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IEEE Guide for the Evaluation of the Remaining Life of Impregnated Paper-Insulated Transmission Cable Systems

IEEE Power Engineering Society

Sponsored by the
Insulated Conductors Committee

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Sponsor

Insulating Conductors Committee
of the
Power Engineering Society

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Abstract: This guide provides technical information regarding factors that can affect the life of an impregnated paper-insulated transmission cable system, and it reviews available methods to evaluate the remaining life of such systems and preventive maintenance to extend their service life.
Keywords: extra high voltage (EHV) cable, high-pressure fluid-filled (HPFF) cable, high-pressure gas-filled (HPGF) cable, impregnated paper-insulated transmission cable systems, self-contained liquid-filled (SCLF) cable, thermal-mechanical bending

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Introduction

(This introduction is not part of IEEE Std 1425-2001™, IEEE Guide for the Evaluation of the Remaining Life of Impregnated Paper-Insulated Transmission Cable Systems.)

The end of the Second World War saw unparalleled growth in the use of electrical energy in many areas of the world, driven by rapid population increases, reconstruction of urban infrastructure, industrialization, and newly found prosperity. In order to meet the growing electrical energy demands, utilities made very large investments in new generation, substations, transmission, and distribution plants. In heavily populated, high load density urban areas, where sufficient rights-of-way were unavailable, transmission lines were installed underground.

Many of these underground transmission lines have now reached, or will soon reach, the end of their theoretical lives. This is understandably a time when many owners are alerted to the possibility of the mortality of their lines and require information on remaining service life. Sometimes they are also alerted by rising maintenance costs, as equipment failure rates increase with age. In other cases, the maximum current ratings of underground cables are rapidly approached because of rising electrical loads or increased power transfers, prompting review of uprating possibilities and system reinforcement alternatives. These issues inevitably result in discussions on the remaining life of transmission cables and life extension strategies, usually with significant financial ramifications.

From a broad perspective, it has been the practice to assume that end-of-life occurs when damage is so extensive that it becomes no longer economic to repair or maintain the cable system, or when failures are so frequent that the reliability of supply is compromised. However, failure of a localized part of the system may not necessarily mean end-of-life for the whole. It is, therefore, useful to evaluate the remaining life of a cable system in the context of the mortality of its individual components and its condition as a whole.

Participants

This guide was prepared by the members of Working Group C4 (3-58) of the Cable Systems Subcommittee of the Insulated Conductors Committee of the IEEE Power Engineering Society. It is attributed to the efforts of many cable industry engineers who took the time to attend the working group meetings, participate in the discussions, and comment on and edit the final document.

The following is a list of participants in Working Group C4 (3-58). Special appreciation goes to members with an asterisk after their name for their effort in preparing the text.

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IEEE Guide for the Evaluation of the Remaining Life of Impregnated Paper-Insulated Transmission Cable Systems

1. Overview

1.1 Scope

This guide provides technical information regarding factors that can affect the life of an impregnated paper-insulated transmission cable system, and it reviews available methods to evaluate the remaining life of such systems and preventive maintenance to extend their service life.

1.2 Purpose

This guide provides technical background, discussion, and advice to those needing to evaluate the remaining life of impregnated paper-insulated transmission cable systems. Guidance is given for both high-pressure fluid-filled (HPFF) (see Association of Edison Illuminating Companies CS2-97 [B12][1]) and self-contained liquid-filled (SCLF) (see Association of Edison Illuminating Companies CS4-93 [B13]) cables, which use a dielectric liquid as the filling and pressurizing medium (dielectric fluid), and for high-pressure gas-filled (HPGF) (see Association of Edison Illuminating Companies CS2-97 [B12]) cables, which use nitrogen gas as the filling and pressurizing medium. The information presented here is intended to provide a complete and concise summary and overview, with frequent references to the technical literature for those who wish to investigate specific subjects in more detail. Emphasis is placed on practical, realistic, and economical methods for performing field and laboratory sampling and testing, and later analysis to determine the actual condition of a cable installation.

This guide describes the various aging mechanisms that act on cable components. This includes aging of the outer protective coverings and the fluid-containing sheaths and pipes. It also includes thermal-mechanical aging of SCLF cable sheaths and their mechanical aging due to creep and fatigue, and thermal-mechanical aging of HPFF insulation due to flexural fatigue resulting from cyclic loads. Thermal and electric stress aging due to cable heating effects and the applied voltage are covered as well.

[1]The numbers in brackets correspond to those in the bibliography in Annex A.

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Methods are presented to assist in evaluating the extent of cable aging. Both intrusive and nonintrusive techniques are described; however, emphasis is placed on the latter. Treatment of the subject includes a description of traditional evaluation methods used in the past, supplemented by newer and emerging methods. Emerging methods include dissolved gas and metals analysis of dielectric fluids, as well as tests for other byproducts of the decomposition of cellulose, which can be used to gauge insulation aging and diagnose incipient failure mechanisms. Finally, advice is provided on preventive maintenance methods, for use in extending the actual service life of a cable system well beyond its economic life.

It is intended that this guide be revised periodically to reflect new developments in diagnostic technology and experience gained with long service-operating cables.

1.3 Unit conversion factors and acronyms

Metric units are used. Unit conversion factors are given in Annex B.

All acronyms used are defined at their first use.

All technical terms are as per IEEE definitions.

2. Cable thermal environment

The cable operating temperature is a direct function of its loading and of the thermal resistivity of surrounding soils (see AIEE Committee Report [B4], Mochlinski [B71], and Schmill [B91]). Although a cable operated continuously or frequently at loads exceeding its design limits will overheat even if the cable thermal environment is unchanged, changes to the environment in which a cable is placed may result in the cable operating at temperatures exceeding design temperatures. Overheating accelerates cable aging (see Kurtz [B66]) or forces cable derating (see AIEE Committee Report [B4]).

For the purpose of this discussion, the cable thermal environment includes, in the case of land cables, the backfill in which it is embedded, the surrounding soil, the surface cover, the water table, and the proximity to external heat sources. In the case of submarine cables, the marine environment and sediments in which the cables are placed have to be considered. The cable environment can change with time due to either natural or man-made processes.

This clause discusses changes in the cable thermal environment and the methods that could be used to mitigate harmful influences on cable service life.

2.1 Thermal resistivity

The thermal resistivity of the backfill in which cables are embedded, and that of the surrounding soils, are dependent on their moisture content or degree of saturation (see Radhakrishna, et al. [B88]). Figure 1 shows the dependency of thermal resistivity on moisture content for some typical soils and cable backfills (see Adams and Baljet [B1] and Radhakrishna, et al. [B88]). Typically, the thermal resistivity can double or triple with the depletion of moisture content below a certain critical level (see Adams and Baljet [B1] and Radhakrishna, et al. [B88]), which leads to thermal instability (see Adams and Baljet [B1] and Radhakrishna [B86]) and cable overheating (see Arman, et al. [B11]).

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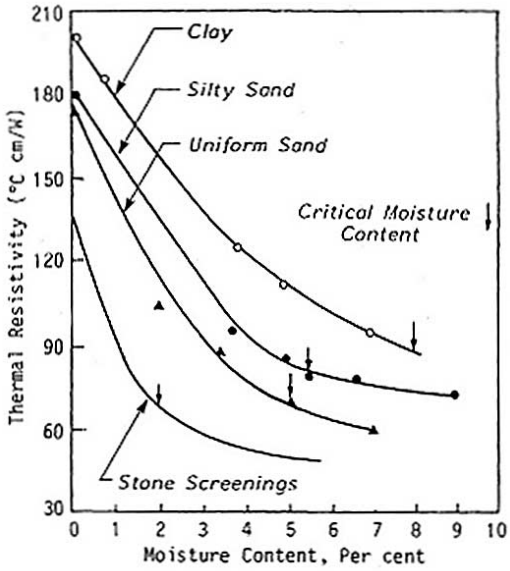


Figure 1—Thermal resistivity of typical soils (see Adams and Baljet [B1])

Moisture content is governed by seasonal variations and changes in weather pattern, which determine how much moisture is delivered to the soil. However, this can be modified by excessive cable loading, which causes moisture migration away from the soils surrounding the cable.

In addition, backfill thermal resistivity is dependent on other factors such as material composition and method of installation. Operating cables are often accessed for maintenance and repairs by excavating the backfill, or the backfill may be disturbed by construction activities. These disturbances may go undetected. If backfill reinstatement is not done properly, it can result in the development of areas of high thermal resistivity (hot spots), which over time could adversely affect the life of the cables. SCLF cables and HPGF cables, which have no intrinsic forced cooling facility to smooth the effect of hot spots, are especially susceptible.

In the case of submarine applications and in certain types of sediments, the heat from cables can cause thermal drying of the immediately surrounding material. This drying can be severe enough, even when water depth is in the tens of meters, to result in thermal runaway (see Tulloch and Cronin [B96]). Also, there is a possibility in organic-rich sediments, of methane gas generation due to the heat from cables, which can impede heat dissipation and lead to cable overheating. The overall effect on the thermal performance of submarine cables should be evaluated by thermal testing of sediments along the cable route.

2.2 Other factors affecting the thermal environment

During a cable's operating life, its thermal environment may change due to the growth of trees, the installation of other heat producing underground plants such as steam pipes or other power cables, the raising of grade elevations, the changing of the nature of soil cover, and excavations that are not properly reinstated.

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Such changes are causes of moisture depletion, increased thermal resistivity, or increased ambient temperature of the soils surrounding the cables. They all result in potentially harmful cable operating temperatures and subsequent premature aging.

2.3 Methods to investigate changes in the thermal environment and evaluate their impact on cable service life

The following steps may be taken to investigate, assess, and record the impact of changes in the thermal environment:

a) Maintain a comprehensive record of changes along the cable route through regular patrols and review of construction permits.
b) Carry out assessment of new construction plans with particular attention to buried heat sources or plans, which may reduce soil moisture content (see Anders and Radhakrishna [B8]).
c) Review, periodically, the operating record to determine cable loading history, conductor and sheath temperatures (if available), and failures (if any).
d) Determine, periodically, the in situ thermal parameters and their variance from the values used in the original design by conducting a soil thermal survey, giving special attention to areas where disturbances to the thermal environment have been noted (see Boggs, et al. [B32]).
e) Determine backfill thermal stability under actual operating conditions by obtaining a sample of back-fill adjacent to the cable and carrying out a thermal stability test with a thermal property analyzer (TPA) (See Boggs et al. [B33]) and a thermal probe (see Black, et al. [B31] and Boggs, et al. [B33]).
f) Take corrective measures, including cable derating, if necessary, to avoid premature cable aging when results of the thermal survey analysis, together with the cable loading history, indicate probable cable overheating (see Anders and Radhakrishna [B8]).

2.4 Methods of mitigation

At locations where analysis indicates thermally unstable conditions, the backfill or surrounding soils could be replaced with backfills that are thermally more stable, such as compacted well-graded sand or crushed screenings of sound rock (see Adams and Baljet [B1]). Fluidized thermal backfills (FTB) are well suited for upgrading the cable thermal environment because of their ease of application and low thermal resistivity even under dry condition (see Radhakrishna [B87]). Although it makes future cable access difficult, concrete, because of its good thermal properties (see Thue [B95]), is sometimes used as thermal backfill at locations where high compressive strength is required for mechanical protection.

Where hot spots are detected, local cooling could be achieved through slow circulation of the dielectric fluid in the pipe of HPFF cables (see Chato, et al. [B36]). Where this is not feasible, and in the case of SCLF and HPGF, external cooling devices would have to be installed to moderate the cable temperature. These can be water circulation or soil irrigation systems (see Baldwin, et al. [B27] and Brooks, et al. [B34]). If such methods are not sufficient, it may be necessary to thermally insulate the interfering heat source, use refrigerant-filled heat dissipation tubes (see Croall, et al. [B38]), or build a ventilated manhole around the hot spot created by the cable crossing of another heat generating utility.

Where new required cable loading would result in severe cable overheating, forced cooling systems that use external heat exchangers to cool the dielectric fluid may be necessary. However, it is usually difficult and expensive to retrofit existing cables with forced cooling.

Further, the need for elaborate mitigation methods can be reduced by

a) Improving coordination and planning procedures in-house and with other utilities
b) Reviewing, in detail, planned construction activities along the cable routes

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c) Enforcing the use of proper materials and procedures for the reinstatement of cable backfills
d) Applying real-time monitoring of cables and cable backfills, especially at hot spots (see Croall, et al. [B38]).

