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Distribution Cable Aging and Reliability Issues

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INTRODUCTION

The subject of water treeing and aging of extruded cables has now been studied for well over 25 years. Water treeing in extruded cables has been the prime cause of premature failure and major efforts have gone into understanding the phenomena, performing aging tests to quantify its impact, and performing diagnostics studies to anticipate premature failure. Bahder and co-workers brought this water-treeing problem to the attention of the North American community in 1974 (1) and one of the first review articles was published in 1980 by Nunes and Shaw (2). Since that time, there have been numerous studies focusing on the mechanism of water treeing, factors influencing initiation and growth (such as ions), effects of surges, influence of water trees on dielectric strength, and other related issues. Recent summary articles have been published by Ross (3) and by Crine (4).

With reference to aging, the use of a pipe to contain lengths of cables subjected to higher than operating stresses and immersed in water was used for many years in the United States (and North America). This methodology was adopted by AEIC, and load cycling to a nominal 75C under accelerated voltage stress for four months was a preferred procedure. Due perhaps to questionable reproducibility, studies employing temperature controlled tanks have now become quite common and generally accepted. The tanks contain coiled cables aged at 3X or 4X rated voltage and load cycled to various temperatures (mostly 75C or 90C under the stress cone); numerous articles have been published (5, 6) describing aging of XLPE and EPR-insulated cables.

In addition to this, due to the poor service reliability of XLPE-insulated cable installed in prior years, (due to primarily to water treeing) an emerging issue has been how to judge the "state" of the installed aged cables. The use of DC testing, a "yes-no" kind of test (the cable is either "good" or it fails under test) has been demonstrated to be inadequate for aged XLPE-insulated cables, and may even be aggravating the problem (7). Information on improved diagnostics has always been of interest, and much prior work has focused on destructive as well as non-destructive tools. The increasing failure rates experienced by many utilities in the United States has added a sense of urgency to develop reliable in-situ testing tools. Along with this, a growing interest has developed in methodology that could be used to refurbish installed cables (particularly those that are direct buried, as compared to those in duct) to increase their dielectric strength; this is performed by impregnation with a silicone based liquid system that reacts with water and "fills voids". This procedure is an alternate approach to replacement and is generally based on economic considerations.

These issues will be review in this article.

EXTRUDED DISTRIBUTION CABLE RELIABILITY

Most medium voltage cables in the United States are comprised of crosslinked polyethylene (XLPE) insulation with semiconducting shields having different ethylene-copolymer based materials as a “carrier” for the carbon black. The service history had been reported by AEIC until about 1994 during which time failure rates were reported on the basis of insulation nature, operating stress, whether the cable is jacketed, and installation environment. Many changes have taken place over the years to upgrade the quality of both the insulation and the shields. Although present technology appears to provide a highly reliable cable (if accelerated aging tests can be considered reliable) the amount of inferior cable that is presently installed is quite large, and represents an area of significant concern and potential significant financial expenditure, due to anticipated replacement costs for utilities.

A 1995 Panel of the Insulated Conductors Committee of IEEE provides a typical overview of reliability concerns at several United States utilities. A common construction in the United States for 15kV has been unjacketed XLPE-insulated cable having 175mm wall thickness (the shields are not clearly defined on the earlier constructions). By 1994, increases in failure rates of this construction were experienced after about 20 years of service at GPU (New Jersey). Even 35kV, 345mm wall XLPE-insulated unjacketed XLPE-insulated cable was undergoing a rapid increase in the failure rate (15-20 year old cable) at that time; this experience was typical. At Baltimore Gas and Electric Company (Maryland) multiple failures (a second failure after an initial repair) was not uncommon; most occurred in the first or middle section of a loop or radial tap. Most failures were in warm weather (July/August), a typical United States occurrence. Wisconsin Public Service reported failures in 220 mil wall thick XLPE-insulated cable. A 1997 report by Puget Sound P&L (Washington State) noted that 1/0 size conductor unjacketed XLPE-insulated cables showed a seasonal failure trend. This is a small sampling; most North American Utilities experiencing similar situations. This wide variety of geographical locations underscores the universality of the problem.

