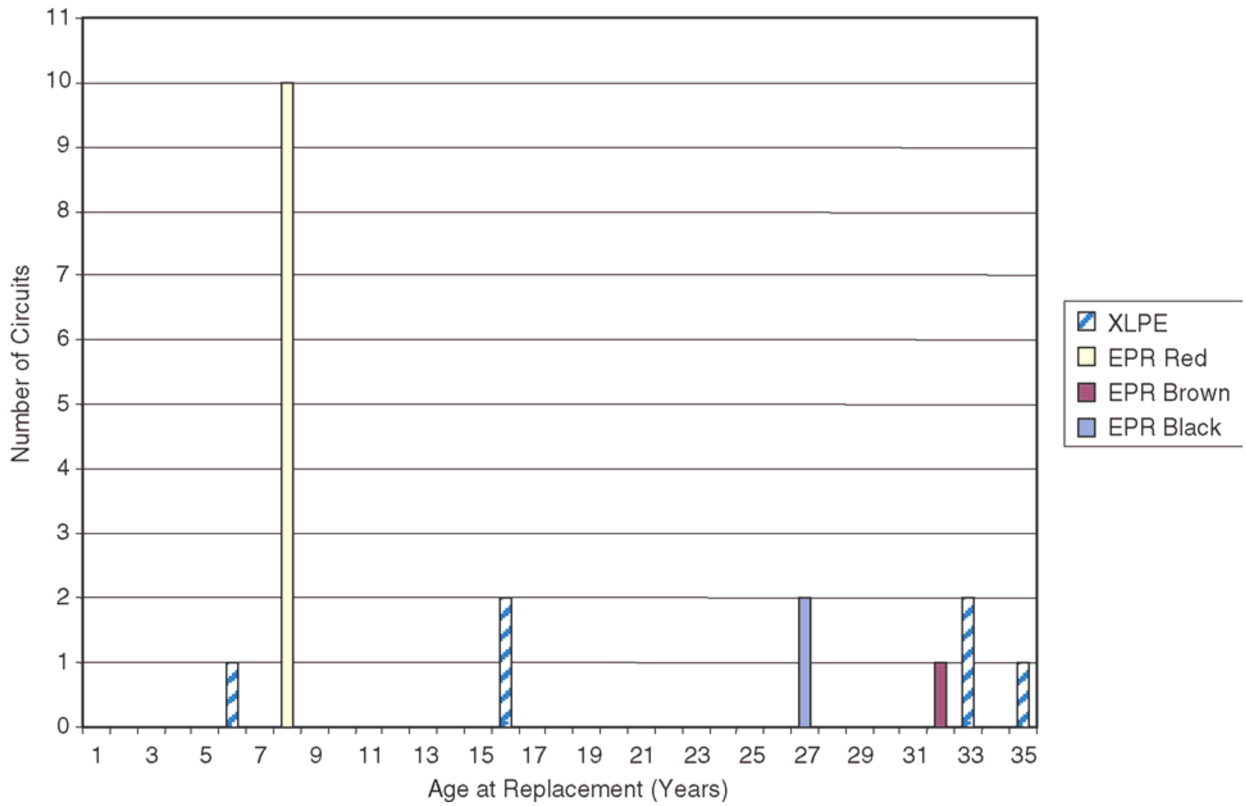

Figure 3-10
Cable Replaced upon Test Results

3.1.1.6.3 Termination and Splice Failures

The evaluation of the NEI Survey, EPIX, and NPRDS data identified eight splice and two termination failures. The distribution of these failures is shown in Figure 3-11. The terminations are located in dry environments. The two splice failures were in wet environments. In general, the use of splices is relatively rare—even in MV circuits.

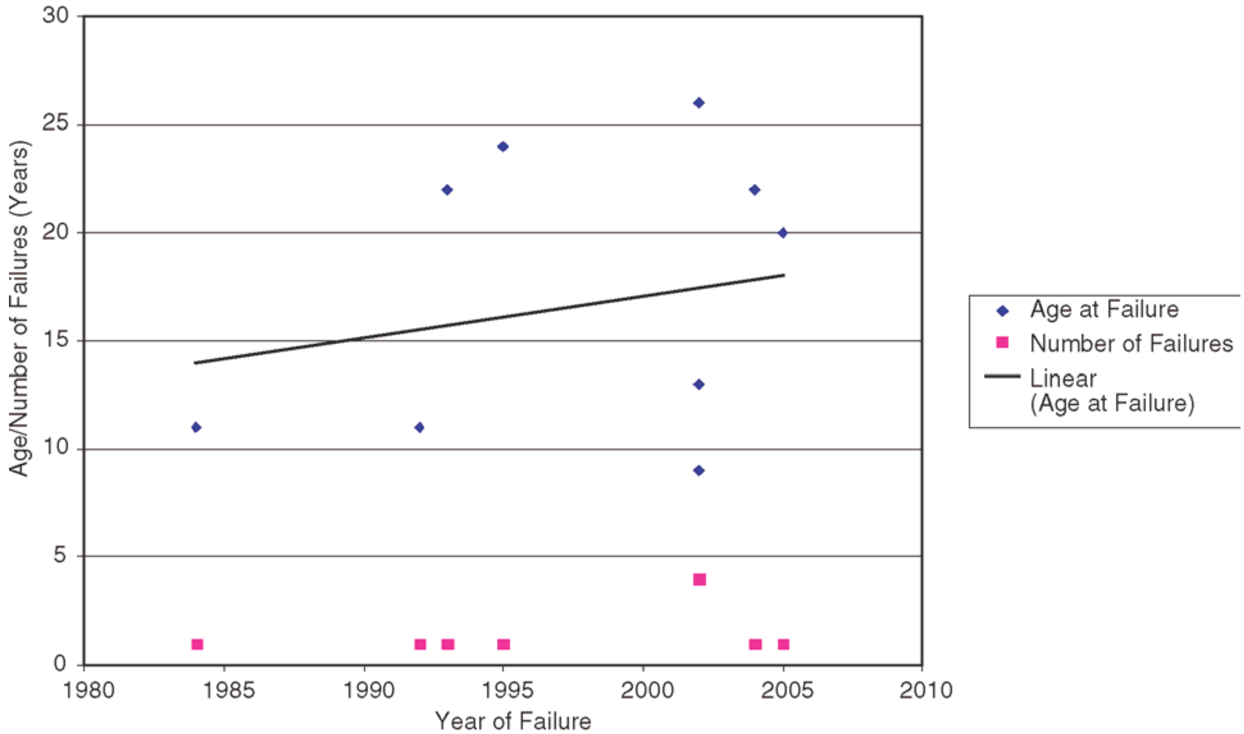

Figure 3-11
Termination and Splice Failure Distribution

Nine of the termination/splice failures occurred during the 1990 to 2005 period. The average number of total MV circuits in a unit is 113. Accordingly, the approximate failure rate for terminations is 9 failures/(113 circuits per unit x 101 units x 15 years) or 0.0000526 failures per circuit per year.

3.2 Generic Communications and Other Reports

3.2.1 NRC Communications

There are several Nuclear Regulatory Commission (NRC) informational sources that provide material relating to MV cables and effects of operation. This material is useful to the operator and is summarized here. Additional material can be accessed directly from the NRC web site at www.nrc.gov.

3.2.1.1 Information Notice No. 2002-12: Submerged Safety-Related Electric Cables

This notice addresses observed protracted submergence in water of electric cables that feed safety-related equipment.

Failure of a 4160-V ac cable was found to have resulted from localized delamination of the cable jacket, aggravated by water intrusion into the underground conduit, with subsequent drying and corona degradation to the insulation.

Lack of a routine monitoring and inspection program allowed safety-related cables to remain in a submerged condition for an extended period of time. In addition, subsequent inspection tours observed leaking duct banks, corroded and broken cable supports, cable jacket tears, inoperable sump pumps, and inoperable level controls.

The trip of a component cooling-water pump resulted from a phase-to-ground fault of a 23-year-old MV cable that had been installed inside PVC conduit, running partially underground. It was concluded that this was an isolated fault to ground.

Licensee corrective actions and evaluation included the following:

- Evaluate replacement cables that are extruded and manufactured with modern techniques.
- Evaluate the use of above-ground cable trays for MV electrical distribution systems.
- Inspect, identify, and repair degraded cable jackets.
- Clean or coat corroded cable supports/components.
- Address leakage of rainwater or groundwater entering manholes, etc.
- Replace sump pumps and switches, as needed.
- Add check valves to pump discharges to prevent water from backing up into manholes.

3.2.1.2 Information Notice No. 86-49: Age/Environment Induced Electrical Cable Failures

This notice describes age/environment failures of electrical cables at an operating nuclear power plant and actions that can be taken to improve in-service cable reliability.