3. Corrosion and mechanical protection

To achieve the dielectric strength required for operation at transmission voltages, the impregnated paper insulation must be kept under hydraulic pressure using a dielectric fluid (mineral oil, synthetic liquid, or nitrogen gas). Jacketed metallic enclosures are used to contain the fluid: a steel pipe for HPFF and HPGF cables and, usually, a lead, copper, or aluminum sheath for SCLF cables. These enclosures, when buried, may be subjected to corrosive environments and damage from external sources.

A weakened enclosure will eventually result in leakage of dielectric fluid and potential partial discharge and moisture ingress into the insulation, ultimately leading to cable failure. As the costs of repair and cleanup, and the loss of revenue associated with cable unavailability, can be substantial, it is imperative that the integrity of pressure containment components be maintained.

3.1 Mechanical protection

Some of the external factors that may cause damage to a cable system include excavation, boring, excessive ground loading or vibration, settlement of the soil and substrate, and corrosive soils. Mechanical protection is required to prevent accidental cable contacts and cable damage, and it is critical to cable system reliability and length of service. Although damaging the cable may result in service interruption and have potentially serious environmental and cost implications, contacting an energized cable may represent a grave hazard and should be avoided.

To protect against accidental contact, the first line of defense could be to provide clear, visible, above-ground markers indicating both the presence of high-voltage cables, the name of the utility, and the “One Call” phone number. In addition, some utilities install a buried cautionary marker tape above the cables and strong barriers such as casing pipes, steel plates, concrete slabs and side walls, or reinforced concrete duct banks.

Patrolling cable routes, monitoring excavation by third parties, and participating in Public Utilities Coordinating Committees that coordinate work on public road allowances, are the most efficient means of ensuring the continued mechanical protection of cables.

3.2 Causes of corrosion

Corrosion of the cable metallic enclosures may be caused by two basic mechanisms (see Husock [B50]):

a) Galvanic corrosion occurs naturally when a metallic structure is in contact with the soil. With the soil acting as an electrolyte, differences in potential may develop between the structure and an adjacent structure of dissimilar metal. Potential differences may also develop along the structure where it is in contact with dissimilar soils. If a continuous electrical path is created as a result of breaches in a cable enclosure protective jacket, such potential differences will cause a current flow. Corrosion (metal loss) occurs at the points where this current leaves the enclosure (anode) through a jacket or coating breach to enter the soil and flow to the cathode.
b) Electrolytic corrosion, also known as stray current corrosion, results from the flow of externally generated dc currents that enter the cable metallic enclosure at grounding locations or at points where the jacket is breached, and exit the enclosure at other points to return to source. Again, corrosion occurs at the points where the current leaves the enclosure through a jacket or coating breach to enter the soil.

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In addition, corrosion may be exacerbated by inadequate design or installation practices, by interference caused by lack of coordination with cathodic protection systems on neighboring structures, or by the malfunction or inadequate maintenance of the cable cathodic protection (CP) system.

3.3 Methods of providing corrosion protection

3.3.1 Protective jackets and coatings

An external jacket provides the primary protection against corrosion of a cable metallic enclosure. Jackets are primarily designed to isolate the enclosure from corrosive environments. They also help reduce the magnitude of protective currents for cathodically protected circuits and provide, in the case of SCLF cables, the electrical insulation necessary to control sheath currents and provide mechanical protection during cable pulling. See IEEE Std 532-1993™ [B55] for guidance on the selection and application of protective jackets.

Initially, protective coatings of HPFF and HPGF cable pipes were usually made of asphalt mastic or reinforced coal tar enamel. More recently, they have been made predominantly of high density polyethylene, but PVC and polypropylene have also been used (see NACE Publication 10A172 [B72]). SCLF cables, on the other hand, were not initially jacketed. Several jacketing materials have been tried since the early 1930s, and in the early 1950s, reinforced neoprene jackets were in standard use. Since the early 1960s, polyethylene has become the predominant material for SCLF cable jackets in North America.

To ensure the quality of external jackets, electrical tests are performed with a coating discontinuity “holiday” tester at the factory prior to shipping and in the field prior to backfilling (see NACE Std RP0274-98 [B76]). In general, HPFF and HPGF cable pipes with asphalt mastic coatings were tested at 35 kV dc. Those with reinforced coal tar coatings and those with polyethylene coatings were tested at 15 kV dc. Because jacket thickness of SCLF cables varies from 2 mm to 3.6 mm (depending on the cable diameter), the electrical test voltages used range from 3 kV ac (7 kV dc) to 11.5 kV ac (28 kV dc), depending on the type and thickness of the jacket.

However, jackets cannot be made perfectly insulating because small imperfections can be present in the material and holidays can be developed during factory application. Jackets can also be damaged by handling during storage, transportation, or installation, or developed later in service by transient overvoltages, by high operating temperatures, or by external agents such as chemicals in the ground, or by dig-ins. These factors cannot always be avoided, and currents may be able to flow into or out of the metallic enclosure. Because of this limitation and to ensure corrosion protection, jackets and coatings are normally supplemented by a cathodic protection system, mainly in the case of HPFF and HPGF cables.

3.3.2 Cathodic protection

Many publications are available that cover the theoretical and practical aspects of cathodic protection design: Husock [B50], NACE Std RP0169-96 [B73], NACE Technical Committee T-2 [B77], Parker [B82], Pope [B85], to list a few.

Cathodic protection systems neutralize the corrosive effects of galvanic activity or stray dc currents at points where the jacket is breached by ensuring that current always flows from either a galvanic or an impressed current anode into the metallic enclosure (cathode). Two types of cathodic protection systems are in common use:

a) Galvanic, zinc or magnesium sacrificial anode systems generate protective currents as a result of the natural potential differences, which exist between their material and that of the cable metallic enclosure. In the process, they are consumed at a rate that is a function of the magnitude of the protective current and the anode material. In general, galvanic sacrificial anode systems are used when a relatively small protective current is required and where the soil resistivity is relatively low.

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b) Impressed current systems use an external source, usually a rectifier, to provide the protective currents. They are used where larger or variable protective currents are required, or where soil resistivity is relatively high, requiring larger driving potentials.

To limit the protective current requirements while providing a low impedance path to ground faults, the metallic enclosure of cathodically protected cables is usually connected to ground through a stainless steel resistor, polarization cell, voltage limiting gap, or, more recently, solid state devices.

3.4 Methods of assessing cathodic protection systems

Surveys and tests provide means for detecting and evaluating the potential causes of corrosion. A systematic program can be broken into the following activities:

a) Gathering Information, including data on the location and operation of dc transit systems, cathodic protection systems used by others, and other equipment operating on direct current in the general location of the line.
b) Performing Corrosion Protection Surveys, which include jacket fault locating surveys, enclosure-to-soil and enclosure-to-other-subsurface-structures potential surveys, and current discharge measurements. Recently, real-time monitoring techniques of cathodic protection parameters have also been introduced (see Hoppe, et al. [B48]).
c) Maintenance Testing to assess the condition of the corrosion protection system, including drainage bonds, rectifiers, and polarization cells.

3.4.1 Jacket and coating integrity testing

Traditionally, jacket integrity testing is done in two steps. First, a jacket resistance test is conducted. The jacket resistance is then calculated. With the circuit de-energized and grounded and the pipe isolated from all grounds, including cathodic protection rectifiers and anodes, a voltage is applied between the pipe and ground and the resulting current across the jacket measured. If the resistance per surface area is found to be larger than 100 $k\Omega/m^2$ for reinforced coal tar coatings, or 1 $M\Omega/m^2$ for asphalt mastic or polyethylene, the coating is considered sound. Although this method can identify pipe sections with problem coating, it does not pinpoint the actual coating damage location. This usually requires the use of an above-ground potential survey (see Peabody [B83]).

In recent years, a less labor-intensive investigative technique has been introduced in some parts of the pipeline industry for monitoring coating integrity. This involves measuring the rate of attenuation of the field intensity of an injected high-frequency signal. Measurements are made from ground surface at regular intervals. With a sound jacket, the field intensity declines uniformly as the distance increases from the signal source. Sudden declines in field intensity generally indicate the presence of coating damage. This technique has been used in some transmission utilities to evaluate HPFF pipe coatings. In these successful applications, it has been used in combination with traditional fault locating techniques to pinpoint coating damage sites.

The effectiveness of this technique looks promising when specific damage sites are present; however, more experience is required before the scope of this technique as a cable maintenance tool is fully evaluated. Some of the factors in the electrical transmission industry hampering the adoption of the technique include the effect of ground return current paths paralleling the pipe, and access to ground electrode sites remote from station ground grids.

It is believed that the most promising maintenance application of the technique lies in a comparison of the results of successive coating surveys when identical connection conditions have been established.

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3.4.2 Enclosure-to-soil potential surveys

Enclosure-to-soil potential measurements are taken at close intervals along the cable route using a copper–copper sulfate reference electrode (see Husock [B49]). The measurements provide a continuous potential profile along the metallic enclosure. For a sound jacket, successive readings should be substantially the same; a less negative value would indicate a jacket discontinuity. The degree of the change in potential is indicative of the size of the discontinuity.

For adequate cathodic protection, the potential difference must meet the criterion of protection for the particular metal used for the enclosure. Although unprotected coated steel pipes usually have a potential to a copper–copper sulfate electrode of –0.5 V to –0.7 V, good cathodic protection is considered to have been achieved when the pipe potential is in general, between –0.85 V and –1.0 V (see Hymes [B51]). More negative potentials may be necessary but should be used with caution as they may cause jacket disbonding. The generally accepted criterion for protection of lead sheathed SCLF cables is a potential difference to a copper–copper sulfate reference electrode of –0.7 V (see NACE Std RP0194-94 [B75]).

Because this type of potential measurement is influenced by operating dc transit systems and other sources of stray currents, it is normal to carry out the measurements very early in the morning or over the weekend.

3.4.3 Measurement of currents in the metallic enclosure

IR Drop measurements (see Edison Electric Institute [B41]) are usually made at manhole locations to establish the magnitude and direction of stray dc currents. The magnitude of the current is indicative of the severity of the corrosion problem, whereas the change in direction indicates the cable section where the stray currents leave the metallic enclosure.

Measurement of ac currents in the bonding leads of SCLF cables can help in identifying cable sections with damaged jackets. They also provide input for determining actual cable operating temperatures.

3.4.4 Testing of empty cable pipes prior to installing new cable

In the case of HPFF and HPGF cable systems, two situations may develop requiring special consideration:

The first situation involves a utility that installs a double-pipe circuit from point “A” to point “B,” but initially pulls cable into one pipe leaving the adjacent parallel pipe empty for a future cable circuit. The spare pipe is usually maintained under a slight nitrogen pressure in the range of 175 kPa. It is not uncommon for the spare pipe to be left empty for 10 or more years before load growth or system changes require installation of the second circuit.

A variation of the arrangement described in the proceeding paragraph is to initially fill the parallel pipe with dielectric fluid and use it as a return pipe for fluid circulation and temperature averaging, or forced cooling. In these applications, the parallel pipe may be one or two sizes smaller than the cable pipe and without flared end/chill ring welds because the intent was not to install conductors later for use as an additional circuit. On the other hand, where the pipe was installed with flared end/chill ring welds and is of suitable size, consideration may be given to pulling in cables for use as an additional circuit.

The second situation involves increasing the capacity of an existing HPFF or HPGF cable circuit by pulling out the original cables and replacing them with larger conductor size or higher voltage-rated pipe-type cables or other alternative types of high-voltage cables.

In the cases described in the two preceding paragraphs, the pipes could have been buried in the ground for many years and may have been subjected to external mechanical damage and corrosive attack. Thus, it is critical to assess the current condition of the pipes prior to pulling in any new cables. This can be done by the following multistep procedure:

a) Disconnect all grounds from the pipe, and measure the end-to-end pipe coating resistance.

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b)
   1) In the case of spare pipes (no cables in pipe), cut pipes in manholes, install joint reducers and measure pipe-coating resistance of each manhole-to-manhole section. Run above-ground survey to pinpoint areas of low readings. Excavate and repair as needed.
   2) In the case of a fluid return pipe, drain dielectric fluid. In the case of cable replacement, drain the dielectric fluid and pull out the existing cables. Install new joint reducers, and measure the pipe-coating resistance of each manhole-to-manhole section. Run an above-ground survey to pinpoint areas of low readings. Excavate and repair as needed.

c) Pressurize each empty pipe section at 2100 kPa (minimum) for 24 hours, and monitor to be sure no pressure drop occurs. Higher test pressures may be required for systems employing forced cooling.

d) Evacuate each empty pipe section to 13 Pa, and then maintain vacuum pump running for an additional 4 hours. Shut off vacuum pump, and run a 1-hour vacuum loss test (13 Pa maximum rise from initial vacuum is permitted).

e) As a final check on the suitability of the pipe for cable installation, cloth swabs and a steel mandrel should be drawn through the pipe between the lead line and the steel pulling cable. The mandrel should have a diameter 9.5 mm smaller than the pipe ID and a 200 mm minimum length, with a minimum 25 mm radius on each end.