Crosslinked polyethylene came into use as a replacement for High Molecular Weight Polyethylene (HMWPE), which had previously shown very poor service history, particularly 1971 vintage. Unjacketed XLPE was first used as a replacement, and while service life was extended somewhat, it was not too long afterwards that unjacketed XLPE cables began exhibiting the same problems. The service experience of XLPE-insulated improved when jacketed constructions were employed. The jacket served the role of minimizing problems from “dig-ins” and PE-type jackets do retard moisture entry to some extent; but PVC, used early, really was not an effective moisture barrier. More recently the use of PE jackets (LLDPE is popular in the United States) have become commonplace.

The information noted above is typical; as time passed, and the significance of not only water entry, but the role of ions (in influencing water treeing) became apparent, suppliers then moved in the direction of providing not only cleaner insulations, but significantly cleaner carbon black for use in shields.

It should be noted that failure rate information able to be reported is limited by what the utility can provide; the information represents only the bare minimum surface of what may be needed for understanding causes. For example, the utility is not able to comment on level of crosslinking agent by-products, or residual antioxidant, both of which may play a role in aging performance (depending on the local environment). The information about cleanliness of the carbon black (ion content) is necessarily lacking. More often than not, the curing conditions for the older cables (dry vs. steam cure) cannot be obtained (although occasionally a halo may be seen, and this is indicative of steam curing). The jacket nature is rarely available, yet PVC, used in the past, is significantly more water permeable than are the various polyethylene jackets. No information can be reported by the utility on thermal history, yet it has been shown in recent years that this is a very significant factor in aging of XLPE. Hence, there are limitations on the true value of commonly available failure rate information from users; such information represents only an "overview", and is an insufficient basis for making totally reliable decisions on future actions regarding the presently installed cables. One could, of course remove specimens, and seek out the above information; a number of studies in the past focused on obtaining information of this type. While some correlations have been observed, relating all this to specific installed sites, and applying this to seek guidance on "when to replace" remains elusive.

WATER TREEING

What do we know about water treeing after 25 years of study? The "scorecard" is not as enlightening as one would hope. We know that water trees represent a defect that develops within the polyolefin insulation under the combined influence of water and voltage stress; both are requirements, as water alone or voltage stress alone will not cause them. These insulation defects can "hold" water, but can be dried out (repeatedly, if one wishes). Water trees will "hold" more water than do non-water treed regions (i.e., non-defect polyolefin). The chemical change that occurs (in the defect) is hydrophilic in nature; at least, some dyes will stain the water tree, but whether the staining process involves a (primary covalent) chemical bond, or "clustering" is not clear; yet it seems logical that a cluster of dye molecules should be fairly readily removable (by soaking).

Increased voltage stress increases tree growth, but the influence of temperature on water treeing is complex; elevated temperature is not a requirement for water treeing, but raising the temperature does many things, sometimes driving the issues in different directions: it will (a) drive off water, eventually causing volatilization if the temperature is high enough, (b) increase the water solubility in the polyolefin (hence, holding water in), (c) change the polyolefin morphology (total crystallinity and also crystalline nature) and therefore alter the "fine structure", (d) modify microvoid presence, possibly causing them to "disappear" at high enough temperatures (microvoids might be "reservoirs" for water not in the water tree, and not "dissolved" in the polymer). Increased temperature will not, however, cause disappearance of any cracks that might be present. Load cycling complicates the situation even further, modifying (b), (c) and (d), and the rate of (a).

Do trees consist of channels, "microcracks" or microvoids with an altered chemical surface? The contradictory information in the literature suggests that the experimental method employed at the time the tree is grown (lab or field) likely influences the results. Assuming that the diagnostic tool itself does not "skew" the data, then we are dealing with a phenomenon that continues to remain elusive insofar as control is concerned. "Water treeing" remains a multiplicity of events, still not fully defined.

When it comes to electrical properties, there is a bit more "daylight". Water trees are reported to possess higher dielectric constants than the "virgin" polymer, but nowhere nearly as high as that of water (~80). Tan delta measurements provide inconsistent data, but there is no controversy about the fact that water trees cause a reduction in the dielectric strength, and that these changes can be very significant. Tree length is a vital parameter here, but even a full and complete breach of the insulation wall does not lead to immediate failure of the insulation. Attempts have been made to correlate tree length with dielectric strength.