Offsite power was lost when a transformer was tripped by its differential relays because of a fault in the cable to the Class 1E 4160 V-bus. Further inspection of the failed cable showed evidence of insulation degradation and arcing between two phases to the sheath of the cable. The most likely cause of the cable failure was determined to be temperature-induced accelerated aging and degradation of the cable insulation. The source of this heat was a bare high-temperature (400°F [204°C]) feedwater line and pipe flange in the immediate vicinity of the cable. The thermal insulation had been removed from the pipe during previous repair of a gasket leak and not replaced, thereby exposing the cable to high-temperature conditions that resulted in severe thermal damage.

The event and subsequent investigations and inspections at the plant indicated a possible weakness in the surveillance and maintenance of station electrical cables. This weakness was characterized by a lack of adequate monitoring of representative electrical circuits to obtain indications of changes in cable characteristics over time that would be indicative of degraded conditions.

As a result of this event, the utility established a special cable evaluation task force, which has investigated and tested 4160 volt and lower voltage cables and identified several degraded cables.

3.2.1.3 Inspection and Enforcement (IE) Circular No. 77-06: Effects of Hydraulic Fluid on Electrical Cables

This circular discusses circumstances under which fire-resistant hydraulic fluid had a deleterious effect on the insulation and jacketing of electrical cables. It then provides suggestions for reviewing design and operating procedures to minimize the probability of leakage, overflow, or inadvertent spill of fluids and reviewing plant housekeeping procedures to ensure that they provide for prompt cleanup of spills or leakage of fluids.

3.2.2 Codes and Standards (Mandatory, Guidance, Associations, Societies)

A number of codes and standards are applicable to the design and operation of MV cable systems and components. The following lists several examples of those codes:

- IEEE 690-1984, “IEEE Standard for the Design and Installation of Cable Systems for Class 1E Circuits in Nuclear Power Generating Stations” [8]
- IEEE 422-1986, “IEEE Guidelines for the Design and Installation of Cable Systems in Power Generating Stations” [9]
- ICEA S-66-524 (NEMA WC 7), “Cross-linked Thermosetting Polyethylene Insulated Wire and Cable for Transmission and Distribution of Electrical Energy” [10]
- ICEA S-68-516 (NEMA WC 8), “Ethylene Propylene Rubber Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy” [11]
- IEEE Std 400-2001, “Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems” [12]
- IEEE Std 400.2-2004, “IEEE Guide for Field Testing of Shielded Power Cable Systems Using Very Low Frequency (VLF)” [13]
- EPRI EL-5036-V4, *Power Plant Electrical Reference Series, Volume 4: Wire and Cable* [6]

4

GUIDANCE FOR PLANT-SPECIFIC SSC CONDITION AND PERFORMANCE ASSESSMENT

This section addresses Steps 8, 10, and 11A in the LCM planning flowchart (Figure 1-2) and provides guidance for the plant-specific LCM planning for MV cable systems and components:

- In Step 8, the plant-specific operating and performance history is compiled, as discussed in Section 4.1 below.
- Step 10 comprises a compilation and review of the plant-specific maintenance program leading to the establishment of a complete inventory of the current maintenance tasks and providing a basis for determining if enhancements or changes are desirable (or necessary).
- In Step 11A, the intent is to characterize the present plant-specific physical condition and performance of the equipment and the implementation of effective preventive maintenance procedures, diagnostics, and component condition monitoring. The assessment of the maintenance tasks should pay close attention to whether and how the tasks address any deviations identified in the SSC performance assessment and condition review.

Also included in this section is a compilation and description of available and useful condition/performance monitoring programs.

4.1 Compiling SSC Operating and Performance History

The current condition and age of the plant MV cabling have a major bearing on LCM planning choices and provide the basis for the condition and performance assessment. In conjunction with performance reviews, a thorough assessment of existing equipment is of paramount importance in making realistic decisions as to what maintenance options or strategies are feasible, let alone optimal.

The performance review entails collecting information on the following:

- Assembling the maintenance history for the cables within the MV cabling system, particularly corrective maintenance actions over the last five years. The maintenance history may also exhibit evidence of performance concerns or unacceptable failures of the other critical components, such as splices or terminations.
- Replacements already made or planned for the near future.
- Design changes, performance enhancements, and technology upgrades that have been instituted.

- Major maintenance improvements (PdM/PM program).
- Trending the historic failure rates to identify any specific equipment that may exhibit unusual performance challenges or high failure incidents. Given that there are a limited number of MV cables in most plants and that these cables were expected to have a long life, multiple failures can be a sign of early aging of like circuits. Understanding the failure cause for each MV cable failure is important in determining if random failures are occurring or if a segment of the cable system is nearing end of life and remedial action is needed.
- Compiling and reviewing performance test results and surveillance tests to determine if trends exist for the same equipment, etc.
- Reviewing the Maintenance Rule (MR) performance parameters and trends, the system health reports, MR periodic assessments, and the number of maintenance-preventable functional failures (MPFFs) and repetitive MPFFs for any performance weaknesses or trends. Trends include the past and present monitoring status (A-1 and A-2), goal setting and goal monitoring, and the effectiveness of corrective actions implemented.
- Reviewing the plant scram and trip history to determine the events caused by the MV cable failures. For those events caused by MV cables, the lost power generation due to forced or unforced plant trips, scrams, extended outages, partial power operation or hot standby conditions is generally the largest historical cost resulting from any type of failures. The results provide a basis for projecting future performance (negative if performance is declining and additional preventive action is not implemented or positive if new PM or PdM tools are applied or equipment enhancements/upgrades are included) in the LCM planning.
- Recording the as-found equipment conditions. Some plants have recently implemented a Maintenance Condition Feedback program for equipment to do this. In this program, the crafts team performing the preventive or corrective maintenance is required to formally document the as-found conditions of the equipment. The documentation is done with a simple form attached to the work order and showing five possible as-found conditions. The crafts person indicates with an "X" the most applicable condition and provides additional notes in case an abnormal condition is encountered. The five categories for the equipment condition scale are:
  - Like new
  - Better than expected
  - Expected
  - Degraded
  - Severely degraded

  The information will facilitate an adjustment to the PM tasks or frequency, commensurate with the equipment condition expectation, considering its age and service environment. The data also provide the intelligence to perform additional inspections, sampling, or testing of equipment with similar characteristics and to avoid potential failures. While this type of assessment is not practical for entire cable runs that snake through the plant in trays or run in ducts out of sight, visual evaluation of condition of terminations of equipment and switchgear is possible during maintenance on that equipment. In addition, if manholes are opened for inspection, the visual condition of the MV cable segment in the manhole could be determined.

4.2 Review of Current Maintenance Plans

4.2.1 Maintenance History (Preventive and Corrective Work Order Trends, Enhancements/Improvements, Design Changes, Replacements, Upgrades)

To develop a clear picture of past equipment performance from which projections can be generated, a thorough review of the maintenance and condition monitoring history is needed. This history is captured at most plants in work orders and test reports, which are often managed by a database. Work orders are written to execute preventive maintenance, corrective maintenance, or troubleshooting and to implement other activities, such as condition monitoring, surveillance tests, design changes, replacements, or upgrades.

The most important work orders are those implementing corrective actions or troubleshooting as a result of a problem. They often contain information that could identify the cause, whether repetitive problems were involved, the cost and work-hours spent in the corrective action, and the reason why the problem was not detected in the incipient stages. This information is used to identify additional preventive maintenance (PM) or predictive maintenance (PdM) activities, potential enhancements to the current maintenance program, and/or the need for replacement, redesign, or upgrades. The basic premise is that performance can be improved only by preventing problems (that is, having the ability to detect incipient failure and degradation before full loss of function occurs). Therefore, it is important to identify the causes of the problems and to determine the actions that could have prevented the failure.

The work order review also provides detailed information as to the annual frequency of occurrence of problems and failures presently experienced by the MV cables and accessories. The number of failures experienced at the majority of plants is relatively low, and as a result, the plant-specific failure history may be very small. Each failure is potentially significant in that it may be indicative of the overall population (especially wet cables) approaching end of life. The problem occurrence rate is one of the most important inputs for calculating the costs of corrective maintenance and failure when performing economic modeling of LCM alternatives. The failure evaluation to determine cause is the significant exercise and may be the most important action to determine whether replacement or implementation of a test program is desirable. Thus, LCM planners should consider including failures identified at plants operated similar to their own with equivalent equipment.

4.2.2 Inventory of Current Maintenance Activities

Once the plant-specific maintenance history has been compiled, the current maintenance activities need to be identified. The word *maintenance* as used in LCM planning, includes the activities associated with the systems, including preventive, predictive, and corrective actions, whether required by regulations (testing, inspection, surveillance, walk-down, monitoring, sampling, EQ, etc.); by applicable codes (IEEE, NFPA, state requirements, local requirements, etc.); by the insurance carrier; or by plant procedures, programs, or policies. Collecting the associated activity parameters, such as the annual frequency of the task, the number of components to which the activity is applied, labor hours required to perform the activity (on a component basis), indirect labor associated with the activity, and the material costs, will provide the key input to developing a base case for LCM planning. The base case is a plant operating strategy to maintain the current maintenance practices on the existing components and can be referred to as the “do nothing” strategy. The base case is important not only because it creates an inventory of the current activities and the total annual maintenance cost, but it also provides a benchmark for comparison to industry practice and a basis from which the need for additional activities, enhancements, or task reduction opportunities can be judged.