Steps a) to e) of this subclause (3.4.4) assure that each pipe section is in suitable condition to receive new cables and will withstand the nominal 1400 kPa everyday operating pressure used in HPFF and HPGF cable systems.

3.5 Methods of mitigation

3.5.1 Testing during manufacture and installation

The pipe coating of HPFF and HPGF cable systems and the protective jacket of SCLF cables undergo various tests during manufacture and installation.

3.5.1.1 HPFF/HPGF cable systems

Early HPFF and HPGF cable installations utilized a nominal 13-mm-thick asphalt mastic or a nominal 3.2 mm thick reinforced coal tar coating over the pipe. In the early 1970s, a high density polyethylene or occasionally polypropylene coating of 1.5 mm thickness applied over a 0.25 mm thick butyl rubber adhesive was developed and became the predominant corrosion protective coating for pipe-type cable systems in North America.

In general, all of these coatings were subjected to electrical tests, known in the industry as Jeep or Holiday tests (see Edison Electric Institute [B41] and NACE Std RP0274-98 [B76]), from the time of initial application to the final stages of installation. See Table 1.

It should be noted that the coating resistance of asphalt mastic-type coatings materially drops to approximately 10 $k\Omega/m^2$ after five years in wet soil, because this coating has only a fair resistance to moisture absorption. The lower coating resistance will result in an increased cathodic protection current to maintain protection. However, even with the lower coating resistance, the steel pipe under intact mastic coatings has been found in as-new condition after 40 or more years of burial.

3.5.1.2 SCLF cables

Early vintage SCLF cables utilized a lead sheath with no protective outer corrosion covering. In the late 1930s, corrosion coverings began to be utilized on these cables and became the standard from the early 1950s to the present.

The first coverings were of reinforced neoprene, but in the early 1960s, polyethylene became popular and was also commonly used to protect the underlying lead (or aluminum) sheath from pulling damage or corrosion.

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Table 1—Electrical tests on pipe coatings

	Reinforced coal tar	High-density polyethylene	Asphalt mastic
At coating plant before shipment	15 kV dc	15 kV dc	35 kV dc
Before lowering coated pipe into the trench	12 kV dc	12 kV dc	28 kV dc
Coated pipe welds	12 kV dc	12 kV dc	28 kV dc
Manhole to manhole section after burial	Coating resistance of 0.1 MΩ /m^2	Coating resistance of 1 MΩ /m^2	
Terminal to terminal after completion of entire line	Coating resistance of 0.1 MΩ /m^2	Coating resistance of 1 MΩ /m^2	

The cable protective coverings are spark-tested at the cable manufacturer's plant prior to shipment. With the jacket thickness varying from 2 mm to 3.5 mm as a function of cable diameter, spark test voltages range from 3 kV ac (7 kV dc) to 11.5 kV ac (28 kV dc), depending on the type and thickness of the jacket. Some cables with polyethylene jackets, especially those not intended for direct burial, are manufactured with a graphite-type coating over the jacket, which provides an outer electrode to permit electrical testing after installation. The jackets of these cables are sometimes tested at up to 25 kV ac for 1 minute, as a factory acceptance test.

During cable installation, a visual inspection is done, but usually no electrical tests are carried out unless cable ducts are flooded, the cables are directly buried in wet soil, or the cables are manufactured with the graphite-type coating over the jacket. Electrical testing after installation is done by using either a megger-type instrument or by applying an ac or dc voltage. The metallic sheath must be isolated from ground if any electrical tests are to be performed on the jacket after installation.

3.5.2 Joint corrosion coordination surveys

These are joint activities conducted by two or more companies operating subsurface facilities, which are subject to corrosive conditions. The purpose of these activities is to arrive at mutually agreeable mitigation measures, which the participating companies will maintain.

Further reading on the topics addressed in this section can be found in AEIC Publication G3-78 [B3], ASTM A523-96 [B14], AWWA Std C203-97 [B26], CIGRE Working Group 21-05 [B37], Dashner [B39], Electric Power Research Institute [B42], IEEE Committee Task Report [B52], Kuhn [B62], Kulman [B63], Kulman [B64], Lawson [B67], Lawson [B68], NACE Std RP0185 [B74], NACE Technical Committee T-4B Publication 4B254 [B78], and NACE Technical Committee T-4B Publication 4B256 [B79].

4. Thermal, mechanical, and electrical aging

4.1 Paper/dielectric fluid insulation systems

Impregnated paper insulation for cable systems consists of kraft paper tapes wrapped helically around the conductor. The paper tapes are vacuum dried and impregnated with dielectric fluid. The cable is operated under pressure in a gas or dielectric fluid environment.

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The main component of paper is cellulose fiber, which is a carbohydrate. Extra high-voltage (EHV) cable is typically made with cellulose, which has a high degree of polymerization (i.e., has a long chain structure). Paper is a hygroscopic material and normally contains a significant amount of water. Part of the water contained in the paper is retained on the surfaces of the fibers or enters the fibers by capillary action (absorbed), and part is chemically bound in the cellulose. For cable insulation, which requires low dielectric power losses, water is removed during the drying part of the drying and impregnating process, typically to levels of 0.02% or less by weight. Drying before impregnation involves removal of the absorbed water, but not the chemically bound water. Overheating in service can drive out the chemically bound water and depolymerize the cellulose.

The dielectric impregnant fills the empty microspaces in the paper and the interstices between the paper wraps. This reduces the size of or eliminates gaseous voids in the cable, which prevents ionization or electrical breakdown within the cable insulation structure. Additionally, the paper fiber can limit travel of ionic species related to the impregnant used, which reduces dielectric loss in the cable. As gas bubble size is reduced, the voltage at which ionization is initiated increases. Thus, with a properly dried and impregnated paper insulation system, the cable, when pressurized, will be able to support normal electrical stresses and periodic impulses or surges without any ionization or breakdown.

Long life of an impregnated paper insulation system requires

a) Proper cable design and proper manufacturing processes
b) Proper drying and impregnation of the kraft paper
c) Proper shipment, storage, and installation of the cable
d) Maintaining pressure on the paper/fluid insulation at all times when the system is energized
e) Ensuring that moisture and oxygen do not infiltrate the system
f) Eliminating or removing impurities in the cable fluid
g) Ensuring the system is not overheated

4.2 Deterioration of mechanical and chemical properties of paper insulation as a function of time and temperature

Aging of cellulose is related to chemical changes in the material structure. As temperature is raised, the chemical reaction rate increases, which results in changes to physical, mechanical, and electrical properties.

Exposure to increasing temperatures results in depolymerization of the cellulose by breaking of C-O and C-C bonds. This process becomes apparent at temperatures of 100 °C and higher. The chemical changes in the cellulose cause deterioration of the mechanical and electrical properties of the insulation, including increase of dissipation factor, gas formation (primarily CO, CO_2, and H2), decrease in dielectric strength, and decrease in mechanical strength.

The rates of mechanical and chemical deterioration of the cellulose paper insulation due to physical/chemical reactions are a function of temperature and time. Thermal “aging” is assumed to occur according to the following [Equation (1)] (see Electric Power Research Institute [B42]):

$$S_t = S_o e^{-kt} \tag{1}$$

This is a first-order chemical rate reaction, where S_t is the value of the aging parameter at time t, S_o is its value time $t = 0$, and k is the aging rate constant. The aging rate constant follows the Arrhenius Aging Law [see Equation (2)]:

$$k = k_T = Ae^{-B/T} \tag{2}$$

where

k_T is the aging rate constant at temperature, T

T is the absolute temperature, K

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A is the constant

B is the constant

According to the Arrhenius formula, the aging rate constant varies directly with temperature.

Life time versus temperature data obtained for key mechanical characteristics of the cellulose tapes, as well as gas generation levels, have shown that these cellulose paper properties conform to Arrhenius's theory (see Electric Power Research Institute [B42]). General agreement (see Allam, et al. [B7], Gazzana-Priaroggia, et al. [B45], and Occhini, et al. [B81]) exists that the rate of deterioration of impregnated paper insulation doubles with each 8–10 °C increase in temperature. Due to the lack of definitive test data, the "8 °C Rule" is frequently assumed when estimating the loss of cable life. On this basis, material life of approximately 40 years is predicted for continuous operation at 85 °C. Using the 8 °C rule, continuous operation at 100 °C would result in an estimated life of approximately 10 years, whereas insulation life would be reduced to only about 1 year for continuous operation at 125 °C.

Published research has shown that the various mechanical and chemical characteristics of impregnated paper insulation have different sensitivities to thermal aging and decay at different rates. Although general agreement does not exist, the characteristics below are listed in order of decreasing sensitivity to thermal aging (with 1 being most sensitive and 5 being least sensitive) (see Lawson, et al. [B69]):

1) Folding strength
2) Tear strength
3) Burst strength and degree of polymerization
4) Extension to break
5) Tensile strength

End-of-life for cable insulation has commonly been defined in published literature as that time when the mechanical or chemical characteristics reach 10% of the original value (see Gazzana-Priaroggia, et al. [B45] and Lawson, et al.[B69]). This is a convenient, but totally arbitrary, value as the mechanical and chemical characteristics of the impregnated paper decay at different rates at a given temperature level and exposure time. The "10% End-of-Life" is, therefore, dependent on which characteristic is being evaluated. For example, when the double-fold strength of impregnated paper has reached 10% of its original value, tensile strength of the material might still be as high as 85% of its original value.

Further, although it is convenient to have a common definition of material end of life, 10% of the above material characteristics do not necessarily represent end of life of an installed cable system. Folding, tear, burst, and tensile strength of paper tapes are extremely important parameters for the manufacture and installation of the cable, but the actual level at which these reduced mechanical characteristics will cause mechanical failures for cables in service is not well known. A given cable design may operate successfully for years with tape tensile strengths well below their original values. Clearly, operating impregnated paper cable systems at increased temperatures will increase the rate of degradation. The only point to be clarified is that the assumed 40-year life for cable systems operating at 85 °C is based on the assumption that end of life is reached at 10% of original characteristics. No clear relationship exists between 10% of paper mechanical characteristics and mechanical or electrical failure of cables in service. Further, it should be expected that mechanical-based failure of cables in service would vary depending on the construction of each cable (i.e., paper taping tensions, insulation wall thickness, tape density, etc.) and movement of cable permitted in the system design.

In addition to measurable differences in paper mechanical characteristics, thermal aging of the cellulose paper results in production of gaseous decomposition products. The rate of gas production is also dependent on time and temperature. Gases generated by thermal aging include carbon dioxide, carbon monoxide, hydrogen, methane, ethane, and ethylene. Carbon dioxide and carbon monoxide are generated in far greater amounts than are the other gases, and carbon monoxide, with low solubility in the dielectric fluid, is of particular concern (see Head, et al. [B47] and Lawson, et al. [B69]). In large enough localized concentrations (in a butt gap, for example), gas bubbles offer a site for ionization (partial discharge). This further increases localized heating and accelerates the material degradation.

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Work has been published indicating that carbon monoxide formation could be the most significant factor in limiting the insulation life of SCLF cables at increased temperatures (see Head, et al. [B47]). Although increasing concentrations of gas in the dielectric fluid indicates decomposition of cellulose, incipient failure of the cable cannot be assumed. Cable performance is in jeopardy if the gas generation is

a) Localized
b) Concentrated in a high electrical stress region of the cable
c) Creating gas bubbles
d) Initiating partial discharge

Thus, measurement of gas in the dielectric fluid is indicative of cellulose decomposition but may or may not be indicative of end of cable life, depending on factors [items a) to e)] listed above.

Electrical properties of the paper tape, including dielectric constant and electrical breakdown levels, do not appear to be particularly sensitive to extended periods of high temperatures. Increased temperatures have been shown to increase dissipation factor (see Kurtz [B66]), although some published work indicates that an increase in dissipation factor does not seem to be proportional to time or temperature (see Gazzana-Priaroggia, et al. [B45]). Although the relationship between mechanical or chemical characteristics of impregnated cellulose and temperature and time may be better defined, a steadily increasing dissipation factor of the paper dielectric is considered a reliable indicator of insulation degradation of HPFF cables. Gas bubble formation is of more concern in SCLF cables because saturation levels decrease with decreasing liquid pressure.

