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IEEE STD. 1205-2000 INCORPORATES NEW GUIDANCE FOR ELECTRICAL CABLE AGING MANAGEMENT AND ASSESSMENTS

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ABSTRACT

A major issue facing nuclear power plants as they mature is the general health of the plant electrical cables. This issue came to the forefront as plants began preparing for license renewal, which requires an evaluation of cables to demonstrate they will perform their function 20 years beyond the original 40-year license period. When the two lead plants started preparing for license renewal, there was no generally accepted approach to the bulk evaluation of plant cables and there were many who thought it not possible to perform a complete plant cable evaluation. The approaches that emerged from the lead plant reviews demonstrated that an assessment of the general health of plant cables could be performed.

In 1997, the Nuclear Power Engineering Committee (NPEC) of IEEE's Power Engineering Society recognized a need for additional industry guidance in this area and authorized its Subcommittee-3's Working Group 3.4 to undertake a revision of IEEE Std. 1205. This revision, now complete, updated the guide to incorporate the aging assessment methods used by the two lead license renewal plants and to add an example annex applying the guidance to electrical cable, which are both summarized in this paper.

1. INTRODUCTION

An aging assessment is an evaluation of appropriate information for determining the effects of aging on the current and future ability of systems, structures and components to function within acceptance criteria. Aging assessments are performed at nuclear power plants on a routine basis, although they may not be identified as such. Aging assessments are normally pursued in response to factors such as regulatory guidance, approaching obsolescence, reduced availability or reliability, or for life extension. The specific factor plus economics can affect the method and the extent of an aging assessment.

This paper first summarizes the generic aging assessment elements found in IEEE Std 1205-2000 and then summarizes these elements as applied to an aging assessment of electrical cable as a specific example. This paper complements Horvath and Colaianni (2000) which outlines other important changes in IEEE Std. 1205-2000.

2. AGING ASSESSMENT ELEMENTS

An aging assessment correlates the stressors to which the equipment is exposed and the stressor sensitivity of the equipment materials – to the aging effects that could lead to a loss of function. The goal is to eliminate age-related equipment failures, so the assessment should be comprehensive enough to adequately determine if aging management is needed and, if needed, to support the implementation of an effective program. The process, which is shown in Figure 1, starts after a decision is made to perform an aging assessment for some specific equipment.

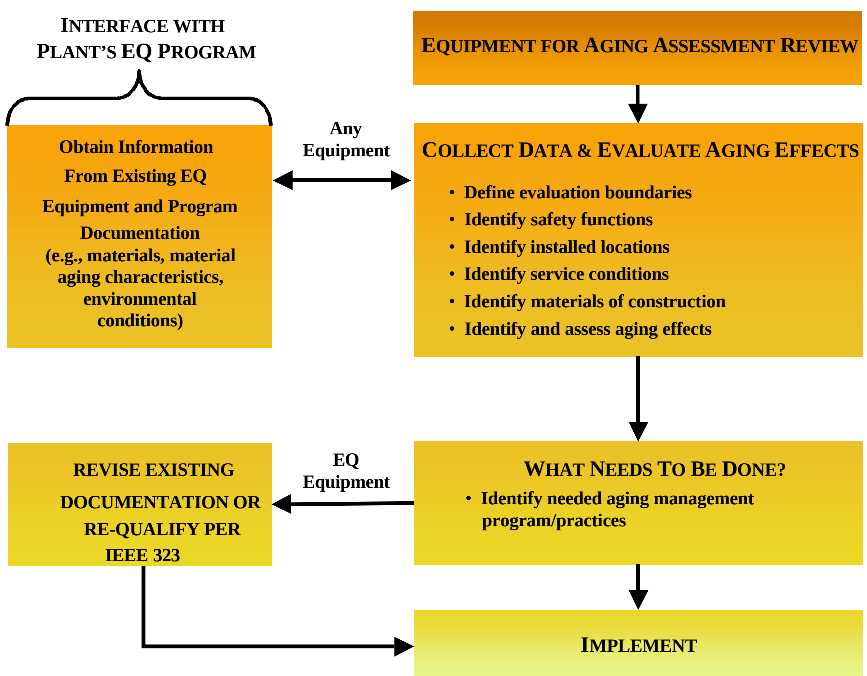

Fig. 1 Process for assessing, monitoring and mitigating aging affects.

The assessment elements that determine if aging management is needed are briefly described below.

2.1 Define evaluation boundaries of the equipment

Electrical components interface with other equipment (e.g., field cables, supports, mechanical equipment) and it is important to provide a clear definition of what is being evaluated. The boundary description identifies the interfaces and the exact boundary between the equipment to be assessed and the interfacing equipment.