4.3 Current Condition and Performance Assessment

The generic performance data and information presented in Section 3 can be used for plant-specific LCM planning in many ways. In particular, for plants that do not have a large database of experience, the generic data may be used for comparison trending or projecting performance or failure data into the future when attempting long-term LCM planning. If the plant is of recent vintage, the failure data provide an indication of the types of MV cable failures to be expected as the plant ages and show potential precursors of problems to be anticipated. Last, and most important, the benchmarking of plant-specific data against generic (industry) performance data provides LCM planners with information to focus on significant opportunities to achieve economic and technical improvements. The steps involved in plant-specific performance and condition assessment, including benchmarking, can be summarized as follows:

- At the MV system level, compare the MV cable components in the associated system contribution to the total plant lost power generation, measured against the industry average, to provide a preliminary assessment of current and past plant system health.
- At the component level, compare plant-specific MV cable failure rates to diagnose and identify potentially unacceptable component performance.
- Compare plant-specific maintenance and condition monitoring tasks against the industry recommendations to identify opportunities for addition or deletion of PM, PdM or condition monitoring activities and adjustments to the associated task intervals. At a minimum, plants should consider electrical testing if practicable. Plants should have procedures for pulling and spare cable available to shorten outage time, and they should have a plan to subject any failed cable to failure assessment by a competent lab.

4.4 Condition Monitoring, Tests, and Diagnostics

Condition monitoring determines the evolving, or changing, current condition of the equipment (that is, it detects whether the condition of the equipment has changed and by how much). With proper analysis, a prediction can be formulated as to whether the equipment can be expected to operate successfully until the next opportunity for refurbishment, which is preventive, not corrective maintenance. Condition monitoring tasks measure significant parameters, such as the direct thrust of an MOV drive train or the temperature of a bearing. When the condition monitoring task supports a decision regarding how long equipment can continue to function successfully before corrective action becomes necessary (that is, before it degrades to the threshold criterion for failure), it is referred to as a "predictive task."

Condition monitoring for electric cables, splices, and terminations involves inspection of accessible portions of the components and measurement of one or more indicators, which can be correlated to the condition or functional performance of the cable system in which it is applied. Generally, the condition assessment techniques will involve one or more electrical tests.

Ideally, condition monitoring data and trends in cable performance indicators can guide maintenance personnel in their decisions to replace electrical cables, splices, or other accessories in a cable system before they fail or may otherwise affect the safe and reliable operation of the associated components and systems. In actual nuclear power plant practice, the types of condition monitoring performed for electric cables and accessories is highly dependent on a number of factors, such as whether the circuit is wet or dry, the importance of the associated system or function to nuclear plant safety, the age/condition of the cable or accessory, and the voltage class of the cable system.

There have been several reports produced over the past 10 to 15 years that discuss the various condition monitoring techniques plants may use to assess the condition of their MV cables [12, 14, 15]. These reports group the various methods into two broad categories: potentially destructive methods and nondestructive methods. These categories may be further segregated into those methods applicable to field testing (*in situ*) and those performed only in a testing lab. For the purposes of this report the focus of this discussion has been narrowed to include only the most common *in situ* testing procedures. While nondestructive tests are generally the most desirable, many of the electrical tests that are believed to be the most important involve placing higher-than-rated voltage on the insulation. These tests can be destructive if misapplied or if the cable is severely degraded. Currently, making the choice to perform testing and determining which test to perform can be difficult If more detailed information is desired on all the various condition monitoring techniques available, the reader is directed to the referenced reports [12,14,15].

4.4.1 Diagnostic Tests and Preventive Maintenance

The *in situ* nondestructive techniques are divided into two main groups: mechanical methods and electrical methods. For power cables, infrared thermography may also be used to identify overheated terminations that could lead to insulation and conductor failure. The following paragraphs discuss the various methods in detail.

4.4.1.1 Mechanical and Visual Techniques

For MV cables, mechanical and visual assessment has some, but limited, usefulness. If a MV cable has been subjected to excessive heating from external sources or very high ohmic heating, mechanical assessment (for example, hardness or Indenter modulus testing of the jacket) may provide insights into whether the cable has been significantly affected. When evaluating MV cable and terminations, appropriate personnel safety precautions must be observed to prevent injuries from elevated voltages. Equipment should be de-energized or other appropriate precautions taken.

Visual and mechanical inspection of exposed sections of MV cable is useful in identifying degradation caused by many degradation stressors (including heat, chemicals, radiation, mechanical stress, moisture, and contaminants). By simply observing physical changes in cable system components, their relative condition can often be ascertained. For example, a cable that shows cracking or whitening and is brittle is likely to have been exposed to heat and/or radiation. Similarly, a cable that has softened and discolored may have suffered external chemical damage. However, the effectiveness of this technique at detecting degradation may be limited in certain circumstances; depending on the type of degradation mechanisms at work, a cable or component that exhibits no outward indications of degradation may nonetheless be degrading at a significant rate [14]. In most cases, electrical degradation is not observable from visual assessment.

Physical properties to consider when inspecting components include: [14]

- Surface condition (including cracking, crazing, texture)
- Color
- Size (swelling, shrinkage, deformation, or compression set)
- Physical integrity (tight or loose)

In addition, the presence of one or more of the following may indicate degradation: [14]

- Dirt, staining, contamination
- Moisture/humidity
- Chemicals
- Corrosion by-products
- Wear products

When inspecting a cable or termination component, several qualitative measures may be used. These include a relative determination of cable flexibility (as opposed to that of a new or significantly aged specimen), evidence of cracking evident in a material upon bending with regard to configuration and depth, and evaluation of material hardness (for example, by pressing a fingernail into the material). Much information can often be gained simply by comparing the cable under evaluation with another of the same type installed at another plant location. However, unless the component will be replaced, care must be exercised to ensure that any existing degradation is not aggravated by this inspection [14].

Physical access and adequate lighting are required to perform an inspection. Consequently, it may not be possible to inspect some cables (for example, armored cable, cable routed in conduit, and cable inside fire barriers). Focused periodic inspection of cable segments at end devices, terminations, or near "hot spots" will likely be the most beneficial because most cable and termination degradation appears to be localized. One additional factor, which should be considered when performing visual/physical inspections, is that much of the degradation noted in dry cable and terminations appears to occur at or near the end device [14]. This is not the case for wet cables, where degradation is likely to occur in the wetted section. In general, inspections of wet sections are not possible due to their inaccessibility.

4.4.1.2 Electrical CM Techniques

Electrical test methods continue to evolve, and consensus on which method is most useful for a specific cable insulation and design exists in only a limited number of cases. The following information, based on a Nuclear Energy Institute report, *Medium Voltage Underground Cable White Paper* [7], provides an overview of some of the more commonly recognized methods. For more details of the various test techniques and a more exhaustive discussion of their strengths and weaknesses, the reader is directed to IEEE 400 [12], its various daughter documents [13, 16, 17], and the references cited.

Electrical field testing of MV cables can generally be divided into two broad categories: diagnostic and withstand. The purpose of the former is to characterize the condition of the bulk of the dielectric; the latter represents a go/no-go challenge to the dielectric integrity of the system and may identify localized degradation. Although these two approaches can be used independently, they may also be applied in a complementary manner when a higher degree of confidence in the system is required.

While these documents provide the user with insights into the various test technologies, the user must be aware that most techniques (and the related literature) were developed for the distribution industry. Though much of the technology readily translates to the nuclear industry, the differences in cable construction, preferred dielectric, shield construction, modes of degradation, and cable system architecture may make the tests less useful for nuclear plant MV cables.

4.4.1.2.1 Shielded Versus Un-Shielded Testing

The various techniques described here depend on the existence of some type of concentric shielding system. During testing, the shielding system (typically consisting of a semiconducting layer and copper tape or set of copper wires) confines the electrical stress to the dielectric and provides a low impedance return path for leakage current or pulses emanating from discharges internal to the dielectric.

As indicated in Section 3, many nuclear plants have an unshielded 5-kV cable system. In the absence of a concentric shielding system, present diagnostic methods cannot be expected to produce meaningful results. Of greater concern for unshielded cables, under certain circumstances, such testing can pose a risk to the cable’s integrity since the distorted distribution of stress in the insulation due to large variations in the resistance of the insulation return path may lead to localized damage or circuit failure from overstress during testing.

Users of unshielded cable systems should give consideration to alternative methods of cable system evaluation. Such evaluations should ensure that their cable system’s failure history (if any) is well-documented and that all failures are rigorously analyzed by a reputable laboratory to establish the actual mechanism of failure. Once a rigorous failure evaluation is performed, the applicability of the failure mechanism to other like circuits can be determined, and appropriate action can be taken.