Insofar as mechanisms of water tree growth are concerned, no single one is generally accepted. Of interest are forces on the water leading to mechanical fatigue of the polymer, or electrochemical oxidation. The former is strictly mechanical, and would not explain dying of the tree, unless that phenomenon is solely physical; the latter would explain increased polarity and higher dielectric constants. Again, both mechanisms likely play a role, depending upon the stresses involved. Crine (4) has provided a summary of this situation, Zeller (8) has proposed that water tree growth is caused by a chemical potential that is influenced by the conductivity of the water in the tree; water trees grow when the chemical potential is above a critical threshold energy region, that is required to induce electrochemical oxidation of the polymer insulation. The chemical potential depends upon the ellipsoid aspect ratio (this assumes the presence of water and ion-containing microvoids/voids that "elongate", or perhaps water-filled channels.) Since oxidation under voltage stress will cause the insulation to become hydrophilic, moisture movement into the tree would be facilitated, and hence tree growth thereby expected to be facilitated.

Boggs (9) has built on Zeller's considerations, and concluded that a lightning impulse will cause a temperature rise adequate to increase the vapor pressure inside the tree, which in time will generate a cavity; he suggests this as a mechanism of water tree conversion to an electrical tree. The hydrophilic nature of the water tree would also facilitate water vapor condensation. A parameter apparently not discussed in the literature is the following; since salt (ions) in water raises the boiling point of the solution, one must consider whether the impulse-induced conversion, via this mechanism, is related not only to conductivity but also salt concentration in the water (all in the water tree).

The potential dual nature of water tree growth has been noted by others; water trees may be induced not only by electrochemical stresses (as discussed above), but also by electromechanical stresses. Needle tests in the laboratory lead to primarily electromechanical induced tree growth (with little or no oxidation occurring), while under service conditions, water treeing is primarily electrochemical in nature (with oxidation taking place).

Crine (4) has noted that water trees grow under nitrogen (at least in the laboratory) and one may inquire whether under the Zeller considerations, this relates to electromechanical (rather and electrochemical) induces water treeing. However, it has also been noted in a detailed EPRI-sponsored study of service-aged cables (10) that such cables did not reveal excess oxidation inside the trees, as compared to the surrounding, non-treed matrix. Perhaps all this information is related to the stresses applied, and even the diagnostics tools employed.

Finally, it has been noted (10) that very highly oxidized XLPE did not undergo water treeing! This may provide guidance to why certain polar additives are satisfactory tree-resistant additives.
Therefore, while numerous publications have appeared, definitive answers as to the mechanism and causes continue to remain elusive. Such being the case, if greater understanding is truly required, then perhaps it is necessary to consider parameters further back along the materials and processing chains, if one is to separate "water treeing" into its component parts. For example, consideration may be given to

- The exact role of the antioxidant, not in processing, but in aging, its location with the cable wall and nature.
- The antioxidant degradation by-products; these are not discussed in the literature
- Antioxidant and peroxide distribution in the pellets
- Residual undecomposed peroxide, and under what aging conditions might it "interface" with adjacent phenomena
- A better understanding of the morphology (spherulite size, lamellae thickness) and temperature influence on these parameters
- Considering the colligative properties of solutions, one may inquire whether it is important (or irrelevant) that oxygen solubility in water decreases as the temperature increases; i.e., is solubility of oxygen in water an issue (must the oxygen be soluble in water, or can it be in the condensed phase for oxidation to occur)? Is solubility of the antioxidant and/or is the antioxidant degradation by-products in the water an issue? Does interaction of the antioxidant and the peroxide occur (it most likely does), and if so, is it relevant.

Perhaps we need to ask new questions such as these if we are to seek to separate the different "water treeing" phenomena.

Regardless of the limited success in the attempts to understand the <u>causes</u> of water treeing, considerable progress has been achieved in seeking to <u>prevent</u> water treeing. This has been achieved via newer materials and superior cable constructions (the latter designed to keep water or ions away). The use of cleaner insulation materials is the most obvious approach, and this has led to novel handling approaches as well as the use of true triple extrusion processing. Use of carbon black processed in such a manner so as to avoid ionic contamination, has led to longer life cables, at least in accelerated aging tests (11). Use of hydrophilic additives in the polyethylene, and also use of additives that respond to field and thermal gradients so as to reduce localized stress (12), have all led to progress. If accelerated aging tests are a true measure of reliability in service, the industry has indeed crossed a favorable threshold.

