$$t_1 = t_2 \, e^{[\phi/k \, (1/T_1 - 1/T_2)]}$$

where:

t_1 = time at temperature T_1
t_2 = time at temperature T_2

According to this form of the equation, exposure of a material of activation energy ϕ to temperature T_2 for a period of t_2 produces degradation equivalent to exposure at T_1 for period t_1. Implicit in this relationship is the idea that exposure of a material at higher temperature for shorter duration will result in degradation equivalent to that resulting from longer exposure at lower temperature.

This relationship is useful in that:

- the longevity of a given material at a different temperature may be estimated;
- long-term, low-temperature aging (similar to that which generally occurs in nuclear power plant environments) can be approximated through the use of higher temperatures for shorter durations (i.e., accelerated aging);
- the model can be used to compare basic properties of one material with those of another during the development of a new cable product.

The Arrhenius model does have several theoretical and practical limitations; for example, (1) reactions and aging mechanisms at high temperature and normal service temperatures may be different (i.e., activation energy (ϕ) may be a function of temperature, rather than constant); (2) the potential for problems when extrapolation through a material phase transition region (e.g., crystalline melting point region) is necessary; (3) use of regressed statistical data, which may generate varying results for activation energy based on the endpoint criterion selected; and (4) unavailability, in some instances, of activation energy information for specific material formulations (i.e., generally, activation energies are available for a given class of material) [4.3], [4.4], [4.5], [4.6]. These limitations stem largely from the relatively simplistic kinetic model used as the basis for the relationship, and the use of empirical data for the determination of activation energy. In addition, highly accelerated aging may produce heterogeneous aging effects within the material, due mostly to the limited opportunity for oxygen diffusion into all but the surface layers of the material [4.7], [4.8]. Thus, artificial aging may produce effects on the material (such as changes in macroscopic physical properties) that are largely an artifact of the accelerated aging process. The Arrhenius relationship should be used with caution. Although it may be used to provide a generalized description of the correlation between thermal exposure and degradation, it may produce results that are not representative of the actual behavior of the material under actual long-term aging conditions. EPRI NP-1588 [4.3], EPRI TR-100516 [4.4], a book chapter on accelerated aging methods [4.5], and SAND88-0754 [4.6] discuss the Arrhenius model, its uses, and limitations in greater detail.

Practical Implications of Arrhenius Model

Arrhenius calculations are commonly used as a part of the basis for the environmental qualification of equipment. The general approach is to use this relationship, empirical data from controlled tests (activation energy and life at test temperature), and enveloping assumptions regarding the equipment's operating environment to determine a theoretical or "qualified" life for a material. This qualified life is essentially the allowable in-service time for the material given the assumption that the component must be able to function under accident environments, even at the end of its qualified life. Even for non-environmentally qualified equipment, the relationship may be used to estimate the effects of environments on material longevity.

As a result of the exponential Arrhenius relationship, a small change in a material's aging temperature produces a substantial change in its longevity. As an example, the extrapolated time for a Neoprene® rubber cable jacket to reach an endpoint of 50% absolute elongation at 40°C (104°F) is roughly 130 years.[4] The time to reach the same endpoint at 50°C (122°F) is approximately 44 years. Hence, reducing the aging temperature from 50 to 40°C increases the estimated longevity of the material by nearly a factor of three (a difference of 86 years). The practical outgrowth of this relationship is that reducing an organic material's service temperature a small amount can result in significant gains in longevity (discounting other potentially life-limiting influences).

Figure 4-1 illustrates the general relationship between aging temperature and longevity for various common cable and termination materials. This graph is derived from experimental aging data obtained from several sources, including manufacturer's aging studies and qualification testing for general applications [4.9], [4.10], [4.11], [4.12], CSPE and Neoprene® [4.13], ethylene propylene diene monomer (EPDM) [4.14], EPR [4.15], ETFE [4.16], PVC [4.17], Silicone [4.18], Viton [4.19], and XLPE [4.20]. *Note that these data are not applicable to all material formulations and plant-specific evaluations are required.* Based on the Arrhenius equation, a linear regression of 1/T versus log(t) can be performed on thermal aging test data to calculate the activation energy resulting from the "best fit" line for the data. Such aging tests are often conducted at elevated temperature (on the order of 140°C or above) to permit more rapid completion of the tests; hence, the resulting curves must be extrapolated to lower temperatures. As previously discussed, such extrapolation of the linear regression curve may or may not be representative of the actual behavior of the material in the lower temperature region. A common aging endpoint was specified for all of the data[5] (50% retention of absolute elongation); hence, the results are comparable in this regard. This endpoint is considered conservative in that bending and manipulation without cracking has been demonstrated for absolute elongation values below 50%. Note that the curve shown for each material is specific to one manufacturer's formulation; thus, the results obtained for a specimen of the same generic class of material yet produced by a different manufacturer may vary substantially. However, the results shown in the figure may be considered representative of the relative thermal aging characteristics of the generic classes of material.

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[4] Based on data contained in "Comparative Heat Resistance of Hypalon and Neoprene" [4.13].

[5] With the exception of the EPDM, PVC, Silicone and PVC data, for which $e_{absolute}$ = 50% data were not available. See Table G-1.

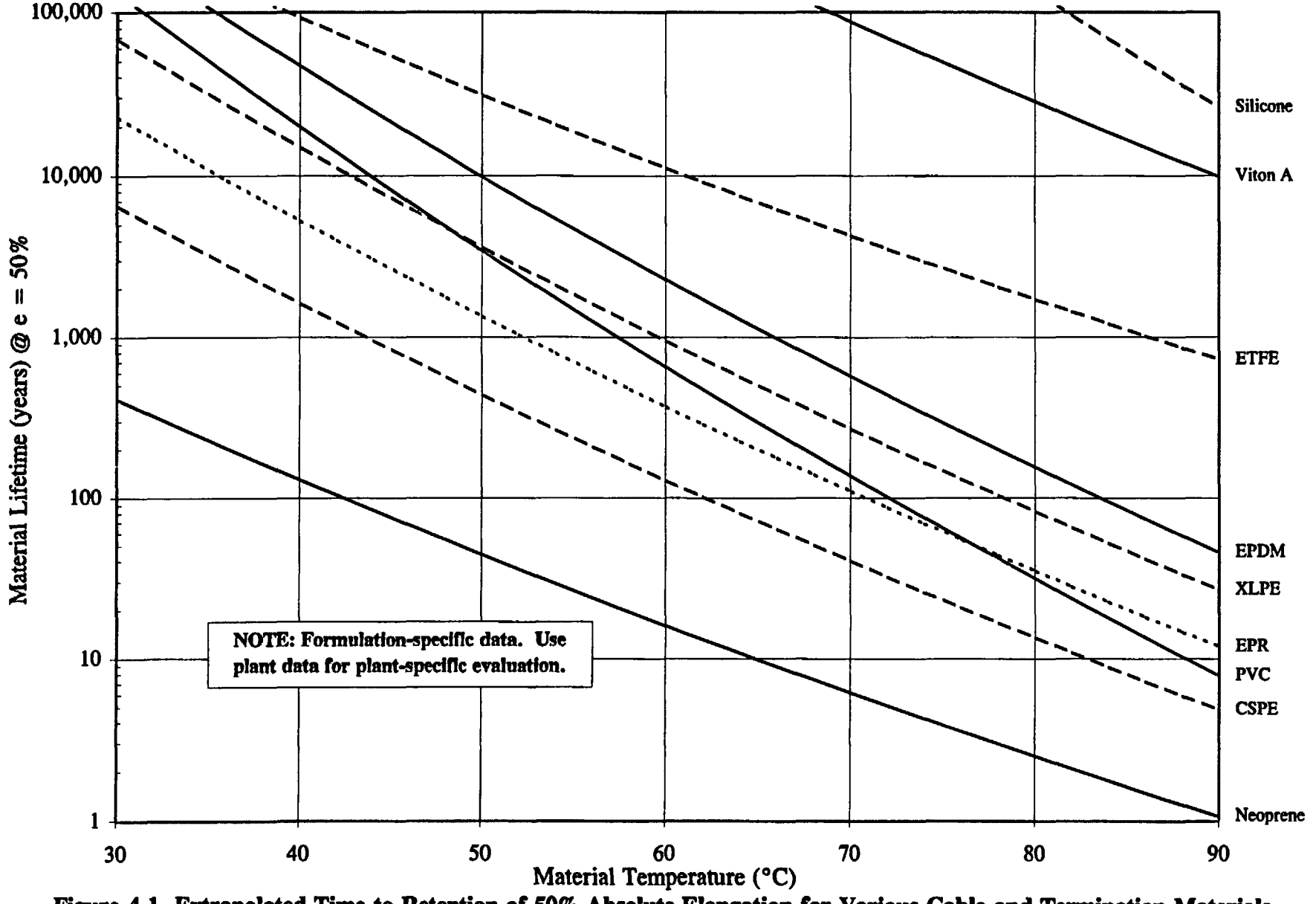

Figure 4-1 Extrapolated Time to Retention of 50% Absolute Elongation for Various Cable and Termination Materials

As shown in the figure, the thermally superior material is silicone rubber, where the extrapolated time to 50% absolute elongation is in excess of 10^4 years at 90°C. Clearly, the common insulation materials [including EPR, EPDM, XLPE, silicone, and ETFE (Tefzel®)] have far superior thermal performance than the common jacket materials (CSPE, PVC, and Neoprene®)[6]. Viton (a common seal material) also shows exceptional thermal capability.

4.1.1.2 Sources of Thermal Stress

For most plant areas, normal (i.e., non-accident) general area temperatures result in slow degradation of cable materials over the entire length of cable exposed to that environment (i.e., bulk aging). Localized heat sources, however, may produce comparatively severe damage in a small section of the cable within a short period of exposure. Elevated temperatures caused by thermal stratification in the ambient air volume can age large sections of cable located at higher elevations within an enclosed space. Aging may also result from ohmic and eddy current heating of cable conductors and associated components. Each of these mechanisms is described in the following paragraphs.

Ambient Effects

Normal general area temperatures within various plant spaces result from the interaction of various influences, such as the types and number of heat-producing equipment in operation in that space; the number and lineup of heating, ventilating, and air conditioning (HVAC) systems in operation; the thermal conductivity of the bounding surfaces such as walls and floors; external (outdoor) temperature; and the temperature of adjacent spaces. These general area temperatures are controlled to remain within technical specifications or other established design limits for that space. Normal general area aging temperatures can be estimated through (1) examination of the plant's environmental study, which estimates a maximum value for each plant zone, or (2) use of installed temperature monitoring equipment. The maximum temperature values obtained from the plant environmental study are considered conservative (i.e., bounding) with regard to actual general area temperatures; hence, estimates of bulk cable aging based on these values may also be conservative. Temperature monitoring equipment (if installed) provides direct data for the representative general area temperature of a given space, assuming the detectors are installed in representative locations that are free from localized effects such as a direct heat source or ventilation air flow.

Localized Heating

Hot spots are a major concern to cable longevity because severe localized aging resulting in embrittlement and cracking of the jacket and insulation may occur. Hot spots affect portions of a given cable run, and the rate of material degradation due to hot spot exposure is generally significantly higher than that experienced in bulk aging. The rate is dependent on the nature of the cable materials (some are more heat resistant than others), the intensity of the heat source and the cable's proximity to it, and the existence of any mitigating factors such as shielding or

[6] Note that the thermal lifetime of polyimide (Kapton®) is estimated to be nearly 10^4 years at 90°C and 0% relative humidity; however, its estimated lifetime at 100% relative humidity (or submerged) is only in the hundreds of hours [4.25].

ventilation. Localized aging caused by hot spots is of more immediate concern due to the potential rapid aging; degradation and possible loss of functionality may occur relatively rapidly for cables exposed to hot spot conditions. Furthermore, as described above, short-term degradation effects (such as melting and flowing, crystallization, and thermally induced mechanical stresses) may result from severe localized heating. It should be noted that most localized aging or degradation will occur at or near the connected end device, because this represents the most significant heat source for most circuits. Typical locations where cables/terminations may be exposed to hot spot conditions include main steam isolation valves (MSIVs), safety/relief valves (SRVs), pressurizer cubicles (in PWRs only), in the vicinity of steam piping (radiant heating) or steam leaks, and areas with degraded HVAC.

Ohmic Heating

Another source of thermal stress on cable materials is ohmic (I^2R) heating resulting from electrical current. This phenomenon generally affects the entire cable run, although localized effects may occur.[7] As current flows through a conductor, heat is generated by the resistance of the conductor. I^2R losses and the rate of heat generation in cable conductors are related to a number of factors, including the resistance (or conductance) of the constituent conductor materials, the current being carried, and the presence of magnetic field interactions determined by the geometry and physical arrangement of the conductor(s) [4.21]. For a given conductor size, increased current will increase the heat generated by the conductor. The radial thermal gradient (ΔT) between the conductor and outer cable surface depends on several factors, including the thermal conductivity of the insulation and jacket (and any other components in between), their thicknesses, and the ambient temperature. Accordingly, ampacity limits (e.g., the design current carrying capability) for a given cable will vary based on the conductor size and resistance, cable materials, installation geometry, and ambient temperature in which the cable operates. Base ampacities are developed to ensure that the maximum temperature rating of the insulation material is not exceeded under the installed and operating conditions of the cable (including the use of 10CFR50 Appendix R fire wrap materials). Power cables are selected such that their base ampacity equals the rated full load current of the connected load multiplied by a "safety" factor (typically 1.15 or 1.25). This safety factor is included to address potential operation of the load above its rating or during periods of peak distribution system demand when voltage is reduced [current increases during low voltage conditions (brown out) since the same power is still required to operate a device (e.g., a motor)].

Relevant ICEA standards assume that all cables located in trays operate at their rated ampacity. Conduit ampacities are based on the use of the smallest possible conduit in which the cable(s) will fit; as conduit size is increased, heat transfer is improved and cable operating temperature lowered. Duct bank ampacities are based on the worst-case seasonal ground temperatures.

Under most conditions, therefore, the cables can be expected to operate at temperatures well below the thermal rating of the insulation. Other factors that may contribute to this general

[7] A second type of ohmic heating may occur due to the presence of leakage currents. In degraded insulation, leakage current through the dielectric may produce direct ohmic heating of the insulation. In severe cases, this heating may result in localized degradation of the insulation and eventual breakdown.

observation include (1) use of over-sized cable due to voltage drop and short circuit considerations, (2) cables to motors requiring less than their rated horsepower, and (3) margins applied for future load growth considerations. Exceptions to this general rule may include electrical faults (the cable may operate at temperatures above the insulation's continuous thermal rating but below its short circuit thermal rating) and accident conditions [such as loss-of-coolant accident (LOCA)] where the ambient temperature exceeds that considered in formulating the base ampacity.

Thermal aging resulting from conductor ohmic heating is potentially significant in power cable applications where the connected load is operated for a significant percentage of its installed lifetime and the current during such operation is a substantial percentage of the ampacity of the cable. Note that ampacity is a function of ambient temperature; therefore, the ambient environments through which the cable passes must be identified to calculate the cable operating temperature and associated aging effect. Intermittently operated, low duty factor loads at high current may result in substantial aging of the associated cable. Loads run continuously at operating currents that are small relative to the ampacity of the cable will result in little cable aging. Instrumentation and control circuits characteristically operate at such low currents that no appreciable ohmic heating occurs. Based on the conservatisms and factors accounted for in the determination of cable, tray, conduit, and duct bank ampacities, and the large number of nonpower applications, very few plant circuits are expected to experience any appreciable amount of ohmic heating-induced aging. Note also that, because the conductor is in direct physical contact with the insulation, the aging resulting from conductor ohmic heating occurs "inside-out" and that this aging may be limited by poor oxygen diffusion to the interior portions of the insulation. Appendix G and IEEE S-135 [4.22] provide additional guidance on estimating conductor temperature for a given type of cable under prevailing environmental and load conditions.

Other circuits in direct proximity to the loaded circuit (e.g., located in the same raceway) may also be affected by the ohmic heating of the loaded circuit. This effect results from heating of the nonloaded cable insulation through direct contact and heating of the surrounding airspace within the conduit. Therefore, the thermal aging of all conductors (loaded or unloaded) in the same raceway as the suspect cable must also be considered. Section 4.1.1.3 and Appendix G provide additional information and guidance regarding the evaluation of individual circuits for potential ohmic heating-induced aging.

In addition to the conductor, ohmic heating of other conductor and termination components may occur due to a variety of phenomena. Corrosion, oxidation, insufficient contact pressure, and improper swaging or crimping may result in poor electrical contact (high resistance connections/joints) between the cable conductor(s) and terminations, or between individual components within a termination conducting path. Organic components in the vicinity of this high resistance (such as cable or splice insulation) will undergo premature thermal aging compared with the rest of the circuit. If the rate of heating/temperature is extreme, more severe damage to the component(s) may occur.

Circulating Currents

Circulating currents may be induced in metallic components by virtue of varying magnetic fields in their vicinity. Magnetic fields are created by current flowing through a conductor; alternating current circuits will accordingly produce alternating magnetic fields. As the magnetic flux permeating the component varies, an electromotive force (emf) is established, which creates circulating current flow within the component. This circulating current may generate heat through ohmic losses in the shield [4.21]. For example, shielding installed in cable that is grounded at both ends may carry significant circulating currents and therefore be subject to appreciable heat. Cable ampacity tables [such as those in Insulated Power Cable Engineers Association (IPCEA) P-53-426/NEMA WC50-1976 [4.23]] are often corrected for the effects of such circulating current losses.

Seasonal Temperature Effects

Another factor that can affect cable system thermal aging is the variation in ambient temperature due to daily, seasonal, or operational effects. Throughout a given day, outside air (and water) temperature may vary significantly; also, solar radiant heat transfer may account for additional temperature rise in exposed components during daylight hours. Much larger ambient temperature variations may occur over the course of a given year; differences in air temperature of more than 50°C [90°F] are not uncommon for some portions of the country [4.21]. Operational temperature effects stem from significant changes in plant operating status, such as maintenance or refueling outages.

Minimum and maximum allowable temperatures are usually specified for most major plant spaces, and HVAC systems are operated so as to maintain these temperatures. However, in some cases, these temperature bands are not or cannot always be maintained. Hence, seasonal or daily variations in temperature within these spaces may be fairly large. Figure 4-2 illustrates seasonal temperature variations for various elevations in the primary containment of a typical U.S. nuclear plant. Note that the magnitude of the change from summer to winter for the plant shown is on the order of 14 to 17°C [25 to 30°F]. Figure 4-3 shows the variations for one elevation in a plant reactor building; similar yet smaller changes are evident. Seasonal temperature changes in other plant areas (such as service water pump houses or other structures separate from the reactor/turbine buildings) may have larger variations in ambient temperature due to daily or seasonal effects because these spaces may have wider allowable temperature bands or no HVAC equipment. However, the effects of these latter variations are not considered of great importance from a cable system aging management perspective because (1) the relative fraction of the total plant cable population installed at these locations is usually quite low, (2) few if any EQ or safety-related circuits are located in such spaces, and (3) the maximum aging temperature to which these circuits would be exposed is generally well below that experienced in hotter areas of the plant (such as inside primary containment or steam piping tunnels).

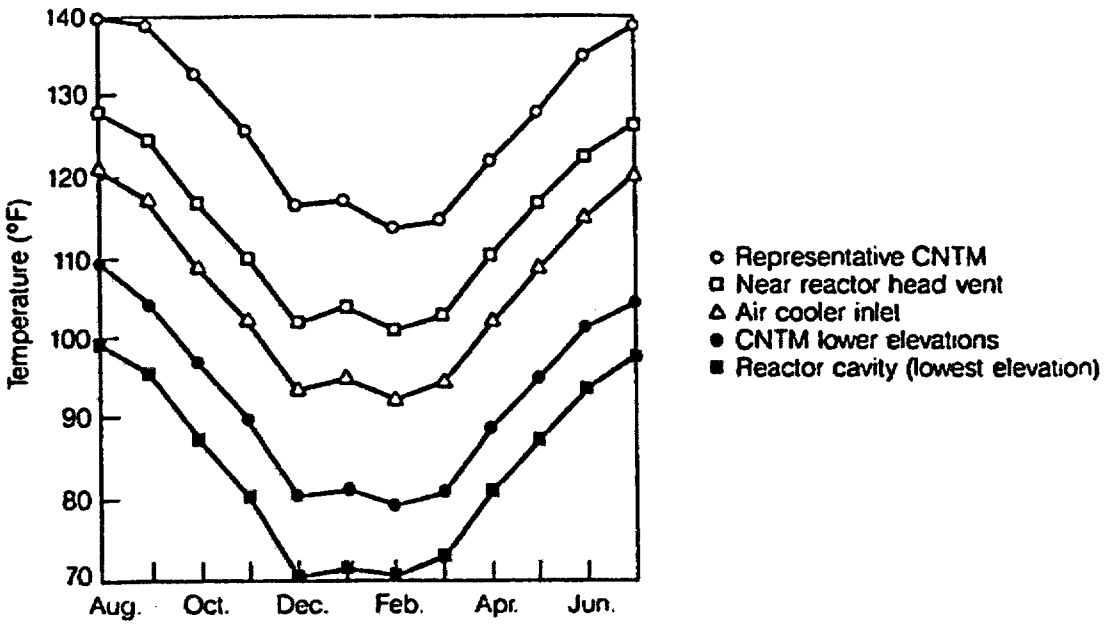

Figure 4-2 Seasonal Temperature Variations Within the Primary Containment of a Typical U.S. Nuclear Plant [4.24]
(Note: In the legend, CNTM is an abbreviation for containment)

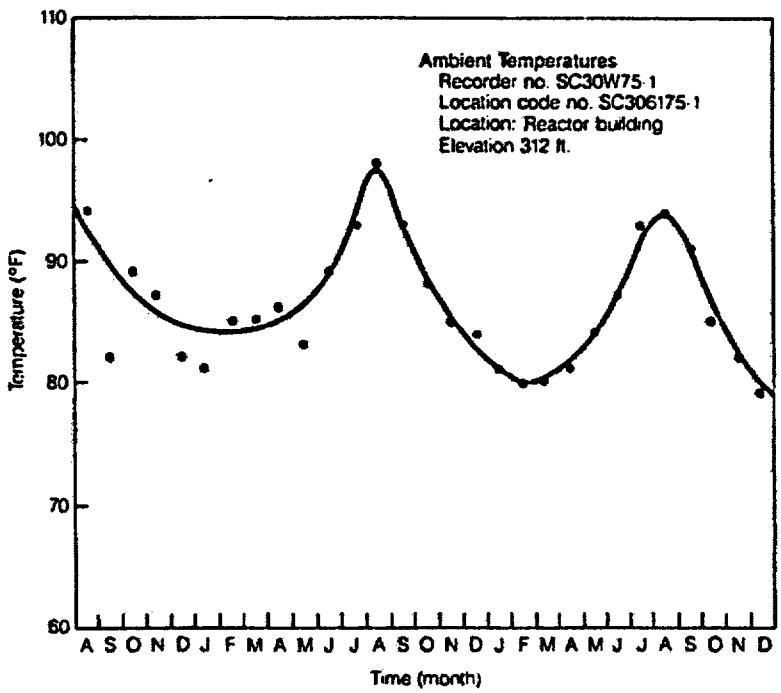

Figure 4-3 Seasonal Temperature Variations for a Single Elevation of Reactor Building of a Typical U.S. Nuclear Plant [4.24]

Changes in the ambient temperature in plant spaces are also largely a function of the operational status of the plant. Figure 4-4 shows variations in one plant's reactor building temperature as a function of time (and outages). Looking at the figure, a significant fraction of the lifetime of a given organic cable or termination component installed at this location will be spent at temperatures below 38°C [100°F]; the thermal aging occurring during these periods will be minimal, and the longevity of the component extended accordingly.

Thermally induced mechanical stress on cable and termination components may occur due to variations in component temperature with time. These variations may result from seasonal, daily, or operational changes in the ambient environment or current loading of an individual circuit. As the temperature of the cable/termination changes, various stresses can be produced by the interaction of components with each other or with surrounding equipment or structures. These stresses are considered mechanical in nature, and are discussed in subsequent sections of this AMG.