In the absence of sound failure analysis data, users of unshielded MV cable systems might consider sacrificial replacement of a segment of a representative underground circuit when 35–40 years of service have passed. The extracted segment could be subjected to a wide range of destructive tests in order to establish the age-condition of the balance of the installed cable systems. Cables in systems that have survived 35–40 years with no failures obviously did not contain manufacturing defects nor have any installation damage. Accordingly, the only significant concern would be long-term, water-enhanced electrical degradation. Testing of the removed cable would indicate whether satisfactory service could be expected of the remainder of the system.

4.4.1.2.2 Testing Methods - General Information

When performing any high-voltage test, proper preparation, insulation, and isolation of the cable ends are required. In general, the cable ends require separation from all elements that are not to be subjected to test by at least 10 kV/inch (390 V/mm) of test potential when conducting a withstand test and substantially more when performing diagnostic testing.

Since there is a presence of lethal voltages, all cable termination ends and all connecting leads should be protected against accidental contact by such means as barriers or enclosures.

4.4.1.2.3 Diagnostic Methods

When applied to sound insulation systems, diagnostic methods are nondestructive. If the dielectric has been severely degraded as a result of physical damage or aging, the application of even these limited voltages and durations may cause the cable to fail. Thus, as with the application of any meaningful test, users should be prepared for such failures and have the necessary cable, splices, terminations, and lugs on hand to facilitate repair or replacement. Withstand methods discussed below are not considered diagnostic in the sense presented here since such methods are intended to break down weak or defective regions.

Diagnostic methods quantitatively evaluate one or more characteristics of the cable insulation system. The results are most meaningful when compared with baseline readings taken on new cables or when trended over a long period of time. Although the ideal diagnostic test would evaluate the overall condition of the cable and identify localized defects, the current state of the technology is such that users must choose between these two attributes when selecting a methodology. For instance, when choosing a method that evaluates the overall condition of the dielectric, users must be aware that test results provide no indication of the existence or condition of any localized defects. Likewise, methods that identify localized defects provide no indication of the overall condition of the cable. Until a single test is developed that considers both attributes, complementary application of diagnostic techniques or a diagnostic and a withstand test should be considered.

4.4.1.2.3.1 Direct Current Methods

Direct current- (dc-) powered diagnostic testing was for many years the preferred method for evaluation of electrical cables in the field. This preference was due to the low cost, the portability of the test sets, and the ease of operation. Traditional dc-based evaluations included the assessment of the leakage current, insulation resistance, and the determination of the system's polarization index. There is much debate in the industry regarding the meaningfulness of such results. The *IEEE Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems* [12] concludes that, "The value of the (DC) test for diagnostic purposes is limited when applied to extruded insulations."

High-voltage dc diagnostic testing of cable is performed with a dc hi-pot set, typically in conjunction with the required withstand tests. Such tests are performed with the cables off-line and isolated from their end equipment. Tests may be performed following a step voltage or constant voltage protocol. Research has shown no clear correlation between the results and the existence of water trees or large defects. Near end of life, dc hi-pot testing can predispose XLPE to failure because of the accumulation of space charge.

Low-voltage dc diagnostic testing presents a low risk to the cable for the accumulation of space charge, but the results generally lack meaningfulness. Such tests are typically performed with a megohmmeter at voltages ranging from 500 to 2500 Vdc. Both high- and low-voltage dc tests are conducted with the cables off-line and isolated from their end equipment.

As a result of the above concerns, IEEE 400 [12] no longer endorses the application of dc as a diagnostic method for extruded insulation systems. It is clear that this position was taken largely because of the large installed base of XLPE-insulated cables in distribution systems. While it is noted that the application of dc to rubber (EPR and butyl) insulation systems is not subject to space charge accumulation concerns, the concerns for value of the dc-diagnostics remain.

4.4.1.2.3.2 Dissipation Factor

Dissipation factor (also called tan δ or loss angle[2]) is a diagnostic method used to assess the quality of cable insulation. While preferably used as part of a trending program, single test readings may also be used to try to predict remaining life or prioritize cable replacement. When the insulation is sound (that is, no water trees, voids, or moisture), a cable is essentially a long coaxial capacitor. In the ideal capacitor, current and voltage are 90 degrees out of phase. In contrast, service-aged cable frequently contains water trees, voids, and moisture. These result in an increase in resistive current through the insulation. Under such conditions, the dielectric no longer mimics the ideal capacitor, and the resultant phase shift will be something less than 90 degrees. The degree to which the dielectric departs from the ideal capacitor is an indication of insulation degradation, assuming that the dielectric was a low-loss (low resistive leakage current) material initially. This assumption is true for XLPE, but not true for EPR and TR-XLPE.

Diagnostic systems based on tan δ are available for both power (50 or 60 Hz) and non-power frequencies (typically 0.1 Hz). Tests have shown that the magnitude of the loss angle increases with decreasing frequency, but that both power and low frequency tests provide useful results as long as the difference from the frequency effect is taken into account.

[2] The terms *dissipation factor*, *loss angle* (in radians), and *tan δ* are used interchangeably. While this is not mathematically correct, the values are equivalent over the range of angles of interest.

The tan δ test unit consists of a high-voltage divider, an analysis unit, and a resonant ac or VLF hi-pot set as the power supply. The cable to be tested must be de-energized and each end isolated from ground and from its associated end device. Using the hi-pot set as the power supply, the test voltage is applied to the cable while the analysis unit takes measurements. The divider measures the voltage and current input to the cable and sends this information to the analysis unit where the calculation of tan δ occurs.

Typically, the voltage is raised in steps with measurements taken up to normal line-to-ground operating potential. If the measurements are indicative of sound insulation, the voltage is then raised to 1.5 to 2 times normal line-to-ground. The measurements at the higher voltages are compared to those at lower voltages, and an assessment of degradation is made. If the insulation is free from defects, the measured results will change little with increasing test voltage. If there is insulation degradation, the measurements will be voltage-dependent, rising with increasing voltage.

The measured values are used as figures of merit to grade the condition of the cable insulation as "good," "aged," or "highly degraded."[3] Those found to be in "good" condition may be returned to service and periodically monitored. Those found to be "aged" may be returned to service and periodically monitored with a shorter interval. Those cables found to be "highly degraded" should be replaced as soon as possible.

One way to determine whether there is sufficient capability to operate for an interim period is to expose the cable to an ac hi-pot test. If the cable withstands the hi-pot test, assurance is provided that the cable is capable of operating for a reasonable period (months to a year) before replacement. Of course, the cable may fail, showing that imminent failure was likely if it was returned to service.

Diagnostic assessment of MV power cable using tan δ is recognized to have the following strengths and weaknesses:

- The method evaluates the overall cable condition. It does not locate discrete defects. The method is most meaningful when used on lengths of cable that have been exposed to the same aging conditions.
- This method is well suited for categorizing a large population of installed cables as candidates for immediate action, frequent monitoring, or routine monitoring.
- The sensitivity of the method to the existence of water trees is better at non-power frequencies (that is, VLF) than at power frequency.

[3] See IEEE 400 [12] for acceptance values for unfilled XLPE. Because of the wide variations in formulation of rubber insulations, it is unlikely that a single set of acceptance values will ever be published for this material. EPRI report 1009017 [18] contains a limited assessment of dissipation factors for five modern EPR cables, including those being used as replacements for nuclear plant cables. Unfortunately, no specimens of the rubber most likely to see moisture-induced degradation (early vintage black EPR) were included.

- The test gives the best results when comparing present measurements against established historical figures of merit for a particular cable.
- It is best performed on circuits containing a single type of dielectric (for example, all XLPE or all EPR).
- The length of the circuits that may be evaluated is limited by the amount of capacitance in the circuits under test and the size of the power supply.
- No industry consensus exists on the correlation of this method to the performance of tree-retardant XLPE or rubber insulation systems.
- True cable condition can be masked by the presence of splices that employ high dielectric stress-control materials.

4.4.1.2.3.3 Partial Discharge - Off-Line

Partial discharges are localized electrical discharges that partially bridge the dielectric material between the energized conductor and ground. As the ac voltage wave rises from 0, a large portion of voltage is distributed across the defective section of the dielectric. As the voltage continues to rise, the defective section of dielectric conducts, and the voltage distributes across the remaining section of insulation. This is called *partial discharge* or PD. It is localized in character and causes a radio frequency disturbance that propagates along the length of the cable. Typical defects within extruded cable systems that can be sources of PD include internal cavities, interfacial voids, broken shields, electrical trees, protrusions, knife cuts, contaminants, and poorly installed accessories. PD characteristics (magnitude, repetition rate, phase, etc.) are known to be a function of the size, location, and type of defect encountered, voltage, time, temperature, and dielectric type. Systems have been developed to facilitate field detection and location of the sources of cable system PD. Such testing is recognized by IEEE 400 [12, 17].

One method of PD testing, known as "off-line," is performed with the cable disconnected from its end equipment. The typical off-line PD test set includes a VLF or resonant ac, variable-voltage power supply, capacitive and inductive sensors, an input impedance network, a digital signal processor, and a computer for data analysis and storage. A typical test involves the exposure of the cable system to a brief over-voltage (up to 2 V_o). During the period of voltage increase, the system looks for the onset of PD. The voltage at which this occurs is known as the PD inception voltage (PDIV). The elevated voltage needs to be maintained no longer than is required to obtain the necessary PD data. During the period of voltage reduction, the system looks for the voltage at which no PD above the background level can be detected. This is known as the PD extinction voltage (PDEV).[4] PD systems provide a location of the discharge via time domain reflectometry.