<u>ACCELERATED AGING</u>

The AEIC accelerated aging water treeing test procedure (AWTT) and the accelerated cable life test procedure (ACLT), performed in pipes and tanks respectively have been summarized by Bernstein and Samm (13). The superior temperature control that can be achieved in the ACLT has enabled the experimental verification of the fact that temperature has a very significant influence on loss of life of XLPE-insulated cables. Of course, the AWTT is simpler to perform and in sense "simulates" the installation of a cable length in a pipe or conduit (whereas the tank test employs coiled cable lengths). In both cases, water is placed in the strands and outside the cable as aging takes place at higher than normal (operating) applied voltage stress. ACLT testing has been employed by Sarma (6) to evaluate tree-resistant XLPE-insulated cables; Caronia (14) and co-workers report on both test procedures in their studies of tree-resistant XLPE-insulated cables.

The significance of temperature on wet aging of conventional XLPE-insulated cables (and also some EPR cables) was demonstrated and should not be underestimated (13). Load cycling provides greater acceleration than does constant elevated temperature for XLPE. A significant loss of life for XLPE under wet aging occurred between 60-75°C, or well below generally accepted operating conditions (although the allowable 90°C is rarely reached in service)

It is also of merit at this point to elaborate on EPR-insulated cables, which are used extensively in the United States. EPR responds significantly differently from XLPE under identical wet aging conditions, and for some EPRs, unexpected failure occurs at four times rated voltage load cycled to only 45°C. The power factor and dielectric strength drop very rapidly, over days to weeks for the EPRs, and not all EPR extruded cables behave similarly. The unusual EPR behavior could only be determined via temperature controlled testing in the laboratory, of course.

EPR cables are significantly different from XLPE; they contain substantial amounts of inorganic filler (coated clay), moisture sorbants and may have 10-20 different components. The clay serves the purpose, among other things, of improving the high temperature properties. The significantly different response of EPR (vs. XLPE) under ACLT testing requires investigation.

A failure model for conventional XLPE cables has been developed based on the ACLT (15); nine different aging conditions caused from the same extrusion run cables to fail over periods varying from two months to over four years. Log normal or Weibull distribution of failure times for eight cable specimens per single condition were used to develop this model, with aging load cycle temperatures varying form 60°C to 90°C, and applied stresses varying from 2 to 4X rated voltage. Also, the cables were continuously immersed in water. The authors estimated the "life" of the cable by extrapolating failure times back to 45C and rated voltage. This model shows that cables that fail (by this definition) after two months under the most accelerated conditions, may be expected to have an average "life" of perhaps 40-50 years, depending upon the cable length. The cable length is a significant parameter in this estimation procedure. It is not clear if this model is applicable in its present form to cables of more modern vintage. Until more data is available on the validity of this model, there is still no acceptable means or relating service and laboratory aging to "remaining life". At present, the ACLT (and AWTT), are used primarily to compare different cable constructions (shields, insulation compounds) relative to each other. However, effort is underway to seek to correlate aging information and certain diagnostic tools.

The AWTT has been employed in the past to study the effect of transients (DC and impulses) on AC breakdown strength and "life". Hartlein and co-workers (16) studied the effect of surges and Srinivas and co-workers (7) studied the effect of DC tests. In both cases, aging was performed under accelerated voltage stress (3X rated voltage) and load cycled daily in the pipe to a nominal 75C under the stress cone. Thermal measurements (use of thermocouples or DSC tests) of the cables being subjected to DC testing showed a variation of as much as 30C within the pipe. Both Groups concluded that the transient stress did not reduce the AC breakdown strength, a significant conclusion as the dielectric strength test is generally employed as an estimate of the "degree of aging". Both Groups also concluded that the transient stress shortened the <u>life</u> of the cable during the aging test; cables subjected to transients (the procedures are described in the references) failed sooner during the aging compared to similar cables never subjected to DC or to the surge. This work suggests that the dielectric strength measurement may not be a satisfactory tool for determining the influence of transients on cable reliability (in contrast to relating it to water treeing). Later work by Katz and co-workers (17) show that for XLPE, surges did not shorten the life of XLPE cables when aging was performed at ambient (i.e., about 30C). Hence, the influence of the surges on life during the accelerated aging process was shown to be aging-temperature-dependent.