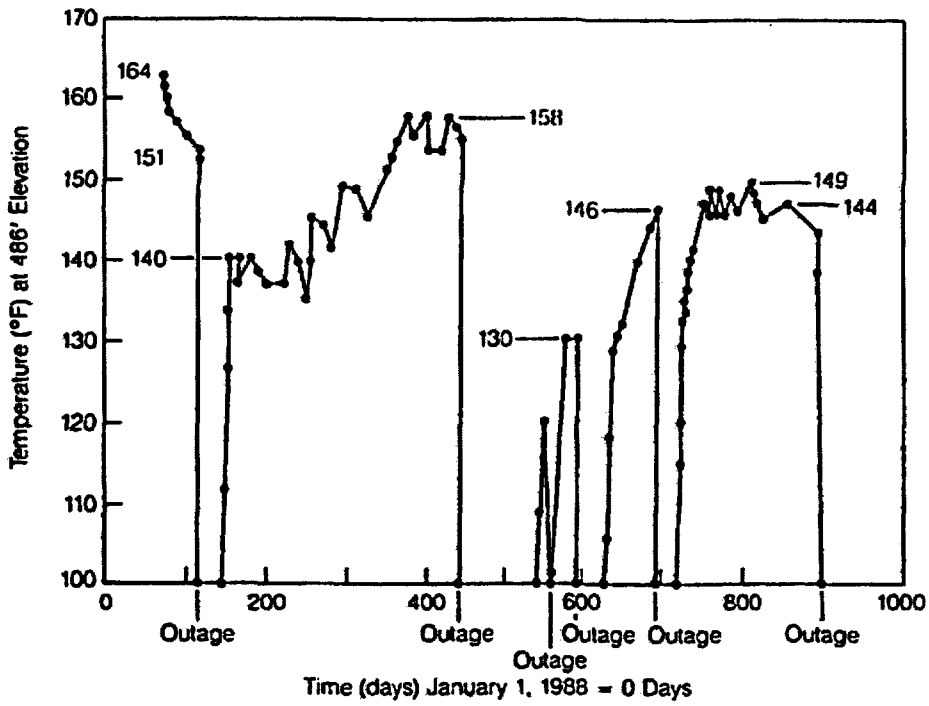

Figure 4-4 Operational Temperature Variations for a Single Elevation of a Reactor Building of Typical U.S. Nuclear Plant [4.24]

4.1.1.3 "If-Then" Criteria for Thermal Stressors and Aging Mechanisms

Table 4-1 lists the "if-then" criteria applicable to thermal stressors and aging mechanisms. Similar tables are presented for other stressors and aging mechanisms in subsequent sections of the AMG. For some of these stressors/aging mechanisms, no specific quantitative guidelines

can reasonably be formulated; therefore, qualitative criteria are included in these instances. As a general rule, any quantitative criteria are set with sufficient conservatism that the functionality of the component will not be affected (based on an assumed 60-year period) if the criteria are not exceeded. For example, the recommended maximum ambient temperatures for each generic material type (Table 4-2 and Appendix G of this document) are derived based on an endpoint of 50% retention of absolute elongation, which is conservative with respect to continued cable insulation and/or jacket functionality during a design basis event.

It should be emphasized that the thermal aging criteria of Table 4-2 are meant only as a general guideline, and are not a replacement for more substantive evaluation based on the underlying stressors applicable to a given plant location and the specific types of materials in use. The model used to develop these guidelines (e.g., Arrhenius) may not explicitly consider the effects of radiation, long-term oxygen diffusion, or combined aging environments.[8] Therefore, caution must be exercised in their application. Accordingly, these criteria should only be applied in low dose-rate environments (less than about 0.02 Gy/hr [2 rad/hr], or roughly 10 kGy [1 Mrad] over 60 years) where thermal aging predominates[9] [4.6].

Note that Table 4-1 and similar tables which follow, where applicable, identify other coincident stressors or environmental conditions that may either be necessary for certain types of degradations to occur or may accelerate their effects. In this manner, significant combinations of stressors may be identified. At the end of this section, Tables 4-14 through 4-18 identify aging mechanisms and effects that are considered significant (i.e., that potentially affect functionality) for each cable and termination subcomponent in Section 3.5.

Table 4-2 differentiates between the maximum recommended temperature for the material based on a 60-year lifetime and the maximum recommended ambient (general area) temperature for power cable applications where the material is used as conductor insulation. The difference between the two stems from the additional temperature rise of the enclosed conductor due to ohmic heating. As discussed in Appendix G, the latter value assumes a continuous and high relative loading (80% of ampacity), and is therefore somewhat conservative. Ratings for each insulation material were chosen based on ICEA standard requirements and/or manufacturer's product data. Note that these ratings may vary for cables of the same insulation material (e.g., three different types of silicone-insulated cables may have continuous ratings of 90°C, 120°C, and 150°C, respectively). Furthermore, the effects of ohmic heating are only significant for power cables; therefore, for instrumentation or control cables, the maximum recommended material temperature will be more applicable in evaluating circuit longevity.

[8] Section 4.1.6 provides additional information on combined thermal and radiation aging environments.

[9] As discussed in Section 4.1.4, the radiation damage threshold for most cable/termination materials is on the order of 10 kGy [1 Mrad]. Furthermore, the analyses described in Section 4.1.6 predict that the time to reach elongation endpoint (TED) is relatively invariant at this dose rate for most materials [4.6].

Table 4-1 Thermal Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Ambient heating (in oxygen environment[1]) (4.1.1.2)	Thermal and thermoxidative degradation	Embrittlement / reduced elongation[2]; variations in tensile strength; loss of antioxidant; loss of plasticizer	- Hard or brittle jackets, insulation, or other organic components - Spontaneous/bending-induced cracking of outer jacket or insulation - Material discoloration or crazing - Conductor discoloration - Shrink-back at joints - Increased compression set	All cable and termination organic materials (Note: Butyl rubber may soften with increased thermal exposure)	See Table 4-2[3]	Continuous (60 years)	Thermal aging of each material is a function of the applicable activation energy. Activation energy will vary somewhat within a generic class of material based on differences in formulation. Other factors (including oxygen concentration, aging temperature, etc.) also affect rate of thermal degradation.
Ohmic heating (in oxygen environment) (4.1.1.2)					See Figure 4-1	Assumes continuous energization	Curves may be adjusted for less than continuous energization; see Appendix G
Localized heating (in oxygen environment) (4.1.1.1.1; 4.1.1.2)					See Appendix G	See Appendix G	Measured at cable/component surface; reduces maximum potential thermal lifetime

Notes:

1. The term "oxygen environment" refers to normal prevailing atmospheric conditions (such as those found outside of primary containment) where the relative oxygen concentration is approximately 20%. As discussed in Section 4.1.5, as oxygen concentration is reduced, the rate of thermal or radiation-induced oxidative degradation is reduced accordingly for most materials.

2. Note that for certain materials, chain scission effects dominate, and increases in elongation may occur with increased thermal aging.

3. Maximum temperature may vary. See Figures 4-2, 4-3, and 4-4.

As an example of the application of the guidelines contained in Table 4-2 and the Arrhenius data in Figure 4-1, consider a 90°C rated, Neoprene®-jacketed, XLPE-insulated power cable installed at a location where the ambient temperature is 45°C (113°F). After 60 years, the insulation will reach 50% absolute elongation; however, the jacket will have degraded beyond the 50% absolute elongation threshold well before 60 years of operation. If the integrity of the jacket is required throughout the 60-year operating period, the lower temperature (14°C [57°F]) associated with Neoprene® must be considered. If jacket integrity is not required, then the less limiting insulation temperature may be used.

From a plant spaces approach (see Section 6), circuits contained in spaces whose degradation-weighted average ambient temperature is below the applicable value from Table 4-2 (e.g., 45°C [113°F] for the XLPE-insulated, power cable described above, assuming jacket longevity is not critical) can be eliminated from further consideration. Note that the application of the Table 4-2 guidelines will be somewhat over-inclusive. That is, all power cables that operate in ambient environments greater than or equal to those in the table will not reach the stated endpoint criterion before the expiration of 60 years, because the assumptions made in the derivation of these values (i.e., continuous operation at 80% of rated load) may be conservative. Few if any cables are expected to actually operate near this loading, especially when considering the effects of plant outages and other interruptions in operation.

However, by knowing the maximum allowable temperature for a given material that equates to a 60-year estimated thermal lifetime, the allowable fraction of rated ampacity for a given ambient temperature can be estimated (see Appendix G). This information can then be used to identify those circuits that are potentially at risk for reaching the endpoint criterion (50% absolute elongation) before the end of 60 years. Figure 4-5 illustrates how constant ambient temperature and constant electrical loading affects cable thermal life for the cable insulation materials listed in Table 4-1. Because the maximum allowable material temperature for a 60-life is fixed, the allowable electrical loading for any given material (and thus the I^2R heating of the cable) decreases as the ambient temperature is increased. In the figure, Neoprene® has the least thermal endurance and silicone rubber and Viton A have the most thermal endurance.[10] See Appendix G for more information on the effect of cable loading on thermal life, including an analysis of cables that are subject to variable service conditions during their life. The effects of fire wrap material or other cable configuration effects are not directly considered in this analysis; however, derated ampacities due to these factors may be substituted into the appropriate equation in Appendix G to analyze how the curves would change.

[10] The silicone rubber actually has greater thermal endurance than the Viton A even though Figure 4-5 appears to show the opposite. This is because the cable thermal ratings of the two materials are different; the silicone rubber cable operates at 120°C when at 100% of its rated ampacity, whereas the Viton A is only at 90°C.

Table 4-2 Recommended Maximum Ambient Temperature for a 60-Year Life Under Purely Thermal Aging Conditions

Generic Material Type[1]	Instrumentation and Control[2] Cable Recommended Maximum Ambient Temperature[3]		Power Cable[4] - Recommended Maximum Ambient Temperature @ 80% of its 30°C Ampacity[3]		Assumed Cable Thermal Rating - Dry
CSPE (Hypalon®)	66°C	152°F	31°C	88°F	90°C
EPDM[5]	88°C	190°F	50°C	121°F	90°C
EPR	75°C	167°F	39°C	101°F	90°C
ETFE (Tefzel®)	122°C	252°F	57°C	135°F	90°C
Neoprene®	47°C	117°F	14°C	57°F	90°C
PVC[5]	76°C	168°F	39°C	102°F	90°C
Silicone Rubber[5]	133°C	271°F	66°C	150°F	120°C
Viton A	147°C	297°F	77°C	171°F	N/A
XLPE/XLPO[5]	83°C	181°F	45°C	113°F	90°C

Notes:

1. Data are formulation specific. Use plant data for plant-specific evaluations.
2. For cables that have no ohmic heating, tabulated ambient temperatures are equal to the maximum recommended material temperature.
3. Based on 50% retention of absolute elongation (see Figure 4-1).
4. See Appendix G for derivation of maximum recommended temperatures for cable applications. Tabulated temperatures are for copper conductors.
5. See Table G-1 for end-of-life conditions for EPDM, PVC, silicone rubber, and XLPE.
6. The longevity of polyimide-insulated (Kapton®) wire varies greatly with temperature and humidity. Applying the methodology of Appendix G to the data contained in Table 4-3 of EPRI NP-7189 [4.25] yields a maximum 60-year equivalent temperature of greater than 100°C for dry cable applications [0% relative humidity (RH)]. However, for 100% RH conditions, Kapton®-insulated wire may fail well before 60 years at 20°C.
7. If the material is used as a jacket, then the maximum ambient temperature can be exceeded unless jacket integrity is required (e.g., for beta radiation shielding, to protect the cable insulation from moisture). Generally, the cable jacket is only required for physical protection of the insulation during cable installation and the insulation's properties would be used to determine the cable's lifetime.

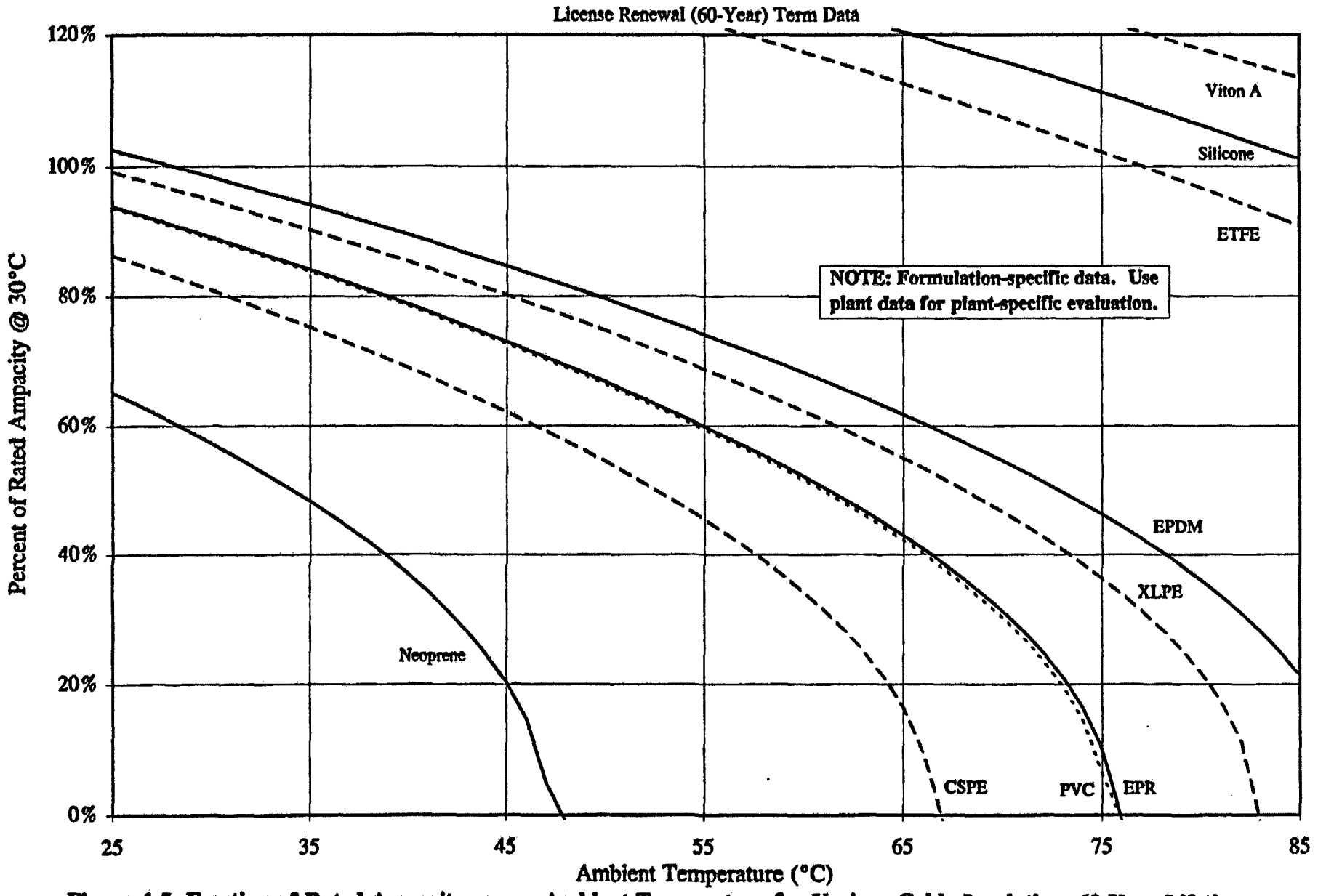

Figure 4-5 Fraction of Rated Ampacity versus Ambient Temperature for Various Cable Insulation; 60-Year Lifetime

As an example of this methodology, consider an XLPE-insulated power cable located in a 60°C [140°F] ambient environment. Per Table 4-2, 60°C would exceed the maximum recommended ambient temperature for a 60-year lifetime (45°C at 80% of its 30°C ampacity), thereby making this cable a candidate for further evaluation. From Figure 4-5, the cable could be operated continuously at up to ~60% ampacity over a 60-year period and the XLPE insulation would still exceed the 50% retained absolute elongation criteria. Therefore, if the circuit is determined to operate below approximately 60% of its 30°C ampacity, the insulation may be eliminated from further consideration.

For cable or termination components that are not exposed to appreciable ohmic heating (e.g., seals used in instrumentation circuit connectors), the I&C cable maximum recommended ambient temperature value from Table 4-2 can be used to determine whether the component is a candidate for further evaluation. Note that for seals and similar components, the compression set of the material is another useful measure of remaining life. Compression set data (such as that contained in Du Pont Report E-46315 [4.26]) can be used in place of the elongation endpoint data described above to generate an analogous estimate of the maximum recommended temperature for the compression set endpoint chosen.

4.1.2 Electrical Stressors and Aging Mechanisms

Stressors associated with the electrical functions of cable and termination components may also lead to age-related degradation. Electrical stresses on cable system components are caused by continuous energization at normal voltage and current levels, and by extreme voltage gradients from over-voltage transients, spikes, and fault interruption. The following topics associated with electrical stresses and aging are discussed in the succeeding paragraphs:

- Energization at normal voltage levels
- Transient conditions
- Partial discharge
- Effects of moisture and contaminants
- Water treeing
- Indications of electrical degradation
- Effects of high potential testing on XLPE-insulated cables

4.1.2.1 Energization at Normal Voltage Levels

Energization at normal design voltage levels can electrically stress cable insulation over the long term; the amount and severity of this stress is determined primarily by the dielectric strength and thickness of the insulating material used, and the operating voltage and frequency.[11] In general, an inverse relationship between the time to failure (breakdown) of an insulating system and the voltage (stress) has been observed. Two mathematical models commonly used to express this relationship are the exponential and inverse power models [4.27].

[11] Cables are designed to specific voltage ratings that always exceed the cable operating voltage (e.g., cables used in 4160-V systems are rated at 5 or 8 kV).

The exponential model is described by the equation:

$$L = C\, e^{-(V - V_t)},\ V > V_t$$

where:

L	=	lifetime, time to failure at voltage V.
V_t	=	threshold voltage, a constant
V	=	operating voltage, a constant
C	=	time to failure at an operating voltage equal to V_t, a constant

Note that a threshold voltage (V_t) is used such that breakdown may only occur when the applied voltage is greater than the threshold.

The inverse power model is described by the equation:

$$L = kV^{-N}$$

where, L is the time to breakdown at constant voltage V, and N and k are constants. A threshold voltage may also be incorporated in the inverse power model.

As with the Arrhenius thermal aging model described previously, several limitations are inherent in the application of the exponential and inverse power models. Constants used in each model are experimentally determined and material specific, and extrapolation beyond the experimental conditions may produce non-representative results (e.g., if a discontinuity in the relationship exists due to the effects of another physical process). Furthermore, the time to breakdown at a specific voltage stress level may vary significantly for several seemingly identical samples; this relationship often may be represented by a probability distribution (such as Gaussian or Weibull). Hence, caution must be exercised in attempting to estimate the longevity of a given application based solely on voltage stress. The literature [4.27] and [4.28] provides additional information on accelerated testing and the evaluation of electrical aging effects on various insulation systems. Additionally, the data [4.27] would tend to indicate that insulation breakdown due to energization at normal operating voltages is of much less concern for low-voltage cable, based on the comparatively low applied voltage stress[12].

Another consideration relates to the presence of impurities in the insulation. For a potential gradient across a stack of equal thickness layers of differing materials, the voltage drop across each of the layers varies inversely with the material's dielectric constant; the highest fraction of voltage drop will occur across the material of lowest dielectric constant. Thus, materials with

[12] For example, Figure B3 of IEC Report 727-1, Part 2 [4.27] shows an estimated voltage endurance in excess of 100 years at a voltage stress of approximately 5 kV/mm (roughly 127 V/mil), which is well in excess of typical operating voltage stress levels for low-voltage cable.

lower dielectric constants will usually be limiting in terms of the overall effective dielectric strength of the insulation system. The dielectric constant of gas or other impurities entrained in the insulation may be low in relation to the surrounding insulation; hence, a larger voltage drop occurs across the impurity, causing a large stress. This can cause localized ionization and breakdown at the inclusion site, which may rapidly degrade the insulating material [4.21], [4.29], [4.30], [4.31]. This effect is generally significant only for medium-voltage cable insulation due to the higher voltage stress present at normal operating voltages.

4.1.2.2 Transient Conditions

Voltage and current surges are characterized by rapid magnetic field generation and collapse and the production of large potentials in the insulation, which can place substantial stress on the dielectrics of the cable and associated terminations. Inductive surges and other electrical transients resulting in high potentials can cause stressors that contribute to breakdown of insulation and other dielectric materials. When an electrical pulse or surge is applied to a cable, the voltage does not distribute uniformly throughout the length of the cable instantaneously and some portions of the insulation may be stressed more severely than others. These stressors can ultimately result in localized degradation or breakdown of the insulation, causing shorts or flashover to ground [4.21].

Voltage or inductive surges may affect both low- and medium-voltage systems. Loads such as dc motors and large solenoids can produce significant inductive voltages on low-voltage systems. If preexisting degradation or defects in the insulation are present, these defects may be significantly exacerbated by exposure to large voltage spikes or surges, so that failure of the cable occurs much earlier than would otherwise be the case [4.32], [4.33]. This is particularly true of medium-voltage systems, which are exposed to a higher normal operating voltage level.

Voltage and current surges occurring in electrical cable systems and their connected loads may be produced through a variety of mechanisms, including electrical switching (bus transfers), fault interruption, blowing of current-limiting fuses, or lightning [4.31]. In such cases, higher dielectric stress is imposed on insulating materials, and greater ohmic heating of the conductor, surrounding insulation, and associated terminations can result. Bus transfers may be either manual or automatic; automatic bus transfers are fast or slow. Manual or operator-induced bus transfers occur on a regular basis for various circuits. This switching is usually conducted in a controlled manner; loads (current) are minimized and phases synchronized so that the severity of the resulting electrical transient is minimized. Similarly, slow automatic bus transfers do not generally create large voltage surges. Fast automatic bus transfers, on the other hand, can create significant voltages because the bus and source voltage may be out of phase. Bus transfers are normally accomplished via medium-voltage circuits and switchgear, thereby "insulating" low-voltage systems from the surge. In addition, transients experienced in low-voltage systems (such as those resulting from load starting/stopping, etc.) are less severe and small in comparison with the rating of the cable and associated termination. However, medium-voltage systems may be directly exposed to comparatively high voltages created by bus transfers or other voltage transients. Furthermore, some medium-voltage switchgear (such as vacuum breakers) have the potential to produce significant transient voltages.

Transient voltages are also influenced by the grounding scheme (if any) on a particular distribution system. Systems that are ungrounded or grounded via high-impedance pathways can experience higher transient voltages.

Electrical faults may produce extremely high currents in both low- and medium-voltage cable systems. These transients are considered in the design and selection of electrical system components (such as electrical cable, terminations, and switchgear); nonetheless, aging of cable insulation occurs through voltage stress[13] [4.21]. Voltage stress results from the near-instantaneous interruption of current flow through the conductor upon termination or clearance of the fault, and can peak at levels well in excess of normal operating voltages. Repeated exposure to fault current or electrical surges may reduce the longevity of the insulation (as well as other cable and termination components) due to cumulative voltage stress.

Lightning strikes may create severe overvoltage conditions; voltages in excess of 500,000 volts and currents greater than 200,000 amperes are possible. In addition, the current may build up at rates as high as 10,000 amperes per microsecond [4.31]. Lightning-induced surges have steep wave fronts that travel along the conductors away from the strike location in both directions. Lightning or surge arresters are typically installed so that they mitigate the effects of the voltage/current surge (see, for example, ANSI/IEEE Standard 142-1982 [4.34]). Most power plant cable is not subject to lightning-induced surges; however, most cables are designed with sufficient basic impulse insulation level (BIL) capability to withstand the voltage stress resulting from most of these events. This capability is typically expressed in terms of voltage withstand capability (i.e., 110-kV BIL for a 15-kV power cable) and is somewhat higher for cable than that of other electrical distribution equipment. Terminations are generally matched to the performance of the cable system (see, for example, IEEE Standard 48-1975 [4.35]).