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[4] The PDIV and PDEV data collected can be used to characterize the cable system. Typically, where the PDIV exceeds 2 V_o, the system can be characterized as "very good." In those cases where the PDIV is low (just above V_o), the cable system can be characterized as "very bad." In between these conditions, interpretation is not as clear, given the many variables involved in PD generation and propagation.

PD systems are well suited for evaluating the workmanship of splices, terminations, and separable connectors. They also are adept at identifying local voids and contaminants in the cable dielectric.

Diagnostic assessment of MV power cable using off-line PD diagnostics is recognized to have the following strengths and weaknesses:

- Off-line PD test systems are moderately expensive. The use of testing service companies is a common alternative to equipment purchase.
- Tests may be performed using power frequency or VLF power supplies.
- The size of power frequency-based sets may limit access to cable ends in a generating station environment.
- The method identifies the existence of PD within the cable or accessories and locates the site of the discharge.
- The method does not provide indication of the degree of water treeing within a cable. It provides an indication of the condition of sites with PD, which does not indicate the degree of water-enhanced degradation, if any. Sites within the insulation having PD at or just above operating voltage are highly likely to fail in the near term.
- Shield construction and condition greatly influence system sensitivity.
- Proper interpretation of off-line PD data requires a high degree of skill.

4.4.1.2.3.4 Partial Discharge - On-Line

An alternative method of diagnostic testing is known as on-line PD assessment. This method differs from the off-line approach primarily in that the cable is evaluated while in service (that is, connected to its end devices and under normal system voltage). No external power supply is required. On-line PD system equipment includes capacitive and inductive sensors, an input impedance network, a digital signal processor, and a computer for data analysis and storage. While on-line systems do not require de-termination from end devices, access to the cables in intervening manholes may be required for maximum sensitivity. On-line PD systems can be used to evaluate the quality of splice workmanship or the presence of cable manufacturing defects. Analysis of observed PD enables identification and location of the source.

Diagnostic assessment of MV power cable using on-line PD diagnostics is recognized to have the following strengths and weaknesses:

- On-line “testing” presents no risk to the cable system since no over-voltage is imposed.
- No outage is required to perform the “test.”
- Proper interpretation of on-line PD data requires a high degree of skill.
- The method identifies the existence of PD within the cable or accessories that are active at operating voltages and locates the site of the discharges.

- The method may not be fully indicative of cable health if no PD is detected at operating voltage. The test is not likely to detect water-treeing degradation until after degradation is severe and PD has begun.
- Shield construction and condition greatly influence system sensitivity.

4.4.1.2.4 Withstand Methods

When applied to sound insulation systems, withstand methods are nondestructive. However, if the dielectric has been severely degraded as a result of physical damage or aging, the application of these voltages is intended to cause highly weakened cable to fail. Plants that apply such tests do them at the start of outages so that if a failure occurs, there is time for a replacement. Users should be prepared for such failures and have the necessary cable, splices, terminations, and lugs on hand to facilitate repair or replacement. Withstand testing has been traditionally performed at the factory as the final step in the production of electrical cables. Such testing was intended to ensure that the cables, as shipped, were free of significant defects or damage.

In the field, withstand testing on cable installation is generally performed to ensure that the rigors of the installation process did not result in adverse degradation of the insulation system and to ensure that cable accessories have been properly installed. The voltages in these and later maintenance tests are generally applied at a slightly reduced level than in factory tests.

Withstand testing is not predictive in nature. Such methods identify only the weakest point in the insulation and are of a go/no-go character. The cable under test either passes or fails. This has been traditionally interpreted as affirming that the cable is suitable for return to service and able to withstand typical voltage transients within a well-designed system. The test also verifies that no serious defects exist in splices and terminations that would lead to early failures.

As with all withstand test methods, the test specimen must endure the application of the specified voltage for a set period of time without breakdown of its insulation. The magnitude of the specified voltage is above the normal system voltage. If the cable’s insulation is sound, no degradation occurs. If the insulation system is sufficiently degraded or a significant installation damage or defect is present, a breakdown can occur during testing.

Such go/no-go testing is appropriate following installation, splicing, and terminating activities. If the cable is suspected of being heavily water-treed, diagnostic testing previously described is typically used prior to withstand testing to assess the overall condition of the insulation and avoid a cycle of test/repair/test/repair/test/repair, etc. If the diagnostic tests show evidence of extensive degradation, the cable can be either immediately replaced or returned to service without withstand testing (and failure) while replacement cable is being obtained and planning is underway.

Unlike diagnostic testing, where leakage currents are monitored and an attempt is made to diagnose the quality of the insulation, withstand testing is simply go/no-go or pass/fail. The test object either holds the voltage or it fails. The test is performed at a notably high voltage to ensure that the cable has sufficient capability to withstand normal operating voltages and surges for a significant period, but the test provides no direct indication of the length of that period. Should the cable fail during the test, conventional fault-locating methods can be used, the repair/replacement made, and the test repeated. Most test sets have the capability to “burn-down” a fault (that is, continue to put energy into the fault to produce a low impedance carbonized fault channel, which can then be found with conventional time domain reflectometry or PD equipment).

While dc withstand testing has been performed in the past, this test method is no longer recommended [12]. Ac withstand testing is preferred. Ac withstand testing may be performed at power frequency (50 to 60 Hz); however, power frequency test sets are very large and generally cannot be brought close enough to cable termination locations within a nuclear plant. Accordingly, very low frequency (0.01–0.1 Hz) test sets that are much smaller are used to perform ac withstand tests. IEEE Standards 400-2001 and 400.2-2004 [12, 13] describe the methodology.

4.4.1.3 Infrared (IR) Thermography

The use of infrared thermography for nondestructive, non-contact inspection of electrical equipment has grown considerably since the 1980s. There are two generic choices available for electrical inspection equipment: spot meters and imagers. Both are capable of accurately measuring infrared radiation emitted from a thermally hot electric cable, electrical connection, cable splice or termination, circuit breaker, transformer, fuse, or other electrical equipment. Infrared imaging is considered a powerful tool for the condition monitoring of electric cables that are subject to high currents with respect to rated ampacity. If a high-resistance termination is suspected, thermography can also be useful to determine the severity of termination overheating.

5
GENERIC AGING AND OBSOLESCENCE ASSESSMENT

This section addresses the steps numbered 11B and 11C in the LCM planning flowchart (Figure 1-2). Its intent is to help characterize the aging of passive SSCs, the wear-out of active components, and the obsolescence of SSCs. This characterization will help to address the need for and timing of the replacement of MV cable components. It will also help to identify potential environmental or service conditions that affect the rate of degradation or that may require special plant-specific attention. MV cable and its accessories are considered passive components.

5.1 Aging Effects and Mechanisms Review (Aging Matrix)

An aging management review is integral to LCM maintenance planning. Normal aging of components occurs when operated within rated power, at rated voltage and frequency, within rated temperatures, and within normal operating conditions over time. The limits of these parameters are defined in national standards. Manufacturers may apply additional internal design standards to meet the user performance specifications for plant life expectancy.

To assess the longevity of MV cables, the following conditions should be considered:

- Operation within the design rating parameters including voltage and temperature
- Monitoring and trending of component and accessory conditions
- Detection of accelerated deterioration and factors that can lead to shortened life such as operating cables under wet conditions
- Preventive and corrective actions taken to ensure component and accessory integrity
- Maintenance of the history of operating conditions

MV cables used in nuclear power plants were expected to have very long lives, at least 40 years. However, the cable manufacturers and non-nuclear power users of MV cable recognized that cables manufactured during the 1970s did not always meet expectations. By the mid-1980s, the industry identified a number of improvements that were incorporated into cables manufactured thereafter. Fortunately for the nuclear industry, even though problems existed in some cases with cable design and manufacture, the voltage stresses in nuclear applications are relatively low. Accordingly, the number of early insulation failures in the power distribution industry associated with higher voltage stress applications did not occur in the nuclear industry's 4–13 kV applications. Water-enhanced degradation has occurred at nuclear plants in conjunction with and separate from manufacturing defects and installation errors.

Early nuclear plant cables were constructed with XLPE or black EPR. In dry applications, these cables have very long lives. However, if continuously wet and especially with the presence of significant manufacturing flaws, lives of less than 40 years can be expected for some cables.

Both EPR and XLPE cables are now produced with higher quality extrusion practices and with high cleanliness materials, reducing the probability of contaminants and voids. Contaminants and voids are a significant problem in wetted extruded cables because they disturb the potential gradient within the insulation and increase the potential across the remaining good insulation, thereby increasing the effects of water enhanced degradation. In addition, for EPR, the clays used in the compound have been treated to prevent water absorption. Manufacturers changed the color of the EPR to red or brown after this change to distinguish the material from earlier EPRs, which were generally black.