More recently, attention has refocused to some extent on the possibility of using high frequency as a means of accelerating the aging of cables (18); frequencies as high as 8000Hz were studied in the 1970s and 1000Hz was used later. The concern with using high frequencies is, of course, that the mechanism of aging might change due to overheating (due to losses) of insulation. This is likely a greater legitimate concern with mineral filled insulations. One way to seek an answer would be to compare the same cables aged at 60Hz and 1000Hz, if that were possible.

It turns out that an EPRI-sponsored project (19) did exactly that in the 1980s for HMWPE-insulated cables. Cables from the same extrusion run using USI NA 310-06 polyethylene, and Union Carbide thermoplastic polyethylene shields containing 35-40% furnace black were studied (these cables passed AEIC CS-75 testing).

Regardless of the fact that these cables are comprised of materials no longer available today, it is the comparative information at 60Hz and 1000Hz that is of initial interest. The Table below shows the exact comparative aging conditions for the cables aged in a pipe at ambient temperature, with water in the strands and also surrounding the unjacketed cable.

FREQUENCY EFFECT ON DIELECTRIC STRENGTH OF HMWPE CABLES

Frequency (Hz)	Voltage Stress (V/ml)	Months of Aging	ACBD (v/ml)	Impulse (v/mil)
60	50	12	312	1657
1000	50	12	277	1372
60	50	24	350	1813
1000	50	24	266	1472
60	85	6	312	1907
1000	85	6	260	1783
60	35	31	345	1621
1000	35	31	308	1457

This limited data, which could be considered, as based on “match pairs”, is developed from 5 samples per data point; the trend does suggest that, for these cables, the drop in dielectric properties is greater at the higher frequency. All this does, however, is suggest that there is enough information to look deeper; the information developed, as described above, does not rule out the concept. However, the validity, of employing high frequency acceleration with newer materials, cleaner material or tree-resistant cables, remains to be demonstrated. From a materials perspective. Information on inorganic filler nature and level become of interest.

DIAGNOSTICS

Since water trees lead to a reduction in dielectric strength, it has not been uncommon, (particularly in the past) to seek to correlate tree length (or number) with ACBD; based on failure experience, replacement decisions have been made. However, even if accurate, this destructive technique requires removal, dissection, staining and microscopy, and is very time consuming. The users really require an in-situ test that is preferably non-destructive. In this area, there has been much activity in recent years. This paper will provide a brief overview of some present activities.

Cable condition assessment techniques can be categorized into approaches performed either on-line or off-line. From this perspective, on-line methods studied include 60Hz partial discharge testing, AC/DC superposition methodology, and harmonic distortion of loss currents. Off-line methods also include partial discharge tests (performed at various frequencies), as well as dissipation factor measurements and, in addition, measurements of recovery voltages. Each approach involves different equipment, different levels of skills are required, and also measures something different about the cable. It is necessary therefore to evaluate what is being measured from an insulation perspective (not only diagnostic information changes) and judge it merits.

Partial discharge measurements are receiving a great deal of attention; for many years, this tool was limited in application to equipment that normally operates under discharge environments, such as rotating machinery. In recent years, the value of applying 60Hz PD testing to extruded cables (20) and the value of applying 0.1Hz PD to paper-oil systems (21) has also been demonstrated. The assumption in applying partial discharge methodology is that discrete weak link sites become more significant as the insulation ages and if they can be located, the cable can be repaired in advance of failure, at the time of choosing. The significance to the Utility, of removing weak links prior to high load seasons should not be underestimated.

One commercial partial discharge test methodology presently in use in the United States (22) is performed by gradually increasing voltage across an isolated cable until partial discharge (PD) is detected. The recommended practice to raise voltage in two 3kV steps above the first PD inception voltage, but only to a maximum test voltage of 3 P.U. The dwell time at each PDIV level is two to three seconds to avoid further deterioration on extruded cables. Hence, the voltage at which PD is detected is referred to as the partial discharge inception voltage. Overall, the technology is a two-step process based on Time Domain Reflectometry (TDR). A low voltage pulse is applied first to estimate the total cable length and locate splices. Then, higher voltage is applied to detect and locate defects.

By combining the results from both steps, it is claimed that the location and severity of defects can be determined within a meter. Not surprisingly, corroded neutrals are a practical problem. Once this is compensated for testing at many utilities in North America has located ‘weak links” in cables, splices and terminations (22).

