A Novel Approach for Prioritizing Maintenance of Underground Cables

Final Project Report

Power Systems Engineering Research Center

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Power Systems Engineering Research Center

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Executive Summary

Distribution businesses serving urban areas are increasingly using underground cable for distributing power to their customers. Extruded cross linked polyethylene (XLPE) insulated cables are employed extensively in the industry. Premature failure of these cables can occur due to aging from exposure to multiple stresses, such as electrical, heat, and chemicals (water). Furthermore, degraded cables are more susceptible to failure during "dig-ins". To help distribution businesses save on maintenance costs while maintaining reliable service, in this study we have developed a method for assessing cable condition so that cable replacement need only occur when the cable approaches the end of its useful life.

For this study we characterized the extent of cable degradation occurring in 15kV cross linked polyethylene (XLPE) insulated distribution cables in hot and dry climates. The extent of degradation was quantified using two parameters: the area of Fourier Transform Infra Red (FTIR) spectrum and the electrical breakdown strength using needle plane geometry. Degradation occurring in a hot and dry climate can be reproduced in a laboratory by accelerated thermal aging testing. The Arrhenius equation for the temperature dependence of a chemical reaction rate was used to establish the accelerated aging test parameters.

An aging model was developed and validated to assess future cable performance. The model is based on theoretical aging models and diagnostic methods. The model uses the intermittent value of the identified degradation markers (available from the field) to assess future performance. The model was successfully validated using new and field aged cables. Analysis of variance (ANOVA), Andersen-Darling test for normality, F-test, and t-test, were tests performed to establish statistical confidence in the results. Therefore, we conclude that this approach can be used with reasonable confidence to prioritize cable replacement and optimize cable maintenance scheduling.

The principal conclusions are as follows.

- In a hot and dry atmosphere (such as that of Arizona, USA), thermal stress plays a prominent role in polymer degradation. The extent of polymer degradation can be quantified, eliminating minor effects of other stresses such as electrical and mechanical. Field degradation can be reproduced by a suitably planned accelerated thermal aging testing in a laboratory.

- Using the FTIR technique, we demonstrated that the reduction of the CH_2 bond yielded a good correlation with reduction in electrical performance after accelerated aging. Hence, the reduction of the bond can be used to assess the condition of field aged cables.

- Aging by approximately 10 years in dry weather resulted in cable performance (in terms of electrical breakdown strength) degradation by at least 25%.

- A combination of the electrical breakdown voltage and FTIR spectroscopy can be used to estimate future cable performance. A simple traffic light approach (Red, Yellow and Green) could be used to communicate the condition of the cable insulation.

A primary incentive for future research is to reduce costs due to accidental failures, and to optimize cable replacement and maintenance schedules. This study showed that these objectives can be reached by collecting a number of field aged samples experiencing the same weather conditions and then by performing experiments in a laboratory.

The testing approach in this study was for cables in hot and dry weather conditions. There are distribution businesses for whom water treeing and moisture are a major concern. The design of the suitable condition monitoring approach for such wet conditions involves identifying sensitive parameters for the cable insulating material that could be use to quantify the extent of degradation, as the CH_2 bond did for cables in the hot and dry weather conditions.

Another potential research direction would be to study whether any other parameter (besides the extent to which the CH_2 bond is reduced) could be used to measure cable degradation in hot and dry climates. Having multiple measures of degradation would increase confidence in using findings from laboratory-based modeling for decision-making involving significant costs.

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Nomenclature

AFM	Atomic Force Microscopy
AIEE	American Institute of Electrical Engineers
ANOVA	Analysis of Variance
ASTM	American Society for Testing and Materials
DF	Degree of Freedom
DSC	Differential Scanning Calorimetery
E	Electric Stress or Electric Field
E_0	Electric Stress below which Electrical Aging can be neglected
E_t	Threshold Electric Field
EDX	Energy Depressive X-ray Emission
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EVA	Ethylene Vinyl Acetate
FTIR	Fourier Transform Infra Red
HMWPE	High Molecular Weight Polyethylene
IEC	International Electrotechnical Commission
IR	Infrared
k	Boltzman's constant
KCMIL	Kilo Circular Mil
L	Life in Years before failure
L_0	Life in Years under threshold conditions of voltage and thermals stresses.
MCM	Mega Circular Mils
MS	Mean Sum of Squares
n	Sample Size when used in statistical analysis, constant when used in life modeling
OIT	Oxidation Induction Time
P	Probability
PAS	Power Apparatus Systems