For XLPE, the water-enhanced degradation takes the form of water-treeing in which the potential gradient gradually forces the water to create small channels in the polymer that look like trees under magnification. The exact mechanism of water-enhanced degradation of EPR is less well understood and harder to observe due to the opacity of the material. The different types of EPR that are in use have different susceptibilities to water-enhanced degradation. Red and brown EPRs are less prone to water-enhanced degradation than older black EPR.

The water-enhanced degradation does not cause direct breakdown of the XLPE or EPR, but rather it reduces the dielectric strength of the insulation, eventually weakening the material to the point where it is susceptible to voltage surges that can initiate partial discharging and formation of an electrical tree. Continuous partial discharging at operating voltages causes relatively rapid electrical degradation that can lead to a faulted condition in weeks to months following inception. Instantaneous failure in the weakened condition would be expected only under lightning strike conditions. However, most nuclear plant MV circuits are not directly exposed to lightning strike conditions, given that the cables are either inside buildings or underground and not terminated to equipment exposed to lightning.

A comprehensive discussion of cable failure and aging mechanisms is provided here and in references previously mentioned.

Table 5-1 provides a summary of the main aging mechanisms, their effect on typical components, the current detection systems, and remedial actions available to aid in the management of aging.

Table 5-1
Typical MV Component Aging Mechanisms

Material	Aging Mechanism	Aging Effect	Aging Management
Insulation*	Electrical degradation	• Reduction in breakdown strength • Ground faults • Phase-phase faults	• Tan δ monitoring • PD monitoring
	Overheating	• Embrittlement • Delamination • Ground faults • Phase-phase faults	• Temperature monitoring • Tan δ monitoring • PD monitoring • Visual inspections of accessible sections
	Abrasion	• Insulation thinning from on-going chafing (rare condition) • Insulation breakdown • Ground faults • Phase-phase faults	• Periodic inspections • PD monitoring (only if abrasion has continued to the point of affecting the insulation system)
	Contamination	• Surface discharges • Jacket damage • Long-term damage to insulation • Ground faults • Phase-phase faults	• Tan δ monitoring • PD monitoring
Terminal bolting	• Overheating • Loose connections	• High temperature • Arcing	• Monitor w/thermal imaging devices • Replace bolting

* Each of these insulation problems would be worsened by continuous long-term wetting.

5.1.1 Aging and Failure Mechanisms

Aging is generally defined as the irreversible changes in the properties of materials or components with time. The type of aging (electrical, thermal, or mechanical), aging rate, and failure mechanisms will differ according to the cable construction, insulation, and the stresses (actual operating voltage, number and level of voltage surges, level of operating current, elevated temperature, physical stress [for example, pinching], wetting, etc.) that the cable is 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). The 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. Examples of this include defects that are introduced into the cable system during material processing, cable/accessory manufacture, transportation, installation, or operation. The main defects responsible for electrical aging are shown in Figure 5-1 and listed in Table 5-2. In highly aged cable, the bulk electrical properties may degrade from numerous localized electrical deterioration sites.

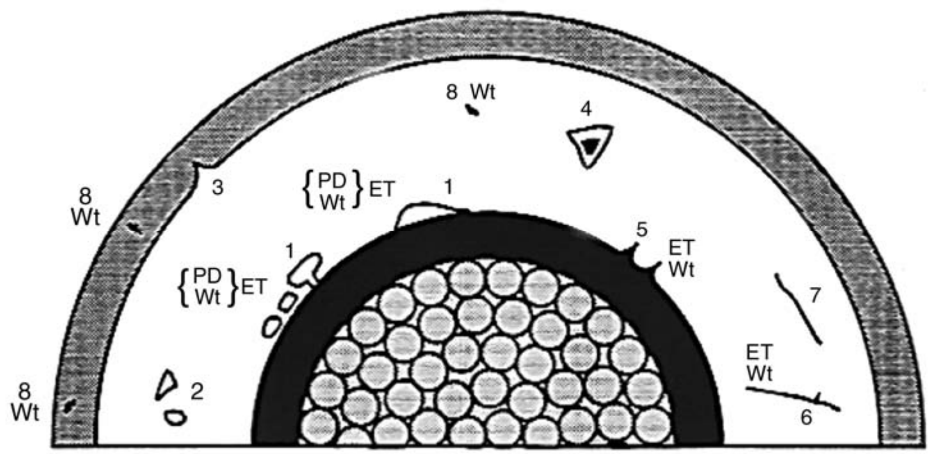

Figure 5-1
Section of Part of Extruded Cable Showing Possible Defects and the Type of Aging Expected [15]

Legend for Figure 5-1:

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. These cavities can be a source of PDs or bow-tie-type water trees if filled with water.
3. Defects in the shield (insulation shield is shown here but this can also occur in the 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-type water trees.
5. Protrusions from the 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 or insulation. Soluble contaminants can be source of vented water trees.

PD – Partial discharge
Wt – Water tree initiation site
ET – Electrical tree initiation site

Table 5-2
Defects in MV Extruded Cables [15]

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 (for example, water, ions) • Particles introduced accidentally at interfaces during installation	SE*
Protrusion 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 micro-voids 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 shield/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	WI*
Installation issues	• Pinching (improper vertical support) • Disruption of shields from overbending	SE*

SE* - Electrical stress enhancement (for example, see #5 in Figure 5.1).

WI* - Weakness in insulation, a region of low dielectric strength (for example, see # 1 or 2 in Figure 5-1).

Table 5-2 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 so 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 electrically induced aging mechanisms are water treeing at contaminants, protrusions, and water-filled micro-voids, and electrical treeing at stress enhancements due to contaminants and protrusions. Another electrical aging mechanism—partial discharges—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 may be slower. The aging mechanisms can occur simultaneously, change with time, and will result in vastly different rates of aging for different cable insulations and operating conditions.

The data from the industry survey in Section 3.1 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 these early cables 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.

5.1.1.1 Water Treeing

A water tree is a collection of water-filled micro-voids, originating from contaminants and protrusions, that propagate over time in the direction of the electric field, when the insulation is immersed in water. Under a microscope, water trees look like trees, hence the name. Water trees cause a gradual reduction in the breakdown strength and can result in premature failures in service. Figure 5-2 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 5-3. Bow-tie trees will also grow from water-filled micro-voids 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 or streamer trees as is shown in Figure 5-2.

Water trees are generally non-conducting, but due to their high dielectric constant, they 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 the type of ions as soluble contaminants and the applied voltage [15].

Figure 5-2
Example of Vented Trees Growing from Conductor and Insulation Shield Interfaces [15]

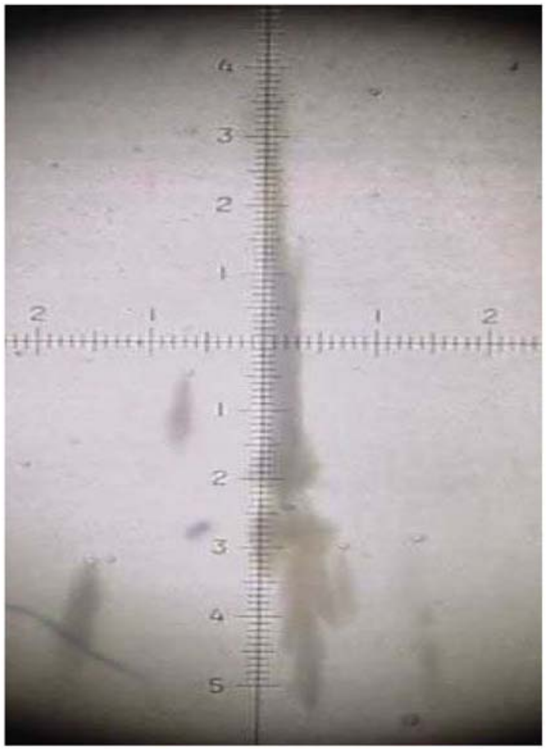

Figure 5-3
Example of Bow-Tie Water Tree Growing in the Interior of the Insulation [15]

Bow-tie trees from micro-voids tend to reach a limiting length of several tens of microns independent of voltage, but a bow-tie tree from a soluble contaminant can grow several millimeters at typical operating stresses (~51 kV/in [~2 kV/mm]). 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 wetted again. 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 [15].

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 all factors that affect the formation and rate of growth of trees.

5.1.1.2 Impact of Water Trees and the Transition to Electrical Treeing

Water treeing is a "silent" deterioration mechanism in that 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 (that is, when one or more gas-filled channels appear shortly before failure). Often, a transient over-voltage, such as lightning or a switching surge, initiates the electrical tree adjacent to a mature water tree, and PDs result.

The change in the 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, 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 tree to grow and propagate through the insulation quickly, 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. The latter condition is detectable by tan δ testing.

The severity of the degradation caused by water treeing will depend on the material and the number and 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. Thus, 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. Long water trees may take several years to penetrate the insulation. 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 early failure under wet conditions, and it would be very difficult to detect such a contaminant by any of the presently available diagnostic test techniques [15].