4.1.2.3 Partial Discharge

Another phenomenon that can degrade electrical cable insulation is internal partial discharge. Also known as *corona*, this effect results from large potential gradients between materials separated by air or similar media. A high voltage gradient results in ionization of the air between the materials, which permits the air to act as an electrical conductor. If the gradient is sufficiently large and the separation sufficiently small, complete dielectric breakdown may occur. Partial discharge can occur between conducting components internal to the cable structure or between insulators separated by a gaseous medium. Partial discharges are usually extinguished when the large voltage difference inducing its formation is reduced; however, the dielectric quality of organic materials may be reduced during each subsequent discharge. As a result, subsequent discharges will occur at progressively lower voltage levels. This process can continue until the discharge extinction voltage level is less than the normal operating level, in which case the discharge will not extinguish and faulting will ultimately occur. If a conductive inclusion is in the insulation wall, the wall thickness will effectively be reduced and the localized stress increased, causing higher voltages across the remaining insulation.

[13] No significant thermal aging caused by ohmic heating is generally experienced due to the extremely short clearing times for most faults.

Partial discharge effect is generally of little concern for low-voltage electrical cables because the requisite voltage gradient necessary to ionize the interposing medium is not present. However, in medium-voltage applications, it may result in degradation of the cable material due to the higher voltage gradient [4.21], [4.30], [4.36], [4.37]. Medium-voltage cable insulation removed from service that has inclusions and voids often identifies the possibility of long-term partial discharge breakdown. The damage patterns identified in the insulation look like trees, thus the term "electrical treeing."

4.1.2.4 Effects of Moisture and Contaminants

In some cable applications, the combination of voltage and moisture can affect insulation that is dirty or deteriorated, resulting in surface tracking paths between conductor and ground, or conductor to conductor. Moisture allows leakage currents to flow across the insulation surface when a potential gradient exists. The leakage current flow will cause some of the moisture in portions of the tracking path to evaporate; however, the leakage current will tend to remain constant which increases the current density in the remaining tracking path. This can result in localized burning of the insulation and carbonization at the ends of the tracking paths and ultimately in insulation failure.

Water penetration into electrical cable insulation may also result in decreased dielectric strength. As water[14] permeates the insulation, the conductivity of the dielectric is increased due to the increased ion mobility and concentration. Increased conductivity results in an increased leakage current flowing either through or on the surface of the insulation; this current flow eventually produces insulation with a permanently degraded dielectric strength. Some insulation and jacket materials have extremely limited water absorption and permeation, and are therefore relatively unaffected. PVC is an example of a jacketing material commonly used in high moisture applications to help prevent radial ingress of moisture to the underlying insulation. Similarly, Tefzel® (ETFE), Hypalon®, and some other forms of polyethylene are highly resistant to moisture. Note, however, that water may penetrate the cable in a longitudinal fashion (such as at terminations) and propagate along the conductor, thereby rendering the moisture resistance of the outer jacket or insulation materials of little consequence.

As used in this guideline, the term "wetting" refers to a significant amount of moisture in contact with the cable/termination components, such as would be produced by repeated instances of standing water, system leakage/spray, or flooding. Note, however, that even minor and/or intermittent surface condensation, in conjunction with voltage stress and contaminants, may create an environment where surface tracking may occur. Furthermore, some evidence exists to indicate that the rate of diffusion of water through a polymer is relatively independent of form [4.38]. Therefore, the water diffusion rate for a "dry" material in a 100% RH atmosphere may not be much different than that for the same material completely submerged in water. Also, as temperature increases, the diffusion rate generally increases as well [4.38]. Hence, water diffusion through a material would seem to be worst in a hot, wet (or humid) environment.

[14] Pure water is a good insulator. However, most water sources contain sufficient impurities to be conductive.

Table 4-3 shows the results of ICEA EM-60 water resistance testing of various cable and termination materials as specified in applicable ICEA cable standards such as ICEA S-66-524 [4.39]. This test involves the submergence of an insulated conductor in high temperature (75°C or 90°C) water for several days while the capacitance and power factor of the insulation are measured. Although these results may not be useful in directly predicting the longevity of a given insulation material in wet environments, they do provide some indication of relative performance. Data for other materials (such as CSPE, PVC, and Neoprene®) are contained in EPRI TR-103834-P1-2 [4.38].

Table 4-3 Insulation Life at 90°C During ICEA EM-60 Testing [4.38]

Material	Time to Failure
Natural Rubber	<24 hours
Silicone Rubber	3-4 months
Butyl Rubber	9 months
EPR	47 months
XLPE	35 months
ETFE (Tefzel®)	>24 months

Moisture may also result in corrosion or oxidation of cable or termination components. The effects of moisture on metallic cable/termination materials are analyzed in Section 4.1.5.3.

Contamination of the cable/termination may also occur during the manufacturing process. This is particularly critical for cable insulation, especially that used on medium-voltage power cable, due to the comparatively high voltage stress that this insulation experiences. Inclusions or voids within the insulation tend to increase the dielectric stress across the void or inclusion, so that the insulation immediately surrounding the problem area is more rapidly degraded via the effects of partial discharge. Failures of medium-voltage cable have occurred at some utilities, and have been traced to manufacturing defects and/or insulation contamination exacerbated by moisture intrusion [4.38], [4.40], [4.41], [4.42].

4.1.2.5 Water Treeing

Water treeing is a degradation and long-term failure phenomenon that has been documented for medium-voltage electrical cable with certain extruded polyethylene insulations and EPR insulations. Water trees occur in hydrophobic polymers used as insulating materials when the materials are exposed to electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. Water trees are a degradation mechanism distinct from electrical treeing, which requires no water to proceed (see partial discharge discussion in Section 4.1.2.3). Despite the distinction, electrical trees are mistaken by many to constitute the final stage of water treeing.

Water treeing may occur in several insulation materials; however, it appears to be associated most often with XLPE or HMWPE insulation. The growth and propagation of water trees in medium-voltage cable insulation is somewhat unpredictable and erratic; hence, the longevity of affected cables is often indeterminate. Water treeing has historically been more prevalent in higher voltage cables; proportionately few occurrences have been noted for cables operated below 15 kV. This is likely due to the comparatively high electric field density and voltage gradient required for significant treeing to occur. However, water treeing in medium-voltage cable operated below 15 kV has been documented [4.38] and investigations are under way regarding EPR (e.g., [4.43]) and tree-retardant XLPE.

Chemical reactions induced by an electrical field cause water treeing. Electrochemical reactions are initiated at the surface of voids or inclusions where the polymer exhibits hydrophilic behavior (i.e., the moisture is condensed out of the polymer matrix). Initiation sites are located in certain regions of the polymer that result from inclusions/impurities, oxidation during compounding, or cable manufacturing. Ionic contaminants attract water to the region; an applied electric field stimulates reduction-oxidation reactions that deteriorate the polymer, thereby creating more polar sites near the polymer/water boundary. Some studies indicate that the purity of the water in the tree region is very high, thereby indicating a high dielectric strength [4.44].

Oxidation theories of water treeing hypothesize that water tree growth results from the electrical oxidation of the insulation polymer in polar amorphous regions and in the direction of the local electric field. As the oxidation occurs, polymer chain scission occurs and a "tree" is formed. As the process progresses, the polymer in the tree region is made hydrophilic, so that water is condensed from the polymer matrix. This water promotes the transport of ions to the tip of the tree, which further promotes oxidation in this region; hence, the water tree is self-propagating. Due to the relatively slow rate of propagation for this process, the effects of exposure to moisture may take several years to manifest themselves; by this time, the cable has usually degraded to the point of requiring replacement [4.45], [4.46], [4.47], and [4.48]. Figure 4-6 shows a medium-voltage power cable cross section with a typical water tree formation.

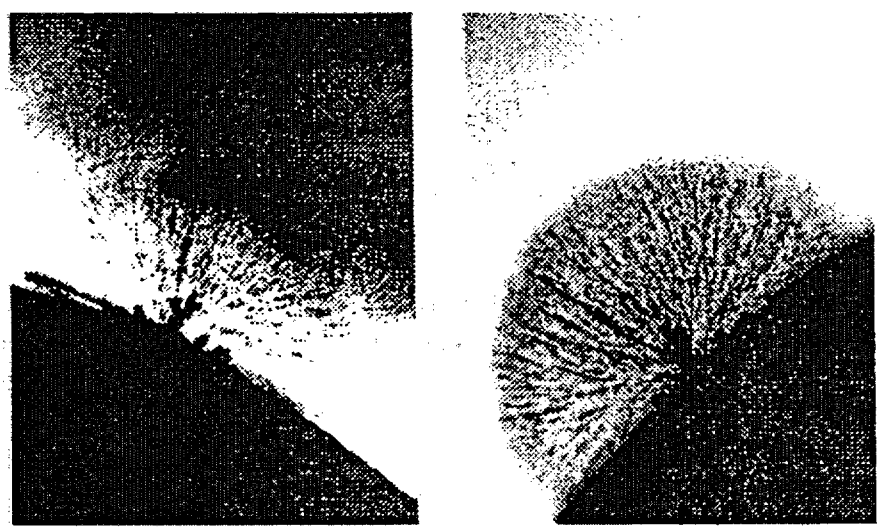

Figure 4-6 Water Tree Formation in Medium-Voltage Cable Insulation

In general, the following observations may be made regarding the growth and prevention of water trees:

- The formation and growth of trees varies directly with operating voltage; treeing is much less severe in 4-kV cables than those operated at 13 or 33 kV. Due to the low dielectric stress, water trees do not occur in low-voltage cables.

- Tree formation and growth is often related to both the void and impurity content of the insulation.

- Drying field-aged cables with inert gas and subsequent conductor impregnation with insulating liquids (such as Dodecanol or Acetophenone) may significantly extend cable life [4.47].

- No evidence that continued operation results in drying of the insulation/tree site, or that operation reduces the rate of treeing, was located in the literature. However, substantial evidence indicates that the operation of a submerged cable may create a "thermal barrier" and actually force water out of the insulation [4.38]. Recall, however, that increased temperature may also accelerate diffusion of water through various media (such as the outer jacket).

- Tree growth appears to be more prevalent in insulation materials that are subject to mechanical tension (as opposed to compression).

- Improved surge protection may extend the life of in-service cable [4.47].

- Water tree formation is generally negligible in low-moisture environments (i.e., it requires ingress of moisture/ions to the insulation). Accordingly, wetting or submergence of insulation that is susceptible to water trees for a sustained period should be avoided.

- Several water-tree retardant polymers [such as tree-retardant XLPE (TR-XLPE)] are currently available. In addition, longitudinally and radially water-blocked constructions are available to combat the ingress of water in the insulation material [4.49].

- The effects of temperature and oxygen concentration on tree initiation and formation are not well understood [4.47].

- Jackets and semiconducting shields may substantially reduce the ingress of moisture and ion migration, thereby reducing the rate of tree formation and propagation. New materials using ion scavengers may be effective at further reducing water tree growth.

4.1.2.6 Indications of Electrical Degradation

Evidence of electrical damage or continuing degradation due to the stressor/aging mechanism combinations described in Sections 4.1.2.1 to 4.1.2.5 may include one or more of the following [4.50]:

- Indications of tracking on surfaces near terminations
- Noise (ionization of air due to partial discharge; medium-voltage only)
- Thermal damage to insulation, jacketing, or other organic components in the vicinity of conductors or terminations
- Corroded, tarnished, or discolored inorganic (metallic) components such as cable conductors or terminations.

4.1.2.7 Effects of High-Potential Testing on XLPE-Insulated Cables

EPRI TR-101245 [4.33] documents EPRI research to determine the effects of dc high-potential (hi-pot) testing on the longevity of extruded XLPE-insulated medium-voltage cables. Direct current hi-pot testing is commonly performed on cables subsequent to manufacturing, for proof or acceptance testing after installation, or for maintenance/troubleshooting during service.

The results of this study indicate that dc hi-pot testing did not adversely influence the ac breakdown strength of unaged or artificially aged XLPE-insulated cables. The study did indicate, however, that hi-pot testing of artificially aged cables with reduced dielectric strength resulted in more rapid degradation than in similar cables not subjected to this testing. The study indicated that the effects of dc testing were most apparent on specimens that contained a new section of cable, a splice, and an aged section of cable. Also observed was an increased failure rate with multiple hi-pot test applications. Water treeing was also identified in most of the failure sites (note that the testing was performed with the cables submerged in water).

Thus, the report indicates that satisfactory ac breakdown strength is not necessarily indicative of the integrity of an aged cable's XLPE insulation. Furthermore, because the results indicate that dc hi-pot testing reduces the longevity of aged XLPE-insulated cables in wet environments, dc maintenance testing of such cables should be discontinued where feasible. However, acceptance testing of new or unaged cables may be performed without adverse effects.

Alternating current hi-pot exposes the dielectric medium to an alternating current at voltage levels that are substantially reduced over those used in dc hi-pot testing for a given duration (typically 5 min). This type of testing more closely approximates the stresses applied to the dielectric during normal operation. Cable insulation can sustain application of dc potentials at basic impulse insulation level (BIL) for extended periods without damage [4.31]; however, most insulating materials will sustain damage from ac overvoltage testing as a function of the overvoltage, time, and frequency of the ac signal. Accordingly, ac hi-pot is generally considered to be more likely to damage cable insulation and exacerbate existing defects than dc hi-pot testing [4.31]. Direct current hi-pot is therefore recommended for any repetitive post-factory testing application.

4.1.2.8 "If-Then" Criteria for Electrical Stressors and Aging Mechanisms

Table 4-4 summarizes the electrical stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components. Note that for many electrical aging mechanisms and effects, no quantitative or specific criteria can readily be developed. For example, the initiation and propagation of water trees in cable insulation depends on many factors, including water and ion concentration, voltage stress, temperature, electrical surges/transients, etc.; no "formula" for water treeing exists. Therefore, only the general environments or conditions that have historically produced this type of degradation are highlighted to alert the plant operator to the *potential* for treeing.

4.1.3 Mechanical Stressors and Aging Mechanisms

Mechanical stressors and aging mechanisms can be caused by a variety of conditions that occur during cable operation and installation. These stressors include vibration (including fatigue stress), thermal/gravity-induced mechanical stress, installation stresses, and external mechanical influences (such as incidental bending, cutting, or abrasion during maintenance or normal equipment operation).

4.1.3.1 Vibration

Vibration may result in fatigue of connection components, as well as cutting, wear, and abrasion of components. Vibration is generally induced by operation of external equipment, which can affect the cable connection, the equipment (such as a power lead connected to a running motor), or components or structures otherwise mechanically connected to the cable (such as cable trays or conduits that are vibrated by an external source). Vibration resulting from the direct connection of a cable/termination to the operating load may produce fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Vibration may also loosen the connection between the termination and cable conductor, resulting in high electrical resistance or separation of the termination from the conductor. Abrasion or cutting of the cable jacket and insulation (e.g., on sharp edges) by the motion of the connected load, nearby structures or components may occur over time, eventually reducing the mechanical (and electrical) integrity of the material and ultimately resulting in short circuits or moisture intrusion.

4.1.3.2 Gravity-Induced Cable "Creep" and Tensile Stress

Mechanical stress on cable and termination components may also result from the installed physical arrangement of these components and the effects of temperature variation and gravity. Due to the weight per unit length of electrical cable (often several pounds per foot for high ampacity cables) and various environmental influences, adequate support for the cable must exist in order to reduce the effects of tensile stress and elongation over time.

Table 4-4 Electrical Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Moisture (wetting); voltage (4.1.2.4, 4.1.2.5)	Water treeing	Tree formation; reduced dielectric strength and eventual breakdown	- Few if any apparent indications; may ultimately result in cable failure	Susceptible materials including nontree retardant XLPE and HMWPE	Medium-voltage cable subject to (1) regular submergence/wetting/ high humidity, and (2) operational voltage stress; jacketed cables at lower risk	Generally a long-term phenomenon	Treeing in aged XLPE cables may be aggravated by dc hi-pot testing
	Moisture intrusion	Reduced dielectric strength	- Reduced insulation resistance; flashover	Moisture-permeable materials[1]	Moisture-permeable materials located in wet/humid environments and exposed to voltage stress	Long- or short-term	Generally of little concern for low-voltage cable
Voltage (no moisture) (4.1.2.1, 4.1.2.3)	Partial discharge leading to dielectric breakdown; electrical treeing	Increased leakage currents; reduced dielectric strength	- Reduced insulation resistance - Visible or audible ionization - Flashover	All organic insulating materials	Medium-voltage applications with voids or air gaps in areas of high voltage stress (such as insulation/shield voids, between adjacent termination components, etc.)	Continuous discharges may rapidly create local degradation in insulating materials	Periodic discharges may gradually degrade insulating properties of material
Voltage stress, moisture, contaminants (4.1.2.4)	Surface tracking	Localized damage to insulation surface; reduced dielectric strength	- Formation of visible tracking paths or carbonization - Localized material discoloration	All organic insulating materials	Areas of high voltage stress with alternating wet/dry or continually wet conditions and substantial dust or dirt contamination; near terminations or electrical stress risers	May result in rapid degradation	

Table 4-4 Electrical Aging Summary for Cable and Termination Components (cont'd)

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Transient voltage stress (4.1.2.2)	Dielectric breakdown	Reduced dielectric strength	- Reduced insulation resistance; flashover to ground	All organic insulating materials	Circuits exposed to faults, repeated switching transients, lightning strikes	May result from one or numerous transients	Switching transients generally small in relation to lightning or electrical faults

Notes:

1. Moisture-permeable or absorptive materials may include acetals, polyimide (Kapton®), some acrylic resins, polyacrylic rubber, and some butyl and natural rubbers. Typical formulations of EPR/EPDM, SR, PE, XLPE, CSPE, and PVC all absorb very little water by weight, yet may be water permeable (see Section 4.1.2).

In vertical runs of power cable, the cable may "creep" with time as a result of the combined effects of the weight of the unsupported vertical cable run (gravity), thermal cycles resulting in expansion/contraction of the cable materials, and routing over a hard or sharp edge at the top of the run. Changes in cable operating temperature are the result of ambient temperature and loading changes. During periods of comparatively high cable temperature, the cable will elongate, permitting the cable to creep over the edge of the vertical drop (i.e., the upper horizontal portion of the cable will thermally expand, thereby permitting the weight of the vertical section to drag the additional length over the edge). During periods of relatively low temperature, the horizontal (and vertical) portions of the cable will contract, thereby attempting to drag the cable back over the edge; however, due to the weight of the vertical portion of the cable and the friction created by the edge over which the cable passes, the cable will not return completely to its original position. Accordingly, increased stress is placed on the portion of the cable at the top of the vertical drop as it contracts, as well as any terminations or splices in that segment of the cable. Repetitive thermal cycles may result in increasing creep and stress at the top of the cable segments/terminations. Ultimately, this stress can result in significant cable wall damage at the top of the run or tensile failure of the upper termination. Indications of this phenomenon include cutting and chafing of the cable jacket/insulation in the vicinity of overhang edge, increased tension on the terminations associated with the horizontal cable run, and pile-up of cable in the bottom of the vertical run. Figure 4-7 is a pictorial representation of this process.

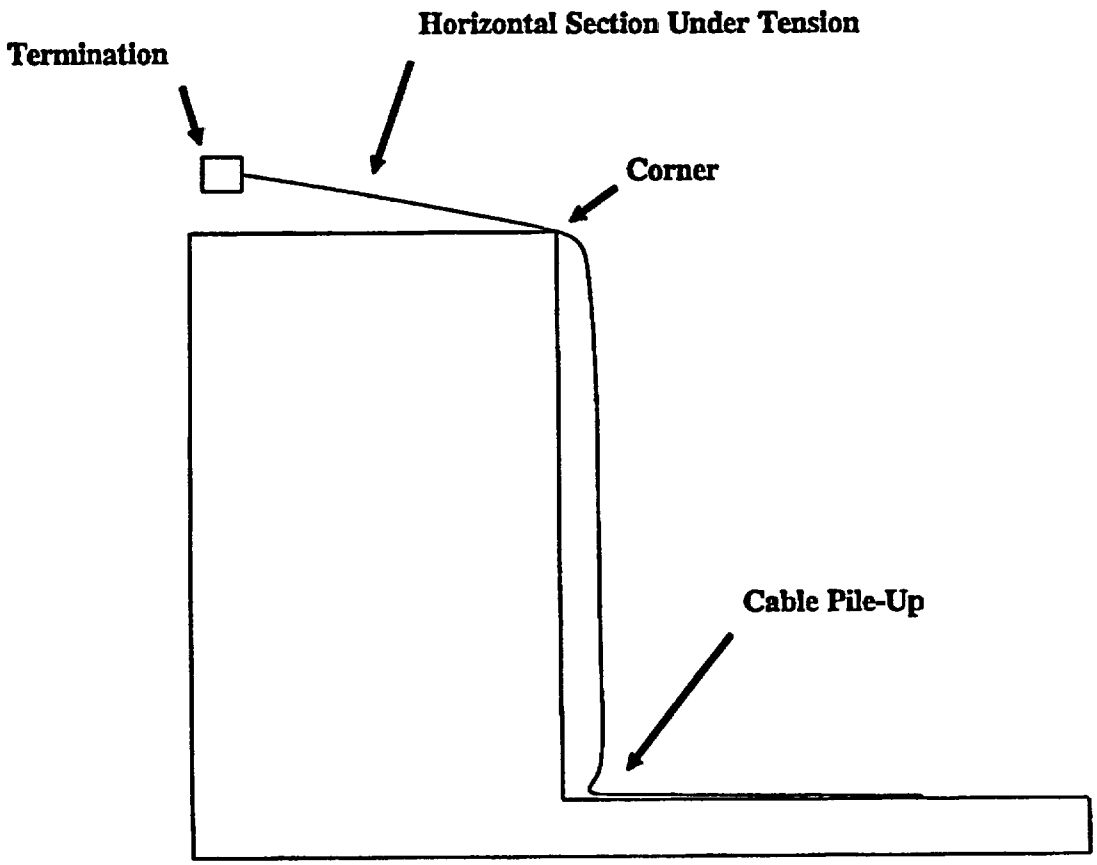

Figure 4-7 Cable Creep in Horizontal/Vertical Runs

A related aging mechanism occurs in right-angled conduit fittings (condulets) interfacing between a horizontal and vertical cable run. The weight of the vertical cable run combined with thermal expansion/contraction tends to pull the cable outer surface across the metallic inner edge of the condulet, thereby resulting in chafing and/or cutting of the cable. In addition, high tensile stress is placed on the horizontal sections of the cable inside the conduit.

To preclude this type of damage, an appropriate system to support the vertical segments and minimize the movement of the cable under thermal expansion/contraction may be used.

4.1.3.3 Compression

Organic materials placed in compression for extended periods may exhibit an effect known as compression set; this is based on the amount that a material fails to return to its original dimension or shape after compressive load is removed[15] [4.51]. This quantity is of primary interest for O-rings, seals, gaskets, and grommets (such as those used in sealed electrical connectors), because it can be related to the ability of the O-ring/seal to perform its design function, especially under situations where the device is disassembled and subsequently reassembled using the same O-ring. Exposure to heat, radiation, chemicals, oxygen, ozone, etc. can produce significant changes in the compression set of a given material. For most elastomers, compression set increases (indicating a loss of resiliency) with increased thermal and radiation exposure. It should be noted, however, that most plants replace such components each time maintenance or testing is performed, thereby obviating the need for further consideration of aging management. Specific information regarding the compression set of a particular material can be obtained from the component manufacturer; compression set properties for a typical seal material (Viton) are shown below [4.26].

Compression set is defined as:

$$set = \frac{t_0 - t}{t_0 - t_c}$$

where:

t_0	=	original, uncompressed thickness
t_c	=	compressed thickness
t	=	thickness after material recovery
0% set	=	total recovery
100% set	=	no recovery

[15] Compression set is defined in ASTM test D 395 as the residual decrease in thickness of a test specimen which is observed 30 minutes after the removal of a specified compressive load applied under established time and temperature conditions.

Percent Compression Set of Viton at Various Temperatures [4.26]

Time (hours)	At Room Temperature	At 300°F (149°C)	At 392°F (200°C)
1000	--	12%	50%
2000	--	16%	65%
4000	21%	22%	79%
8000	21%	32%	98%

4.1.3.4 Installation-Related Degradation

4.1.3.4.1 Cables

Degradation during cable installation is not an aging mechanism, but it can adversely affect the longevity of both low- and medium-voltage cable systems. Installation degradation is normally controlled or prevented through use of approved procedures, controls, and standards during cable installation. EPRI EL-5036 [4.29], Cablec's Cable Installation Manual [4.52], EPRI EL-3333 [4.53], and applicable IEEE standards provide guidance on the proper installation of cables in various applications. Installation damage usually occurs as a result of failure to use or properly implement such guidance.