PE	Polyethylene
PEA	Pulsed Electro-Acoustic
PMAPS	Probability Methods Applied to Power Systems
R	Degradation Rate
$S_{1,} S_2$	Sample Variances
S_p	Estimate of the Common Variance
SS	Sum of Squares
TDS	Time Domain Spectroscopy
TMA	Thermo-Mechanical Anlaysis
TRXLPE	Tree Retardant XLPE
TSC	Thermally Stimulated Current
XLPE	Cross Linked Polyethylene
XPS	X-Ray Photoemission Spectroscopy
$\bar{y}$	Sample mean
θ	Absolute (thermodynamic) temperature
ΔW	Activation Energy in electron Volt

1. Introduction

1.1 Background of Power Cables

The beginning of power cable technology can be traced back to the 1880s, when the need for power distribution cables became pressing, following the introduction of incandescent lighting. The illumination of some of the larger cities advanced at such a quick rate that under certain circumstances it was impossible to accommodate the number and size of feeders required for distribution, using the overhead line system approach. The situation in New York City deteriorated, so notably, that apart from technical and aesthetic considerations, the overhead line system began to pose safety hazards [1]. Due to this fast growth, by the early 1990s, underground electrification via insulated cables was on its way to become a well-established practice. Some of the more common early solid and liquid insulating materials employed in various underground cable installations were natural rubber, gutta-percha, oil and wax, rosin and asphalt, jute, hemp, and cotton.

1.1.1 Oil Impregnated Paper Power Cables

During the period of World War I, oil-impregnated paper cables of the three-conductor belted type were used extensively. The belted cable proved to be highly partial discharge susceptible when attempts were made to extend the operating voltage range to 35 kV, due to non-uniform stress distribution in the cable construction.

1.1.2 Solid Dielectric Extruded Cables

Prior to and within the early 1950s various forms of rubber had been employed in the distribution-voltage cable. After hydrocarbon thermoplastic polyethylene (PE) had been invented in England in 1933, it took a substantially longer time for polyethylene insulation to be introduced into the power cable area. Solid-polyethylene-extruded power distribution cables were first introduced in the 1950s. In these early days of the 1950s, polyethylene, because of its intrinsically low dielectric loss characteristics, was always viewed as an attractive substitute for the more traditional solid-liquid insulating systems. In the beginning, plastic cables were manufactured using low density high-molecular weight polyethylene (HMWPE), which has been used since 1951 for distribution voltages up to 35 kV and sometimes higher [2]. In 1952, Arthur Charlesby subjected samples of polyethylene to irradiation and found “a new type of plastic” was produced with some new properties compared to polyethylene and this new type of plastic is named as cross linked polyethylene (XLPE) [3]. Commencing with 1964, a changeover began toward the deployment of XLPE, which infers an equivalent ampacity increase of 12% over an HMWPE insulated cable [4]. Finally, in the 1980s, further remarkable advances were made to control water treeing by the introduction of the dry-curing process, super smooth and clean semiconducting shields, and ultra clean, tree-retardant XLPE (TRXLPE).

In the late 1960s, ethylene-propylene-rubber (EPR) insulated cables, having clay filler contents as high as 50%, appeared on the market for voltage ratings up to 60 kV. They are generally preferred over XLPE insulated cables, where mechanical flexibility is of prime concern.

1.1.3 Ethylene-Propylene-Rubber (EPR)

Wherever increased mechanical flexibility is required, EPR is the main contender to XLPE, for distribution cables up to 35 kV. Most EPR are formulations that are almost amorphous, and EPR is an elastomer synthesized from ethylene and propylene, using a ratio of 1:1. The molecular structure of EPR is shown in Figure 1.3, where χ is the repeating unit that may range anywhere from about $2x10^3$ to $5x10^3$. The filler content in EPR cable insulations is relatively high and may even exceed the 50% mark. Evidently, the fillers principally determine the dielectric losses in EPR. It suffers from poor oil and flame resistance and is susceptible to degradation by partial discharges and treeing.