This information indicates that keeping MV cables dry, if possible, leads to longer lives.

5.1.1.3 Electrical Trees

If the stress at the tip of a protrusion or contaminant is sufficiently high, typically greater than 3800–5080 kV/in (150–200 kV/mm), 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 5-4 [15].

Figure 5-4
Examples of Electrical Trees in XLPE Insulation [15]

Failure results when one or more of the channels penetrate 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.

Electrical trees, unlike water trees, require PDs to grow. Also unlike the water-filled micro-voids 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.

5.1.1.3.1 Partial Discharges

Partial discharges (PDs) are electrical discharges that can take place in gaseous cavities and in cavities containing loosely bound contaminants in insulation and shields, which can accidentally occur during the manufacture of MV insulations. PDs do not bridge the whole insulation (that is, do not extend from conductor to ground), but they can lead to ultimate failure. A PD takes place in nanoseconds and causes high-frequency currents to flow in the external circuit that can be measured by PD detection equipment. 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 and thus 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 will be seen of various magnitudes, repetition rates, and phase angles relative to the applied voltage. During testing when 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 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 resulting from 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%. Thus, to ensure that a cable is discharge free at operating voltage, it is necessary to test for PD up to twice the operating voltage. A cable that has PD at operating voltage or within 1.25 X operating voltage is generally significantly deteriorated and may fail in the near term. Cables that have no significant PD up to twice the operating voltage have no immediate expectation of failure from PD and can be expected to operate satisfactorily for a significant period of time [15].

There are several sources of PDs in cable systems:

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

The interfaces between the cable and accessory insulations may be sources of PD. If the interfacial pressure is not sufficient to maintain firm contact between the surfaces, voids can form, and PD can initiate and eventually form carbonized tracks along the interface. PD 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, spherical or flat cavities or voids, electrical trees, and interfaces may be differentiated by frequency content and phase angle of the discharge. 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 PD sites 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.

5.2 Technical Obsolescence

For some SSCs, obsolescence rather than aging is the most life-limiting issue, and this can be of substantial consequence to a plant (Step # 11C). While no SSC is completely immune, the problem affects mainly electrical and instrumentation systems, particularly analog-controlled equipment, active electrical components, equipment using computers, electronic cards/logic, and signal processing and monitoring components. To evaluate the potential for technical obsolescence, a nine-point criteria and severity ranking scheme was developed and may be used for generic assessments of obsolescence concerns of MV components and accessories, as shown in Table 5-3.

The severity ranking of the SSC is performed by completing the responses to the nine questions. For each affirmative answer (YES), the corresponding score is entered in the YES column. If the answer to the question is NO, then no weighting factor score is entered. A total score is determined by summing the YES answers. The individual questions have been assigned weight factors because not all questions are of equal importance. The lower the overall score, the higher the concern for obsolescence.

As noted earlier, most MV cable components and accessories in use in U.S. nuclear plants were installed in the late 1960s and early 1970s. Table 5-3 provides the weighting for the various issues with obsolescence. The ranking guidance for the table is presented below, along with a short evaluation of the scoring for typical MV cable. Note that for cable and accessories, the original types are likely not to be available. However, modern cables and accessories of equivalent types, but likely to have longer lives, are available as replacements. Table 5-3 has been completed based on the availability of modern cable.

Table 5-3
Technical Obsolescence Checklist for MV Cable and Accessories

Technical Obsolescence Evaluation Criteria		Weight if YES	Score
1	Is the SSC still being manufactured, and will it be available for at least the next five years?	5	5
2	Is there more than one supplier for the SSC for the foreseeable future?	3	3
3	Can the plant or outside suppliers manufacture the SSC in a reasonable time (within a refueling outage)?	3	0
4	Are there other sources or contingencies (from other plants, shared inventory, stock-piled parts, refurbishments, secondary suppliers, imitation parts, commercial dedications, etc) available in case of emergency?	3	3
5	Is the SSC frequency of failure/year times the number of the SSCs in the plant times the remaining operating life (in years) equal to or lower than the number of stocked SSCs in the warehouse? (Site specific.)	3	0
6	Can the spare part inventory be maintained for at least the next five years? (Yes, but it is site specific.)	3	3
7	Is the SSC immune to significant aging degradation?	1	0
8	Can newer designs, technology, concepts be readily integrated with the existing configuration ? (Yes, if available, but not generally done for MV components and accessories.)	3	3
9	Is technical upgrading desirable, commensurate with safety, and cost effective? (Only insofar as replacement components may be needed for maintenance, but not a wholesale change-out.)	3	0
	Total Obsolescence Score		17

Ranking Guidance for Table 5-3:

- If the total score is < 6, then the SSC obsolescence is serious and will have an immediate impact on LCM planning. Potential options to address obsolescence and contingency planning should be identified.
- If the total score is between 6 and 10, the SSC may have long-term concerns with obsolescence.
- If the total score is >10, then obsolescence is not of concern for the SSC.

The estimated score for typical MV cables and accessories is 17. Therefore, obsolescence is not seen as a major concern for these items. However, plants that do not stock MV cable are likely to experience manufacturing lead times of 16 or more weeks if an MV cable fails in service.

5.3 Expected Lifetimes for Preventive Replacement

This subject has been discussed at length in earlier sections of this sourcebook. Typical lifetimes of MV cables and accessories are in multiples of decades, provided that routine maintenance, such as pumping manholes is performed to prevent long-term wetting. As noted, too, failure causes typically consist of manufacturing defects, improper installation, damage during transport, exposure to high temperature around uninsulated pipe, improper assembly of accessories to the cable, and personnel error. Some of these can be eliminated by attention to installation and the conditions of application. Manufacturers have attempted to reduce manufacturing defects through improved compounds and extruding practices.

6
GENERIC ALTERNATIVE LCM PLANS

This section addresses Steps 12 to 17 in the LCM planning flowchart (Figure 1-2). The EPRI LCM Demonstration Project Report [1] summarizes alternative LCM plans as follows:

> "Following the assessment of aging and reliability, potential alternative LCM plans should be identified. The objective here should be to explore whether there are potentially better ways of addressing the aging management of the SSC. These inputs can come from plant staff, but input should also be solicited from outside experts and industry benchmarking projects."

The following guidance for these steps includes the identification of possible plant operating life strategies and the development of alternative LCM plans that are compatible with or integral to the strategies identified. Also provided is a hypothetical illustration of alternative plans for the MV cables and accessories with the attendant discussions of the logic used to build the alternatives along with the derivation of the assumptions.

6.1 Plant Operating Strategies and Types of LCM Planning Alternatives

The determination of LCM planning alternatives will be driven mainly by the plant operating strategies that, implicitly or explicitly, are being followed or evaluated, along with the current reliability of the MV cable components. Accordingly, the set of LCM planning alternatives that will be evaluated are plant specific. The typical plant operating strategies and standard approaches to LCM planning are discussed below.

The example alternative plans in the sections that follow are typical of how plants approach obsolescence. The two plant operating strategies discussed are:

- Strategy 1: Operate plant for currently licensed period of 40 years
- Strategy 2: Operate plant for 60 years with license renewal

Note that a single plant long-term strategy should be determined before detailed LCM planning can begin, or the result will be excessive effort, building cases for multiple plant strategies. For the plant strategy dictated by management, a base case, usually denoted by the letter "A," is developed. The base case is often referred to as the "do nothing" plan because it projects life cycle costs based on essentially maintaining the status quo for SSC maintenance. Next, alternative plans, denoted for example as 1B and 1C, etc., are developed. The alternative plans are stand alone and mutually exclusive cases so they can be individually evaluated on their own merits. One plan may include the elements of another plan, but it will also include additional measures. In other words, plans may overlap each other. Plans can also present radically different approaches with few if any elements in common with the base case plan or other alternative plans.

6.1.1 Plant Strategy 1: Operate Plant for Currently Licensed Period of 40 Years

This strategy requires minimizing risk during the remaining operating period until the plant's license expires and identifying limiting SSCs that could result in premature power reduction or replacements forcing an economic decision regarding early decommissioning. LCM plan alternatives that might be developed under this strategy include:

- *LCM Plan Alternative 1A – Maintain Status Quo:* A base case to determine the cost of the activities performed under the current maintenance plan, assuming that the activities will continue as-is for the 40-year licensed plant life. This case assumes also the *continuation of the existing maintenance program* without any major capital investments unless absolutely necessary.
- *LCM Plan Alternative 1B – Partial Upgrade:* An alternative plan in which the most susceptible components are replaced with upgraded replacements in an effort to minimize vulnerabilities, but done only when necessary, owing to the inherent difficulty in replacing cable. One way to implement this strategy is to perform periodic electrical testing and to replace cable when electrical testing indicates that it is appropriate. An alternative is to perform laboratory failure assessments of cable that has failed and to replace cable in like applications if the failure assessment indicates that age-related failure has occurred.
- *LCM Plan Alternative 1C – Full Replacement:* An alternative in which all MV cables and accessories are replaced with modern cables and accessories.