2.2 Identify safety functions of the equipment

The safety functions of the equipment being assessed are identified to aid in the assessment of potential aging effects and to support program implementation. This is most important for large, complex pieces of equipment with several subassemblies.

2.3 Identify plant locations where the equipment is installed

A general area description is normally sufficient except where specific locations in a general area have significantly higher stresses and a detailed location is needed to determine if the equipment is subject to these higher stresses.

2.4 Identify service conditions of the equipment

The equipment service conditions are identified since they have a great influence on the equipment's service life. Service conditions include both environmental conditions (e.g., thermal, radiation, moisture) and, if applicable, equipment operational conditions (e.g., self-heating, vibration). These service conditions are the stressors that may cause aging of the electrical equipment.

2.5 Identify the materials of construction of the equipment

The materials used in the construction of the equipment are identified. In cases where it is not possible to identify an age-sensitive material, it is adequate to assume a material with aging properties that likely bound those of the actual material.

2.6 Identify and assess aging effects of the equipment

There can be several possible aging effects for each equipment material. These possible aging effects are identified from industry literature along with the service conditions that cause them and the aging characteristics of the material. As most materials degrade over time even in a fairly benign environment and the rate of degradation is set by the intensity of the service conditions, it is important to set a specific evaluation endpoint for the assessment, which defines a projected time in service of the equipment.

The aging characteristics of a material are expressed in terms of the material's withstand capability, which can be represented in a couple of ways: (a) define the stressor value (e.g., a room temperature) and determine how many years the material will remain functional while exposed to it or (b) start with the projected time in service and determine the maximum stressor value (e.g., a maximum temperature) the material will be able to withstand during its time in service and still remain functional.

An aging assessment is performed by comparing the actual equipment service conditions to the material's withstand capability (which takes into account the evaluation endpoint). When this comparison indicates that the material may not be able to function through the evaluation period, aging management should be looked at as a means to ensure that the equipment remains functional.

3. AGING ASSESSMENT OF INSULATED ELECTRICAL CABLES

IEEE Std. 1205 Annex D has equipment and system examples where the standard's guidance is applied. Annex D.4 provides an aging assessment of insulated cables at a nuclear power plant as part of its license renewal review. The data summaries included in this paper from the Annex D.4 example are abbreviated to fit the required publication format. Consult the standard for the full example.

With license renewal in mind, the evaluation endpoint for the assessment of insulated cables is 60 years. Cables within the scope of license renewal include safety-related cables, some nonsafety-related cables and cables required to demonstrate compliance with the regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram and station blackout. The license renewal rule allows cables that are replaced based on a qualified life to be excluded from the aging management review so cables in the plant's environmental qualification (EQ) program are not included in this assessment.

Cable terminations are normally included in a license renewal cable aging assessment but are not because it would have lengthened the annex. Assessing only cables still provides a good example of the assessment process. To include cable terminations in such an assessment requires only that they be specifically added to each element.

The insulated cables aging assessment follows.

3.1 Define evaluation boundaries of insulated cables

The evaluation boundary for cables includes the cable along its entire run but does not include the cable where it becomes part of the termination.

3.2 Identify safety functions of insulated cables

The function of insulated cable is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals.

3.3 Identify plant locations where insulated cables are installed

Cables are found in most areas of the plant. Those areas of interest for this assessment are the buildings and structures within license renewal scope. These include the **REACTOR BUILDINGS, AUXILIARY BUILDING** including spent fuel pools and penetration rooms, condenser circulating water pump **INTAKE STRUCTURE**, **STANDBY SHUTDOWN FACILITY, TURBINE BUILDINGS** including switchgear blockhouses, and **YARD STRUCTURES** including all areas and components outside the other buildings such as transformer yards, cable trenches, buried cable conduit and direct buried cable. As part of this review it was determined that in-scope **REACTOR BUILDING cables are insulated with EPR**. It is assumed that **all insulation materials are installed in the other plant buildings and structures**.

3.4 Identify service conditions of insulated cables

Service conditions include both environmental and operational conditions.

Environmental Conditions

The environmental conditions considered relevant for insulated cables are thermal, radiation and moisture.

Normal design temperatures are identified from various design documents and for areas where no design data could be found, conservative temperatures are used. The temperatures identified are: **REACTOR BUILDINGS 55.6°C (132°F); TURBINE BUILDINGS, INTAKE STRUCTURE** and **YARD STRUCTURES 40.6°C (105°F); AUXILIARY BUILDINGS** and **STANDBY SHUTDOWN FACILITY 40.0°C (104°F)**.