While EPR is tacitly assumed to be completely amorphous, it may in fact be partially crystalline. Crystallinity in the EPR polymers is essentially determined by the ethylene content, because it is the ethylene groups that tend to form organized repeated segments. When the ethylene content reaches 60% by weight, crystallinity is manifest in the copolymers. Since most EPR formulations have ethylene contents in the range from 50 to 75% by weight, some EPR cables may exhibit some residual crystallinity. With increasing crystallinity, the ability to process EPR compounds is reduced and the flexibility of the cable becomes poorer; however, the hardness of the extruded compound is augmented. Also, the capacity to accept higher filler contents is increased, thereby resulting in reduced production costs [7].

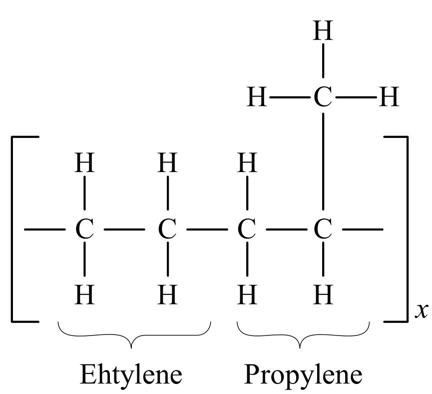


Figure 1.1. Molecular Structure of EPR

1.1.3.1 Polyethylene

Polyethylene is a long-chain hydrocarbon plastic produced by the polymerization of ethylene gas (C_2H_4) either under high or low pressures. The high-pressure process yields low-density polyethylene, which is the result of the branching introduced by the high-pressure process. The high-density polyethylene produced at low pressures is stiffer, harder and more brittle. Due to its relatively low price, resistance to chemicals and moistures, flexibility at low temperature, and excellent electrical properties, more than

10% of the world's total output of polyethylene is being applied to electrical uses. The usual linear polyethylene consists of long chains of paraffin molecules of the form depicted in Figure 1.5. If the molecules are very long and linear with very little branching, the molecules become closely packed; consequently, this type of linear polyethylene exhibits a high density. If the molecular structure of the polyethylene becomes branched and less linear, its density decreases.

In North America, the early manufactured polyethylene power cables were of low-density, branched-type polyethylene. Due to higher molecular weight of the low-density polyethylene used, they are commonly referred to as high-molecular-weight polyethylene (HMWPE) cables.

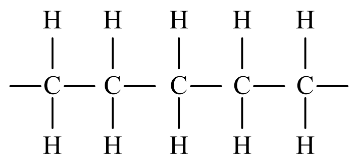


Figure 1.2. Molecular Structure of PE

1.1.3.2 Cross Linked Polyethylene (XLPE)

Cables insulated with XLPE presently dominate the distribution cable filed in North America, Japan and Northern Europe. XLPE is manufactured by the process of compounding polyethylene with a radical at $240\text{-}260^0$F. In the process, free ethylene radicals in the polyethylene molecules react with each other to form vulcanized or cross-linked material. The cross-linking process causes polyethylene to change over from a thermoplastic to a thermosetting material with a marked improvement in both the physical and electrical properties. Because of its thermoset character, XLPE maintains its mechanical properties when exposed to temperatures that would cause linear polyethylene to melt, lose shape, and flow.

Sometimes carbon black is added to guard against ultraviolet radiation, which, due to its absorption by the carbonyl group ($C = O$), may induce degradation. The addition of carbon black increases the tensile strength and hardness but affects adversely the electrical properties.

In the cross-linking or curing process with chemical cross-linking agent, dicumyl peroxide is usually used as the cross-linking agent. Alternatively, cross linking may be induced with radiation, but this is usually confined to thin insulations. As the dicumyl peroxide is terminally decomposed during the cross linking process, acetophenone is formed. There are some indications given in [9] and [10] that presence of acetophenone retard electrical and water tree growth. Evidence also indicates that acetophenone is actively involved in some chemical synthesis reactions in the degradation process occurring within discharging voids [11] [12]. However, it should be emphasized that acetophenone, $C_6H_5COCH_3$, diffuses fairly rapidly out of the insulation at elevated temperatures [13].