Dissipation factor increases with increased moisture level in the cable system. As absorbed and chemically bound water are released from the paper insulation with increasing temperature, dissipation factor will increase. Further, as H2 is generated from the paper insulation and dielectric fluid at higher temperatures, additional water will be formed in the cable system, also affecting the dissipation factor. As dissipation factor increases, power loss becomes high enough to increase local heating. This local heating increases the rate of degradation of the paper and further increases the dissipation factor of the insulation. Increasing dissipation factor may ultimately lead to a significantly shortened life of the cable system due to thermal runaway.

A number of tests can be performed on the paper tapes to evaluate the paper mechanical, chemical, and electrical characteristics. These tests include those shown in Table 2.

Table 2—Mechanical, chemical, and electrical tests on paper tapes

	Test description	Test method
Mechanical tests	Tensile strength	ASTM D-828 [B17]
	Folding endurance	ASTM D-2176 [B24]
Chemical tests	Degree of polymerization	ASTM D-1795 [B22]
	Moisture content	ASTM D-3277 [B25]
	Magenta dye[a]	Pohnan [B84], Robinson [B89]
Electrical tests	Dissipation factor	ASTM D-150 [B16]
	Electrical breakdown	ASTM D-149 [B15]

[a]Magenta dye test for wax is only of use with insulating paper impregnated with mineral oil. This test is of no value for paper impregnated with synthetic dielectric fluids.

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It will be helpful to have the result of work currently underway comparing unaged paper insulation to aged samples of paper insulation. Although significant reductions in mechanical characteristics of the paper would give an indication as to the temperatures the system has been exposed to, these data do not yet provide a quantitative measure of "end-of-life" of the cable.

The evaluation tests listed in Table 2 have the disadvantage of being "intrusive." That is, the cable circuit must be taken out of service and a cable sample must be cut out in order to obtain data. Unless the cable system is already out of service, due to a cable failure, maintenance, or upgrade, it is expensive and time consuming to obtain material for testing.

In comparison, fluid samples for gas-in-fluid analysis can be obtained with relative ease and provide at least a qualitative indication of the degree of degradation (IEEE Std 1406-1998™ [B56]).

4.3 Deterioration of impregnated paper insulation caused by thermal-mechanical stresses

Unlike the mechanical degradation of the paper insulation discussed in 4.2, which is caused by chemical breakdown of the paper due to temperature exposure, the insulation capability of the cable can also be degraded by damage to the structure of the installed cable.

As an HPFF cable expands and contracts, it moves within the cable pipe. While in the pipe, it is constrained (i.e., typically there is not much clearance between the three cables and the pipe inside diameter); within the joint casing, more room exists, and some past cable designs were prone to bending damage, typically at the unsupported ends of the joint. Present day design practice is to mechanically restrain flexing of the cables within the joint casing by use of multiple supports (spiders) and binding the three cable legs together. Thick-walled pipe-type cables that were installed in earlier years without constraining the flexing of the cables within the joints have been prone to thermal-mechanical bending (TMB) damage.

TMB damage results from the cable being bent to a relatively sharp bend radius or flex point. During load cycling, the cable tends to bend repeatedly at the same location. Over time, when the cables are not constrained, this repeated bending can cause the cable papers to shift, which causes alignment of butt spaces (registrations), and the paper tapes can tear and crease. TMB-damaged cable is characterized by serious softening of the cable at the location of repeated cable bending. As butt spaces align and creases form, the increased size of these dielectric fluid-filled gaps provide sites for partial discharge. Thus, TMB is initiated by repetitive flexing of the cable, and if allowed to continue, the insulation structure is weakened and leads to electrical failure at the TMB-affected area.

Impregnated paper-insulated 345 kV HPFF cables were in service almost 10 years before TMB problems were found. If identified early, the cables can be constrained, which eliminates further paper movement. For more severe damage, the cable insulation can be reconstructed or a small section of cable can be replaced. The TMB failure mechanism is dependent on conductor size, insulation wall thickness, tape structure of the cable (taping tensions, tape thickness and width, etc.), cable pipe route and elevation changes, joint design, and the cable maximum temperature cyclic load pattern. No quantitative method of identifying TMB damage sites or determining the degree of damage exists.

Potential TMB problems can be identified nonintrusively by X-ray of the cable pipe in the area of the joint, to locate any severe bends in the cables. Other nonintrusive electrical measurements, such as dissipation factor measurements, are not effective for identification of this problem in the field because the TMB damage is localized, and measurable differences in the cable system average dissipation factor will not be identifiable. Alternatively, if the cable joint is drained and opened, the cables can be examined manually, with TMB damage easily identified as a soft area on the cable or joint.

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4.4 Deterioration of impregnated paper insulation caused by high electrical stresses

The lifetime of electrical insulation material after application of voltage is assumed to follow the relationship shown in Equation (3):

$$t = A/V^n = K/F^n \quad (3)$$

where

t	is the insulation lifetime
V	is the applied voltage
F	is the electric stress
A, K, and n	are the constants

Equation (3) is used when performing accelerated testing at higher than normal ac voltages. For normal operation of an impregnated paper-insulated cable, as long as the cable structure is correctly dried and impregnated with dielectric fluid and pressure is maintained on the cables in service to prevent the formation of voids, ionization cannot start at operating voltage. Thus, at normal operating voltage with pressure maintained on the cables, no material degradation due to voltage stress would be expected (i.e., electrical aging should not occur at all).

If the dielectric fluid is not continuously maintained at or above the proper pressure within the cable structure, degradation of the insulation fluid and paper would be caused by high electrical stresses within gaseous voids between or within the cellulose paper tapes. Impregnated paper-insulated high-voltage transmission cables are not designed or meant to operate subjected to partial discharge conditions, so this case should not be considered as voltage aging. Rather, it is a localized breakdown problem, which would eventually result in cable failure.

As noted in 4.2, the major factor related to the deterioration of impregnated paper insulation is time and temperature. Chemical changes to the paper insulation due to thermal environment can cause production of gases and the formation of gas bubbles, which would allow initiation of partial discharge and eventual breakdown. In this case, exposure to higher temperatures is the primary cause of insulation degradation, and electric discharge and breakdown is the result.

Electrical failure of impregnated paper-insulated cables is typically a very localized event (i.e., at a hot spot, at a mechanically damaged area, at a defect on the conductor shield, etc.). Although the problem sites are serious and will eventually cause a failure, the damage to the insulation structure is so localized that it is not likely that cable system measurements of dissipation factor or dc high potential testing would be beneficial in identifying electrical aging. Carbonization of insulation tapes at a few localized spots is not likely to make measurable changes to a cable system average dissipation factor. Similarly, if the cable system is drained, opened and paper insulation samples are obtained. Unless insulation samples are tested very near or exactly at the site of distress, identification of material degradation is not likely.

Electrical properties of the impregnated paper tapes can be measured with the tests outlined in Table 3.

Table 3—Electrical tests on impregnated paper tapes

Test description	Test method
Dielectric breakdown strength	ASTM D-149 [B15]
Radial dissipation factor	IEEE Std 83™ [B54]

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Changes in the electrical properties could be the result of a localized breakdown event or of thermal degradation.

Increased levels of gases in the dielectric fluid would most likely be due to thermal decomposition of paper tapes. Methane can be generated due to corona, and acetylene is typically produced only at extremely high temperatures, such as at an arcing or sparking location. Thus, even traces of these gases could be an indication of localized electric discharge within the cable structure.

4.5 Degradation of dielectric fluids

The thermal degradation of the dielectric fluid is not as significant as the degradation of the paper in sealed, air-free cable systems below 150 °C. In aging tests with impregnated paper tapes in dielectric fluid, no change in dielectric fluid dissipation factor or viscosity was noticed. However, an increase in acidity was identified (see Gazzana-Priaroggia, et al. [B45]), but it was determined to be due to degradation of the paper. Contaminants in the cable system, such as water, metallic salts, particles, or oxygen, can have noticeable effects on dissipation factor, breakdown strength, acidity, and color of the dielectric fluid. A number of papers address the increase of the dissipation factor of the fluid and oxidation in the presence of metals. The available literature indicates no apparent relationship between the dissipation factor of paper, or changes to it, and the dissipation factor of the dielectric fluid.

Electrical or chemical tests of the dielectric fluid alone are unlikely to provide any information of value in determining cable system end-of-life. Operating commercial HPFF cable systems, where the dielectric fluid has been analyzed for dissolved gases, have shown low levels of gases, such as CO and CO_2 that would be associated with thermal degradation of the paper. This is not surprising because most of the cable systems have been operating at low temperatures (i.e., below 85 °C). Interestingly, what have been more commonly found are higher levels of hydrogen, methane, and ethane. Evaluation of the dissolved gases in the fluid has, in general, been of more value in the identification of localized electrical discharge problems, rather than in determination of aging.

In addition to (see IEEE Std 1406-1998™ [B56]), a number of tests are available to evaluate the condition of the dielectric fluid, including those listed in Table 4.

Table 4—Tests to evaluate the condition of dielectric fluids

Test description	Test method
Dissipation factor	ASTM D-924 [B19]
Dielectric breakdown strength	ASTM D-877 [B18]
Moisture content	ASTM D-1533 [B20]
Acidity	ASTM D-1534 [B21]

If dissipation factor, breakdown strength, moisture content, acidity, or dissolved gas content is determined to be unacceptably high, the dielectric fluid can be degassed and treated to return the fluid to its original specification values. This process can be important in preventing a premature failure of a cable system, but degassing and treating the fluid do not change the basic thermal aging mechanisms and would not change significantly the ultimate lifetime of the cable system.

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A disadvantage of degassing dielectric fluids is that the gas content of the fluid provides an indication of the state of the insulation system. Removing significant and trace gases during the degassing operation can mask valuable data. Dissolved gas data should therefore be obtained before degassing and treating are performed and again afterward to obtain new baseline data.

4.6 Aging of metal sheaths on SCLF cables

Metal sheaths are required to maintain the dielectric fluid of SCLF cables under positive pressure. Lead alloys and aluminum are among the earliest and most commonly used materials for sheathing of SCLF cables.

Commonly used lead alloys include 1/2C, E, F3, Tellurium-copper, Arsenical lead, and so on. Commercially pure lead is not commonly used because of its comparatively poorer fatigue resistance. Lead alloys are extruded tightly and smoothly over cable cores using a lead press or lead extruder. Reinforcing tapes, either metallic or nonmetallic, may be applied over the lead sheath to increase its capability to withstand internal liquid pressure or to protect the cable in certain marine environments.

Aluminum used for cable sheathing is of high purity, usually 99.5% or higher. It is applied over cable cores by extrusion using an aluminum press. Aluminum sheaths can be smooth or corrugated depending on cable size, application, and preference. A corrugated aluminum sheath considerably increases the bendability of the cable, but an inadequate corrugation profile could increase strain concentration and result in shorter fatigue life. Because of the high mechanical strength of aluminum, creep is not a concern for aluminum sheaths, except in extraordinary circumstances, in which an extra high liquid pressure is present. Reinforcing tapes are not usually applied over the aluminum sheaths, but protective jackets are virtually always used to provide corrosion protection and to help in eliminating sheath-circulating current.

Selection of less than adequate materials, sheath design, cable manufacturing processes, or installation conditions could lead to accelerated mechanical aging of the sheath and sheath failure. Sheath failure will result in a dielectric fluid leak, and if liquid supply and pressure become insufficient, ionization would occur, leading eventually to electrical failure.

The major causes of mechanical sheath aging are fatigue and creep, which could occur in both lead alloy and aluminum sheaths.

Sheath fatigue is caused by the application of cyclic stress/strain to the sheath. The major sources of cyclic stress/strain are thermal-mechanical cycling and vibration.

Increased rate of fatigue aging due to thermal-mechanical cycling can be experienced inside manholes, where cables are installed in a duct-manhole system. The cables in the duct-manhole system are usually provided with offsets inside the manholes to allow for cable movement due to the longitudinal expansion/contraction resulting from the circuit loading fluctuations. The cable movements inside the manhole cause strain variations along the cable offsets. The offsets must therefore be properly designed to control the strain variations within acceptable limits for the type of sheath material/design used in order to avoid premature sheath fatigue. Methods to estimate strain at cable offsets are published in various industry references.

Increased rate of fatigue aging due to vibration could be caused by heavy traffic, especially on bridges, cable transportation, transformers, vortex shedding oscillations for submarine cables, and so on.