Normal radiation dose environmental conditions are identified from the plant's EQ program documents. The 40-year normal dose values given are conservative maximums. The projected normal dose for 60 years (the evaluation endpoint) is determined by multiplying the current 40-year normal dose by 1.5 (i.e., 60 years ÷ 40 years). Radiation doses less than 1×10^3 rad are considered negligible. The 60-year radiation doses identified are: **REACTOR BUILDINGS 4.5×10^7 RADS; AUXILIARY BUILDINGS 1.5×10^6 RADS; NEGLIGIBLE** for **TURBINE BUILDINGS, INTAKE STRUCTURE, STANDBY SHUTDOWN FACILITY** and **YARD STRUCTURES**.

Moisture conditions are identified from observations made during plant walkdowns that identified areas where components are subjected to wetting. Wetting refers to a significant amount of moisture in contact with cable, such as would be produced by repeated instances of standing water, system leakage/spray, flooding and outside areas exposed to precipitation. Moisture conditions identified are: **INTAKE STRUCTURE** and **YARD STRUCTURES subject to precipitation; CABLE TRENCH FLOORS, BURIED CONDUIT AND MANHOLES subject to standing water; DIRECT BURIED CABLES subject to surface water drainage and soil moisture**.

Operational Conditions

The operational condition considered relevant for insulated cables is self-heating temperature rise. For this purpose, cables are divided into two categories: power application and non-power application where self-heating temperature rise is applied only to power cables. At this plant, power system voltage and load flow study normal current flow values are matched up with the size and number of conductors from one-line drawings and conductor ampacity ratings, which are based on plant cable derating and ampacity design criteria. Combining this data into a spreadsheet the self-heating temperature rise is calculated and sorted – highest to lowest rise.

At this plant, design documents made it possible to correlate power cable conductor insulation material, application voltage and conductor size as shown in Table 1. With the Table 1 data, possible insulation materials are identified for each cable in the spreadsheet. The highest-to-lowest ranking is split at 10°C rise with the highest calculated rise applied to materials used for cables with a 10°C or greater rise, a 10°C rise applied to other materials used for power cables and a 0°C rise applied to materials used only for non-power application cables. The results are: **EPR, KAPTON 30°C RISE; HYPALON, PE, SILICONE RUBBER, XLPE 10°C RISE; PVC 0°C RISE**.

3.5 Identify materials of construction of insulated cables

Conductor insulation materials, conductor size and application information are identified through plant design documents and a cable routing database. A summary of this information is provided in Table 1.

Table 1 Conductor insulation materials correlated to cable applications

Insulation Materials	Applications and Power Application Voltage & Conductor Sizes
EPR	**Non-power**; **Power:** 600V, 4kV, 7kV, 15kV Power; #12, 10, 6, 4, 2, 1, 2/0, 3/0, 4/0 AWG, 250, 350, 500, 600 kcmil
Hypalon	**Non-power**; **Power:** Festooned Cable; #8, 6, 5, 4 AWG
Kapton	**Power:** Pressurizer Heater Cable; #6 AWG
PE	**Non-power**; **Power:** 120 & 208V Lighting & Transformer Secondaries; #12, 10, 2, 2/0 AWG, 250 kcmil
PVC	**Non-power**
Silicone Rubber	**Non-power**; **Power:** 600V Power; #8, 4, 3/0 AWG, 300, 500 kcmil
XLPE	**Non-power**; **Power:** 120 & 208V Lighting, Power Panelboard, Transformer Secondaries; #12, 10, 6, 2, 2/0 AWG, 500 kcmil

3.6 Identify and assess aging effects of insulated cables

The significant and observed potential cable aging effects and the stressors that cause them are listed in Table 4-18 of SAND96-0344. These are repeated in Table 2 and are used as the starting point for identifying aging effects for cables. The stressors as they relate to this plant are evaluated in the following subsections.

Table 2 Significant and observed cable stressors and potential aging effects

Voltage	Component	Stressor	Potential Aging Effects
Medium-voltage	Conductor insulation	Moisture & voltage stress	Electrical failure (breakdown of insulation)
Low-voltage, Medium-voltage	Conductor insulation	Radiation, oxygen	Reduced insulation resistance; electrical failure
		Heat, oxygen	Reduced insulation resistance; electrical failure

<u>3.6.1 Medium-voltage cable, conductor insulation - moisture & voltage stress</u>

The effects of moisture-produced water trees on medium-voltage cable are examined in Section 4.1.2.5 of SAND96-0344. Water treeing is a degradation and long-term failure phenomenon that has been documented for medium-voltage cable with certain insulations such as XLPE or high molecular weight polyethylene (HMWPE). Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture but their growth and propagation is unpredictable. Few occurrences have been noted for cables operated below 15kV and treeing is much less likely in 4kV cables than those operated at 13kV or higher. The in-scope medium-voltage cables potentially subject to moisture exposure are listed in Table 3.