In the past, XLPE power cables were steam cured, with the result that considerable moisture was retained in the insulation. Following the development of the dry curing process, most XLPE cables are now produced using this method. It was definitely established that the use of a dry curing process results in a lower number of micro voids that may or may not be implicated in water tree growth.

1.1.3.3 Tree Retardant XLPE

Various attempts have been made to develop additives with tree-retardant propensities to prevent or reduce appreciably water tree occurrence and propagation. In HMWPE considerable use was made of dodecanol ($CH_{12}H_{25}OH$) as a tree inhibitor, though its effectiveness was found to diminish with time. The early tree-retardant ethylene vinyl acetate (EVA), utilized in XLPE, tended to also lose its effectiveness over prolonged time periods under voltage stress. In 1983, a tree-inhibiting compound was made available by Union Carbide as an additive in their XLPE compounds commonly known to be polar. The introduction of the polar tree-retardant additive into the XLPE compound augments the dielectric loss remarkably.

The addition of a polar tree retardant to XLPE diminishes greatly the number and size of bow tie water trees when current state of the art semiconducting shields are employed; however the effect on vented-type water trees is essentially insignificant [14-15].

1.1.4 Oil Impregnated Paper

Oil-Impregnated papers have been used since the earlier days of cable development and constitute, even today it is one of the most extensively used cable insulations. Despite the recent advances made in the field of plastics for cable application, oil-paper insulation is still regarded as perhaps the most reliable composite insulation system for cable applications. In most cases, kraft papers, which consist of cellulose fibers felted together to form mechanically strong sheets, are used. There are a number of parameters describing electrical insulating papers that are of considerable importance as they influence greatly both the electrical and mechanical properties of the kraft paper tapes such as paper density, voltage gradient, and dielectric constant. When paper insulation tapes applied helically on the cable conductor, great care must be exercised to ensure proper tension and overlay to provide constant-width butt gaps [16]. It is possible to use oil-impregnated paper insulated cables for voltages up to 69 kV, however on the average their application has been confined to voltages below 35 kV. The main reason for the upper limit has been associated with the occurrence of partial discharges, which has in numerous instances led to the deterioration and failure of the dielectric at the elevated voltages.

1.2 Overview of the Problem

The distribution system most utilities serving urban areas in the USA is predominantly underground for reasons of aesthetics. Periodic cable maintenance and repairs are necessary in order to maintain high reliability. For example, SRP a utility serving central Arizona, has installed over 22,000 miles of cable, where 4,000 miles were installed prior to 1980. Cables made during this period were prone to impurities and moisture as there were no controls/specifications on the cleanliness of the materials used for the insulation and semi-conducting shield. The condition of the older cables is unknown at this stage. With their service life exceeding 20 years of anticipated 30 years of useful life, it is reasonable to expect that the cables will exhibit deterioration in insulation properties. *But is the deterioration significant? Should all of the older cables be replaced with new cables? Is there any evidence to suggest that 20 years is positively the useful life?* This research project is undertaken to answer these very important questions.

SRP's experience with cables has been encouraging in compared to many other utilities. Cable faults have largely been due to stray factors like punctures due to rocks and bad splicing. There have been some instances of failures due to overheating caused by increased loading. Water treeing has not been a major problem. Under these circumstances (which could be true for several other utilities), it is reasonable to expect a longer life of the older cables than what is considered normal by many utilities. It is also reasonable to expect that not all circuits will be overloaded regularly.

Utilities allocates a certain dollar amount for cable replacement on an annual basis. It makes sense to replace those cables that are near to the end of life immediately, and to defer replacement of other cables that are not in imminent danger of failing quickly. Therefore, a scientifically sound method of prioritizing the cable replacement is required.

2. Literature Review

Aging of solid insulating materials and systems, according to IEC and IEEE standards, is the '*occurrence of irreversible deleterious changes that critically affect performance and shorten useful life* [65].' Experience has shown that the degree and the rate of aging of insulation depend on:

- The physical and chemical properties of the material,
- The nature and duration of applied/induced stresses, and
- Material processing and treatment during manufacturing and subsequent use in equipment [17].