Creep is caused by the application of prolonged stress. Two creep properties that could affect the performance of lead alloy sheaths are creep ductility and creep strength. Creep ductility is a measure of the ability of a material to deform under a prolonged loading condition. Ductility is important in ensuring that lead alloy sheaths make adequate contact with the reinforcing tapes at butt gaps, and that the reinforcing tapes adequately support the sheaths against internal pressure. Creep strength is a measure of the ability of a

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material to sustain a prolonged stress application. High creep strength is required for aluminum sheaths and for lead alloy sheaths with no reinforcing tapes, or where only one layer of reinforcing tape is applied with butt gaps. Submarine cables could also be subjected to lead sheath creep at long unsupported spans.

Fatigue and creep properties of lead alloys are greatly influenced by the alloy type, extrusion conditions, grain size and uniformity of grain size, degree of cold working, and the temperature to which the sheaths are exposed. Additionally, strain variations, rate of strain cycling, and the presence/absence of a protective jacket also influence fatigue properties of lead alloys. Published data on fatigue and creep properties for different lead alloys are available and should be carefully applied.

Additional reading on the aging of metal sheaths on SCLF cables can be found in AEIC CS4-93 [B2], Anneli, et al. [B10], Bauer, et al. [B28], Beckmann [B29], Betzer [B30], Dollins, et al. [B40], Havard [B46], Iizuka, et al. [B58], Inoue, et al. [B59], Lawson, et al. [B70], and Oasa, et al. [B80].

5. Evaluation techniques

5.1 Introduction

It is well known that thermal deterioration of the kraft paper insulation is one of the major factors limiting the service life of HPFF, HPGF, and SCLF cable systems. The thermal aging process has been studied in great detail. Data on the rate at which kraft paper loses its physical strength as well as the rates of production of the principal decomposition products—gases (e.g., carbon dioxide and carbon monoxide, and water) are available in the technical literature (see Head, et al. [B47] and Lawson, et al. [B69]). On the other hand, the usefulness of these data in predicting the life expectancy of HPFF and SCLF cable systems is restricted by the lack of knowledge concerning the failure mechanism. At least three failure mechanisms have been proposed:

a) The physical properties of the paper insulation deteriorate to such an extent that it is no longer able to withstand mechanical movement. This proposed failure mechanism is of special interest in the case of HPFF cable systems.
b) The concentration of decomposition gases in the dielectric fluid reaches saturation with the formation of gas bubbles and the onset of partial discharges, which lead to electrical failure.
c) The formation of water, most of which will be absorbed by the paper, leads to a progressive increase in dielectric loss and eventually to a thermal runaway failure.

However, support for any [item a), item b) and item c)] of the proposed failure mechanisms from the accumulated service experience of HPFF cable systems is lacking because it is unlikely that any such cable system has ever failed because it had reached its end-of-life. Consequently, life tests carried out in the laboratory under accelerated aging conditions appear to be necessary to resolve the issue. A major industry program of this type: The Electric Power Research Institute (EPRI) Research Project, “Transmission Cable Life Evaluation and Management,” has recently been completed at the Waltz Mill Test Facility. This program had as its objective the acquisition of a better understanding of the failure mechanism in HPFF cable systems in order to determine their useful life. Initial published results (see Singh, et al. [B93]) seem to indicate that degree of polymerization may offer a better indicator of remaining life than either folding endurance or tensile strength. It is true that life tests on HPFF and SCLF transmission cables have been carried out in the past; however, the scope of such work has generally been to demonstrate a design life capability in the region of 40 years at the design temperature rather than to research end-of-life criteria (see Burrell and Young [B35] and Englehardt and Blodgett [B43]).

From the foregoing, it is clear that final recommendations concerning the techniques to be used in evaluating the remaining life of HPFF and SCLF transmission cable systems must await the successful outcome of such research programs and publication of results. The proposals made in the remainder of this clause reflect the current state of the art and should, therefore, be regarded as provisional.

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5.2 Assessment of the physical characteristics of kraft paper tapes

As noted in Clause 4, the electrical integrity of an HPFF, HPGF or SCLF cable depends on the physical properties of the kraft paper insulation (burst strength, folding strength, tear strength, tensile strength, and degree of polymerization), and that electrical failure will result when its physical properties deteriorate beyond an acceptable minimum level. However, at the present state of the art, it is not possible to provide guidance on the permissible level of deterioration. It has been suggested that a reduction to 10% of the original value of a physical parameter might be taken to give a rough estimate of the end-of-life. The problem with this approach is that values of cable life estimated on this basis range from 6–70 years, depending on the particular parameter chosen to characterize the deterioration. It is clearly not possible to define cable life in this way. However, sufficient accelerated aging tests have been carried out on HPFF and SCLF cables to be confident that life expectancy at a continuously maintained conductor temperature of 85 °C will be at least 40 years, even if the end of useful life remains to be defined. Until additional information becomes available, it is recommended that the nominal life of 40 years at 85 °C be taken as the basis for evaluating the condition of field-aged HPFF and SCLF transmission cables.

The curves of Figure 2 are derived from the deterioration rate data presented in Head, et al. [B47]. They show the calculated relationship between the percentage retention of burst and tensile strengths of kraft paper and the amount of remaining nominal life.

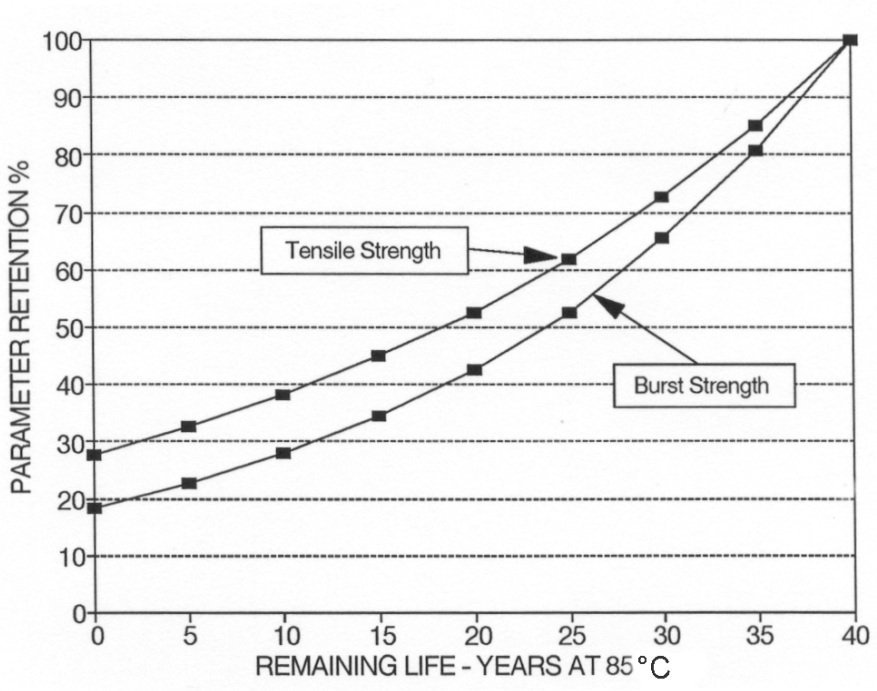


Figure 2—Relationship between percent retention of the burst and tensile strengths of kraft paper (taken from a field-aged cable) and remaining nominal life

A sample of kraft paper is taken from the innermost part of the insulating wall of a field-aged cable. Measurements of either tensile strength or burst strength are made. If the tensile strength is determined to be 52%, say, of the value corresponding to virgin cable, then according to Figure 2, the cable would have a remaining life of 20 years of continuous operation at 85 °C conductor temperature. Similarly, if the burst strength was determined to be 52%, say, of the value corresponding to virgin cable, then according to Figure 2, the cable would have a remaining life of 25 years of continuous operation at 85 °C conductor temperature.

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The removal of a sample from a cable in service is the surest way to determine the physical and chemical characteristics of the insulating papers. For all its shortcomings, the procedure described in the preceding paragraph is available to evaluate the condition of impregnated paper insulation. However, other variables have to be considered when evaluating the remaining life of a cable system.

5.3 Determination of the diagnostic gas content of cable dielectric fluid

Carbon monoxide and carbon dioxide are the most significant gases in terms of volume produced during the thermal decomposition of kraft paper. These gases dissolve in the cable dielectric fluid, and their concentrations can be determined using nondestructive fluid sampling and gas analysis techniques (see IEEE Std 1406-1998™ [B56]). Figure 3 shows calculated values, developed from data obtained from Head, et al. [B47], of the concentrations of these diagnostic gases in the fluid of a typical HPFF cable operating with a uniform temperature of 85 °C throughout its insulation wall. This is an artificial situation, and account would have to be taken of temperature drop across the insulation and temperature variations along the cable route, which would occur in practice. Also, it has been assumed in the calculations that there has been a complete mixing of the gases throughout the cable and pipe fluids. If the foregoing requirements can be complied with, then the method described in 5.2 can be applied to obtain an estimate of the remaining nominal life of the system in a nondestructive way. In principle, if the thermal history of a given transmission cable circuit is accurately known, it should be possible to correlate the diagnostic gas content with the physical characteristics of the cable insulation.

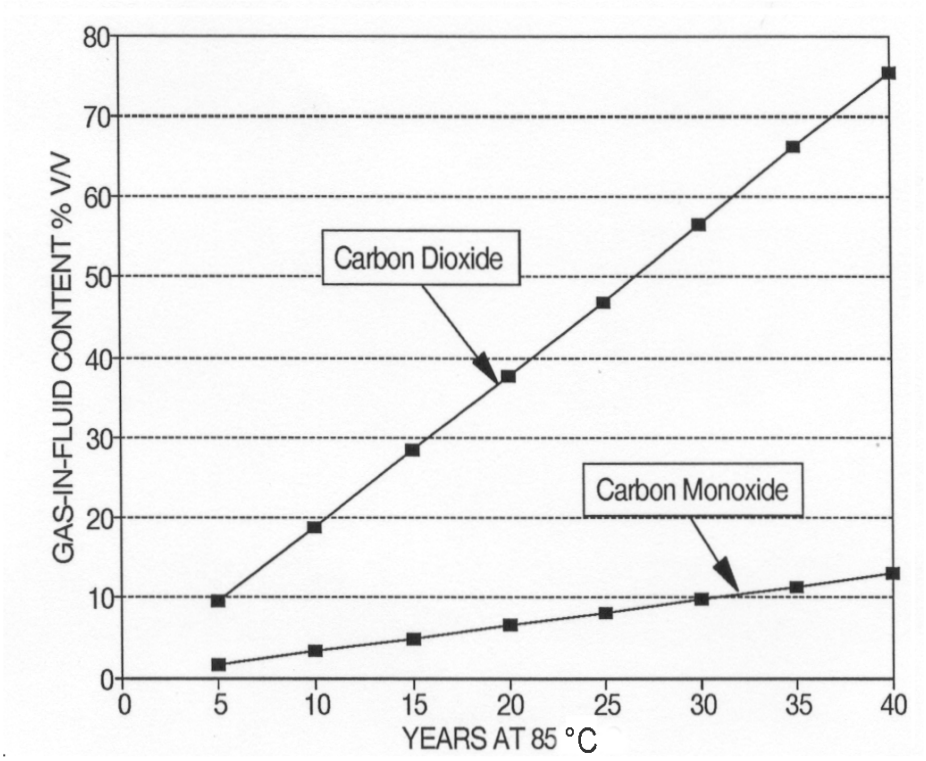


Figure 3—Calculated carbon monoxide and carbon dioxide contents in the fluid of a typical HPFF cable as a function of aging time at a steady uniform temperature of 85 °C

Meanwhile, the information contained in Figure 3 is considered useful to the extent that carbon monoxide and carbon dioxide contents in the pipe fluid that are greater than those shown in the figure would be indicative of abnormal thermal aging behavior, i.e., of overheating.

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In addition to monitoring the carbon dioxide (CO_2) and carbon monoxide (CO) content of the cable fluid, further useful information on the condition of the paper insulation can be obtained by determining the concentration of the following gases in the fluid:

- Nitrogen: N2
- Oxygen: O2
- Hydrogen: H2
- Methane: CH4
- Ethane: C2H6
- Ethylene (Ethene): C2H4
- Acetylene (Ethyne): C2H2

Details of the methodologies for sampling and analysis of dielectric fluids are given in IEEE Std 1406-1998™ [B56].