These cables are constructed with EPR conductor insulation, shield tape, inter-locked armor and an overall PVC jacket. Moisture in contact with the outer jacket does not present a moisture concern for these cables at this plant. The overall PVC jacket is designed for being direct buried and, unless the cable is improperly installed or otherwise damaged during installation, the overall PVC cable jacket precludes moisture from contacting the conductor insulation. The 13.8kV (phase-phase) cables, which could be the more susceptible to water treeing due to their operating voltage, carry power only 4 hours per outage and are energized without load less than 12% of the time so the voltage stress put on the conductor insulation is not significant. Therefore, aging effects related to moisture and voltage stress are not a significant concern for these cables at this plant.

Table 3 Potential moisture exposure of medium-voltage cables

Potential Exposure Area	Description	Nominal Operating Voltage
Cable Trench	Condenser Circulating Water Pump Cables	4160V
	Standby Shutdown Facility Switchgear Power Cables	4160V
	230kV & 525kV Switchyard Power Cables	4160V
Outside Ambient	CCW Pump Cables	4160V
Direct Buried	Transformer CT4 Power Cables	13.8kV
	Transformer CX Power Cables	4160V
Buried Conduit	Auxiliary Service Water Switchgear Cables	4160V
	High Pressure Service Water Pumps A & B Cables	4160V

3.6.2 Low & Medium-Voltage Cable, Conductor Insulation – Radiation, Oxygen

The **moderate damage gamma radiation dose** for insulation materials was obtained from industry documents. The moderate damage dose indicates the value at which the material has been damaged but is still functional. The results are: **KAPTON 2X10^8 RAD; XLPE 1X10^8 RAD; EPR 5X10^7 RAD; PE 2X10^7 RAD; PVC 2X10^7 RAD; SILICONE RUBBER 3X10^6 RAD; HYPALON 2X10^6 RAD**. Comparing these dose values with the 60-year normal radiation dose conditions where the cable insulation materials are installed indicates that all of the insulation materials can withstand the dose with only moderate damage through the evaluation period.

3.6.3 Low & Medium-Voltage Cable, Conductor Insulation - Heat, Oxygen

The total thermal life of cable materials can be calculated using the Arrhenius method. The Arrhenius method is normally used to calculate a thermal life at a given temperature; however, it can be used to calculate a maximum continuous temperature for a specified time. With the time fixed at 60 years, calculations are performed to determine the maximum average temperature to which the material can be exposed so that the material will have the indicated “end-of-life condition” at the end of 60 years.

Table 4 Cable Material Temperature Data

Insulation Material	Maximum Temperature for a 60-Year Life	Condition at the End of 60 Years
Silicone Rubber	133.9°C (273°F)	50% Retention-of-Elongation
Kapton	120.0°C (248°F)	Failure
XLPE	86.7°C (188°F)	60% Retention-of-Elongation
EPR	68.3°C (155°F)	40% Retention-of-Elongation
Hypalon	67.8°C (154°F)	50% Elongation
PE	55.0°C (131°F)	T_{75} Induction Period
PVC	44.4°C (112°F)	Mean-Time-To-Failure

Comparing these 60-year life temperatures with the temperature service conditions where the cables are installed indicates that, except for EPR used in power applications, the insulation materials can withstand the temperatures through the evaluation period.

The condition of EPR after being exposed to their 60-year temperature is 40% retention-of-elongation. At 70.6°C (159°F), their bounding power application temperature service conditions, the actual condition of these materials at the end of 60 years may be slightly lower than 40%. This is acceptable since these are non-EQ cables that are either not subjected to an accident environment or are not required to function during or after being subjected to an accident environment. In addition, the calculated self-heating temperature rise assumes normal operation 100% of the time since initial operation whereas the units have operated less than 75% of the time, which lessens the amount of aging actually occurring. Given these conservatisms, there is reasonable assurance that EPR can withstand the temperature service conditions through the evaluation period.

4. CONCLUSIONS

This example shows how the methods provided in detail in IEEE Std. 1205-2000 can be applied as a practical approach to evaluate electrical insulated cables.

NOMENCLATURE

CFR United States Code of Federal Regulations
EPR Ethylene propylene rubber
EQ environmental qualification, per 10 CFR 50.49
IEEE Institute of Electrical and Electronic Engineers
PE Polyethylene
PVC Polyvinyl chloride
XLPE Cross-linked polyethylene

ACKNOWLEDGMENTS

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REFERENCES

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