The applied/induced stresses are either of sequential or simultaneous nature, which leads to aging and deterioration, but the rates of aging are different and are not easily explainable. The interaction between aging factors is not simply additive but synergistic in nature, and that is what makes the process complex. Figure 2.1 is an illustration of how various stresses interact with each other more or less in a cyclic fashion [17]. To have a better understanding of degradation and aging, it is important to understand first how various stresses; applied singularly and/or in combination influence physical and chemical processes at the interface between metal/solid dielectric/atmosphere.

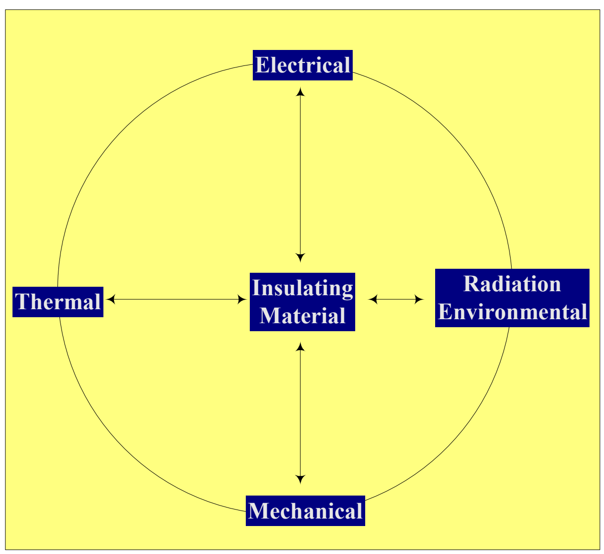


Figure 2.1. Multistress Aging

In this work, focus is placed, on thermal stresses, which mostly age and cause failure of cable insulation system in the case of hot and dry atmosphere.

2.1 Thermal Stress Modeling

In 1930, Montsinger studied the behavior of some insulating material exposed to high temperatures, in order to find the relationship between temperature and time to failure [18]. The relationship he found was an exponential one which led him to state the so-called 'Montsinger rule': '*life is halved by a temperature increase of 8 to* 10^0C*.'* On the basis of this empirical relationship, Dakin proposed his theory that:

"The effect of temperature is to increase the rate of chemical reactions, thus the relationship between the degradation rate R and temperature has the same form as the equation of the chemical reaction rate".

Using the well-known Arrhenius equation, the time-to-end point, i.e. thermal life, is given with the help of [19-20] as

$$L = \frac{C}{R} = A\,exp\left[\frac{B}{\theta}\right]$$
$$A = \frac{C}{R'} \tag{2.1}$$
$$B = \frac{\Delta W}{k}$$

Where, ΔW is the activation energy of the reaction involved
k is the Botlzmann constant
θ is the absolute (thermodynamic) temperature.

Equation (2.1) is known as the Arrhenius model and is usually represented in graph, having coordinates log (L) vs. $-1/\theta$, where model gives rise to a straight line of slope B. In [21] and [22], it has been concluded that the existence of the compensation effect, consisting of a linear relationship between the ordinate intercept (log(A)) and the slope (B) of the thermal life lines, involves changes in the life models, so that the Arrhenius equation (Equation (2.1)) becomes:

$$L = A\,exp\left[\frac{k_1\,log\left[A\right] + k_2}{\theta}\right] \tag{2.2}$$

Where, k_1 and k_2 are the regression parameters describing the log (A) vs. B relationship.

International standards that are in use today require 5000 h or more of testing [22]. Such long testing time becomes a significant constraint for the characterization of cable insulating materials, especially today when technology and material research are progressing at a fast pace. It has been suggested in [23] that the testing duration can be reduced to 1000 h or less, if the slope of the thermal endurance line is determined by analytical measurements such as oxidation induction time, weight loss etc., and the ordinate intercept of the thermal endurance line is obtained by a conventional life test, as described in the standard. The goal of this research is to identify and quantify the sensitive parameter(s) that describe thermal degradation of cables.