Installation Damage Mechanisms

The pulling or bending of cables exerts either a tensile or compressive stress on many cable components; such bending or pulling normally occurs during the installation of the cable. Damage to the cable insulation resulting from cutting, chafing, or excessive stress during pulling cuts or tears the dielectric so that increased voltage stress occurs at the location of the damage; over time high stress accelerates the breakdown of the dielectric and may eventually result in cable failure (electrical fault). This effect may be aggravated by the presence of wetting, where water can permeate the damaged area in the dielectric and increase its conductivity. Indications of installation damage include elongation or twisting, cuts, rips, tears, abrasions, or "shrink back" (i.e., apparent shrinkage of the jacket near its terminations so that portions of the underlying components are exposed). Although visual indications will occur primarily on the jacket, they may also affect any underlying components such as shielding, wraps, or insulation. Note that installation-related degradation may exist with no external indications.

Sidewall Bearing Pressure

Sidewall bearing pressure is that compressive force applied to the side of the cable at the point of contact with the conduit or bend through which the cable is being pulled. Excessive sidewall bearing pressure may result in over-compression of, or damage to, the insulation/jacketing by the conductor or conduit. This is significant in that the primary source of sidewall bearing pressure is pulling tension during installation. The longer the cable and the

more tortuous the pulling path, the greater the likelihood for cable damage due to excessive sidewall bearing pressure. To avoid damage, cable installation procedures must establish controls for pulling tension. Two tension calculations are generally used: maximum allowable tension and the estimated pulling tension. Difficult pulls should be controlled by means of a tension-limiting device such as a dynamometer.

The minimum bend radius of the cable must also be considered during routing and installation. The larger the radius, the less tensile stress on components in the outer radius of the bend, and the less compressive stress on those in the inner portion. Shielded power cable generally requires special conduit due to its large minimum bend radius [4.29], [4.52], [4.53].

Pull-Bys

A pull-by is the installation of a cable in a conduit or duct where other cables are already installed. This process is potentially damaging to the existing cable in the conduit by virtue of the pulling mechanisms employed for the new cable being installed (such as ropes and swivels). Although pull-bys may be performed successfully by following strict guidelines, incorrectly performed pull-bys can result in damage to either the cable being installed or the existing cable in the conduit. Pull-by damage most frequently occurs at bends in the conduit system where a surface of an installed cable must bear the loading of the pulled cable. The resulting friction and cutting, generally by the pull rope, cuts through the installed cable. Also, the pull rope or cable being pulled can wrap around installed cables, resulting in a knot that will tear the installed cable's insulation if the pulling continues [4.29], [4.52], [4.53].

Jamming

Jamming is a condition under which three similarly sized cables pulled into a conduit experience a dramatic increase in the pulling tension required. The increase is the result of friction or binding between the outer surfaces of two of the cables with the conduit; this friction results from the third cable being forced between the other two so that the total diameter of the three cables is roughly equivalent to that of the conduit interior. Jamming may tear or crush the cable insulation due to the increased pulling tension. Jamming is of greater concern for larger power cables [4.29], [4.52], [4.53].

Incidental Cable Damage

In addition to the mechanisms described above, incidental damage to the cable may occur during, but not as a direct result of, the installation process. For example, cable may be degraded by abrasion, cutting, or similar mechanisms before actually being installed. This is especially true for softer insulations, such as silicone rubber, or those which are unjacketed. One utility contacted as part of this study indicated that it had experienced damage to braided silicone-insulated cable after the cable was removed from the reel (but before installation) due

to an apparent mechanical trauma (such as having a heavy object dropped on top of it while it was laid out).[16]

Effects of Installation Damage

Low-Voltage Cables

The effects of installation damage are generally less severe for low-voltage cable than for medium-voltage cable. Low-voltage cables experiencing almost complete insulation cut-through may not have a significantly reduced life (even in the presence of moisture) due to the low-voltage stress in relation to the dielectric strength (volt per mil) of their insulation. Even a few mils of insulation on a 600-V system are sufficient to provide the necessary dielectric strength to prevent significant leakage current through the dielectric (see, for example, the testing described in NUREG/CR-6095 [4.54]). In addition, the electric field strength intensity at any given point is not sufficient to create partial discharge across areas of locally high stress (such as voids or inclusions) in the insulation.

Medium-Voltage Cables

The stressor combination of installation damage and moisture appears to have a far greater impact on medium-voltage cables [4.38]. Failure data [4.38] indicate that a substantially higher rate of failure results in medium-voltage cables that have been damaged by being pulled through a raceway during installation and which operate in high moisture environments. Medium-voltage cable has voltage stress one or more orders of magnitude higher than that for low-voltage cable. Installation damage sites, voids, or inclusions may experience sufficient dielectric stress to create ionization (and its resulting degradation) within that area. Moisture present in this region will only increase the conductivity of the surrounding insulation, and eventually produce a failure at this site [4.55].

Damage to the cable jacketing, although not directly affecting the dielectric strength of the medium-voltage cable, may nonetheless affect its longevity. Once the integrity of the jacket has been violated, any moisture present on the jacket may permeate into the insulation via absorption or damage created coincident with the jacket damage [4.29], [4.52], [4.53], [4.56].

4.1.3.4.2 Terminations

As with cables, termination components may be degraded or damaged during installation. This degradation may result from improper assembly or installation practices and/or incidental damage. Types of degradation or damage potentially occurring during installation of terminations include (but are not limited to):

- Galling or stripping of connector threads

[16] The damage mechanism was determined by subsequent analysis of the insulation, which indicated that the interior surface of the insulation on several cables in a common conduit had been damaged by their conductors at nearly the same point along each cable's length (Section 3.7.1).

- Bending and/or pushback of connector pins/contacts
- Improper crimping pressure and/or tool (compression fittings)
- Heat damage to conductor or surrounding insulation (fusion fittings)
- Improper solder joints
- Improper tape splice or stress cone fabrication
- Improper heat shrink insulation (over- or underheated during curing with heat gun)
- Abrasion, cutting, or chafing of organic seals or gaskets
- Overtightening of terminal block hardware (and cracking of the insulating base)
- Cold flow (creep) of conductors due to tensile stress

A number of sources ([4.29], [4.31], [4.51], and [4.57]) provide additional guidance on the proper selection and installation of various types of terminations. Manufacturer's guidance should also be consulted, because the configurations of terminations and materials used may vary widely, and standardized installation practices may not be available for certain termination types.

4.1.3.5 Maintenance/Operation-Related Degradation

Component Manipulation

Degradation of cable system components results largely from manipulation of the component during maintenance or testing. Because the greater part of cable is not disturbed or moved subsequent to its installation, little or no degradation of cable components (such as abrasion of exposed jacketing/insulation resulting from movement of the cable[17]) is expected. Manipulation of cables can result in cracking and possibly exposure of bare conductors in those cables with embrittled insulation or jacketing. Generally, the cable insulation and/or jacketing must be sufficiently aged and embrittled so that its elongation-at-break is very low. As the cable is bent, the outer radius of the jacket/insulation is placed in tension; if the bend is of sufficiently small radius, the elongation capability of the aged material can be exceeded and cracking can occur. For jacketed cables, the jacket will often age more rapidly than the underlying insulation, thereby cracking much more readily under sufficient bending stress. This is usually of little concern for the insulation, because cracking of the jacket will tend to release the stress on the insulation. However, in some bonded jacket/insulation systems, cracking of the jacket may localize the stress at the site of the insulation/jacket interface (within the newly formed crack) and precipitate a rupture of the underlying insulation. Section 3.7 discusses potential issues

[17] This type of wear is to be distinguished from incidental mechanical damage (such as that resulting from work in the immediate vicinity or personnel traffic).

related to bonded jacket/insulation interactions. Thermal criteria set forth in Tables 4-1 and 4-2 help limit the reduction in elongation so that cracking during manipulation is avoided.

For some terminations such as multi-pin or threaded connectors, wear may represent a significant aging mechanism. As a result of maintenance, inspection, or periodic surveillance testing activities, these connectors may be disconnected and reconnected at an appreciable frequency, so that their hardware or mating components may eventually wear out from friction or fatigue. The same may be true of terminal block hardware or any other termination component that is both moveable and manipulated frequently.

Work Hardening

In extreme cases, work hardening of the cable conductor or metallic termination components may occur due to manipulation and bending, thereby resulting in embrittlement and possible breakage. Work hardening (or cold working) occurs in metals that are worked at low temperatures. As the yield strength of the metal is exceeded, progressively higher amounts of stress are required to continue plastic deformation (strain) of the material. This increase in stress correlates to an increase in hardness and a corresponding loss in ductility. This process is illustrated through the bending of a new conductor; the first bend occurs with relative ease, whereas subsequent bends at the same location require more and more stress until finally embrittlement and breakage occur. Work hardening may occur in components that are frequently moved or manipulated (such as a wire that is routinely bent or moved out of the way during maintenance, or a contact pin in a multi-pin connector that is bent during engagement/ disengagement of the connector) [4.58], [4.59]. The severity of the work hardening effect depends primarily on the frequency of manipulation, the range of motion/stress applied, and the type of material being stressed. In most power plant applications, the frequency of manipulation is sufficiently low that work hardening is of minimal concern.

Physical Damage

Cables outside of raceways are also susceptible to physical damage from incidental contact during maintenance, and from personnel traffic. This is especially true where cables are routed at or near ground level, across passageways, or in space-restricted locations where contact or abrasion is likely. Armored cables may be afforded more protection, but these cables are not immune from such damage. Furthermore, cables in open trays, flexible conduits, and even rigid conduits are susceptible to physical damage when used in a manner inconsistent with their design (e.g., as hand- or footholds). Damaged raceways and cables are usually identified promptly and repaired as necessary.

Terminations are also subject to a variety of different types of physical damage. As with cables/conduit, connectors may also be improperly used as hand- or footholds by plant personnel. Connectors and similar plug-in type terminations are especially susceptible to incidental impact, tension, or shear stresses because the connector is often rigidly mounted to some structure, thereby reducing its ability to move when stressed. In addition, stress may be focused on a termination when a connected cable run is moved, pulled, or allowed to hang freely without support.

Electrical Faults

Mechanical stress on cable system components may also be induced by fault currents. Due to the large electric and magnetic fields generated by cable conductors during fault conditions, substantial mechanical forces may result which can move or stress the cable. This is especially true where the cable is unrestrained or not fully supported. Although the duration of the fault conditions is usually very short, the currents and resulting forces may be sufficient to cause the unrestrained portions of the cable to thrash so that large stresses are imposed on restrained portions or nearby terminations. These forces are usually only of concern in larger sizes of cables because of their higher current and greater weight. In general, cable and raceway installation practices and standards account for fault-induced stress through proper support and restraint of susceptible circuits.

Thermal Cycling

Circuits exposed to appreciable ohmic or ambient heating during operation may experience loosening related to the repeated cycling of connected loads or of the ambient temperature environment. Differing materials used in various cable system components can produce situations where stresses existing between these components change with repeated thermal cycling. For example, under loaded conditions, appreciable ohmic heating may raise the temperature of a compression termination and cable conductor well above the ambient temperature, thereby causing thermal expansion of both components. Differing thermal expansion coefficients may alter mechanical stresses between the components so that the termination may tighten on the conductor. When the load or current is reduced, the affected components cool and contract. Repeated cycling in this fashion can produce loosening of the termination under ambient conditions, and may lead to high electrical resistance joints or eventual separation of the termination from the conductor. Note that this effect is not necessarily limited to compression-type terminations; threaded connectors, splices, and terminal blocks may loosen if subjected to significant thermally induced stress and cycling.

Because most plant environments do not routinely experience the magnitude of temperature changes necessary to induce these effects, heavily loaded power circuits (i.e., those loaded to a high enough fraction of their rated ampacity to produce significant ohmic heating) that are routinely cycled are the most likely to experience such effects. Despite consideration of such stresses during component design, selection, and installation, instances of terminations loosening were identified by several plants contacted during preparation of this guideline, and are evidenced in the empirical data presented in Section 3.

4.1.3.6 "If-Then" Criteria for Mechanical Stressors and Aging Mechanisms

Table 4-5 summarizes the mechanical stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components.

Table 4-5 Mechanical Aging Summary for Cable and Termination Components[1]

Stressor	Aging Mechanisms	Material Changes	Aging Effects/Indications	Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Vibration; external mechanical influences (4.1.3.1; 4.1.3.5)	Cutting/ chafing of organic materials	Reduced dielectric strength; exposed conductors	- Visible cuts, chafing, or other damage to insulation - Exposed conductors, shielding, etc.	All insulation and jacketing materials	Cables or terminations attached to vibrating component and in contact with nearby equipment; routed across sharp edges, in high traffic areas, etc.	Rate of degradation depends on type of material and stressor	
	Metal fatigue (see also Work Hardening)	Reduced ductility; embrittlement	- Broken conductors or other metal components - Significant force required to bend conductors - Discoloration	Metals	Conductors/metallic components subject to vibration by nearby equipment or end device	Generally long-term; however, may occur rapidly (based on frequency/amplitude of vibration, etc.)	Restraint and/or rerouting of cable can significantly reduce effects
Bending during maintenance (4.1.3.5)	Work-hardening/ fatigue of metallic components	Reduced ductility; embrittlement	- Broken conductors or other metal components - Significant force required to bend conductors - Discoloration	Metals	Conductors or metallic termination components that are routinely terminated/ determinated or otherwise bent	Generally long-term	Severity depends on maintenance frequency, material, and stress applied
	Cracking of embrittled insulation/ jacketing	Reduced dielectric strength; exposed conductors	- Surface or through-cracking of insulation - Shattered or flaking jacket	All organic insulating/ jacketing materials	Heat or radiation-damaged cables with embrittled organic components bent so that residual elongation is exceeded	Occurs during maintenance or movement of cable in tray or conduit	Absolute elongation greater than 50% generally allows sufficient flexibility for all typical maintenance activities.[2] As a rule of thumb, avoid bending insulation of noticeably hardened cable more than a few degrees.

Table 4-5 Mechanical Aging Summary for Cable and Termination Components[1] (cont'd)

Stressor	Aging Mechanisms	Material Changes	Aging Effects/Indications	Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Gravity; temperature variations (ambient or ohmic) (4.1.3.2)	Cable creep; tensile stress on components	Elongation, deformation, tearing	- Tearing of jackets and/or insulation - Deformed or high-resistance terminations - Exposed conductors near terminations - Stretched or twisted appearance of cable outer jacket (including labels)	Organic and inorganic materials	Cables with significant unsupported vertical hangs	Generally long-term phenomenon	May be accompanied by cutting or chafing of cable jacket or insulation at overhang point
Compressive load (4.1.3.3)	Material deformation/ relaxation	Compression set	- Reduced seal thickness or other dimensional changes - Seal leakage - Hardening/loss of flexibility	All organic materials	Organics seals placed in compressive stress (such as in assembled electrical connectors)	Percent compression set increases as a function of time; depends on material	Routine replacement should be considered as measurement or trending of compression set not practical for small seals

Notes:

1. Installation stressors are not considered an aging mechanism, and are not included in this table.
2. This is only a guideline, and may not be true for certain cable configurations (such as those with bonded jacket/insulation systems).

4.1.4 Radiation Stressors and Aging Mechanisms

The types of radiation that may be expected in nuclear power plants may be classified as either a particle or electromagnetic wave. Four primary types of radiation exist: alpha, beta, gamma, and neutron [4.60], [4.61]. Although all four types are present in the typical nuclear power plant, the significance of each varies greatly with respect to cable and termination aging. Other types of radiation to be considered include Bremsstrahlung (a by-product of beta radiation interaction) and ultraviolet radiation (electromagnetic radiation of energy or frequency lower than that of gamma or X-rays).

In most plant areas, normal radiation dose rates (all sources) are roughly commensurate with natural background levels (i.e., <0.01 mGy/hr [<1 mrad/hr]). In some spaces, however, the dose rate during normal operation is significantly higher; this is especially true of the primary reactor containment, in which normal radiation dose rates may range from about 0.1 to 1000 Gy/hr [0.01 to 100 rad/hr], depending on plant type [4.62]. Because electrical cable and terminations are routed through these higher-dose spaces, the aging of these components resulting from exposure to radiation must be considered.

Alpha

Alpha (α) radiation is helium atom nuclei emitted at high speed during the disintegration of unstable nuclei. Alpha radiation is highly damaging to some organic materials; however, due to its electric charge and relatively large mass, alpha radiation is easily shielded. Alpha emitters have short half-lives, and the range of alpha particles in free air is extremely limited [4.60], [4.61], [4.63]. No appreciable alpha dose is anticipated for any cable or connection in the plant under normal conditions, and any alpha dose incident upon cable system components would be attenuated within the first few mils of material; thus, no degradation of the underlying material would result. Alpha radiation is not considered further in this AMG.

Beta

Beta (β) radiation is an electron emitted from a nucleus when a proton changes to a neutron, or vice versa; it can be produced from a number of sources and varies in its energy level (expressed in million electron volts, or MeV). Beta penetration is proportional to the density of the absorbing material, and is more penetrating than alpha particles [4.60], [4.63]. Under certain accident scenarios, significant beta radiation may be produced from sources liberated during the accident (i.e., leaking reactor coolant/steam). This dose must be considered in the environmental qualification of the cables and terminations; however, under normal conditions, beta-emitting sources are not present in the ambient environment.

Gamma

Gamma (γ) radiation is electromagnetic in nature, and is emitted from a broad variety of nuclear species. Gamma energy varies in relation to its frequency and wavelength, so that higher frequency radiation is more energetic [4.60], [4.63]. Gamma sources exist in the reactor core and are created as a result of the fission process. Gamma radiation is highly penetrating in comparison with alpha and beta radiation. The gamma dose rate attributable to natural

sources is extremely low (< <0.01 mGy/hr [< <1 mrad/hr]) and for the most part, invariant with time. The gamma dose rate attributable to reactor plant operation varies widely as a function of location within the plant and reactor power level, and may range up to 2 Gy/hr [200 rad/hr] inside primary containment. Therefore, gamma dose must be considered in the aging of some cables and termination insulations and jacket materials. Because individual electrical circuits may span multiple plant locations, a single cable may be exposed to varying dose rates and, therefore, different radiation aging effects along the length of its run.

Bremsstrahlung

A related form of radiation known as Bremsstrahlung (braking radiation) results from the interaction of a beta particle with an inorganic material. Photon (gamma or X-ray) radiation is produced from the deceleration of an incident beta particle upon striking the absorber. Accordingly, the dose rate arising from Bremsstrahlung interaction is related to the incident beta dose rate. As a general rule, the Bremsstrahlung dose is conservatively estimated at about 3% to 5% of the incident beta dose [4.60], [4.63]. Because Bremsstrahlung is electromagnetic radiation, its effect on organic cable materials is comparable to that of gamma rays. Bremsstrahlung radiation of an intensity sufficient to result in significant degradation of organic materials in cables or terminations is created only during accident conditions (i.e., when high concentrations of beta-producing nuclides are released to the atmosphere)[18]; accordingly, Bremsstrahlung radiation is not significant with respect to cable aging, but rather is considered only in the context of equipment qualification during accident conditions.

Ultraviolet

Ultraviolet (UV) radiation is a form of electromagnetic energy with a lower frequency than that of gamma or X-rays [4.63]. Due to its reduced energy, it is far less penetrating; however, UV may affect certain organic materials through an interactive process known as photolysis.[19] Photolysis operates through the excitation of electrons within specific molecular functional groups in a polymer. Some polymers, including polyester, PVC, and polyurethane, contain these functional groups as part of their basic molecular structure. Hydrocarbon polymers (such as polyethylene/polyolefin, polypropylene, and EPR), although ideally not containing the functional groups necessary for photolysis, may exhibit some degree of photolytic behavior due to aging or because the polymer formulation includes photosensitive materials (fillers or impurities containing ketones or hydroperoxide groups) [4.64].

For photolysis to occur, a quantity of energy at a particular wavelength must be absorbed so as to initiate the dissociation of the molecules into their constituent radicals, thereby

[18] The only beta radiation sources with potential aging effects on cable and termination systems (during normal operation) identified as part of this study were those associated with refueling and spent fuel storage systems. However, these were not considered significant because (1) the resulting Bremsstrahlung dose is estimated at approximately 3% to 5% of the incident beta dose, and (2) the fuel pool water has a shielding effect. Note also that as indicated in a typical FSAR for a late 1980s BWR, the typical design basis criteria for spent fuel storage facilities is to maintain radiation levels at or below those for continuous occupational exposure during normal operations.

[19] UV radiation may also interact with free oxygen to produce ozone (Section 4.1.5).

ultimately affecting the overall physical properties of the polymer. Indications of UV photolysis include embrittlement, discoloration, and spontaneous cracking.

UV stabilization is generally accomplished through the use of UV absorbers, quenchers, and hindered amines. More than one of the UV stabilization methods may be employed in a single material; synergistic effects have often been noted when stabilizers are used in this manner [4.65].

Many polymers commonly used in cables can exhibit photolytic behavior if they are not stabilized. Polyethylene and polypropylene are subject to rapid embrittlement and crazing under exposure to UV, whereas PVC is subject to darkening, cracking, and embrittlement. Fluorocarbons (such as Teflon® and Tefzel®) are extremely resistant to UV radiation. Polyimide (Kapton®) may undergo some minor loss of tensile strength after prolonged UV exposure. Thermosets (such as epoxies and phenolics) exhibit generally good UV resistance, with some discoloration and minor cracking often occurring with long-term exposure. Elastomers such as Hypalon®, EPR/EPDM, Neoprene®, butyl, and silicone rubber are all generally resistant to the effects of UV radiation, with some minor effects noted. Table 4-6 generally describes the effects of UV radiation on various materials, when there is no photolytic stabilization.

Table 4-6 Effect of Ultraviolet Radiation on Polymer Stability (No Photolytic Stabilization) [4.66]

Polymer	Effect of Ultraviolet Energy
Plastics	
Mylar	Decreases tensile strength and elongation
Polyamide (nylon)	No significant effect
Polymethyl methacrylate	Surface discoloration and crazing
Polyethylene	Embrittlement
Polypropylene	Embrittlement
Polyimide	No significant effect
Polystyrene	Yellows
Plasticized polyvinyl chloride	Develops tacky and discolored surface
Teflon®	No significant effect
Elastomers	
Butyl	Increases tensile strength and elongation
Hypalon® (chlorosulfonated polyethylene)	No significant effect
Neoprene®	Increases tensile strength, decreases elongation
Nitrile	Decreases tensile strength and elongation
Styrene-butadiene (SBR)	Decreases tensile strength and elongation
Silicone	Surface crazing
Viton A	No significant effect

Note: Results are for relative comparison only; spectral distribution or dose not specified.

It should be noted that most commercially available cables using polymers susceptible to UV damage have stabilizers added to preclude this effect. For example, carbon black is a typical additive to cable polymer formulations; even a few percent of this material greatly enhances UV stabilization in polyolefins through absorption [4.65]. One notable exception that has been identified is PVC insulation containing less than 3% carbon black; at least one nuclear plant has experienced degradation of this material in cables located in close proximity to overhead fluorescent lights. Although not a definitive test, UV-sensitive polymers may sometimes be identified by a white or very light color, which results from the lack of any carbon black or similar stabilizer.

UV radiation sources at nuclear plants include solar radiation and ultraviolet or fluorescent lamps [4.21]. UV radiation is readily shielded by even a thin layer of opaque material; hence, only materials directly exposed to these sources may be degraded. Electrical cables and terminations may be routed outdoors above-grade (primarily medium-voltage cable) or in proximity to fluorescent sources indoors so that comparatively intense UV exposure results. Cable used in certain plant applications (such as closed-circuit television, meteorological, or telephone circuits) may be routed almost completely outdoors.

Degradation of cable installed outdoors will vary with a number of factors such as the duration of exposure, ambient and cable temperature, annual solar intensity, and the type of material used on the exposed surfaces of the cable. Most cables suitable for outdoor use are purposely formulated to resist degradation caused by solar UV exposure. An additional consideration relates to nonstabilized cable stored on reels in outdoor locations. Cable stored in this fashion may sit undisturbed for several years; in areas of significant solar exposure, susceptible cable materials may degrade rapidly under such conditions if left uncovered. Some of the cable stored outdoors may not be intended for outdoor use; hence, its UV resistance may be comparatively low.