Low frequency dissipation factor measurement technology is also being examined to estimate the state of aged cables. The claimed advantage of low frequency (0.1 Hz) relates to low reactive power requirements, smaller equipment and some evidence exists that larger changes are measured as compared to 50-60Hz (23). Dissipation factor testing focuses on different mechanisms of aging and loss of life (as compared to PD), since losses are related to changes along the entire length of the insulation (not only at discrete locations). The DF measurements will provide guidance therefore on the general “health” of the cable as a whole. The source voltage can be 0.1Hz, 60Hz, or even MHz range or greater. It is also possible to determine the capacitance and dielectric constant and loss as a function of frequency.

In principle, these measurements are non-destructive in nature; however, if the voltage is raised ‘too high” during the testing, the possibility of imparting latent damage does, in principle, exist. The data collecting process seeks changes at as low a voltage stress as possible, and never above pre-set limits. The partial discharge and dissipation factor methods appear to be complementary as different mechanisms of degradation are monitored.

Polarization/depolarization methods provide information on the polarity of the insulation, which presumably changes as a result of aging. There is significant information from prior R&D to demonstrate that XLPE-insulation does become more polar due to oxidation resulting from aging (see prior discussion on water treeing). The relationship between the oxidation-induced changes and loss of life has not been quantified; however, in principle, this type of diagnostic will provide information that represents a response of the insulation resulting from these (transient) changes. Polarization methods provide information on the insulation regions and on the conductivity while the (DC) diagnostic stress is applied; depolarization methods measure current after that stress is removed, as a result of the previously oriented species moving “back” as orientation due to the charge is now lost. Hence the depolarization measurement cannot be “skewed” by the applied stress.

Since this method provides information related to the polyolefin insulation polarity, a question exists as to the true value of this approach for tree resistant crosslinked polyethylene insulations (TR-XLPEs), which are often deliberately made polar in order to achieve the desired tree-resistant qualities. For these reasons, it is always vital to relate the changes measured by any diagnostic tool to the nature of the insulation itself, if meaningful interpretation of the results are to be obtained.

A recent state-of-the-art summary of present and emerging diagnostic tools is available as an EPRI Project Report (25). A different EPRI project (26) is presently seeking to correlate partial discharge test information, low frequency power factor information and aging information, that quantifies loss of life of XLPE-insulated cables from the mid-late 1980s; the objective is to be able to estimate future performance in a semi-quantitative fashion, solely from in-situ diagnostic testing. A correlation between “time to failure” in the tank test and AC breakdown strength has been recently developed and is being applied (27).

CABLE IMPREGNATION

Impregnation of aged XLPE-insulated cables with silicone systems that polymerize in situ after application, have become commonplace in the United States (28). The technology, referred to as “dielectric enhancement” employs a silicone material possessing chemical functionality that reacts with water. This water reactivity serves to dry the cable and at the same time polymerizes itself to a larger molecule that exudes from the cable at a rate orders of magnitude slower than, e.g., acetophenone. This approach obviates the need for air drying and perpetual replenishment. Many of the silicone treated cables have been rated at 15-25kV and have been small residential distribution cables, although larger feeder cables have been treated in this manner also. Issues relate to not only to the chemistry, but practical handling and impregnation procedures. The driving force for this technology relates to cost effectiveness for individual utilities, as clearly decisions may differ for direct buried vs. duct cables.

CONCLUSIONS

A review of XLPE-insulated distribution cable reliability is provided, and issues surrounding this concern are such as water treeing, aging methodologies and diagnostics, are discussed. Advances have been made in understanding water treeing, but a complete clarification of the mechanisms continues to remain elusive. It is suggested that deeper study of parameters not yet explored be considered. Accelerated aging to quicken loss of life under controlled conditions, to estimate future performance, is impregnated with complexities; issues such as applied stresses – voltage, temperature and frequency acceleration – are noted. It is suggested that their potential impact and relation to subtle features such as lamellae thickness morphology, antioxidant by-products, soluble salt concentration in water, etc., be considered. Significant advances have been made in applying newer in-situ diagnostic test methods to estimate future performance, and this topic is briefly reviewed, along with upgrading of aged cables using silicone systems.

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