2.2 Electric Stress Modeling

Basic work for the insulation design for electrical (voltage) endurance was developed in the 1970s. Life models based on either the inverse power law or the exponential law was proposed. Equation (2.3) and (2.4) indicates the life model based on the inverse power law and the exponential law respectively.

$$L = C_1 E^{-n} \tag{2.3}$$

$$L = C_E \exp[-hE] \tag{2.4}$$

Where, C_1, C_E, n and h are constants depending on temperature and other factors of influence

E is the magnitude of the electric field.

Both the models specified in (2.3) and (2.4) give straight line in log-log or semi log coordinate systems, with slopes of $-1/n$ and $-1/h$ respectively, if E is the ordinate and log (L) is the abscissa. These models are essentially based on empirical background because most of the accelerated life test data can be fitted by straight lines in log-log or semi log plots. These models can be explained using a theoretical background also. The inverse power model was associated with a statistical approach based on Weibull distribution, generally used for breakdown of solid dielectrics, and it was applied, in particular, to power cable insulation [23-24]. For the exponential model, an exponential dependence of breakdown times on applied stresses was first proposed in [26] and [27] for breakdown due to surface discharges. From the observation of a tendency of the life line at low gradients to become horizontal, with breakdown times much larger than those expected under a linear hypothesis (based on (2.4)), the discharge inception gradient as a threshold field E_t was introduced in [26-27], and (2.4) has been modified as follows

$$L = C_E \frac{\exp[-hE]}{E - E_t} \tag{2.5}$$

A threshold behavior, i.e. a tendency of the lifeline to become horizontal at low gradients, has been observed for life data plotted according to Inverse Power Model, obtained for various materials. This promoted the definition of inverse power threshold models [28-31]. For example:

$$\frac{L}{L_0} = \left(\frac{E - E_t}{E_t - E_0} \right)^{-n} \tag{2.6}$$

Where, L_0 is the life for $E = E_0$, and

E_0 is the stress below which electrical aging can be neglected in the presence of any other stresses.

The new concept of threshold for aging has been translated mathematically as an infinite life for the stress, which is equal or less than the threshold. In practice, this corresponds to an extremely long life at low stress, much longer than that expected life from linear extrapolation from high stresses. The determination of threshold opened a clue for insulation design, since designing a system below the threshold would ensure very high reliability [29] [31].

Other work on applied statistics was triggered by an increased sensitivity in the statistical treatment of experimental results, and by vastly more efficient and fast computers, allowing long and complex calculations such as spatial distribution and Monte Carlo simulations. This generated several contributions targeting improvement of estimate accuracy of the failure probability distribution parameters and percentiles. Existence of the threshold stress prompted investigators to non-parametric models such as applying Kalman Filter to electrical thermal and electro thermal life test data [32-35].

Most of the accelerated life test data can be fitted by straight lines in log-log or semi log plots. One of the features of these plots is a tendency of the lifeline to become horizontal at low voltage gradients (or electric stress). This means an infinite life for the cable dielectric under conditions where the electric stress is below the threshold value. This limits the use of such plots, as it is not possible to get a realistic idea about the life expectancy of a cable.

Practical engineering dictates that cable life is finite even if the average electric stress is below the degradation threshold. It is important to determine if this infinite life means 30 years, 50 years, or more. The widely accepted practice of assuming that cable will need to be replaced after 30 years is questioned today, as there are many cables that are still functional even beyond this time limit. If cable can last longer than 30 years, the next logical question is how long will they work? There is a need for fundamental research to be able to predict that the cables will work for 10, 20 or more years, beyond the originally established 30 years. One aspect that needs to be examined and quantified is changes occurring in the bulk of the dielectric due to electric stress. With knowledge of the exact changes, or with measurements that are indicative of such changes, it will be possible to modify the relationship between the electric stress and degradation.