Indoor cable may be exposed to UV radiation from fluorescent lamps installed in the plant. A significant fraction (roughly 20%) of the total energy emitted from a fluorescent lamp can be UV radiation of varying wavelengths [4.21]. Although this radiation is not known to be particularly harmful to humans, it may nonetheless degrade certain polymeric cable and termination components. Factors affecting the rate of degradation include the type of material used, the proximity of the cable/component to the fluorescent source, the presence of any attenuating media (such as plastic lenses or coverings), and the duration of exposure. Symptoms of UV cracking in such applications are similar to those for outdoor cable, and may include discoloration and cracking, especially in the immediate vicinity of the fluorescent source (such as cables run near overhead fluorescent lamps in a plant control rooms) [4.64], [4.65].

In addition to the aging mechanisms already described, UV radiation may produce ozone through interaction with diatomic oxygen. Section 4.1.5 discusses potential effects of ozone on cable and termination materials.

Neutron

Neutron (*n*) radiation emanates from the reactor core during operation (and to a greatly reduced degree during shutdown). Neutrons are relatively massive subatomic particles that vary

in energy level (fast/thermal) and penetration capability. Energetic neutrons may be destructive to both inorganic and organic materials [4.60]; however, the neutron reflectors, moderators, and radial shielding installed around the reactor core and vessel ensure that the net neutron flux (and hence dose rate) out of the vessel shielding is extremely low in comparison to that of gamma radiation. Thus, virtually no cable within primary containment is exposed to significant neutron dose, with the possible exception of any cables located inside the neutron shielding or directly adjacent to the reactor pressure vessel in areas of high relative neutron flux. Cables used in such applications generally contain inorganic or metallic materials with a high damage threshold for neutron radiation.

Effects of Radiation Exposure

Radiation interacts with matter in two principal ways: ionization/excitation of atoms in the material (radiolysis), and displacement of atoms or subatomic particles, thereby altering the molecular structure of the material. Both processes are applicable to radiation-induced degradation; however, displacement effects are usually not significant for organics because of their less rigid structure and covalent bonding. Similarly, ionization effects are of little significance to inorganic materials because of their ionic bonding and rigid structure. In general, radiation effects are much more severe on organic than on inorganic materials [4.60], [4.61].

Ionization and excitation within organic materials result in accelerated chemical reactions; the type of reaction is determined by the material. Their magnitude or extent is determined by the total energy deposited into the material. In most cases, the effects of radiation type and energy spectrum on the total energy deposited are minimal; thus, equal doses of various types of radiation will produce roughly equal damage in an organic material. This relationship does not generally hold for inorganic materials. Accordingly, the specific type of radiation dose applied to an inorganic as well as the type of material irradiated must be carefully considered. Of the types of radiation produced by a nuclear reactor, neutron radiation is clearly of most concern to inorganics and metals for the reasons stated above [4.66].

Radiation incident on cable and termination organic components produces aging/degradation through scission, oxidation, or crosslinking of polymer chains; this process is generally known as radiolysis [4.64]. (Note that radiation-induced oxidation is considered separately in Section 4.1.5.5 of this AMG.) As with thermal exposure, the tolerance of an individual material to various types of radiation will vary according to the general type of material (i.e., elastomer, fluoropolymer, etc.) and its individual chemical structure and formulation. Organic materials commonly used in nuclear plant cable and termination applications vary widely in their susceptibility to radiation. Changes in the material's overall mechanical properties (such as elongation-at-break, tensile strength, and hardness) and electrical properties (such as dielectric strength and conductivity) may result from exposure to radiation. As a general rule, cable system organic materials exposed to total gamma doses less than about 1 kGy [100 krad] (corresponding to a dose rate of ~2 mGy/hr [~0.2 rad/hr] over 60 years) will experience little or no aging from radiation exposure [4.60]. Above this level, however, progressive changes in physical properties begin to occur as dose is increased. The threshold[20] is unique for each

[20] Defined by EPRI NP-2129 [4.60] as "... the first detectable change in a property of a material due to the effect of radiation."

material, and can be affected by environmental conditions such as temperature [4.67]. For a given dose[21], radiation-induced damage to polymers in oxygen environments may depend on the dose rate of the exposure [4.5], [4.6], [4.9], [4.68], [4.69], and [4.70]. Table 4-7 lists approximate radiation threshold values for generic cable and termination materials. For many of the polymers used in fabricating cables and terminations, the radiation threshold is roughly 10 kGy [1 Mrad]. References [4.60] and [4.61] provide additional information on the degradation of specific materials with radiation and other environmental influences. Section 4.1.5 discusses the effects of radiation exposure on the loss of fire retardants within cable materials.

Macroscopic effects of radiation-induced degradation of organics may include embrittlement, cracking or crazing, swelling, discoloration, and melting, as well as a change in the mechanical or electrical properties of the affected material (such as reduction in elongation-at-break, insulation resistance, or change in tensile strength). Radiation damage to cable jacketing and insulation may make them difficult to handle or terminate due to brittleness. In addition, severe radiation exposure may induce swelling (due to increased moisture absorption) for certain materials [4.71]. This effect generally occurs at high radiation levels where corresponding mechanical properties of the material are significantly degraded [4.60]. One plant contacted during the preparation of this guideline indicated that some swelling of jacket material had been experienced in cables located in immediate proximity to the reactor vessel and subject to high humidity. Similarly, other organic cable and termination components (such as O-rings or seals) may swell, thereby producing increased tension or pressure on other components in direct proximity.

For inorganic materials, a rough estimate of the threshold level of concern can be made. Figure C-6 of Reference [4.3] (reproduced here as Figure 4-8) shows approximate levels of radiation damage for various inorganic insulating materials based upon changes in their physical properties. Note that a neutron fluence of roughly 1×10^{18} n/cm^2 (equivalent to a gamma dose of about 3×10^7 Gy [3×10^9 rad]) results in no significant damage or change in material properties for the materials listed (with the exception of glass). Metals generally have comparable or higher damage thresholds, on the order of 1×10^{19} n/cm^2 (approximately 2.5×10^8 Gy [2.5×10^{10} rad]) [4.66]. The predominant effects on metals are increased hardness and reduced creep rate. Fatigue properties and electrical resistance are among the least affected [4.66]. Accordingly, a conservative threshold dose of 1×10^{17} n/cm^2, or 3 MGy [300 Mrad] gamma, can be set for mineral insulations and metals used in cable and termination components. Below this dose, little or no aging effects should be noted in such materials. Note that few locations within primary containment could experience this level of exposure.[22]

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[21] ASTM E 1027-1984 gives generalized procedures on preparing and exposing test samples to ionizing radiation, and reporting test results.

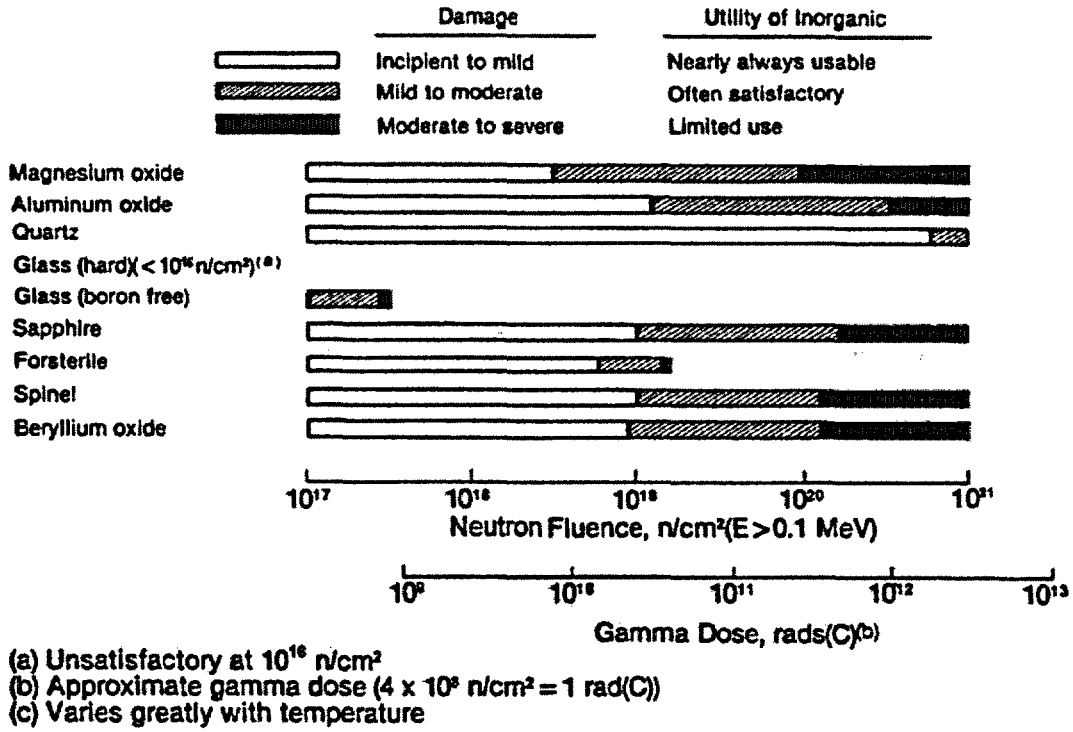
[22] The neutron flux calculated at the inner reactor pressure vessel beltline wall of a late 1980s BWR is roughly 1×10^9 n/cm^2-sec (all neutron energies >0.1 MeV) at 100% power (per the FSAR). Assuming 60 years of operation at 80% of capacity, the total neutron fluence for this location would be approximately 1.5×10^{18} n/cm^2. Per Regulatory Guide 1.99 [4.69], the neutron fluence is a function of depth in the reactor vessel; accordingly, the expected neutron fluence at the outer (non-wetted) surface of the typical vessel is roughly 20% of that at the inner surface (assuming a beltline vessel thickness of 16.5 cm [6.5 in]. Hence, inorganic or metallic cable components located immediately adjacent to the outer surface of the reactor vessel beltline would be exposed to a maximum 60-year neutron dose on the order of 3.0×10^{17} n/cm^2.

Table 4-7 Representative Radiation Dose Thresholds for Common Cable and Termination Organic Materials [4.60, 4.61]

Material Category	Material Name	Lowest Reported Threshold or Applicable Threshold Range for γ Radiation (Gray)	(Rad)	Estimated Applicable Threshold Range; Neutron (n/cm^2)[1]	Property Measured
Elastomers	EPR/EPDM	10^4	10^6	4×10^{14}	Compression Set
	Neoprene®	10^4	10^6	4×10^{14}	Compression Set
	CSPE	5×10^3	5×10^5	2×10^{14}	Elongation
	Nitrile (Buna N)	10^4	10^6	4×10^{14}	Compression Set
	Butyl	7×10^3	7×10^5	2.8×10^{14}	Tensile Strength
	Viton	10^3	10^5	4×10^{13}	Elongation
	Silicone	10^4	10^6	4×10^{14}	Tensile Strength, Compression Set
Thermo-plastics	XLPE/XLPO	10^4	10^6	4×10^{14}	Elongation, Tensile Strength
	PVC	10^3	10^5	4×10^{13}	Unstated
	Polyethylene	3.8×10^3	3.8×10^5	1.5×10^{14}	Elongation
	ETFE (Tefzel®)	Note 3	Note 3	Note 3	-
Thermosets	Epoxy Resins	2×10^6	2×10^8	8×10^{16}	Varies
	Polyimide (Kapton®)	10^5	10^7	4×10^{15}	Tensile Strength, Elongation
	Phenolic Resins	3×10^5 to 3.9×10^6	3×10^5 to 3.9×10^8	1.2×10^{14} to 1.6×10^{17}	Elongation
	Furanic Resins	3×10^6	3×10^8	1.2×10^{17}	Tensile Strength, Elongation
	Polyester Resins	10^3 to 7.9×10^5	10^5 to 7.9×10^7	4×10^{13} to 3.2×10^{16}	Elongation
	Melamine Formaldehyde	6.7×10^4	6.7×10^6	2.7×10^{15}	Impact Strength

Notes:

1. All data are formulation specific. See the referenced reports.
2. Based on approximate conversion factor of 4×10^8 n/cm^2 = 1 rad (see Figure 4-8).
3. No radiation threshold data were located for ETFE; however, based on manufacturer's data and elongation data at 75% and 50% retention of elongation in Reference [4.60], the radiation threshold may be conservatively estimated at 10^4 Gy [10^6 rad].



(a) Unsatisfactory at 10^{16} n/cm²
(b) Approximate gamma dose (4 x 10^8 n/cm² = 1 rad(C))
(c) Varies greatly with temperature

Figure 4-8 Relative Radiation Resistance[c] of Inorganic Insulating Materials Based Upon Changes in Physical Properties
[NOTE: A rad(C) is a rad deposited in the element carbon (C)]

4.1.4.1 Radiation Dose-Rate Effects

In nuclear plants, a variety of polymeric materials are exposed to radiation at relatively low dose-rates for long periods. To estimate the long-term degradation that occurs, many accelerated aging studies have been performed by increasing the radiation dose-rate based on the assumption that the amount of degradation will depend only on the integrated dose. However, evidence exists to indicate that, in air environments, certain polymeric materials can show significant dose-rate effects. A dose-rate effect may be defined as an effect on a material that differs in magnitude or type (for the same total dose) according to the irradiation rate [4.60]. These effects may be transient or permanent. Dose-rate effects are very common in radiation aging of polymeric materials, and can range from very large to insignificant, depending upon such factors as polymer type, aging conditions, sample geometry, and degradation parameter being monitored [4.8].

Dose-rate effects typically involve oxidation mechanisms. When aged at high radiation dose rates, a large fraction of polymeric materials has been found to have physical dose-rate effects caused by diffusion-limited oxidation degradation. A much smaller fraction has chemical dose-rate effects. No evidence exists for dose-rate effects in a nitrogen environment [4.8]. In materials found to have dose-rate effects, usually there was more mechanical degradation for a given dose as the dose rate was reduced [4.8]. Dose-rate effects for PE and PVC were

determined at low dose rates of 87 and 44 Gy/hr [8700 and 4400 rad/hr], respectively. A difference in the mechanical properties of these materials irradiated at low dose rates could be identified only after a total dose greater than ~20 kGy [~2 Mrad] had been absorbed, and the difference did not become significant (i.e., >10%) until the total dose exceeded ~100 kGy [~10 Mrad] [4.8]. For other common cable and termination materials (such as XLPE, EPR, and ETFE), synergistic effects were either not noted or occurred at dose rates above those for PE and PVC. There was no evidence in the literature of dose-rate effects occurring at exposure rates less than those indicated above.

Dose-rate effects must be considered from both aging and environmental qualification perspectives for realistic simulation of normal operating and predicted accident conditions. From an aging perspective, the use of test and laboratory data obtained under high dose-rates may result in an underestimate of the degradation of a material for a given dose under normal (low dose-rate) operating conditions. Thus, the aging portion of an EQ test might underestimate the pre-LOCA degradation that occurs under natural aging conditions. From an accident simulation perspective, the degradation resulting from exposure at a comparatively low qualification test dose rate and that resulting from the higher postulated accident dose rate may differ.

Environmental qualification testing does not typically include a segment that addresses the actual radiation dose rate during the component's design life. To do so would require a test program that lasts 40 years or more. As stated previously, the highest anticipated dose rate during normal operating conditions is on the order of 2 Gy/hr [200 rad/hr] inside primary containment. The lowest dose rates discussed in the literature for any material at which dose-rate effects have been observed (more than 10 Gy/hr [1000 rad/hr]) greatly exceed those for the typical plant under normal operating conditions. Although the maximum 60-year total dose inside a typical primary containment is anticipated to be on the order of 0.1 to 1 MGy [10 to 100 Mrad], most of the areas should receive a lower total dose [4.62]. If the dose rate during accelerated testing is more than 10 Gy/hr [1000 rad/hr], the aging results might not be representative of the effects that would actually occur.

For equipment located outside primary containment, the dose rate and TID for most plant areas during normal operations is low (typically less than 1 mGy/hr [0.1 rad/hr] and 500 Gy [50 krad] over 60 years). These dose rates and doses are much lower than the minimum dose rates and doses at which dose-rate effects (and radiation degradation) have been observed. Note, however, that a few areas outside primary containment (e.g., in the proximity of radwaste or BWR main steam systems) may be subject to higher dose rates.

A typical qualification test also does not match the actual radiation dose rate during accident conditions. The maximum accident dose rate for a plant may exceed 100 kGy/hr [10 Mrad/hr] [4.8], whereas the maximum dose rate used during qualification testing is 10 kGy/hr [1 Mrad/hr] and usually is only 40% to 80% of that value. The accident dose rate used for qualification testing is far in excess of the dose rate at which dose-rate effects have been observed, but these effects are considered in the applicable standards and regulations. Exposure at a maximum dose rate of 10 kGy/hr [1 Mrad/hr] is recommended in IEEE 383-1974 [4.72], which has been accepted by the NRC in Regulatory Guide 1.131 [4.73] to establish qualification.

To determine the significance of a potential dose-rate synergism, the analysis or test report used to establish qualification may be reviewed to compare the dose-rate and total dose used in the test with those actually occurring at the installed location. If the dose-rate and total dose at the installed location are not in the same range as values for known synergistic effects for the material or component in question, then the test/analysis dose-rate and total dose may be considered acceptable to establish qualification. Note that components that contain no Teflon® and are subjected to a total dose of less than 1 kGy [0.1 Mrad] may be excluded from further analysis for dose-rate synergisms. At these levels, there is no significant degradation of mechanical or permanent electrical properties, and no indications of significant synergistic effects of radiation combined with either environmental stresses or sensitization to subsequently imposed stresses [4.60].

It should be noted that aging dose-rate effects are also generally of little potential significance for components qualified for accident doses, because the fraction of the total dose applied that is potentially subject to non-conservative dose-rate effects (i.e., the aging dose) is comparatively small.[23]

4.1.4.2 Radiation Aging Sequence Effects

The chemical composition of a polymer determines its possible reaction mechanisms. Environmental conditions generally determine which of these possible reactions will occur and at what rates. This implies that changes in a material subjected simultaneously to radiation and another environmental stress could be different from the changes that would occur in the material if the material were subjected to the stresses separately and sequentially. A "synergistic" effect could occur [4.60].

If some type of reaction occurs in a material because of two environmental stressors, the best approach would be the use of appropriate combined-environment accelerated simulation. On the other hand, if synergistic effects were not important, sequential exposure to the two environments might adequately simulate the ambient aging conditions. The possibility also exists that sequential exposure to the two environments might adequately simulate cases where synergistic effects are important, thereby eliminating the necessity for more complex and expensive exposure to combined environments [4.8].

Important synergisms of low-temperature radiation and elevated thermal environments and important ordering effects in sequential aging experiments can occur, and these are mechanistically related to radiation dose-rate effects. NUREG/CR-4301 [4.8] and NUREG-0237 [4.74] concluded that significant evidence existed for the possible presence of important synergistic effects in combined radiation-thermal environments. If a material was determined to have important synergistic effects in combined radiation-thermal environments, it was probable that sequential aging simulations would give different material degradation results. These results led to an important conclusion, namely, the normal sequential exposure of thermal aging followed by ambient-temperature, radiation aging can result in an underestimate of material damage when strong synergistic effects related to radiation and temperature exist for a material [4.8].

[23] A typical qualification radiation exposure might include 0.5 MGy [50 Mrad] to simulate the pre-LOCA aging dose and 1.5 MGy [150 Mrad] to simulate the accident dose.

The aging response of many materials to sequential exposure (radiation followed by thermal or thermal followed by radiation) is similar to their response to a combined radiation plus thermal exposure. In materials where significant differences do occur, the radiation followed by thermal sequence is usually more severe than the thermal followed by radiation sequence, and the radiation followed by thermal sequence more closely matches simultaneous exposure conditions. This indicates that the most conservative approach to sequential aging simulations should use the radiation followed by thermal sequence. Significant sequential ordering effects usually occur in materials that also have large synergisms related to radiation and temperature and large radiation dose-rate effects [4.8]. In sequential aging experiments, the thermal exposure can bring about rapid degradation for certain polymeric materials that have been presensitized by previous radiation exposure [4.75].

NUREG/CR-3629 [4.76], which examined the effects of aging sequence, concluded the following:

- For several materials, tensile properties at completion of aging were only slightly affected by both the temperature during irradiation and the order of the sequential aging environmental exposures.

- In general, the choice of temperature during irradiation was secondary to the choice of aging sequence in its effect on polymer properties.

- If the sequential order of irradiation and thermal exposure was important to the aging degradation of tensile properties, usually irradiation followed by thermal exposure was most severe [4.8].

Section 6.3.2 of IEEE Standard 323-1974 [4.77] provides a test sequence to be used for qualification testing, namely that the equipment shall be aged to a simulated end-of-qualified-life condition prior to being exposed to a simulated design basis event. While IEEE 323-1974 also states that "the sequence shall be justified as the most severe for the item being tested," this does not mean that the simulated accident might be performed prior to the simulated aging. Instead, it means that the various components of a sequential aging exposure (radiation and thermal) shall be performed in the order that is the most severe for the item being tested, and similarly, the various components of a sequential accident exposure (LOCA radiation and LOCA steam/chemical-spray exposure) shall be performed in the order that is the most severe. Common sense would indicate that the most realistic method of performing qualification testing is to utilize a simultaneous radiation and thermal aging exposure followed by a simultaneous LOCA radiation and LOCA steam/chemical-spray exposure. However, most test facilities are not capable of performing such simultaneous testing and, therefore, the test sequence usually consists of sequential aging followed by a sequential LOCA.

While certain sequences are not representative of what could actually happen in a plant (e.g., DBE radiation followed by thermal aging), IEEE 323-1974 requires that the test sequence be the most severe. NRC approval should be obtained for any test sequence other than the most severe, and approval should be documented in the licensing basis. A possible basis for justification of an alternate sequence might be that the alternate sequence more realistically simulates the real aging environment.

Various tests performed during the past 20 years have shown that certain properties of some materials vary significantly depending on the sequence of radiation and thermal aging. More damage can occur in some materials if radiation aging is performed before thermal aging. However, test results do not demonstrate that this is always the case, even for the same generic material (that is, different compounds of EPR can give different or contradictory results). Although test data are limited, the results seem to be somewhat dependent on the temperature used for thermal aging. Many of the research reports cited used a temperature that was much lower than the typical range of 121°C to 150°C [250°F to 302°F] used in qualification test programs. When the accelerated aging temperature was closer to those typically used in qualification tests, the results concerning sequence were not conclusive. Consequently, caution must be used when attempting to relate the results of the research tests with those of qualification tests and with actual plant environments.

4.1.4.3 "If-Then" Criteria for Radiation Stressors and Aging Mechanisms

Table 4-8 summarizes radiation stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components.

4.1.5 Chemical/Electrochemical Stressors and Aging Mechanisms

Chemical stressors result from the exposure of cable and termination components to moisture, solvents, fuel oils, lubricants, or other substances. Chemical stressors can affect the structure and properties of both organic and inorganic materials. Because electrical cable is present in most every space in a nuclear plant, and a single circuit may be present in many of the spaces, cable and termination components may be exposed to a wide variety of chemical stressors. In general, chemical stressors are highly local and typically affect only very small portions of the plant cable inventory. The degradation of inorganic (metallic) cable materials is generally electrochemical compared with the purely chemical processes primarily associated with organic material degradation. Each of these degradation mechanisms is described in the following sections.

4.1.5.1 Chemical Attack of Organics

Chemical attack of organic materials used in cables and terminations may occur following exposure to acids, alcohols, alkalines, esters, ketones, oils, oxidizers, salts, solvents, or water. These agents may reach the material through a number of different mechanisms such as accidental or intentional application, airborne transport (atomization), splash or spray, leaching, or direct contact with another material. Chemical attack of polymers may result in dissolution, swelling, or breaking of chemical bonds within the polymer, ultimately affecting its mechanical and/or electrical properties [4.2].