5.4 Dielectric measurements

Accelerated life testing in the laboratory has shown that the dissipation factor and the dc resistivity of HPFF and SCLF cable insulation remain remarkably stable until the degree of thermal aging is significant. Beyond this limit, there is a gradual increase in the dissipation factor and a corresponding decrease in the dc resistivity of the insulation. Figure 4 shows dissipation factor results as a function of time at 120 °C for two SCLF transmission cables, one impregnated with low viscosity mineral fluid and one with dodecyl benzene (d.d.b.) impregnating fluid. In both cases, the dissipation factor begins to increase, more or less rapidly, after 600 days of aging. At this stage, the tensile strength and burst strength would have reduced to 10% and 5%, respectively, of their initial values so that the aging can be considered as extremely severe, equivalent to 70 years at 85 °C. Nevertheless, a substantial amount of time elapsed before ultimate failure took place in one of the cables after 840 days of aging; the remaining cable survived for 950 days without failure when the aging test was discontinued. Hence, monitoring of the dissipation factor or dc resistivity could provide a means of identifying, at an early stage, the onset of end-of-life. Unfortunately, too few data are available at present to allow firm recommendations to be made of limit values for either electrical parameter, which would represent an end-of-life condition. However, monitoring of the dissipation factor is recommended as a useful diagnostic because the absence of any significant and progressive increase is apparently indicative of a cable insulation system far removed from the end of its useful life. In addition, there is a good possibility, once sufficient data have been accumulated, that such measurements could eventually be used to predict the end-of-life of insulation.

The measurements of the dissipation factor of an installed cable are rendered difficult by the fact that the metallic sheath or pipe is at ground potential. A suitable method for offline dissipation measurements has, however, been developed (see EPRI TR102449 [B44]).

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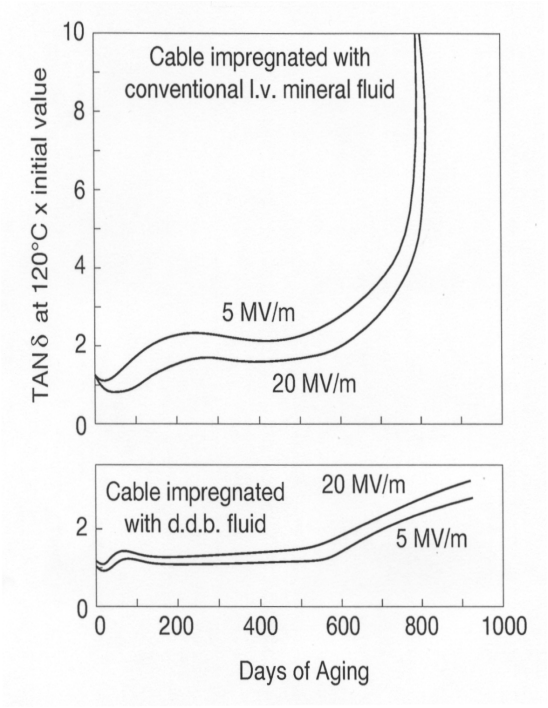


Figure 4—Effect on continuous thermal aging at 120 °C on the dissipation factor of an SCLF transmission cable

It is also known, at least for kraft paper in its virgin state, that there is a relationship between the dissipation factor of the fluid-filled paper insulation and that of the fluid. This relationship is developed in 5.5 and may, in due course, provide the basis of assessing the dissipation factor of a transmission cable by performing dielectric measurements on fluid sampled from the cable system.

5.5 Relationship between the dissipation factor of impregnated paper and the impregnant

In theory, if the permittivity and dissipation factor of the cable fluid can be measured, it is possible to calculate the corresponding values of these parameters for the fluid-filled paper insulation. Full details of the theoretical model can be found in Lawson, et al. [B69], whereas the results of the analysis can be summarized in Equation (4) and Equation (5) as follows:

$$\varepsilon_t = \varepsilon_f \times P_f + \varepsilon_o \times P_o + \frac{\varepsilon_f \times \varepsilon_o \times (S_f + S_o)^2}{\varepsilon_f \times S_o + \varepsilon_o \times S_f} \quad (4)$$

$$Tan\ \delta_t = (A + B \times K_d) \times Tan\ \delta_f / (A + B) \quad (5)$$

where ε_t and $Tan\ \delta_t$ are the permittivity and dissipation factor of the fluid-filled paper insulation and the other parameters are given by

ε_f is the permittivity of cellulose fiber, which is equal to 6.35

ε_o is the permittivity of cable dielectric fluid

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$Tan\ \delta_f$ is the dissipation factor of cellulose fibers and is given by $(0.55 \times 10^{0.01 \times T} + 0.62 - 0.0067 \times T)\%$

where

T is the temperature in degrees Celsius.

P_f is the fraction of the total volume of fluid-impregnated cellulose occupied by the cellulose and considered to be in parallel with the cable dielectric fluid and given by $D_a / (4 \times D_f)$

where

D_a is the apparent density of cellulose paper

D_f is the density of cellulose fiber, which is equal to1.53 g/cm^3

P_o is the fraction of the total volume occupied by the cable dielectric fluid and considered to be in parallel with the cellulose fibers and given by $1/\left(3 \times 10^{2 \times D_a}\right)$

S_o is the fraction of the total volume of the fluid-impregnated cellulose occupied by the cable dielectric fluid and considered to be in series with the cellulose, which is equal to $1 - (P_f + S_f + P_o)$

S_f is the fraction of the total volume of the fluid-impregnated cellulose occupied by the celluose and considered to be in series with the cable fluid, which is equal to $3 \times D_a/(4 \times D_f)$

A is $P_f \times (K_\varepsilon \times S_f + S_o)^2 + K_\varepsilon \times S_f (S_f + S_o)^2$

B is $P_o \times (K_\varepsilon \times S_f + S_o)^2 + S_o (S_f + S_o)^2$

where

K_ε is $\varepsilon_o / \varepsilon_f$

K_d is $Tan\ \delta_o / Tan\ \delta_f$

where

$Tan\ \delta_o$ is the dissipation factor of the cable fluid

Using Equation (4) and Equation (5), the permittivity and dissipation factor of the fluid-filled cable insulation may be calculated for any given value of paper density, fluid permittivity, and fluid dissipation factor.

As an example, calculations for $\varepsilon_o = 2.2$ and a range of values of $Tan\ \delta_o$ from 0.0002 to 0.002 have been carried out at 100 °C for fluid-filled paper insulation having a paper density of 0.8 g/cm^3. The results are shown in Figure 5. As may be seen from Figure 5, the results lie in the range 0.0016 to 0.0029 and are, therefore, realistic values for good quality paper insulation.

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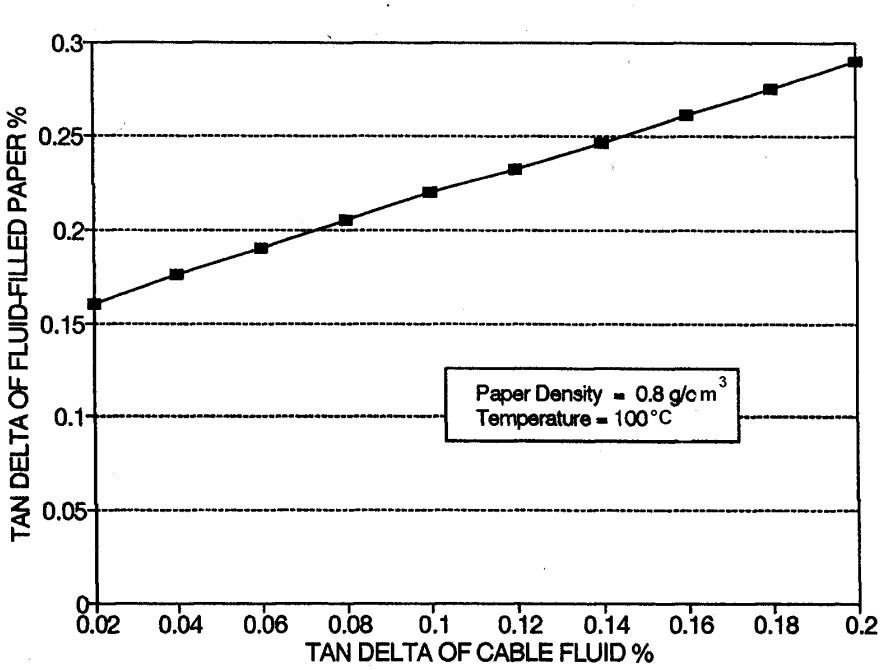


Figure 5—Calculated dissipation factor of fluid-filled paper insulation as a function of the dissipation factor of the cable fluid according to EPRI TR102449 [B44]

One difficulty with the method is that it is necessary to assume that there is complete mixing of the fluid in contact with the paper with that in the surrounding space. For an SCLF cable, this assumption would appear to be a reasonable one; however, the situation is not so straightforward in the case of an HPFF cable, in which the mixing of pipe and cable fluids could be a slow process.

As far as carrying out the measurements is concerned, two approaches are feasible, viz., fluid sampling and measurement using standard dielectric fluid tests (e.g., ASTM D-924 [B19] or IEC 247) or on-line measurement.

5.6 Assessment of aged metal sheaths on SCLF cables

Many old SCLF transmission cables develop dielectric fluid leaks before they experience insulation failure. Although some dielectric fluid leaks develop as a results of corrosion of the metal sheaths, especially in the case of older cables that do not have a corrosion protective covering, or where the covering is in poor condition or has not been maintained, fluid leaks are caused mainly by external damage or aging mechanisms such as fatigue and creep. Utilities with leaky cables are forced to repair, and sometimes replace, the leaky sections or even the entire circuit.

The purpose of this section is to discuss techniques to evaluate metal sheath aging.

It should be noted that because several lead alloys are used to sheath SCLF cables, and that even the same lead alloy can exhibit different mechanical properties depending on the manufacturing process, operating history, and so on, the aging evaluation of lead alloy sheaths is more involved than that of an aluminum sheath.

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The condition of the metal sheath of an SCLF cable can be assessed by utilizing three levels of increasingly detailed evaluations:

Level I evaluation is nonintrusive and requires knowledge of the sheath mechanical loading history, i.e., maximum strain and cyclic strain with cycle duration for fatigue aging, and duration of applied stress and temperature for creep aging. To estimate the remaining life of the sheath, the historical loading data are compared either with data published in the literature or data generated through in-house testing. It is necessary to adjust the data for temperature, frequency of vibration (lead alloys), strain variations, and so on as the fatigue curves and creep data are usually produced for constant testing conditions.

Level II evaluation is semi-intrusive and requires an in situ aging test/examination. It requires removal of the corrosion protection covering and reinforcing tapes, but it does not require removal of the sheath. Although this level of evaluation affords only limited examination of the cable sheath, the method should produce more reliable results than those of Level I evaluation as the actual samples are examined. The evaluation method has not yet been well developed for transmission cables, although a method to evaluate certain lead alloy sheaths for telecommunication cables has been reported. The major advantage of this evaluation method is that it requires considerably less circuit outage time and is less costly than that of the Level III evaluation. For reliable in situ test methods, the methods must be first proven by actual destruction tests.

Level III evaluation is intrusive and employs a direct testing of sheath samples removed from the cable. The method is highly reliable. Tests include microscopic examination, hardness analysis, metallurgical analysis, and tensile, fatigue, and creep tests. The major disadvantages of the method are that it requires samples to be removed from in-service cables, which results in relatively long circuit outages, and the cost of evaluation is high. Based on the results obtained, the aging of the sheath can be evaluated and the remaining life can be, in theory, estimated. If previous test records from the time of manufacturing are available, these can be helpful for comparison purposes.

It should be noted, however, that due to many factors, including inherent variations in sheath properties, inaccurate loading history data, difficulty in predicting future loading scenarios and varying environmental conditions, no methods can provide absolute accuracy in predicting the expected remaining life of metal sheaths.

Whichever evaluation method is selected, it is important to estimate whether the results obtained apply only to the local area where the sheath was tested, or are applicable also to other areas along the cable length. Consideration should be given, for example, to the fact that although sheath fatigue at off-set bends in a manhole is usually due to the thermal-mechanical effects of load cycling and is limited to that area, fatigue due to traffic vibration, such as for cables installed on bridges, is likely to be more widespread. On the other hand, sheath aging due to creep caused by internal liquid pressure is likely to occur in many sections of the cable under similar operating liquid pressure. If it is determined that significant aging is widespread, the entire cable length may have to be replaced in the near future, whereas if aging is localized, remedial action can be limited to the affected area.

During evaluation, consideration should also be given to the fact that although fatigue failure can occur in both lead alloy and aluminum sheaths, creep failure is likely to be limited to lead alloy sheaths.

6. Assembly and analysis of the operating record

In order to have insight into the significance of cable system characteristics observed during a range of operational extremes, it is helpful to have records available that detail the original specifications and past operational performance of the system (see AIEE Committee Report S-110 [B5], AIEE Committee Report S-110A [B6], IEEE Committee Report, ICC Task Group 7-22 [B53], and IEEE Transactions Paper 69TP 44-PWR [B57]).