6.1.2 Plant Strategy 2: Operate Plant for 60 Years with License Renewal

This strategy recognizes the potential for license renewal and extended operation of the plant. Major investments may be required to achieve extended operation. LCM planning alternatives that might be considered under this strategy include:

- *LCM Plan Alternative 2A – Maintain Status Quo:* A base case to determine the cost of the activities performed under the current maintenance plan, assuming that the activities will continue as-is for the 60-year licensed plant life. This case assumes also the *continuation of the existing maintenance program* without any major capital investments unless absolutely necessary.

- *LCM Plan Alternative 2B – Partial Upgrade:* This alternative includes the rigorous preparation for license renewal combined with the resulting aggressive aging management program including electrical testing, system performance enhancements, and component replacements or upgrades to current accessories and components where needed and where available. The upgrade could include replacing all MV cable that had been subjected to long-term wetting.
- *LCM Plan Alternative 2C– Full Replacement:* See LCM Plan Alternative 1C.

6.2 Development of Alternative LCM Plans

For each alternative LCM plan, detailed preventive maintenance and monitoring activities and scheduled equipment expenditures should be identified. These plans may include:

- Adjust the frequency of time-directed maintenance activities (PM) to enhance reliability or to reduce maintenance costs. Such activities could include inspections of accessible terminations, splices, and cable surfaces.
- Add PM and condition monitoring activities to enhance availability (inspections and monitoring) (for example, the addition of electrical testing of the cables and accessories).
- Develop new time-directed maintenance activities to support the new components.

In each of the identified LCM plan alternatives, all pertinent costs and estimated benefits should be considered.

6.3 Hypothetical Illustration of Assembling LCM Planning Alternatives

A hypothetical case was developed to illustrate the process of developing LCM planning alternatives for the MV components and accessories.

Consider a nuclear plant with two units. Each unit has the same nominal rating of 1000 MW and has the same manufacturer, employing the same design.

In this hypothetical case, the components are selected on the basis of plant-specific failure data, and comparisons are made only for those components that have recorded failures. This list will be different in each plant.

A review of the current maintenance practices notes that monitoring of the MV cable and accessory condition is limited to such output parameters as voltage, phase current, jacket temperatures, ambient temperature, radiation dose rate, and whether the cable is in a wet or dry application.

Periodic component inspections, tests, PM, and CM work are completed during normal operation on a frequency schedule that is consistent with standard industry practice.

The base case 1A assumes that the present maintenance program will continue without major upgrades or component replacements. The latest condition assessment concluded that the MV cables and accessories are capable of operating for 40 years under the current licensed term. It is expected that future failure rates could improve as a result of increased monitoring and surveillance, but they are certainly expected to at least remain below the industry average.

The LCM alternative 1B proposes to adopt some of the elements of condition-based maintenance that have been mentioned here, by enhancing on-line monitoring for detection of early signs of aging.

In LCM alternative 1C, a more aggressive plan could be considered, but only if determined to be absolutely necessary. This approach would involve the actual replacement of cable, from specific portions all the way to complete cable runs. Since the cost may very well be prohibitive, this step should not be considered except as a last resort. A reasonable estimate of this type of activity is difficult due to the high variability of costs possible and the plant-specific nature of cable routing and pulling issues. Accordingly, a budget, either in terms of financial or human resources, is not provided here.

The EPRI LCM planning tools (LcmPLATO or LcmVALUE [1,4]) can be used to determine the cost of the alternatives on an net present value (NPV) basis. The tools are capable of handling fairly complex models, including non-linear failure assumptions and phasing in and out of individual tasks over time. The software calculates the change in total NPV in going from the current plan (base case) to each alternative plan. It also calculates the benefit-to-cost ratio (where cost is the present value of PM costs) for each alternative plan relative to the base case.

These costs are based on a one-unit analysis. If the data on another unit are the same (or similar), the costs can simply be doubled to obtain the total plant cost information. If reliability data between units are significantly different, a separate cost analysis for each unit should be conducted. Different LCM plans may be adopted for each unit.

7 GUIDANCE FOR ESTIMATING FUTURE FAILURE RATES

This section addresses a part of step 18 of Figure 1-2. Failure rates are a main driver of the LCM planning process.

General guidance for estimating SSC failure rates can be found in Section 2.6 of the LCM Sourcebook Overview report [2]. Below are some guidelines useful for estimating failure rates in the LCM planning studies:

- If "in-kind" replacements are to be made, existing failure rates may be applied for the future. Although modern cables that will be used to replace original cables are expected to have a lower failure rate, insufficient data are currently available to predict the decrease.
- Frequent failures of certain components could be an indication of aging or design deficiency. With respect to MV cables, failures of two or more cables operating under similar conditions may be highly indicative of an age-related problem, especially if they occur over a relatively short period (for example, a few years).
- A review of corrective work orders provides a way to monitor the MV cable failure rates. In order for this review to be meaningful, at least five years of history should be reviewed. It should be noted that some plants have never experienced an MV cable failure—even after 30 or more years of operation.
- When components are replaced with similar components from different vendors, the failure rates may be different from the originally installed equipment. It is reasonable to project the existing failure rates until new failure rates are determined, based on the component-specific failure trending.
- When the plant-specific PRA is used as a basis for the plant-specific failure rates, verification of the basis for the PRA input should be considered.

In summary, failure rate predictions for plant-specific MV cables and accessories are made using the above guidance and the generic guidance presented in Section 2.6 of the LCM Sourcebook Overview report [2]. Maintenance Rule records may be an important source of information. The LCM planning process should be fairly complete with carefully defined activities for each of the LCM alternative plans. In this way, the influence of new or additional PM activities, implementation of replacements, and redesigns can be appropriately considered in estimating future failure rates for input to LCM economic evaluations.

8
INFORMATION SOURCES AND REFERENCES

8.1 Information Sources

The references provided below were found to be the most relevant sources of meaningful data. While most of the useful information from these sources has already been mined and summarized in this sourcebook, individual plants may find it useful to interrogate plant-specific data sorts or search for equipment failures under the same vendor, model or size.

- Institute of Nuclear Power Operations, INPO Website, SEE-IN provides up-to-date information and listings of industry-wide component problems documented in:
  - Operating Experience Reports (OEs)
  - Operations and Maintenance Reminders (O&MRs)
  - Significant Event Reports (SERs)
  - Significant Event Notifications (SENs)
  - Significant Operating Experience Reports (SOERs)
- Institute of Nuclear Power Operations, NPRDS and EPIX databases provide equipment failure reports and sorts by equipment code, system code, vendor, failure mode, plant, etc.
- EPRI Generic Communications Database, Version 3.0, Release 4.0, October 2002 [19], provides applicable generic communications sorts (for safety-related SSCs only) by equipment name, type of NRC document, aging mechanisms, aging effects for the following NRC documents:
  - Generic Letters (GL)
  - Information Bulletins (IE)
  - Information Notices (IN)
  - Regulatory Issue Summaries (RIS)
  - Generic Safety Issues (GSI)

8.2 References

8.2.1 In-Text References

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9
ABBREVIATIONS AND ACRONYMS

BWR	boiling water reactor
CM	corrective maintenance
CPE	chlorinated polyethylene
CSPE	chlorosulfonated polyethylene, (Hypalon)
DBE	design basis event
DC	direct current
EPIX	Equipment Performance & Information Exchange
EPR	ethylene propylene rubber
EPRI	Electric Power Research Institute
EQ	equipment qualification
GE	General Electric
GL	Generic Letter
GSI	generic safety issue
HELB	high energy line break
Hz	Hertz
IE	Information Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IR	insulation resistance
LCM	life cycle management
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	loss-of-coolant accident
MCM	thousands of circular mils
MPFF	maintenance-preventable functional failure

MR	Maintenance Rule
MSLB	main steam line break
MV	medium voltage, 601 V to 15 kV
MW	Megawatt
MWH	Megawatt-hour
NDE	nondestructive evaluation
NEC	National Electric Code
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Council
NMAC	Nuclear Maintenance Applications Center
NPAR	Nuclear Plant Aging Research
NPRDS	Nuclear Plant Reliability Data System
NPV	net present value
NRC	Nuclear Regulatory Commission
NUREG	Nuclear Regulation
OE	operating experience
OEM	original equipment manufacturer
PD	partial discharge
PdM	predictive maintenance
PI	Polarization Index; ratio of 10 minute IR to 1 minute IR
PILC	paper insulated, lead covered
PM	preventive maintenance
PRA	probabilistic risk assessment
PVC	polyvinyl chloride
PWR	pressurized water reactor
SEE-IN	Significant Event Evaluation Information Network
SEN	Significant Event Notification
SER	Significant Event Report
SOER	Significant Operating Experience Report
SOV	solenoid-operated valve
SSC	system, structure, component

SYSMON	System Monitoring (an EPRI tool for system engineers)
TDR	time domain reflectometry
TSI	turbine supervisory instrumentation
VAC	volts alternating current
VDC	volts direct current
VLF	very low frequency
W	Westinghouse
XLPE	crosslinked polyethylene

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