Table 4-8 Radiation Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/ Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Radiation (gamma; in oxygen environment) (4.1.4)	Radiation-induced oxidation; radiolysis	Embrittlement/ reduced elongation; variations in tensile strength; loss of plasticizer; loss of antioxidant	- Hard or brittle jackets, insulation, or other organic components - Material discoloration or crazing - Swelling (moisture absorption)	All cable and termination organic materials	60-year equivalent TID greater than or equal to the applicable value in Table 4-7 (material-specific gamma dose)	Continuous (approximately 0.02 Gy/hr [2 rad/hr] over 60 years; TID of 10 kGy [1 Mrad])	Radiation damage threshold (TID) for most common cable organics is approximately 10 kGy [1 Mrad], see Table 4-7
Radiation (neutron) (4.1.4)	Displacement	Hardening/ embrittlement; reduced creep rate (metals)	- Cracking - Increased conductor rigidity	Inorganic (mineral) insulations and metals	10^{17} n/cm fluence (approximately 3 MGy [300 Mrad] gamma)	Continuous (60 years)	Damage threshold for inorganic (mineral) insulation and metal components only
Radiation (neutron) (4.1.4)	Chain scission; displacement	Embrittlement/ reduced elongation; variations in tensile strength; loss of plasticizer; loss of antioxidant	- Hard or brittle jackets, insulation, or other organic components - Material discoloration or crazing - Swelling (moisture absorption)	All cable and termination organic materials	60-year equivalent TID greater than or equal to the applicable value in Table 4-7 (material specific neutron dose)	Continuous (60 years)	Damage threshold for inorganic (mineral) insulation and metal components only
Radiation (UV) (4.1.4)	Photolysis	Embrittlement/ reduced elongation, variations in tensile strength	- Cracking or crazing - Discoloration	Organic photo-sensitive polymers (including polyethylene, polypropylene, and PVC)	Nonstabilized photo-sensitive material exposed to fluorescent light or located outdoors	(n/a)	Applicable to few cable/termination materials because most are UV stabilized

Significant differences in the chemical resistance of substances exist between categories of polymers (thermoplastics and thermosets) and between individual families within those categories. Furthermore, individual formulations of a particular polymer can have significantly different chemical resistance based on the ratios and types of constituents included in the formulation. The chemical properties of common cable materials are summarized in Table 4-9; these properties are only generalizations and may not be representative of a material's performance upon exposure to specific chemical compounds. In addition, other environmental influences (such as heat, humidity, and radiation) may substantially alter the effect of any chemical interaction so that it is more or less severe. Table 4-9 is meant only as a general guide; manufacturer's literature or other comparable sources should be used to determine the resistance of a particular material to a specific chemical agent under prevailing environmental conditions.

Changes in the appearance of chemically affected organics will vary with the specific material and the chemical to which it has been exposed. For example, changes in color may indicate contact with a strong solvent (often producing a bright or vivid color) or oxidizer (lightened or white color). Changes in the texture of the material (such as surface roughness, cracking, or oily residue) may also result. Also, changes in the mechanical properties of the compound, such as swelling or softness, may occur [4.50]. Table 4-9 shows some common organic materials used in electrical cable and termination construction and their relative susceptibility to certain chemicals [4.2], [4.25], [4.26], [4.50], [4.78], [4.79].

4.1.5.2 Chemical Decomposition of Cable Materials

In addition to exposure from foreign or external chemical substances, cable and termination components may be exposed to chemical by-products of the thermal or radiolytic decomposition of cable jacketing, insulation, fire-resistant coatings, or other organic components. Many materials commonly used in cable construction either contain or are manufactured using potentially corrosive chemicals such as chlorides, peroxides, or sulfurous compounds. Chemical by-products originating from decomposition of cable components may result in several degradation mechanisms, including corrosion of metallic components (conductor, shield, drain wire, or terminations), and softening, swelling, or decomposition of other organics within the cable structure. Plasticizer migration in PVC materials can also result in swelling of adjacent elastomers.

For example, Neoprene® rubber (chloroprene), PVC, CSPE, and CPE all may produce chlorine ions (and hydrochloric acid) upon decomposition. In addition, EPR, EPDM, and other elastomers are cured using peroxide or sulfur compounds that may be leached from the material as it ages or is subjected to certain environmental conditions (such as heat or wetting). Copolymers such as ethylene vinyl acetate (a semiconducting shield material) may also decompose to produce by-products such as weak acids [4.50].

Table 4-9 Chemical Compatibility of Common Cable and Termination Organic Materials [4.2], [4.25], [4.26], [4.49], [4.77], [4.78]

Compatibility	Elastomers							Thermoplastics				Thermosets			
Chemical Agent	EPR/ EPDM	Neoprene	CSPE	Nitrile	Butyl	Viton	Silicone	PVC	Poly-ethylene	XLPE/ XLPO	ETFE (Tefzel)	Epoxy Resins	Polyimide (Kapton)	Phenolic Resins	Furanic Resins
Acids, inorganic	Poor	Poor	Good	Poor	Fair	Good[1]	Poor	Good	Good	Good	Good	Poor[2]	Fair[2]	Fair	Poor
Acids, organic	Fair	Poor	Fair	Fair	Fair	Poor	Good	Good[3]	Poor	Poor	Good	Good	Fair	Good	Good
Alcohols	Fair	Good	Good	Fair	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good
Alkalines	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Poor	Good	Good
Esters	Fair	Poor	Poor	Poor	Fair	Poor	Fair	Poor	Fair	Fair	Good	Fair	Good	Good	Good
Ketones (acetone)	Good	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Good	Fair	Good	Good	Good
Oil, Mineral	Poor	Fair	Fair	Good	Good	Good	Good	Good	Poor	Poor	Good	Good	Good	Good	Good
Oil, Petroleum-based and Fuels	Poor	Fair	Fair	Good	Poor	Good	Poor	Fair	Fair	Fair	Good	Good	Good	Good	Good
Oil, Silicones	Good	Good	Good	Good	Good	Good	Good	Good	Poor	Poor	Good	Good	Good	Good	Good
Oxidizers	Poor	Poor	Poor	Poor	Poor	Good	Poor	Good	Fair	Fair	Fair	Poor	Poor	Poor	Poor
Salt, Inorganic	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Fair[4]	Good	Good
Solvent, Chlorinated	Poor	Poor	Poor	Fair	Poor	Good	Poor	Poor	Poor	Poor	Good	Fair	Good	Good	Good
Solvent, Hydrocarbon	Poor	Fair	Poor	Good	Poor	Good	Poor	Poor	Poor	Poor	Good	Fair	Good	Good	Good
Water (including steam)	Good	Good	Good	Good	Good	Good	Good[5]	Good	Good	Good	Good	Good	Poor	Good	Good

Good = No significant effect Fair = Mild effect or limited use Poor = Strong effect or prohibited use

Notes:
1. With exception of chlorosulfonic and chloroacetic acids.
2. Good in weak acids, poor in strong acids.
3. With exception of acetic and formic acids.
4. Poor for alkaline salts.
5. May be swollen by exposure to steam.

Degradation resulting from copper-catalyzed oxidation reactions may occur in certain polymers [4.13], [4.80]. A catalyst is defined as a substance that affects the rate or the direction of a chemical reaction, but is not appreciably consumed in the process [4.81]. Because of its proximity to the insulation, ions from copper-based conductors may act as catalysts for oxidation reactions within the insulation, thereby accelerating its degradation [4.82]. This will occur primarily in areas where the insulation is in direct contact with the conductor. Note that often little (if any) degradation of the conductor will occur as a result of this catalysis. Also note that tinning a copper conductor will not prevent this type of reaction because small amounts of copper will migrate through the tin coating.

By-products are also generated from chemically crosslinked XLPE as a result of the high temperature/pressure curing process. By-products such as acetophenone, cumene, and alpha methyl styrene are produced as the chemical crosslinking agent (dicumyl peroxide) decomposes. The results of testing aimed at defining the effect of these chemicals on electrical aging (ac and impulse breakdown strength) indicate that some effect does exist[24]; however, this effect is complex in nature, relatively small in magnitude, and depends not only on the concentration of the by-products but also on their mixture. Hence, no clear-cut rule can be formulated regarding the effects of these chemicals on aging of XLPE insulation [4.83].

Another potential aging mechanism is hydrolytic[25] degradation of Mylar (polyethylene terephthalate) shield film under exposure to high temperature and moisture. In this mechanism, water increasingly reacts with the Mylar polymer as temperature is increased[26] [4.84]. Normally, the Mylar shield in an electrical cable is contained completely within an overall jacket; however, moisture may ingress to the shield through the ends of the cable (which may be loosely wrapped, such as in twisted shielded pair configurations) or through cuts or other damage to the jacket.

It should be noted that, in general, the effects of the chemical decomposition processes on the overall cable inventory appear to be negligible because the fraction producing such by-products is small and the severity of the effects of these by-products is limited.

4.1.5.3 Electrochemical Attack of Metals

Corrosion is a destructive process that is characterized by either chemical or electrochemical attack on metals. Direct chemical corrosion occurs in instances of highly corrosive environments, high temperatures, or both. More common is electrochemical corrosion, which accounts for most degradation experienced by metals exposed to moisture or atmosphere. Electrochemical corrosion can occur at a junction between two dissimilar metals (galvanic reaction) or within one homogeneous metal. Homogeneous metals corrode as a result of variations in electrostatic potential between various regions of the metal (caused by anodic and

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[24] The ac breakdown strength of compression-molded XLPE is increased, whereas the impulse breakdown strength is reduced.

[25] Hydrolysis refers to a reaction with water; in this case, a reaction of the ester group linking the polymer chain with water.

[26] Figure 3 of "Electrical Insulation Deterioration" [4.84] indicates less than 100 hr average life at 100% RH at 110°C, approximately 1 year at 70°C, and roughly 20 years at 50°C.

cathodic areas, inclusions, residual stress, etc.); this potential results in electron flow from anodic to cathodic areas, eventually producing pitting and wastage.

Numerous different types of corrosion may occur, depending on the types of metal involved and the environment. A discussion of each type of metal and its applicable corrosion(s) is beyond the scope of this guideline; however, several common factors can be identified. These include the presence of an electrolyte (such as water), soluble ions in the electrolyte (such as chlorides), elevated temperature, and high oxygen concentration. In addition, some forms of corrosion depend upon the presence of other factors (such as tensile stress). The occurrence and rate of corrosion is affected by a number of factors, including the type of metal, the type and properties of the fluid (electrolyte) in contact with the metal, the presence of other influences (such as stress), and the concentration of oxygen and ions present. Corrosion of cable systems may be enhanced by the presence of stray dc currents from open ground circuits or strong fields.

A related phenomenon is the oxidation of metals to metal oxides. In this case, dissolved oxygen combines with the metal at the surface of the component to form an insoluble metal oxide [such as ferric oxide (rust)]. These oxide layers may have significantly different electrical and physical properties than the underlying parent metal. For example, metallic electrical contacts that oxidize with a less conductive species may experience higher electrical resistance and therefore result in overheating of electrical junctions or interference with circuit operation. In some cases (e.g., passivated metals such as Inconel), the formation of an oxide layer can actually protect the metal and subsequently reduce the rate of certain types of corrosion.

Corrosion of metallic components is important because the electrical and mechanical properties of the component may be affected. Corrosion can attack the surface of conductive components such as electrical contacts, thereby increasing their resistance and reducing their electrical conductivity. Also, if left unimpeded, corrosion may result in loss of the mechanical integrity of a component; this property loss may be significant if the component is under mechanical stress (either during normal or transient conditions) so that mechanical failure occurs.

Cable and termination components are generally fabricated from noncorroding or corrosion-resistant materials, or have nonoxidizing compounds applied to them during assembly. Metals used in cables and terminations vary somewhat, based on their application. Cable conductors are typically copper or aluminum alloys, both of which are somewhat resistant to corrosion under normal power plant environments. However, both materials will oxidize so that a surface oxide layer forms. Termination materials may be fabricated from a variety of different conductive materials (ferrous or nonferrous), and therefore may experience varying rates of corrosion/oxidation [4.21], [4.58]. As previously stated, various chemical by-products may also leach from organic cable and termination components under certain circumstances; these chemicals may result in premature corrosion or oxidation of nearby metallic components.

4.1.5.4 Loss of Fire Retardants

Fire retardants contained in common nuclear plant cable and termination insulating materials volatize under thermal exposure [4.85]. As the cable is thermally aged, increased volatization of certain flammable polymer constituents also occurs, resulting in no increase or even a decrease in flammability. Reference [4.86] documents flammability testing of aged

and unaged EPR and XLPE (BIW Bostrad and Rockbestos Firewall) cables which exhibited reductions of flammability with increased thermal aging for both cable types.

Radiation aging has been observed to have a substantially smaller effect on fire-retardant volatization for some materials, and a broad array of irradiated insulation/jacket combinations (including EPR/Neoprene®, EPR/CPE, and CSPE) passed vertical flame tray testing [4.87]. Therefore, flammability testing of new cable is considered to be conservative in demonstrating the fire retardancy of thermally aged or irradiated materials.

The loss of fire-retardant compounds in cable insulation and jacketing due to thermal aging or irradiation is considered insignificant[27] in that it has been demonstrated that the actual flammability of the most common materials (including XLPE, EPR, and CSPE) either decreases, remains roughly constant, or only increases slightly. This occurs because flammable volatiles within the chemical formulation are lost at nearly the same rate as the fire-retardant [4.88], [4.89], and [4.90].

4.1.5.5 Effects of Oxygen

Another consideration in aging and degradation of organic material relates to the concentration of oxygen in the local atmosphere. As previously discussed, dose rate and synergistic effects all require oxygen. Many aging studies of polymers to date have been conducted in inert or low-oxygen environments; comparatively few studies have been performed in air (roughly 20% oxygen) [4.8]. In addition, many studies focus on analysis of the pure base polymer and not on the more complicated formulations often found in commercial cable and termination materials. However, the great majority of cable systems installed in the typical nuclear plant possess both of these attributes (e.g., operate in a relatively high oxygen concentration and are composed of more complex formulations).

Oxygen effects can be divided into two major categories: physical effects and chemical effects [4.8]. Physical effects are concerned primarily with diffusion-limited oxidation, whereas chemical effects involve oxygen reactions. Substantial evidence indicates that the dominant aging processes for some materials may be quite different in oxidative and non-oxidative (inert) conditions.[28] Oxygen is also generally required for dose-rate effects to occur.[29]

The thermal and radiation-induced degradation described in previous sections may proceed without the presence of oxygen; however, oxidative degradation processes initiated by heat or radiation (thermoxidative or radiation-induced oxidation) within polymers are often dominant over these mechanisms. Accordingly, although a few polymers actually age slower in oxygen (as opposed to nitrogen or other inert gases), the presence of oxygen increases the aging rate of

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[27] Note that this aging mechanism is considered "significant but not observed" in that functionality may be affected, yet no indications of occurrence/effects exist.

[28] NUREG/CR-4301 [4.8] (citing NUREG/CR-3643) describes the aging of Viton fluoroelastomer, which becomes hard and brittle under high dose-rate exposure (limited oxygen permeation), and soft and stretchy at low dose-rates (high permeation).

[29] Note also that NUREG/CR-4301 [4.8] identified no evidence of the existence of dose-rate effects in a nitrogen environment.

most common cable polymers [4.60], [4.62], [4.64]. Higher concentrations of oxygen often result in a greater oxidation reaction rate and hence, more rapid degradation of the physical properties of the material. The aging may also affect the material in nonuniform fashion; if oxygen diffusion occurs slowly with respect to the rate of reaction, sections of the polymer unexposed to oxygen will experience less deterioration (e.g., diffusion-limited degradation) [4.5], [4.60], [4.91], [4.92]. The mechanical properties of the outer surface of the cable polymer will sometimes dictate those of the polymer as a whole. For example, reduced elongation or cracking at the surface of a cable's insulation may result in a crack or tear propagating through the thickness when the cable is bent or pulled. In natural aging (i.e., low temperature, low dose rate) environments, oxidation processes normally dominate [4.8], and oxygen permeation is more complete, thereby resulting in more uniform aging. If cracks in a diffusion-limited material quickly propagate from the hardened outer surface through the thickness, proper simulation of natural aging can result.

For most cable and termination polymers, environments with reduced oxygen concentration will produce reduced rates of aging. Accordingly, organic cable and termination components located inside nitrogen-purged primary containments (typically a few percent oxygen) may experience a somewhat lower aging rate than they would in more heavily oxygenated environment. Although the rate of degradation is also coupled to several other factors (including temperature, ohmic heating, radiation dose/dose rate, and cable configuration/construction), and the effects are difficult to quantify, the presence of oxygen is often a very significant determinant of the aging rate for these materials.

4.1.5.6 Effects of Ozone

In addition to the effects of oxygen described above, the degradation of certain organic insulation and jacketing materials may be affected by ozone (O_3) in the surrounding media. Ozone is generated in air as a result of the interaction of ionizing radiation with oxygen, or by corona discharge ionization. Applicable cable standards (e.g., ICEA S-19-81 [4.93]) discuss ozone performance and testing requirements for ozone-resistant cables.

Reference [4.7] documents an investigation of the effects of ozone on styrene-butadiene rubber (SBR) and Buna-N rubber under gamma irradiation. This study concludes that the heterogeneous degradation of these materials due to irradiation is the result of two processes: (1) radiation-induced oxidation coupled with oxygen diffusion effects, and (2) ozone effects in the surface regions of the sample. The study also suggests that ozone and ionizing radiation may be synergistic in their effect on these materials.

References [4.94] and [4.95] indicate that, in the absence of ionizing radiation, tensile stress on elastomers tends to increase the likelihood of ozone-induced damage in the form of macroscopic surface cracks that propagate progressively through the thickness of the material. The testing described in Reference [4.7] subjected SBR specimens to irradiation under tension (15% elongation), resulting in the formation of substantial cracks at a dose of 0.3 kGy [30 Mrad].

There was no mention in the literature of the applicability of these observations to other commonly used cable and termination organic materials; however, elastomers with double bonds

are most susceptible to ozone effects. Note that Buna-N and SBR account for only a very small percentage of organic cable and termination components currently in use (see, for example, Table 3-4 of this AMG). It can be postulated that the effects of ozone are implicitly considered in the material-specific radiation threshold and degradation data referenced in Section 4.1.4, because a good number of these studies were conducted in oxygenated environments. However, it should be noted that (1) many studies were conducted in inert environments (nitrogen, argon, or vacuum), and (2) some studies performed in air were conducted with limited volumes of oxygen that may have been largely consumed during testing (p. 2.6-1 of [4.8]). It cannot be said with surety, therefore, that all radiation threshold values set forth in Section 4.1.4 include the effects of ozone degradation. Examination of the chemical properties of common cable and termination organics, however, does indicate a good resistance to ozone. For example, EPR/EPDM, CSPE, PVC, silicone rubber, and Viton are all quite ozone resistant ([4.2], p. 474 of [4.31]).

4.1.5.7 "If-Then" Criteria for Chemical Stressors and Aging Mechanisms

Table 4-10 summarizes the chemical stressors, aging mechanisms, and "if-then" criteria applicable to cable and termination components.

4.1.6 Combined Aging Environments

4.1.6.1 Synergisms

Combinations of stressors acting on a given cable or termination component may produce synergistic degradation effects. A synergistic effect is defined as an effect caused by two or more stresses applied simultaneously, which is different in magnitude or type than the summed effects of the same stresses applied separately [4.60]. Two commonly acknowledged synergisms applicable to components covered under 10CFR50.49, namely, dose-rate effects and sequence effects, are discussed in Section 4.1.4.1. Appendix H provides additional information on the regulatory requirements related to these two effects. Other potential synergistic stressor combinations that may affect cable and termination aging are discussed in Section 4.1 and include (1) voltage stress in the presence of moisture (medium-voltage cable insulation); (2) bending stress (tensile elongation) of thermal aged and/or irradiated organic cable materials; (3) thermal cycling and gravity (vertical-horizontal cable runs); (4) thermal aging/irradiation of organic materials in oxygenated environment; and (5) exposure of susceptible metallic cable/termination components to oxygen, moisture, and ionic species.

4.1.6.2 Sandia Research on Combined Thermal-Radiation Aging Environments

Investigations performed by Sandia National Laboratories into combined thermal and radiation aging environments are documented in References [4.5], [4.6], [4.9], [4.70]. As discussed in Section 4.1.4.2, aging of most materials under a sequential aging regimen is comparable to that of a combined (simultaneous) environment. However, for some materials under certain conditions, this may not be the case. Hence, the properties of several common cable insulation and jacket materials under combined thermal/radiation environments were studied in an attempt to better understand the behavior of these materials under "normal" plant aging conditions.

Table 4-10 Chemical Aging Summary for Cable and Termination Components

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/ Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
External chemical agents (4.1.5.1)	Chemical reaction with organics	Variations in elongation, tensile strength, density	-Softening -Material discoloration -Swelling	All cable and termination organic materials	Cable jackets, insulation, or other organic components exposed to direct chemical contact	Varies with duration	See Table 4-9
Internal chemical by-products (4.1.5.2)	Corrosion of metals; chemical reaction with organics	Reduced strength and integrity of metals; variations in elongation, tensile strength, density (organics)	Pitting, wastage, breakage, corrosion by-product formation; high electrical resistance (metals); softening, material discoloration, and swelling (organics)	Chemically X-linked XLPE; chlorinated elastomers (CSPE, Neoprene®, etc.)	None readily determinable	Generally long-term	Copper-catalyzed reactions may affect all elastomers
Heat and/or radiation (4.1.5.4)	Loss of fire retardants	Increased flammability	None evident	All materials with fire-retardant additives	None readily determinable	Generally long-term	Flammability may increase, decrease or remain constant with aging, yet magnitude of overall effect is small. Most modern materials contain fire retardants.
Moisture, heat (4.1.5.2)	Hydrolytic degradation	Changes in density, tensile strength	Reduced shield integrity, noise	Mylar (polyethylene terephthalate)	Cable shielding exposed to high temperature (above roughly 50°C) and high humidity/ moisture	Varies with temperature and humidity	Significant moisture ingress or shield exposure required

Table 4-10 Chemical Aging Summary for Cable and Termination Components (cont'd)

Stressor	Aging Mechanisms	Material Property Changes	Aging Effects/ Indications	Potentially Affected Materials	Applicable "If-Then" Criterion	Relevant Time Period	Remarks
Oxygen, moisture, heat, soluble ions (4.1.5.3)	Electro-chemical corrosion	Reduced tensile and fatigue strength; reduced electrical conductivity	Pitting, wastage, breakage, corrosion by-product formation; high electrical resistance	Primarily ferrous metals, although cuprous and aluminum alloys may be affected	Metal components in wet, oxygenated environments	Generally long-term	May affect conductors, shield/drain, and terminations
Oxygen, moisture (4.1.5.3)	Oxidation of metals	Electrical conductivity	High electrical resistance; discoloration	Metals	Low-current instrument applications where contact electrical resistance is critical	Generally a long- term effect; however, may occur relatively rapidly under certain conditions	Gold-plated contacts used in many applications to minimize oxidation
Oxygen (4.1.5.5)	Thermoxida-tive, radiation-induced oxidation of organics	Elongation, tensile strength	Surface hardening, embrittlement	Most organics	Susceptible materials in oxygenated environments subject to ionizing radiation	Varies	
Ozone (4.1.5.6)	Oxidation of organics	Elongation, tensile strength	Surface hardening, embrittlement	SBR, Buna-N[1]	Susceptible materials in oxygenated environments subject to ionizing radiation	Varies	

Notes:

1. May also affect other materials; see discussion in Section 4.1.5.6 of text.

The approach used in the Sandia investigations was to expand upon existing time-temperature superposition methodology (commonly embodied by the Arrhenius relationship) through development of functional relationships using isothermal dose for a given amount of damage versus dose-rate curves for various materials. These relationships were then extrapolated to predict the time to equivalent damage (TED) as a function of dose rate for various aging temperatures. In this manner, the time to achieve a given damage (in this case, degradation of material tensile elongation to a predetermined value) can be predicted for a given aging temperature, thereby providing an estimate of material longevity under combined thermal and radiation environments.

Figure 4-9 shows a plot of TED versus radiation dose rate for an EPR material, as predicted by the time-temperature-dose rate superposition model.