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Ideally, this data will span the entire life of the cable system, commencing with the tests and observations made during commissioning, together with a detailed record of all the initial operating parameters of the system. All of these data will serve as a helpful guide in the interpretation of observations by providing a realistic context for their assessment.

A body of data spanning such a period can only be assembled through consistent and accurate record keeping by all maintenance and operating personnel who are involved in the cable program. It is important that such record keeping be incorporated into the cable system maintenance program as one of its foundation components.

The use of computerized systems for record storage and retrieval would greatly simplify these tasks and allow greater benefits to be derived from the stored data. The use of systems such as a geographic information system (GIS) would provide an excellent platform for integrating the stored information in a proper relationship to the physical makeup and routing of the cables. Although the set-up costs of such systems may seem to be an obstacle to their adoption, the payback earned through improvements in maintenance productivity and consistency in maintenance practices can be even more substantial.

The following paragraphs describe the type of record recommended and the approaches to take when analyzing this record.

6.1 Assembly of the cable system record

6.1.1 The “as-constructed” record

The foundation of the cable system database is the “as-constructed” documentation. This is usually assembled during commissioning and is intended to be a permanent record, which is to be maintained and expanded over the full life of the cable system.

Such documentation should include very detailed information on the design and construction of

a) The cable
b) The pipe (for HPFF and HPGF systems)
c) Terminations and associated subassemblies
d) Joints (if any) and associated subassemblies
e) Components and subassemblies of the pressurization system, including the operating characteristics of the completed system
f) The corrosion protection system and associated subassemblies
g) Cable trenches, ducts, tunnels, vaults, joint bays, thermocouple and IR drop connections, anodes, and markers

The “as-constructed” record should also include

— The complete plan and profile of the cable route, including the location of any thermocouples, joint bays, vaults, bondholes, anodes, or changes in cable placement, mechanical protection, or configuration
— The type and location of other underground facilities within 1 m of the cables, especially external heat sources
— Results of the thermal survey of the native soil along the cable route
— The thermal envelope design together with details of deviations necessitated during construction
— Results of all acceptance (commissioning) tests performed on the installed cable system
— Names of key people involved in the design, construction, commissioning, and maintenance of the cable installation

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6.1.2 Cable loading history

Permanent records of typical loading patterns for the cable system should be kept based on Operating Center data. In addition, specific records of all short-term overloads should be maintained. This record should include the date, duration, and extent of all of the short-term overloads to which the cable is exposed. This data should be in a form that permits easy determination of the cumulative overload history of the cable.

Ideally, in a modern cable system, accurate loading information will be available to the operators of the power system through the use of real-time monitoring. In addition to providing immediate information to the operator on current loading and the magnitude and duration of allowable load increase, these systems provide a comprehensive and complete loading record for subsequent analysis.

6.1.3 Cable route interference record

The primary goal of the interference record is to assist in maintaining the power transmission capability at the level to which it was designed and constructed. In order to meet this objective, the cable route interference record should be organized in a manner that allows a ready assessment of the cumulative impact of all interferences on the operating capability of the cable system.

Permanent records should be maintained of all encroachments into the cable thermal backfill envelope. The threshold value for recording separations between structures may vary somewhat depending on local conditions, road allowance congestion, and the cable load design criticality. Despite local variations, the common purpose of the record is to identify locations where physical damage may have occurred due to construction disturbance or where hot spots may have been introduced due to changes to the thermal environment.

This record should be originated with any substandard separations that were sanctioned during the original installation. The location and nature of all intrusions as well as the separation provided between the cable and the intruding structure(s) should be identified. Any remedial treatments that have been prescribed to maintain the backfill thermal environment or the physical separation should also be recorded. Sketches can be particularly helpful in showing the overall relationship between the cables and the intruding structures.

The use of a GIS-based data record system is highly recommended, although the initial cost of drawing conversion and the development of linkages with other databases may seem high. GIS-based systems offer the promise of fast and reliable retrieval of cable system information and can greatly simplify the exchange and communication of detailed cable route information with other groups while permitting the prompt update of cable route records when major changes in stretchiest occur. The improved access to such information can greatly improve the monitoring effectiveness and interference remediation on all projects, particularly the long-term ones. Traditional methods of monitoring the effects of long-term construction projects that disturb cable routes are sometimes less effective than anticipated. Changes in project plans, schedules, and personnel over the life of such projects can interfere with fully effective impact remediation by blurring the continuity of information required.

6.1.4 Routine cable maintenance record

A record of inspections, minor maintenance incidents, observations, dielectric fluid analysis results, and minor defect corrections should be maintained throughout the life of the cable.

A tendency sometimes exists to rely partly on the memories of long-serving trade staff for this type of information. This practice can be tempting when time pressures create a conflict between the performance of maintenance work and the writing of reports. Despite this pressure, the inconsistencies in memory recall and staff turnover over the period of time that the cable system is expected to be in operation make this an unreliable practice.

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The routine maintenance record need not be very detailed but should be sufficient to provide an index for all inspections and routine maintenance work carried out at cable terminations, pressurization system elements, vaults, cable joints, bonding systems, pipe (HPFF and HPGF systems), and corrosion protection system elements. Checklists can be used to identify the items examined and checked during periodic inspections so that the recording of results can be done with minimal administrative effort.

The maintenance record should be arranged in a manner that allows easy identification, for each cable system, of any patterns such as periodic replenishment of the pressurization system, recurrent alarm incidents, or defective component replacements. A spreadsheet of the results of analysis of cable dielectric fluid samples aids significantly in identifying relevant patterns from the large body of data that is quickly developed.

6.1.5 Major cable maintenance record

Despite the enviable reliability of transmission cable systems, it is to be expected that there will be a requirement for some major maintenance or relocation during the lifetime of most cables. Typically, this may involve the replacement of some cable, cable joints, or termination components. These are important opportunities for obtaining additional information about the condition of the cable system. It is important that the reports prepared after such major work be detailed and specific, and include all observations on the internal conditions found while performing the work. Discussions at the work site with the cable trade staff often yield valuable observations that might otherwise be overlooked.

It is sometimes difficult to interpret observations made during major maintenance work or relocations; nevertheless, these observations should be recorded with the same diligence as the more straightforward ones. The explanation for some anomalies may only be forthcoming at a later date when combined with observations from other sources.

These records should preferably be kept in a system that permits effective review of the maintenance history of individual cable installations.

6.1.6 Corrosion protection system record

At a minimum, the outputs of the cathodic protection rectifiers should be periodically monitored and the results recorded. Currently available systems make it possible to continuously monitor and record these quantities, as well as structure to soil potential values from test stations along the route.

Such data, combined with the results of surveys of cable jacket or pipe coating condition surveys (see NACE Publication 10A172 [B72]), provide a first level assessment of the effectiveness of the protective measures.

Further valuable information may be obtained through recording the results of detailed examinations of the protective covering condition at all excavation sites. Frequently, in urban streetscapes, these opportunities can occur with little added expense due to the exposure of cable trenches for construction activities undertaken by other utilities.

Detailed documented records of the observations and values recorded during all of these activities should be retained for analysis and identification of any changes in cable risk factors.

These records should preferably be kept in a system that permits easy review of the overall history of corrosion protection effectiveness on individual cable routes.

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6.2 Analysis of the cable system record

The objective of the recording and analysis of cable system characteristics is to gain insight into both the present condition and future life expectancy of the cable system.

Accurate assessment of the overall condition of a cable system and the prediction of its remaining life are never a simple matter. The historic reliability, repair costs, and frequency of failure of a cable system are obvious indicators, but these macro indicators cannot be used in isolation to determine a specific course of action.

Although a record of the changes to individual cable system characteristics may also be available, analysis of trends can be somewhat complicated by changes that occur naturally during the life of the cable. Both the dissipation factor and dissolved gas content of dielectric fluids are typical characteristics that may exhibit change. A steadfast adherence to original specification values as a yardstick for operational performance would be unrealistic and could result in the suggestion of economically unattractive options.

It is a matter requiring careful judgment to determine what constitutes an acceptable range of values for characteristics that exhibit change. When such changes are identified, there is usually an exploration of both the cause and the stability of the new value(s). Further response will vary depending on the assessment of the situation. In the case of severely elevated values of a critical characteristic, especially when supported by trend analysis suggesting that failure is a possibility, immediate withdrawal of the cable from service may be necessary. In the case of a less dramatic change in a characteristic value (possibly suggesting that a new equilibrium has been established), more frequent monitoring during normal operation may be the optimum response.

The analyst should also be alert to trends that may indicate external factors are involved in some of the cable performance observations. These factors may range from a misapplication of internal maintenance practices to interference from other utilities along the cable route.

When an in-depth analysis of unsatisfactory cable performance indicates that the cable is basically sound, a variety of alternative remedies may be available. These may include

a) Treatment of the cable system pressurizing fluid
b) Replacement of cable joints containing generic design weaknesses
c) Replacement of cable terminations containing generic design weaknesses
d) Introduction of special thermal treatments at known hot spots
e) Correction of identified installation deficiencies
f) Installation of specialized cathodic protection equipment systems
g) Repair of faulty cable jackets or pipe coating
h) Replacement and upgrading of obsolete cable pressurization systems
i) Installation of modern surge arresters at terminal ends of the cable
j) Installation of modern surge diverters on sectionalizing insulators of joints, and on support insulators of terminations, installed on specially bonded SCLF cable systems

In reaching any of the conclusions necessary for the extension of useful cable life, the ability to access a comprehensive cable system operating record is a critical advantage. It is only with the insight into cable condition gained through effective analysis of relevant recorded observations that courses of action can be developed that are both economically and technically sound.

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7. Preventive maintenance to maximize service life

Preventive maintenance activities and cycles vary from location to location and from circuit to circuit depending on local environmental and loading conditions. These activities must be designed and implemented in a manner that recognizes personnel safety and avoids undue disturbance of equipment. Intrusive inspection and testing procedures should be carefully planned to minimize the number of occurrences during the lifetime of a cable system.

Preventive maintenance activities effectively serve one of two purposes:

a) Monitor and adjust for any adverse external influences
b) Monitor and adjust for any intrinsic changes resulting from equipment or system operation

The following subclauses describe preventive maintenance procedures recommended for different cable circuit components. The procedures are necessary to maximize service life.

7.1 Dielectric fluids and pressurizing equipment

An underground, pressurized cable is effectively a closed hydraulic system. At the time of installation, the total cable system is filled with a designed amount of dielectric fluid. Reservoirs/storage tanks are designed into the hydraulic system to accommodate the changes in fluid pressures and volumes that result from load and ambient temperature variations. Provided that the cable system is operated within its design limits, no addition or removal of dielectric fluid should be necessary throughout its operating life.

Testing of the electrical and physical characteristics of the dielectric fluid should be carried out on a periodic basis for each circuit. A 3- to 5-year cycle is often adopted by many utilities, but a shorter cycle may be more appropriate depending on the operating and maintenance record. A cable system that is operating closer to its designed capability or is operated under extreme load cycling conditions may warrant more frequent sampling.

Typically for HPFF and SCLF cables, this type of testing should include analysis of fluid samples to determine dissolved gas content, water content, and dissipation factor at elevated temperature. For HPGF cables, testing should include gas analysis and dew point.

The fluid testing locations should be chosen so that the dielectric fluid sampled represents all parts of the hydraulic circuit. The migration rates of different gases vary considerably, and it cannot be assumed that the results of one sample are representative of the entire cable. Testing only at the reservoir/storage tank locations will not adequately represent the conditions along the route. The cable fluid should also be tested at jointing locations, terminations, and other accessible locations. It is advisable to include all possible testing locations in the initial set of tests carried out during commissioning to provide a benchmark.

The latest dielectric fluid test results should be compared with previous results. Large deviations from previous results are indicative of internal electrical activity, thermal aging of the paper insulation, or contamination by foreign materials. Progressive small increases in these values should be expected, but any sudden increase in dissolved gas content or dissipation factor should be cause for further analysis. The subject of gas-in-fluid analysis for HPFF and SCLF cables is treated more fully in IEEE Std 1406-1998™ [B56].

For HPGF cables, a typical nitrogen gas specification (see ASTM D-1933-97 [B23]) would be as follows:

— Nitrogen, minimum by volume: 99.993%
— Hydrogen, maximum by volume: 0.005%
— Oxygen, maximum by volume: 0.002%
— Dew point, maximum: −60 °C

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Should the results of the fluid tests show deterioration of the characteristics of the dielectric fluid, subsequent preventive maintenance procedures may include treatment or replacement of the dielectric fluid. This type of activity represents a major and expensive undertaking but has proven to be very cost-effective in some instances.