Results of the Sandia model predictions for very low dose rates show generally good consistency to those of the standard time-temperature (Arrhenius) model. For example, as shown in Figure 4-9, the curve for the 65°C aging temperature indicates a time to reach 100% absolute elongation in excess of 100 years for a dose rate of 0.1 Gy/hr [10 rad/hr], or 53 kGy [5.3 Mrad] over 60 years. Therefore, at dose rates much lower than 0.1 Gy/hr, the predicted life (TED) is far in excess of 100 years. The Arrhenius model (Figure 4-1) predicts a time to reach 50% absolute elongation of several hundred years at 65°C; hence, the results of both models are seemingly consistent. Other materials show similarly consistent results at low dose rates. One significant inconsistency is evidenced by the data for silicone rubber; the Sandia model indicates a lifetime between 10^3 and 10^4 years at 65°C and low dose (<0.01 Gy/hr), whereas the Arrhenius projection of lifetime in Figure 4-1 is in excess of 10^6 years at the same temperature. Closer examination of the activation energies used, however, shows a great disparity between the Sandia value (21 kcal/mole, or 0.91 eV) and the value derived from a manufacturer's qualification report (1.80 eV)[30]; this disparity explains the large difference in results, and underscores the sensitivity of Arrhenius lifetime predictions to the use of formulation-specific activation energy.

As part of the Sandia studies, the concept of "approximate life" is used to facilitate comparisons between materials. Approximate life is defined as the time required for the elongation of a material to decrease to 100% absolute under "normal" plant conditions of 45°C [113°F] and 0.1 Gy/hr [10 rad/hr]. Note that this concept is completely distinct from that of qualified life previously described. Approximate life simply provides an estimate of the longevity of a material under the assumed plant conditions, based on the time-temperature-dose rate superposition model. Table 4-11 lists some of the approximate life values predicted by the Sandia model for various materials in combined thermal-radiation aging environments.

[30] Note that Rockbestos was both the manufacturer of the silicone cable used by Sandia and the source of the test report containing the thermal aging data used to develop Figure 4-1.

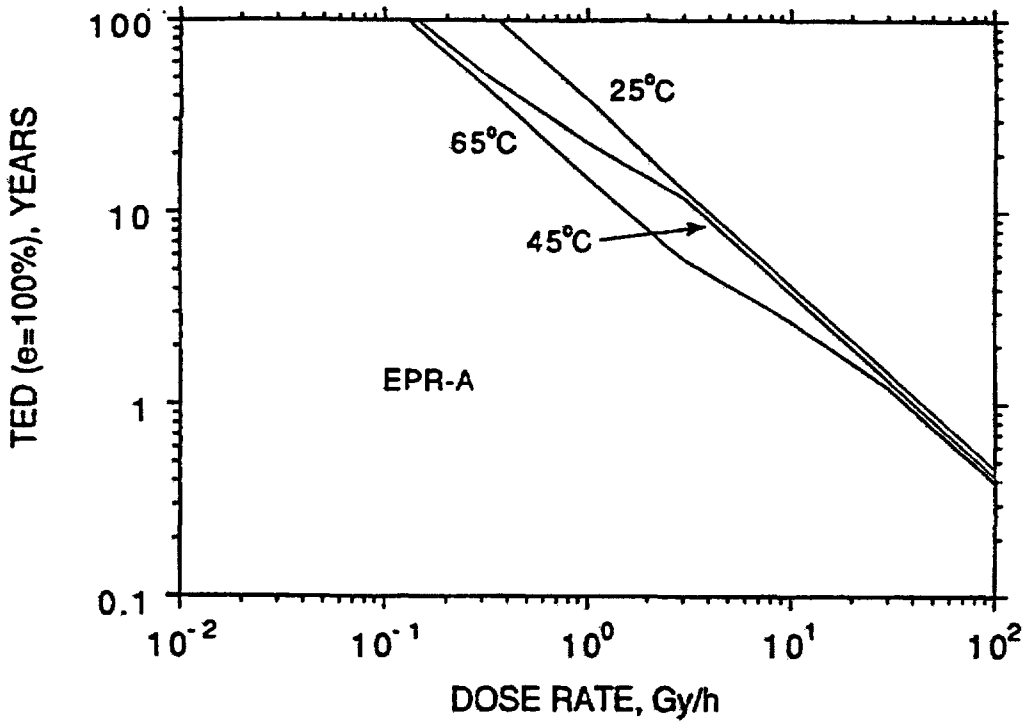

Figure 4-9 Time to Equivalent Damage (TED) versus Radiation Dose for Anaconda EPR (FR-EP) Insulation Material

It should be noted that part of the basis for the approximate life values listed in Table 4-11 was a radiation dose rate of 0.1 Gy/hr (10 rad/hr), which equates to a total dose of approximately 53 kGy [5.3 Mrad] over 60 years. This is roughly the same order of magnitude as the damage threshold radiation value for many cable system polymers (see Table 4-7), and equates to doses found only in locations within primary containment. A dose rate of 10 rad/hr is substantially above the dose rate for most areas outside primary containment (in which the bulk of plant cable is located); hence, the lifetimes predicted for these areas under the Sandia model in References [4.5], [4.6], [4.9], and [4.70] would necessarily be longer, and would approximate thermal-only (e.g., time-temperature superposition) aging as the dose rate approaches zero. Thus, the approximate life values listed in Table 4-11 would seem to be primarily applicable to cable system components located inside of primary containment, where radiation degradation becomes significant. Also, the end of life criterion used in determining the Table 4-11 values is 100% absolute elongation, which is more conservative than the criteria to be proposed in Section 5.2.2.1.1, and used in Table 4-2 and Figures 4-1 and 4-5.

Table 4-11 Approximate Life Values for Cable Insulation and Jacket Materials

Material	Application	Approximate Life[1] (Years)
CSPE (Hypalon®)	Jacket	~90
EPR	Insulation	>100
ETFE (Tefzel®)	Insulation	~100
LDPE	Insulation	~10
Neoprene®	Jacket	~5
PVC	Jacket	~60
Silicone Rubber	Insulation	~50
XLPE (including XLPO)	Insulation	>100

Notes:
1. Derived from SAND90-2009 [4.9] and SAND91-0822 [4.70].

4.1.7 Discussion of Material Similarity

Although it is common to describe conductor insulations using the name of the base polymer (such as EPR or XLPE), the constituents used to make electric cable insulation include materials other than the base polymer in order to obtain specific performance characteristics that cannot be obtained from the base polymer alone. Typical of an actual cable insulation composition are the following: base polymer, clay, fire retardants, anti-oxidants, coloring agents, and anti-radiation compounds. Table 4-12 shows the chemical composition of a typical EPR formulation for nuclear plant cable [4.70].

In general, the larger the fraction of nonbase polymer additives, the more widely the physical characteristics and performance of the compound may vary from those of the base. Additives often constitute more than half of the formulation. Because the additives are proportioned on a weight basis and usually have higher densities than the base polymer, the base polymer still may account for a large percentage of the volume of the insulation. Manufacturers have their own proprietary formulations for each type of application of an insulation identified by the base polymer. Some manufacturers often do not even identify the base polymer, choosing to maintain this information as proprietary. However, because all insulations must meet common requirements of the standard issued by ICEA, the basic characteristics of an insulation are the same regardless of the manufacturer. Some of the performance requirements that any insulation must meet are the following:

- minimum tensile strength
- minimum elongation unaged and aged
- minimum fire resistance
- minimum dielectric strength

- temperature rating
- water resistance measured by specific inductive capacitance (SIC) or specific insulation resistance (SIR)
- thickness tolerances

Table 4-12 Chemical Formulation of a "Typical" EPR Cable Material [4.70]

Constituent	Relative Amounts (by weight)
EPDM	90
Low density polyethylene	20
Zinc oxide	5
90% Red lead dispersion	5
Paraffin wax	5
Zinc salt of mercaptobenzimidazole	2
Low temperature reaction product of acetone and diphenylamine	1
Treated calcined clay	60
Vinylsilane	1
SRF black	2
Diadduct of hexachlorocyclopentadiene and cyclooctadiene	33
Antimony oxide	12
Dicumyl peroxide	3

The specific composition of a material may play an important role in the longevity or performance of a particular cable or termination organic material with respect to thermal, radiation, or other aging influences. Thermal or radiation aging evaluations such as those previously discussed ideally should be based on material aging data pertinent to the specific formulation in use at the plant as opposed to data for a generically similar material. This is particularly true of environmentally qualified components, because the demonstration of post-accident functionality is dependent on the properties of the specific materials used during qualification testing. For non-EQ components or those qualified by analysis, use of generic aging data may be the only viable alternative for the reasons stated in the next paragraph. While there is substantial generic behavior of materials, examination of laboratory test data for various cable system materials during preparation of this guideline [4.6], [4.8], [4.9], [4.60], [4.61], [4.66], and [4.70] has indicated that the performance of two ostensibly similar materials (e.g., belonging to the same generic class) may vary widely based on differences in chemical formulation.

At present, the exact chemical compounding of many organic cable system components cannot be readily determined because (1) manufacturers will often maintain the formula of their material as proprietary, (2) variations in the product may occur within a given production period in the manufacturing facility, (3) the manufacturer may not keep records of adequate specificity for the required historical time period, and (4) many manufacturers of cable installed in nuclear plants are no longer in business, or the product lines have been sold and marketed under different trade names and formulations. Furthermore, the cable/termination manufacturer's source for the base polymer or other constituents of a given material may have changed over time. 10CFR50, Appendix B quality assurance requirements are applicable only to safety-related components; hence, manufacturer traceability for chemical formulation is more likely to exist for such components. For nonsafety-related components (especially those manufactured many years ago), information on precise formulation may be lost altogether. Note, however, that many plants use the same type of cable for both safety- and nonsafety-related applications in an effort to maintain uniformity and reduce the number of different cable products used in the plant and maintained in stores.

Generally, cable system components produced by a given manufacturer can be differentiated in terms of their production date/lot number. The specific cable lot or production date may be obtained through examination of plant or carrier records (including delivery tickets, purchase orders/specifications, and receipts) or, in lieu of this information, contacting the manufacturer directly (if still in business). However, knowledge that a cable reel purchased by the plant is from one lot as opposed to another, or is of one formulation rather than another, is of little practical value unless these differences can be correlated to differences in material aging performance or qualification. For example, one formulation of a generic polymer may have advantageous thermal aging properties; if it can be demonstrated that cable manufactured with that polymer is installed, the estimated (and actual) life of that cable may be extended accordingly.

With regard to EQ components, 10CFR50.49(f) indicates that electrical equipment important to safety may be qualified through testing or analysis of identical or "similar" items. No additional regulatory guidance as to what constitutes an adequate demonstration of material similarity was located during the preparation of this guideline. ANSI/IEEE 323-1983 [4.96] discusses material similarity and indicates that the construction materials of the item to be qualified should be the same or equivalent to those tested; any differences identified should be shown not to affect safety function.

Note that a certificate of conformance (C of C) is typically issued by the component manufacturer to indicate that a particular component was certified to a particular qualification test report. It is the utility's responsibility to ensure that the materials, configuration, service environment, etc. of the installed component are comparable to the parameters in the qualification test report.

4.2 Determination of Applicable Aging Mechanisms and Effects

This section defines the applicable aging mechanisms resulting from stressors identified in Section 4.1. Stressors acting on cables and terminations and their components include:

- Thermal
- Electrical
- Mechanical
- Radiation
- Chemical and Electrochemical
- Oxygen

Generic aging mechanisms associated with these stressors include the following:

Thermal

- Thermal degradation of organic materials

Electrical

- Voltage-induced degradation (including electrical treeing)
- Partial discharge
- Moisture-induced degradation
- Loss of surface insulating properties (including surface tracking)
- Water treeing

Mechanical (Conductor and Metallic Termination Components)

- Vibration-induced fatigue
- Tensile elongation due to creep
- Maintenance handling wear (including work hardening)
- Incidental physical damage
- Electrical fault-induced tensile damage

Mechanical (Insulation, Jacket, and other Organic Components)

- Vibration-induced cutting or abrasion
- Elongation and cutting/abrasion due to creep
- Incidental physical damage
- Electrical fault-induced tensile elongation
- Compression set
- (Note: installation damage is not considered an aging mechanism.)

Radiation

- Radiolysis of organics
- Photolysis of organics

Chemical and Electrochemical

- Direct chemical attack of organics
- Chemical decomposition of organic materials

- Electrochemical attack of metals (including oxidation and corrosion)
- Loss of fire retardants

Oxygen

- Thermoxidative degradation
- Radiation-induced oxidation

Aging mechanisms for each cable and termination subcomponent considered to be significant are discussed in Section 4.2.1; however, the applicability of some aging mechanisms to actual cable systems may be very limited or the frequency of their occurrence may be extremely low. For example, conductor corrosion is expected to affect only an extremely small fraction of the cable population. For most cables, this aging mechanism will be of no consequence. Similarly, UV-induced degradation of organics is significant only for circuits that use components which are both susceptible to UV and exposed to substantial UV sources (a very small fraction of the total population). Hence, Section 4.2.2 identifies that subset of significant aging mechanisms which is considered most important to continued cable and termination functionality. Those aging mechanisms considered nonsignificant (i.e., which have no identifiable effect on functionality if left unmitigated) are discussed in Section 4.2.3.

4.2.1 Significant Aging Mechanisms

An aging mechanism is considered to be significant when it may result in the loss of functionality of a component or structure during the license renewal period if it is allowed to continue without mitigation. Loss of cable or termination functionality resulting from an aging mechanism is determined through examination of the design function of each subcomponent and the potential effect of the aging mechanism on that function. In the following tables, these aging mechanisms have been substantiated where possible through evaluation of operating history. Tables 4-13 through 4-17 summarize significant stressors, aging mechanisms, associated degradations, and potential effects of these degradations for each cable and termination subcomponent.

4.2.2 Significant and "Observed" Aging Mechanisms

Significant and "observed" aging mechanisms are those significant aging mechanisms that have been shown to occur with a relatively higher frequency than background within the applicable voltage category. Classification of an aging mechanism as significant and observed is based upon analysis of operating and maintenance experience. Those aging mechanisms that are reflected in substantial proportions of the NPRDS and/or LER failure reports for a given voltage category, are evidenced in information provided by host utilities or in surveys, or are otherwise cited as significant in industry sources or studies, may be designated as significant and observed mechanisms. This empirical approach is used because it describes an aging mechanism and provides information on the frequency of occurrence in relation to other aging mechanisms. This approach also implicitly identifies only those aging mechanisms applicable to appreciable portions of the total cable population (within a given voltage category) because such mechanisms will, in general, result in greater numbers of failures. Furthermore, it helps eliminate purely "hypothetical' aging mechanisms and effects.

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Conductor	Electro-chemical stress (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces	Increased resistance and heating at terminations	Generally requires severe damage to jacket/insulation wall coupled with moist environment; more of a concern for fine stranded conductors or high current applications
	Vibration, manipulation	Fatigue; work hardening	Embrittlement of conductor	Broken or weak conductor; high resistance	Usually at or near terminations; rare condition
	Tensile stress	Creep; tensile elongation; cold flow	Elongation of conductor; loosening of termination	High connection resistance/heating; reduced strength	Rare; most often associated with improperly installed and/or supported cables. Cold flow of aluminum conductors only
Insulation (including semi-conducting shield)	Heat	Thermal degradation of organics (environmental and ohmic/induced currents); loss of fire retardants	Embrittlement, cracking, melting, discoloration	Reduced IR; electrical failure; noise; changes in flammability	
	Radiation	Radiolysis and photolysis of organics; loss of fire retardants	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure; changes in flammability	Photolysis only applicable to sensitive materials exposed to significant UV sources
	Chemical agents	Chemical degradation of organics	Softening, swelling, flowing, cracking, discoloration	Reduced IR; electrical failure	Material specific; limited number of cables exposed
	Moisture; contaminants	Moisture intrusion; water treeing; contamination with dirt or foreign material	Formation of water trees; contamination by soluble/insoluble ions	Reduced IR; electrical failure	Water treeing for medium-voltage cable only
	Voltage	Voltage-induced degradation (including partial discharge); loss of surface insulating properties (including surface tracking)	Tracking path formation; dielectric breakdown	Reduced IR; electrical failure	Slow, long-term mechanism applicable to medium-voltage cable operating at or above 4 kV
	Copper ions from conductor	Copper-catalyzed oxidation	Embrittlement, cracking, discoloration	Reduced IR, electrical failure	Identified in both radiation and thermal environments for polyolefin materials (EPR, LDPE, XLPE, XLPO).

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Oxygen	Thermoxidative and radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor.
	External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure	Work in area; personnel traffic; poor support practices
Conductor Jacket	Heat	Thermal degradation of organics; loss of fire retardants	Embrittlement, cracking, discoloration	Note 1; changes in flammability	
	Radiation	Radiolysis of organics; loss of fire retardants	Embrittlement, cracking, discoloration, swelling	Note 1; changes in flammability	
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, discoloration	Note 1	Material specific; affects few cables.
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR, electrical failure	In oxygen environments, this is usually the dominant stressor
	External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Note 1	More common in panels or covers where wiring could be subject to tight bends, sharp edges, or pinching in covers during reassembly. Work in confined space may aggravate this type of aging.
Shielding (including drain wire, shielding wraps, and braid)	Heat	Thermal degradation of organics	Embrittlement, cracking, melting, discoloration	Reduced shield effectiveness (increased noise or leakage)	Applicable only to organic portions of shield (such as mylar) if any
	Radiation	Radiolysis of organics	Embrittlement, cracking, discoloration	Reduced shield effectiveness (increased noise or leakage)	Applicable only to organic portions of shield (such as mylar) if any. No photolysis
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, discoloration	Reduced shield effectiveness (increased signal noise or leakage currents)	Material specific; assumes penetration through outer jacket

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Tensile or other mechanical stress	Creep; tensile elongation	Elongation/breakage of drain wire	Reduced shield effectiveness; accumulation of charge	Usually associated with improper installation or support of cable
	Electro-chemical (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion of shield and drain wire	Reduced shield effectiveness; accumulation of charge	
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failures	In oxygen environments, this is usually the dominant stressor
	Heat and humidity/ moisture	Hydrolytic degradation	Loss of shield integrity	Reduced shield effectiveness (increased noise/leakage)	Rate of degradation proportional to both moisture (humidity) and temperature
Outer Jacket	Heat	Thermal degradation of organics	Embrittlement, cracking, melting, discoloration	Reduced mechanical integrity and protection from environment	
	Radiation	Radiolysis; photolysis (of UV sensitive materials only)	Embrittlement, cracking, discoloration, swelling	Reduced mechanical integrity and protection from environment	Swelling of jacket may make re-termination difficult
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, discoloration	Reduced mechanical integrity and protection from environment	Material specific
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor
	External mechanical influences	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced mechanical integrity and protection from environment	Work in area; personnel traffic
Armor/Sheath	External mechanical influences	Work hardening or deformation of metallic sheath	Bending or crimping; reduced flexibility in localized areas	Reduced mechanical integrity/protection from environment	

Table 4-13 Summary of Cable Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Cable Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Electro-chemical (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion of metal sheath	Reduced sheath integrity; moisture/chemical intrusion	
	Chemical agents	Corrosion and oxidation of metals; chemical degradation or organics (where installed)	Direct corrosion or chemical attack	Reduced mechanical integrity/protection from environment	Material specific; most materials specifically used to resist corrosive environments

Notes:

1. Degradation of the conductor jackets of some bonded insulation/jacket systems may produce damage to the underlying insulation. This generally occurs only in cases where the aging of the jacket is substantial, and substantial tensile stress (such as that during bending of the conductor) is applied. See Section 4.1.3.4 of this guideline for further information.

Table 4-14 Summary of Connector Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Connector Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Electrical contacts	Electro-chemical stresses (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion/oxidation of external contact surfaces	Increased resistance and heating; loss of circuit continuity	
	Mechanical stress; manipulation	Wear; fatigue; work hardening	Bending/breakage of contacts; wear of contact surfaces	Increased circuit resistance and heating; loss of continuity	May result from frequent assembly/disassembly of connection
	Dirt/ contaminants; moisture	Contamination with dirt or foreign material	Fouling/contamination of contact surfaces	Increased resistance; loss of continuity	
Electrical terminations/ solder joints	Tensile/ fatigue stress; manipulation	Creep; tensile elongation; fatigue; work hardening	Embrittlement/breakage of solder joints; loosening of compression fittings	Increased resistance/heating; loss of continuity	
Dielectric materials (organic)	Heat	Thermal degradation of organics	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	
	Radiation	Radiolysis and photolysis of organics	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	Photolysis only for exposed UV-sensitive organic materials
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking, discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor.
	Voltage; contaminants	Partial discharge; loss of surface and/or volumetric insulating properties	Tracking path formation; dielectric breakdown	Reduced IR; electrical failure	High voltage stress required
O-Rings/seals	Heat	Thermal degradation of organics	Embrittlement, cracking, swelling, or discoloration	Leakage or moisture intrusion	May be aggravated by assembly/disassembly of connector
	Radiation	Radiolysis of organics	Embrittlement, cracking, swelling, or discoloration	Leakage or moisture intrusion	May be aggravated by assembly/disassembly of connector
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement, cracking,discoloration	Seal failure	In oxygen environments, this is usually the dominant stressor
	Chemical agents	Chemical degradation of organics	Softening, flowing, cracking, swelling, or discoloration	Leakage or moisture intrusion	Material specific; may be aggravated by assembly/disassembly of connector

Table 4-14 Summary of Connector Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Connector Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
	Compressive stress; manipulation	Wear	Cutting, chafing, abrasion, or adhesion during connector assembly/disassembly	Reduced integrity; leakage	
		Stress relaxation	Increased compression set	Leakage	Varies as function of material and aging environment
Hardware (coupling mechanism, cable clamp, and backshell)	Electro-chemical stress; moisture	Corrosion and oxidation of metals	Corrosion, oxidation	Loss of mechanical integrity; loose electrical connections; increased stress on cable or wire components	Occurs mostly in connectors located in moist or wet environments
	Mechanical stress; manipulation	Wear; fatigue; work hardening	Deformation/breakage of components	Loss of mechanical integrity; loose electrical connections; increased stress on cable or wire components	Overtightening; repeated assembly/disassembly (for maintenance or surveillance); work in area/personnel traffic; stress from attached cable

Table 4-15 Summary of Compression and Fusion Fitting Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Compression Fitting Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Crimped fitting	Electro-chemical	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces	Increased resistance and heating; loosening of crimp; breakage of lug	
	Mechanical stress; manipulation; insufficient crimp	Fatigue; work hardening	Embrittlement or deformation of lug; loosening of crimp on conductor	Poor electrical contact (high resistance)	Crimp may loosen with time due to thermal expansion, vibration, or other effects (see cold flow of aluminum conductors; Table 4-13)
Mechanical clamp assembly (bolt/hardware)	Electro-chemical	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces and clamp mechanism	Increased resistance and heating; failure of mechanism/loosening of conductor	
	Mechanical stress; manipulation	Fatigue; work hardening	Embrittlement or deformation of clamp mechanism and lug; loosening of lug on conductor	Poor electrical contact (high resistance)	Clamp may loosen with time due to thermal expansion, vibration, or other effects; may be tightened
Fusion fitting	Electro-chemical	Corrosion and oxidation of metals	Corrosion/oxidation of external surfaces of lug and weld	Increased resistance and heating; failure of fusion weld/loosening of conductor	Corrosion of weld depends on type of fusion process and materials used
	Mechanical stress; manipulation	Fatigue; work hardening	Embrittlement or deformation of lug; loosening of lug on conductor	Poor electrical contact (high resistance)	Fusion welds typically highly resistant to mechanical stresses

Table 4-16 Summary of Splice Insulation Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Splice Insulation Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Insulation/ sealing system (including heat shrink and tape wrap)	Heat	Thermal degradation of organics (environmental and ohmic/induced)	Embrittlement; cracking; melting; discoloration	Reduced IR; electrical failure	
	Radiation	Radiolysis and photolysis of organics	Embrittlement; cracking; discoloration	Reduced IR; electrical failure	Photolysis applicable only to exposed UV-sensitive materials
	Chemical agents	Chemical degradation of organics	Softening; flowing; cracking; discoloration	Reduced IR; electrical failure	Material specific
	Moisture; contaminants	Moisture intrusion	Contamination by soluble/ insoluble ions	Reduced IR; electrical failure	
	Voltage	Partial discharge, loss of surface and/or volumetric insulating properties	Tracking path formation; dielectric breakdown	Reduced IR; electrical failure	Slow, long-term mechanism applicable to medium-voltage systems operating at or above 4 kV
	Oxygen	Thermoxidative, radiation-induced oxidation	Embrittlement; cracking; discoloration	Reduced IR; electrical failure	In oxygen environments, this is usually the dominant stressor
	External mechanical influences	Wear or low-cycle fatigue	Cutting; cracking; abrasion; tearing	Reduced IR; electrical failure	Work in area; personnel traffic

Table 4-17 Summary of Terminal Block Subcomponent Stressors, Significant Aging Mechanisms, Degradations, and Potential Effects

Terminal Block Subcomponent	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Terminal hardware and accessories	Electro-chemical (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion/oxidation of terminals/lugs	Increased resistance and heating; loss of continuity; failure of hardware	
	Mechanical stresses/ manipulation	Wear; fatigue	Loosening; deformation or breakage of hardware	Increased resistance or loss of circuit continuity	Wear/damage during landing of terminations
Terminal block (dielectric)	Heat	Thermal degradation of organics	Embrittlement; cracking; discoloration	Reduced IR; electrical failure	
	Radiation	Radiolysis or photolysis of organics	Embrittlement; cracking; discoloration; swelling	Reduced IR; electrical failure	Photolysis applicable only to exposed UV-sensitive materials
	Chemical agents	Chemical degradation of organics	Softening; cracking; discoloration	Reduced IR; electrical failure	Material specific
	Moisture; contaminants; voltage	Loss of surface insulating properties; contamination with foreign materials	Contamination by dirt or other particulates; formation of tracking paths	Reduced IR; tracking; eventual electrical failure	Failure more likely with combination of dirt followed by condensation.

Although the total or absolute rate of occurrence for a specific aging mechanism or effect cannot be reliably determined from the information sources used in this study, a good estimation of the relative frequency of occurrence can be made. For example, it was determined from the NPRDS data in Section 3.7 that thermal degradation of low-voltage cable insulation accounted for a much higher percentage of failure reports than conductor corrosion. Therefore, it may be inferred that the rate of occurrence of thermal degradation is much higher than that of conductor corrosion. It should be remembered that because the data and industry information indicate that the overall failure rate for cable and terminations of all voltage classes is extremely low (see Section 5.4.2 of this guideline), even these "principal" aging mechanisms are often of little consequence to the continued functionality of the plant cable systems as a whole. Accordingly, no truly significant aging mechanism/component combinations will be excluded through consideration of only the "significant and observed" aging mechanisms and effects. Finally, as noted in Section 3, current operating experience does not include accident reliability data and normal operating condition data may not be useful for predicting accident reliability.

An additional consideration relates to possible changes in the rate of aging or failures identified in industry/plant data (such as NPRDS or LERs). Specifically, aging mechanisms or effects that may not be observed at one point in time may later become more significant. Therefore, the list of significant and observed aging mechanisms is not necessarily limited to those described here; subsequent indications of increased failure rate/degradation in the data, especially as more plants reach the end of their current operating period, may dictate consideration of additional mechanisms and effects not currently included as "significant and observed."

It should be noted, however, that data from plants of ages ranging from a few years to more than 30 years were used as the basis for the determination of significance, and no aging mechanisms or effects occurring solely during the license renewal period (previously referred to as "age-related degradation unique to license renewal," or ARDUTLR) were identified as part of this study. Furthermore, no appreciable enhancement or acceleration of aging stressors is anticipated for most plants (for example, the mean ambient temperature or dose rate for cables/ terminations located in a given plant space is not expected to increase significantly as the plant ages). Therefore, the likelihood of substantially increased effects or failure rate resulting from aging mechanisms currently categorized only as "significant" is considered low.

Section 3.7.6 identified the following aging mechanisms as occurring at a relatively high frequency in comparison to other mechanisms:[31]

Low-Voltage Cables (including Panel and Hookup Wire)

- Localized thermal/thermoxidative aging and embrittlement of insulation and jacketing[32]
- Bulk thermal/thermoxidative aging of insulation/jacketing due to ambient and ohmic effects

[31] Based on review of the operating history (NPRDS and LER) and other available industry sources.

[32] Where required for environmental qualification considerations.

- Localized radiolytic degradation of insulation/jacketing
- Localized degradation of insulation/jacketing due to external mechanical stressors

Terminations

- Oxidized, corroded, or dirty connector contact surfaces
- Loosening or breakage of compression fitting lugs

Medium-Voltage Cables

- Wet aging of voltage-stressed insulation

Neutron Monitoring Cables

- Oxidized, corroded, or dirty connector contact surfaces
- Localized thermal, radiolytic, and incidental mechanical damage to neutron detector circuit cables located in proximity to the reactor vessel

Based on the above considerations, these mechanisms were designated as the most significant aging mechanisms for electrical cable and terminations used in low- and medium-voltage and neutron monitoring systems. These mechanisms are summarized in Table 4-18.

In addition, one other related consideration regarding cable/termination aging was identified in Section 3.7.6:

- Damage to medium-voltage cable insulation during installation

Cable installation damage is discussed further in Section 6 of this guideline.

4.2.3 Nonsignificant Aging Mechanisms

Those aging mechanisms identified in Section 4.1 but that did not meet the criteria for significance are described in the following three subsections.

4.2.3.1 Aging of Filler Material

Filler material is used to fill the interstices between individual conductors and maintain the mechanical rigidity in some cables. Degradation of this material does not affect the aging or functionality of the cable as a whole; the only potential results are "wicking" of moisture along conductors (if the ends are open and wet), loss of mechanical rigidity, or possible release of chemical by-products from the decomposition of the filler.

Table 4-18 Summary of Cable and Termination Stressors, Significant and Observed Aging Mechanisms, Degradations, and Potential Effects

Voltage Category	Component	Subcomponent(s)	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Low	Cable	Insulation and jacketing	Heat, oxygen	Thermal/thermoxidative degradation of organics (environmental and ohmic/induced currents)	Embrittlement, cracking, melting, discoloration	Reduced IR; electrical failure; increased vulnerability to failure in harsh environments	
			Radiation, oxygen	Radiolysis and photolysis of organics; radiation-induced oxidation	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure	Photolysis only applicable to exposed UV sensitive materials
			External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure	Work in area; personnel traffic; poor support practices
	Connector	Contact surfaces	Electrochemical stresses (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion and oxidation of external surfaces of contacts	Increased resistance and heating; loss of circuit continuity	
	Compression fitting	Lug	Vibration, tensile stress	Deformation and fatigue of metals	Loosening of lug on conductor; breakage of lug	Loss of circuit continuity; high resistance	
Medium	Cable	Insulation	Moisture and voltage stress	Moisture intrusion; water treeing	Formation of water trees; localized damage	Electrical failure (breakdown of insulation)	

Table 4-18 Summary of Cable and Termination Stressors, Significant and Observed Aging Mechanisms, Degradations, and Potential Effects (cont'd)

Voltage Category	Component	Subcomponent(s)	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects	Remarks
Neutron detecting	Cable	Insulation	Heat, oxygen	Thermal/thermoxidative degradation of organics (environmental)	Embrittlement, cracking, melting, discoloration	Reduced IR; electrical failure	Typically occurs near heat source such as reactor vessel
			Radiation, oxygen	Radiolysis of organics; radiation-induced oxidation	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure	Typically occurs near or under reactor vessel
			External mechanical stresses	Wear or low-cycle fatigue	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure	Incidental contact, work in area
	Connectors	Contact surfaces	Electrochemical stresses (moisture, oxygen, etc.)	Corrosion and oxidation of metals	Corrosion and oxidation of external surfaces of contacts	Increased resistance and heating; loss of circuit continuity	

4.2.3.2 Electrical Fault-Induced Mechanical and Thermal Stress

Faults occurring in power circuits may induce significant forces and mechanical stresses on cable and termination components.[33] However, in most plants, (1) the total number of faults occurring on an annual basis in relation to the number of power circuits in the plant is extremely small, (2) the number of faults occurring on any one circuit during its lifetime (if any) is also extremely small, (3) the fault clearing time is extremely short so that significant forces are experienced by the cable for only a brief period, and (4) many cable runs are in conduits, duct banks, or otherwise constrained so that damaging forces on cable and termination components due to acceleration of the cable cannot be developed. Thermal stresses resulting from these events, although potentially large in magnitude, usually last only for very short durations and occur so infrequently as to be an insignificant contributor to the thermal aging degradation of organic cable and termination components.[34]

4.2.3.3 Aging of Tape Wrap

Mechanical tape wrap is used to maintain the mechanical rigidity of some electrical cables during its fabrication. Degradation of purely mechanical tape wraps poses no threat to cable functionality in that these wraps serve no real function after manufacture of the cable. However, degradation of aluminized Mylar or other similar wraps used for shielding is considered a significant aging mechanism.

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[33] Faults do not include electrical overload conditions for the purposes of this discussion.

[34] Note, however, that thermal degradation (such as insulation melting) may occur under extreme conditions of conductor temperature.

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5. EVALUATION OF AGING MECHANISMS AND EFFECTS

5.1 Aging Management Review

The amended version of 10CFR54 [5.1] discusses the concept of an "aging management review"; specifically, the Integrated Plant Assessment (IPA) described in Section 2.4 of this AMG must list those structures and components subject to an aging management review, and must demonstrate that the effects of aging on the functionality of such structures and components will be managed to maintain the current licensing basis so that there is an acceptable level of safety during the period of extended operation. Furthermore, the time-limited aging analyses required by 10CFR54.21 for some SSCs,[1] which form the basis of a plant operator's conclusion regarding the capability of those SSCs, must consider the effects of aging and be based on explicit assumptions defined by the current operating term of the plant. The specific methods to be used by the plant operator in meeting these requirements are not mandated; each operator can select the most appropriate method(s) or technique(s) for the plant's aging management review.

Section 5.2 of this guideline discusses maintenance, surveillance, and condition monitoring techniques applicable to electrical cable and terminations. Section 5.3 identifies those practices and programs that are currently being used by plant operators to maintain these systems. Section 5.4 evaluates the effectiveness of these systems in mitigating the significant and observed aging mechanisms identified in Section 4.2. Section 6.3 discusses proposed methodologies for performing an aging management review.

5.2 Maintenance, Surveillance, and Condition Monitoring Techniques for Evaluation of Electrical Cable and Terminations

Maintenance, surveillance, and condition monitoring are performed to ensure that the characteristics or attributes of components that are essential for operation are maintained. The following generic activities may be performed during the operation, maintenance, testing, and condition monitoring of cable systems:

- Visual or physical inspection
- Measurement of component or circuit properties
- Operability testing
- Cleaning
- Component repair or replacement

[1] The most notable example of a time-limited aging analysis (TLAA) for electrical cable and terminations is that pertaining to the qualified life of environmentally qualified components pursuant to 10CFR50.49. 10CFR54.21(c) requires such analyses to remain valid for the license renewal term; the analysis must be updated or the effects of aging otherwise demonstrated to be adequately managed during the extended operating period.

- Thermographic inspection
- Monitoring of temperature or other environmental conditions
- Analysis of circuit loading and operating time
- Arrhenius analysis and use of accelerated aging data

Each of these maintenance, testing, and condition monitoring activities is discussed in the following subsections. Note that despite the apparent quantity of industry standards applicable to electrical cable and terminations (Appendix C), little specific guidance is available for *in situ* tests to evaluate the component condition or remaining qualified life. The great majority of these standards do not address anticipated modes of failure. One notable exception is IEEE 1205-1993 [5.2], which provides useful information on identifying, assessing, and mitigating the effects of aging degradation in Class 1E equipment. Although not specifically oriented toward cables and terminations, much of the guidance is generically applicable to these devices.

5.2.1 Physical Properties by Inspection

One of the most powerful techniques for evaluating the aging of cable systems is periodic visual and mechanical inspection, because the effects of many degradation stressors (including heat, chemicals, radiation, mechanical stress, moisture, and contaminants) are readily detectable in this fashion. By simply observing physical changes in cable system components, their relative condition can often be ascertained. For example, a cable that shows cracking or whitening and is brittle is likely to have been exposed to heat and/or radiation. Similarly, a cable that has softened and discolored may have suffered external chemical damage. However, the effectiveness of this technique at detecting degradation may be limited in certain circumstances; depending on the type of degradation mechanisms at work, a cable or component that exhibits no outward indications of degradation may nonetheless be degrading at a significant rate.[2]

Physical properties to consider when inspecting components include:

- Surface condition (including cracking, crazing, texture)
- Color
- Size (swelling, shrinkage, deformation, or compression set)
- Physical integrity (tight or loose)
- Flexibility or embrittlement (requires manipulation in accordance with an inspection procedure)

[2] This limitation is also true of many other techniques, as discussed later.

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

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

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

Physical access, adequate lighting, etc. are required to perform an inspection. Consequently, it may not be possible to inspect some cables, for example, armored cable, cable routed in conduit, and cable inside fire barriers. Focused periodic inspection of cable segments at end devices, terminations, or near "hot spots" will likely be the most beneficial, because most cable and termination degradation appears to be localized. Bulk runs of cable may also be inspected; however, experience has tended to indicate a much lower incidence of significant bulk run aging compared to that occurring near end devices due to the typically higher incidence of localized stressors (such as heat, radiation, and chemicals) near the end devices.

Degradation affecting internal termination components (such as O-rings, contact surfaces, etc.) can only be visually assessed through disassembly of the termination; hence, maintenance activities that involve such disassembly provide a good opportunity to perform these inspections. Some components can be inspected during non-maintenance periods or without disassembly. For example, terminal blocks can be visually inspected during operation for signs of surface tracking, insulator cracking, or other degradation. Similarly, corrosion of metallic components can often be directly observed. Looseness of a connector or lug can often be identified by moving the attached cable or grasping the termination when it is deenergized.

One additional factor should be considered when performing visual/physical inspections. Based on the data presented in Section 3, much of the degradation noted in cable and terminations (especially low-voltage systems) appears to occur at or near the end device. Therefore, unless the entire run of cable is to be inspected, these efforts should be conducted preferentially in the vicinity of end devices or near high stress areas, with bulk cable runs inspected on a sampling basis. Because most plant maintenance activities are also focused on these end devices, maintenance provides a good opportunity to conduct coincident inspections of nearby cable and terminations. Accordingly, credit may be taken for those cases where cable

system inspections are performed during maintenance. Note, however, that to take credit, records containing evidence of performing inspections or inspection results must be retained.

Table 5-1 correlates various degradation mechanisms to their applicable inspection techniques and indications. Note that these techniques are meant only as a guide and may not be a suitable substitute for a more detailed evaluation and/or root cause analysis. Furthermore, if some signs of degradation are noted through inspection, plant operators may wish to employ more quantitative methods for assessing component condition.

5.2.2 Measurement of Component or Circuit Properties

Diagnostic techniques to assist in assessment of the functionality and condition of power plant cables and terminations are described in this section. Some of these techniques are useful for evaluating installed cables, whereas others are destructive tests that must be conducted with samples of cable materials removed from service. Some of these methods are useful for predicting the long-term performance of cables, and others are useful primarily for troubleshooting. The remainder consist of laboratory tests for characterizing the properties and performance of specific cable materials. A limited number of these techniques are at a stage of development to permit practical application, whereas others require further investigation and evaluation to determine their usefulness as a condition monitoring, troubleshooting, or laboratory evaluation tool. Currently available techniques are described in Section 5.2.2.1; those still under development are discussed in Section 5.2.2.2.

The diagnostic techniques described below may also be categorized in terms of the type of degradation they address. Localized degradation, as the name indicates, refers to aging effects that are spatially localized within small areas or to one portion of a circuit. Bulk degradation refers to aging that affects a relatively large portion of one or more circuits. For example, thermal exposure of a termination and cable end connected to a motor would constitute localized aging. Conversely, thermal aging of a number of circuits in an area with a high ambient temperature would be considered bulk aging. With respect to diagnostic techniques, the distinction is significant, because bulk degradation cannot necessarily be inferred from measurement of a localized component area, and vice versa.

Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal- and radiation-induced aging. For low-voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed. For medium-voltage cables, however, changes in mechanical properties may or may not precede electrical failure. Accordingly, the test and diagnostic techniques applicable to low-voltage systems may differ substantially from those used for medium-voltage systems.

Table 5-1 Inspection Techniques Applicable to Various Degradation Mechanisms - Cables and Terminations

Stressor Category	Aging Mechanism	Indications/Effects Detectable Through Inspection	Potential Causes	Applicable Inspection Techniques	Accelerating Factors/Remarks
Thermal	Thermal/ thermoxidative	Hardening, embrittlement, cracking, discoloration, surface crazing, shrink-back, melting (in extreme cases for thermoplastics)	Ambient or localized thermal exposure; ohmic heating	- Visual inspection - Flexibility determination - Evaluation of hardness	Oxygen, radiation may accelerate
Radiation	Radiolysis, oxidation	Hardening, embrittlement, cracking, discoloration, surface crazing, swelling (with moisture)	Ambient or localized radiation exposure	- Visual inspection - Flexibility determination - Evaluation of hardness	Oxygen, thermal aging may accelerate
	Photolysis	Crazing, surface cracking, or discoloration of UV-sensitive materials	UV exposure (indoor or outdoor)	- Visual inspection of surface - Flexibility determination - Identification of UV source	Comparatively few organics are UV sensitive
	Displacement	Embrittlement, discoloration, or hardening of metals	Neutron exposure	- Visual inspection - Evaluation of hardness/flexibility	Requires very high neutron dose
Mechanical	Bending/ manipulation	Cracking of embrittled organics	Bending or handling during maintenance or inspection	- Visual inspection - Flexibility determination - Evaluation of hardness	Frequently handled components most susceptible
	Wear (terminations only)	Friction; wear products	Assembly/disassembly; inadequate lubrication	- Visual inspection - Feel during assembly/disassembly	Frequently maintained components most susceptible
	Cable creep	Piling of cable; cuts, abrasions, or other external damage to cable jacket/insulation; broken or deformed terminations	Thermal cycling of cable in vertical-horizontal runs; improper support or fairleader	- Visual inspection	Sharp edges/corners at point of cable contact can increase likelihood of occurrence
	Work hardening	Hardening, discoloration, and ultimate failure of metals	Bending or handling during maintenance	- Visual inspection - Evaluation of hardness/flexibility	Frequently handled or maintained components most likely
	Damage from external influences	External cuts, tears, chips, or abrasions (Note 1)	Personnel traffic; equipment vibration; incidental contact; poor maintenance or installation practices	- Visual inspection	High maintenance or traffic areas, restricted spaces, exposed sharp corners or edges, manholes

Table 5-1 Inspection Techniques Applicable to Various Degradation Mechanisms - Cables and Terminations (cont'd)

Stressor Category	Aging Mechanism	Indications/Effects Detectable Through Inspection	Potential Causes	Applicable Inspection Techniques	Accelerating Factors/Remarks
Electrical	Water treeing (cable only)	No external indications of degradation	Exposure of susceptible insulation materials to submergence/wetting while energized	- Visual inspection for submergence/wetting	Medium-voltage cable only
	Partial discharge/ ionization	Visible or audible ionization; flashover	Degraded insulation; nearby metallic objects/edges	- Visual/audible inspection	May produce rapid localized degradation of insulation
	Surface tracking	Formation of visible tracking paths; discoloration	Degraded insulation in alternatively wet/dry location w/ contaminants	- Visual inspection	May produce rapid localized degradation of insulation
	Moisture intrusion	Visible moisture, discoloration, corroded metallic components nearby, damaged cable jacket/insulation	Submergence/wetting of susceptible material	- Visual inspection	Most common insulation and jacket materials impermeable to water
Chemical	Chemical reaction with organics	Discoloration, softening, swelling, odors	Spill, spray, or other contact with chemical agent; decomposition of jacket/insulator	- Visual inspection - Evaluation of material hardness	See Table 4-7 for compatibility of materials with various substances
	Oxidation of metals	Discoloration; formation of surface layer	Oxidation of nonprotected metals	- Visual inspection	Accelerated by oxygen and susceptible material
Electro-Chemical	Corrosion of metals	Discoloration; formation of corrosion byproducts such as iron oxides or cuprous chloride; pitting; wastage	Exposure of susceptible metals to moisture and oxygen	- Visual inspection	

Notes:

1. Damage may occur internally for softer materials such as silicone rubber.

5.2.2.1 Currently Available Cable Condition Monitoring, Testing, and Troubleshooting Techniques for Cables

Currently available condition monitoring, testing, and troubleshooting techniques are listed in Table 5-2. These techniques can be classified as either destructive, nondestructive, or essentially nondestructive. Destructive techniques, as the name implies, result in destruction of all or part of the specimen under evaluation. Nondestructive techniques have no deleterious effect on the specimen. Essentially nondestructive techniques generally use small specimens for destructive testing; however, these specimens are so small that they may be removed from an active cable or termination with little or no repair required.

The following paragraphs describe the basic theory of each identified technique as well as its potential uses related to cable systems and terminations. These descriptions are not meant to be exhaustive analyses of each technique, but rather an overview from an aging management perspective.[3] Experimental results related to specific cable materials are included where available. Note that the list of references presented under the "implementation" section of each discussion is not necessarily comprehensive; other relevant guidance or research may be available, potentially in the form of internal plant procedures or proprietary data. IEEE 943-1986 [5.3] also provides some general guidance in selecting tests for power cable condition evaluation.

Currently available maintenance, testing, and condition monitoring techniques are summarized in Tables 5-3 through 5-5.

5.2.2.1.1 Destructive Techniques

Two measurements from a destructive technique known as ultimate tensile testing are discussed in this section:

- Elongation-at-break
- Tensile strength

Elongation-at-Break

General Description

Elongation-at-break (elongation) is a mechanical property that evaluates a material's ability to elongate under tensile stress without cracking or rupture. Elongation testing is performed by taking a dumbbell- or tube-shaped sample of the material and pulling it in an apparatus that applies tensile stress by elongating (stretching) the specimen at a fixed velocity.

[3] A CEA Report (Project No. 139D875) evaluating many of the techniques discussed below is expected to be published in 1996. The EPRI Cable Diagnostic Matrix is expected to be published in 1996 as well. This latter document will provide a step-by-step methodology for the evaluation and analysis of various types of cable and termination applications based on information supplied by the plant engineer.

Table 5-2 Destructive, Nondestructive, and Essentially Nondestructive Condition Monitoring Techniques

Type	Technique	Degradation Addressed	Test Type	Test Category	Field/Lab Test[1]	Trouble-shooting (TS) or CM
Destructive	Tensile Testing, Elongation-at-Break	Localized[2]	Hands-on	Mechanical	Lab	CM
	Tensile Testing, Tensile Strength	Localized[2]	Hands-on	Mechanical	Lab	CM
Non-destructive	Compressive Modulus	Localized[2]	Hands-on	Mechanical	Field	CM
	High Potential (Hi-pot)	Bulk	Remote	Electrical	Field	TS
	Insulation Resistance (IR)	Bulk	Remote	Electrical	Field	CM, TS
	Insulation Power Factor	Bulk	Remote	Electrical	Field	CM
	Polarization Index (PI)	Bulk	Remote	Electrical	Field	CM
	Capacitance	Bulk	Remote	Electrical	Field	TS
	Partial Discharge	Fairly Localized	Remote	Electrical	Lab	CM, TS
	Time Domain Reflectometry	Bulk	Remote	Electrical	Field	TS
	Tan Delta/Low Frequency Tan Delta	Bulk	Remote	Electrical	Field	CM
	Density [Computed Tomography (CT)]	Localized[2]	Hands-on	Physical	Lab	CM
Essentially Non-destructive	Density (gradient columns)	Localized[2]	Hands-on	Physical	Lab	CM
	Oxidation Induction Time (OIT)	Localized[2]	Hands-on	Chemical	Lab	CM
	Oxidation Induction Temperature	Localized[2]	Hands-on	Chemical	Lab	CM
	Fourier Transform Infrared (FTIR)	Localized[2]	Hands-on	Chemical	Lab	CM
	UV Spectroscopy	Localized[2]	Hands-on	Chemical	Lab	CM
	Gel Content	Localized[2]	Hands-on	Chemical	Lab	CM
	Plasticizer Content	Localized[2]	Hands-on	Chemical	Lab	CM
	Electron Spin Resonance (ESR)/Nuclear Magnetic Resonance (NMR)	Localized[2]	Hands-on	Chemical	Lab	CM

Notes:

1. Field techniques may also generally be used in the laboratory.
2. Test is performed on localized sample of material; properties of bulk of material can be inferred.