Preventive maintenance of the pressurizing equipment consists primarily in monitoring and maintaining the pressures and levels of the dielectric fluid within the safe limits identified at the design stage or recommended by the cable manufacturer. Deviations outside of these limits or unexplained variations between data sets usually indicate a hydraulic leak or, alternatively, a mode of operation that exceeds the original design limits.

The hydraulic system monitoring and alarm equipment should be maintained free of corrosion and in an operational state by periodic inspection and testing. In the case of active pressurization equipment, usually associated with HPFF cable systems, the pressurizing equipment should be serviced at intervals consistent with the manufacturer's recommendations.

7.2 Corrosion protection system

Preventive maintenance of the cable corrosion protection system is essential for the satisfactory operation of all cables, especially those cables that are pressurized. In the case of such cables, perforation of the metallic enclosure can have severe consequences. Considerable amounts of dielectric fluid may be discharged into the surrounding area before proper restorative measures can be implemented, and water and other substances may enter the cable system and contaminate the insulation. This is a condition that may only be remedied by the complete replacement of many meters of cable.

The minimum preventive maintenance procedures applicable to a jacketed cable system consist of monitoring the jacket at all accessible locations, and carrying out repairs where required. These locations would include areas near the terminations, in jointing chambers, and where the cables have been exposed. An above-ground survey using a field intensity monitoring technique is capable of locating jacket defects. This technique is relatively inexpensive to perform and can be a good indicator of the cable jacket condition.

In the case of a cathodically protected cable system (powered or galvanic), preventive maintenance techniques should also include monitoring the CP equipment, inspecting the CP accessories and connections, and surveying the pipe-to-soil potentials along the entire length of the cable route to ensure that proper and complete protection is maintained.

The surveys should also pay particular attention to all indications of stray DC currents in the ground from such foreign systems as DC traction, pipeline CP, and so on. The presence of stray DC currents in the vicinity of the cable system requires increased monitoring and interference surveying to ensure that such currents do not adversely affect the cable cathodic protection system. Real-time monitoring of the cathodic protection system can be effective in the early identification of potential problems and avoiding costly repairs and clean-up (see Hoppe, et al. [B48]).

7.3 Bonding and grounding system

A bonding and grounding scheme is included in the design of every transmission cable system to create safe operating conditions for personnel as well as for the cable insulation. In the case of SCLF cables, the bonding scheme is crucial in determining the cable ampacity.

Inspection is the primary component of preventive maintenance for the bonding and grounding aspects of all cable systems. The leads and connections should be inspected regularly to ensure that they remain intact, continuous, and free of corrosion.

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For HPFF and HPGF cable systems, all accessories associated with the bonding or isolation between the carrier pipe or risers and station ground should be checked. This includes such items as polarization cells, solid state isolation devices, shunt resistor connections to ground, pedestal insulators for the terminations, and insulating flanges.

For SCLF cable systems, all accessories associated with the bonding or isolation between the cable sheath and station ground should be checked. This includes such items as surge arresters, ring gaps, pedestal insulators, dielectric fluid line insulators, and so on. For SCLF cable systems designed with single point or cross-bonding schemes, the link boxes, bonding leads, and connections should be inspected on a periodic basis. For a cross-bonded system, which relies on reduced sheath currents, the magnitude of the currents in the bonding leads should be verified periodically to ensure that the system continues to function as designed. The measured bond lead currents must be related to the circuit loading and should be compared with previously recorded results.

7.4 Mechanical support systems

An underground transmission cable system can be subjected to large thermal excursions during its lifetime. These thermal excursions result in mechanical stresses for the cable and its enclosure.

Locations where the thermal-mechanical forces can result in uncontrolled movement of the insulation can result in cable failure. Radiological inspection of cable joints of pipe-type cables can be effective in the early detection of TMB.

Locations where the thermal-mechanical forces can result in movement of the cable enclosure or support are subject to fatigue or abrasion. Either of these conditions could result in susceptibility to corrosion due to jacket damage or the loss of hydraulic integrity due to mechanical failure. Effective preventive maintenance procedures can usually detect these conditions before they become critical and while relatively simple remedial measures can still be implemented.

Inspection of mechanical supports in jointing chambers at riser locations and at termination supports should be carried out periodically. All accessible locations where the cable system support mechanism changes (i.e., at duct mouths of jointing chambers, buried versus hangers, horizontal versus vertical, suspended versus rigidly mounted) should be investigated. Locations where the cable system has been exposed or undermined should be restored in a manner that ensures subsequent settlement will not occur or result in nonuniform mechanical stresses.

In locations where the cable system crosses under a river or a lake, or is installed on a side-slope, attention should be paid to the condition of the overburden. Washouts, erosion, or landscaping changes can cause the thermal backfill to disappear and the jacket to become more vulnerable to damage. In side-slopes, shifting of the soil may cause unplanned shear or tensile stresses to be imposed on the cable system.

7.5 Cable system thermal environment

At the time of installation, the cable system is designed for known or assumed conditions along the route. Changes to the conditions along the route will invariably occur during the normal lifetime of the cable system. These subsequent changes can introduce conditions that cause the cable system to operate outside of its designed parameters. For example, paving, installation of a steam conduit or power cable duct, change of drainage, planting of trees, or improper replacement of thermal backfill could each cause the designed thermal parameters of the cable system to be exceeded. It becomes a matter of preventive maintenance to monitor, record, and address the changes.

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8. Summary and conclusions

This guide provides technical information regarding factors that can affect the life of an impregnated paper-insulated transmission cable system, and it reviews available methods to evaluate the remaining life of such systems and preventive maintenance to extend their service life. With all of the possible nonintrusive and intrusive test techniques, repair/upgrade alternatives, and preventive maintenance methods, the ultimate questions are as follows:

a) What should be done to evaluate the remaining life of the transmission system?
b) Are life extension options cost effective?

These questions are particularly important given the reality of limited budgets typically available for cable system evaluation and the tendency to avoid investing in an "old" system that has already been in service 25, 35, or 45 years or more.

8.1 Factors to consider

With regard to evaluation of remaining life of a transmission cable system, the expensive testing is "intrusive" testing, which requires opening the cable in order to sample and test the paper insulation. For most impregnated paper-insulated cable systems, use of intrusive tests on the cable insulation is probably not necessary. There are four key factors to consider:

a) Cable Operating Temperature: In general, operating experience has shown that typical operating conditions, i.e., conductor temperature of 70 °C or less, have resulted in very little evidence of thermal, chemical, or mechanical deterioration. It is unlikely that significant insulation thermal deterioration will be observed unless the cable has been operated at conductor temperatures equal to or exceeding 100 °C or higher for extended periods of time.
b) Dielectric Fluid Pressurization: If the cable when energized has been at or above its required dielectric fluid pressure, partial discharge should not have occurred and electrical deterioration of the cable would not be expected, regardless of the number of years in service.
c) Dielectric Fluid Contamination: The dielectric fluid introduced into the pipe of an HPFF or HPGF system, or the core and sheath of an SCLF system, must be maintained free of outside contaminants and moisture. If not, the contaminants could move into the cable structure over time, with deleterious effects on the dielectric structure of the cable.
d) Mechanical Installation: A cable system that was not properly installed or supported could sustain mechanical damage. Thermal mechanical bending (TMB) is a typical result of poor design/ installation practices. Thin wall cables and heavy wall cable systems that have been installed with adequate cable supports (spiders) and other support devices are unlikely to exhibit long-term mechanical deterioration. Similarly, years of industry experience have shown that cable systems installed with adequate slack in the cable, proper clearance between cable and pipe, and so on are not likely to show any mechanical damage.

Thus, if a cable system has been operated at moderate temperatures, has been maintained at required pressures, has not been externally contaminated, and was installed correctly, "intrusive" dielectric testing is probably not needed and significant "life extension" can probably be achieved at minimal cost.

If the cable has been subjected to excessively high conductor temperatures, the next important consideration is how much of the cable was subjected to the high temperatures. A localized hot spot problem may require replacement of a length or two of cable, but other sections of the cable may not show any signs of deterioration. Similarly with fluid contamination and mechanical installation problems, the key issue is how much of the cable circuit was subjected to damage.

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The most common and widespread cable system problems relate to corrosion of the pipe or sheath, sheath fatigue, and failure of manhole-installed components, such as pressure reservoirs. The commercial reality has been that “end-of-life” occurs when corrosion-related problems (fluid leaks) along the cable or near joints are so widespread and reoccurring that the cost of maintenance or repair results in retirement of the circuit. Further, these corrosion and sheath fatigue problems are typically not due to thermal or mechanical “aging” but to the fact that jacket integrity and corrosion protection were not properly maintained.

The above news is good because pipe coatings, cable jackets, and corrosion protection systems can be evaluated and maintained at a moderate cost, whereas an overall deterioration of the dielectric system could only be resolved by replacement of the cable.

8.2 Evaluation method

The following steps should be taken in the evaluation of cable system life and consideration of preventive maintenance programs.

8.2.1 Review the maintenance history

This is one of the most important steps. It typically indicates the type and magnitude of problems related to the cable, and it is the most obvious way of identifying what additional testing is required and what potential maintenance or upgrade should be evaluated. Just as in the case of an individual, when told “don't ignore what your body tells you,” the cable system's maintenance record of type and severity of problems, and of trends, provides the best indication of the system condition and the possibilities for life extension. A leaking cable system indicates pipe or sheath corrosion or fatigue. TMB failure at one or two joints could be indicative of further mechanical problems. Pressure reservoir problems are indicative of lack of maintenance on the reservoirs and alarms. Reports and data related to electrical failures of cable or joints should be carefully reviewed to determine the cause and implications of any long-term trends. Thus, it is essential to carefully review and evaluate the cable maintenance history.

8.2.2 Review the cable load history and installation environment

As noted 8.1, it is likely that no measurable insulation deterioration or indication of an aging trend will occur if

a) Cable loading has been such that conductor temperature has been below 70 °C for most of its operation
b) Few emergency load periods exceeded 100 °C
c) Dielectric fluid pressures have been maintained at prescribed levels

8.2.3 Perform a thermal survey and evaluation of the cable route

If the thermal environment is significantly different from the original installation environment, use the corrected thermal data and actual loading data to calculate expected maximum cable temperatures. If local hot spots appear possible, these cable sections should be targeted for testing.

8.2.4 Sample and test dielectric fluid

Dielectric fluid should be sampled from a variety of locations along the cable system, including terminations (potheads), joints, pressurization plants, or reservoirs. These samples should be tested to evaluate dielectric characteristics, evaluate dissolved gas-in-fluid levels, and determine if contamination problems are present in any segments of the cable system. Treating (filtering, degassing, drying) the dielectric fluid will probably extend the life of a cable system that has degraded due to time/temperature conditions.

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8.2.5 Survey cable, pipe, equipment, and manholes

A survey and inspection of cable terminations and accessory equipment, and of manhole joints and accessories, often provides important information regarding the cable system condition and requirements for upgrade and maintenance. Given that many commercial installations suffer from corrosion or external mechanical damage, it is essential to evaluate the condition and effectiveness of cathodic protection equipment. If it is found to be out of service or that proper voltages are not being maintained, a detailed pipe inspection should be performed to accurately determine the condition of the pipe.

8.2.6 Specify additional testing

After the steps in 8.2.1 through 8.2.5 have been completed, additional specific cable system tests can be completed to provide further technical information to allow an educated “remaining life” determination to be made.

8.3 Conclusions

Experience has shown that without the influence of adverse external factors, pressurized impregnated paper-insulated cable systems that have not been operated at elevated temperatures for extended periods of time and that have been well monitored and maintained, have a useful life that exceeds 40 years. Although no test method now exists that can accurately quantify the “remaining life” of a cable based on the chemical and mechanical properties of the insulation or its dissipation factor, work is in progress to develop such a method. Results to date are promising.

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Annex A

(informative)

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[3]CIGRE publications can be purchased in paper form from mailto://sales-meetings@cigre.org or directly from CIGRE web-site in electronic form (http://www.cigre.org).

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Annex B

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Unit conversion

Unit conversions are shown in Table B.1.

Table B.1—Conversion factors

To convert	Multiply by	To obtain
mm	0.03937	inches
mm	39.37000	mils
kΩ /m^2	10.76000	kΩ /ft^2
MΩ /m^2	10.76000	MΩ /ft^2
pascal (Pa)	7.50000	micron (vacuum)
Pa	0.00750	mm Hg (vacuum)
mm Hg	1000.00000	micron (vacuum)
kPa	0.14500	lbs./in^2 (pressure)

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