2.3 Multi-stress Modeling

Multistress modeling mainly deals with electrical and thermal stress, which can be called electro thermal modeling. The main idea of the electro thermal life model is to explain thoroughly the dependence of the model parameters on the two stresses. The other important aspect is to introduce appropriate additional terms in order to account for the synergism between electrical and thermal stress [36]. In [37], Endicott et al. explained the dependence of thermal reaction rate parameters as a function of electrical stress, rewriting the Eyring equation as,

$$R(E,\theta) = k_1 \theta^{\omega} \, exp\left[-\frac{B}{\theta}\right] exp\left[\left(k_2 + \frac{k_3}{\theta}\right) f(S)\right] \tag{2.7}$$

Where S is the stress (electrical or mechanical),

k_1, k_2 k_3 are constants, independent of time, temperature and stress;

Exponent $\omega \approx 1$.

If $f(S) = 0$, equation (2.7) becomes the thermal life equation. If θ is constant and $S = E$ (Electrical Stress), equation (2.7) becomes

$$R(E) = C' \; exp\left[h\, f(E)\right] \tag{2.8}$$

with $h = k_2 + \frac{k_3}{\theta}$ and $C' = k_1 \theta^{\omega} exp\left[-\frac{B}{\theta}\right]$.

Considering $f(E) = E$, the exponential model for life is obtained (equation (2.3)), whereas for $f(E) = log\,[E]$ the inverse power model is achieved (equation (2.4)). The fundamental relationships for life of electrical insulation as a function of temperature and / or electrical stress are included in (2.7), so that this equation can be taken as the linear combined stress model. It must be emphasized that (2.7) is of multiplicative nature, i.e. the thermal and electrical rates are multiplied to obtain the combined stress rate. Simoni constructed his first model with proper boundary conditions after modifying (2.7), which can be written using [38-40] as

$$L = L_0\, exp[-BT - h\,E' + b\,E'T] \tag{2.9}$$

Where E' is electrical stress, given by $E - E_0$, or $log\,[E/E_0]$, according to the selected electrical model, exponential or inverse power respectively,
T is the thermal stress, defined as $T = 1/\theta_0 - 1/\theta$, and
θ_0 is the temperature below which thermal aging can be neglected.

This model gives four coefficients for insulation characterization, i.e. B and h for thermal and electrical endurance, respectively, b for extent of stress synergism, and L_0 as the scale parameter.

The existence of a threshold field and the consequent modification of the electrical life models forced changes in the multi stress model. The changes are made in such a way that the lifeline tends to be horizontal when stress tends to be the threshold. The multi stress threshold model that satisfies the boundary conditions and gave rise to a threshold line having a shape in agreement with the experimental data can be obtained starting from (2.9) using [41]

$$L = \frac{L_0\, exp\left[-BT - hE' + bE'T\right]}{\frac{T}{T_{t0}} + \frac{E'}{E'_{t0}} - k_c\,\frac{T}{T_{t0}} - 1} \tag{2.10}$$

Where T_{t0} and E'_{to} are the threshold values of T and $E' = 0$ and of E' for $T = 0$, respectively,
k_c is a coefficient affecting the shape of the isochronal lines, i.e. the constant life lines obtained from the life model for given life values and corresponding to proper E' and T values.

Model (2.10) is valid for threshold materials, whereas model (2.9) is valid for non-threshold ones. In [39], models (2.10) and (2.9) are unified in a single model, valid for threshold and non-threshold materials. This has been done by raising the denominator of (2.10) to an exponent $\mu = \mu\ (E, T)$ such that $\mu = 0$, if both stresses are larger than the threshold, i.e. $T \geq T_{t0}$ and $E' \geq E'_{t0}$, and $\mu > 0$ if at least one of the stresses is lower than the threshold. Then, for $\mu = 0,\ D = 1$ the model coincides with (2.9), which holds in the absence of threshold, while for $\mu = 1$, model (2.10) is obtained again.

Figure 2.2 and 2.3 show the application of the model to predict useful life for a wide range of electric stress and temperature experienced by insulation [39]. These figures were generated using MathCAD® for a range of electric stress and temperature experienced by cables. For example, XLPE cables for power system distribution operate with an average stress of about 3 kV/mm, and temperature of 90^0C. Based on the model, cables should have infinite life, which is obviously not true. These facts emphasize that a life model cannot be replaced by a simple polynomial regression of the experimental points. This clearly suggests that more research is needed in order for the model to be of practical use. This work attempts to address these issues and develop improved models for life estimation.

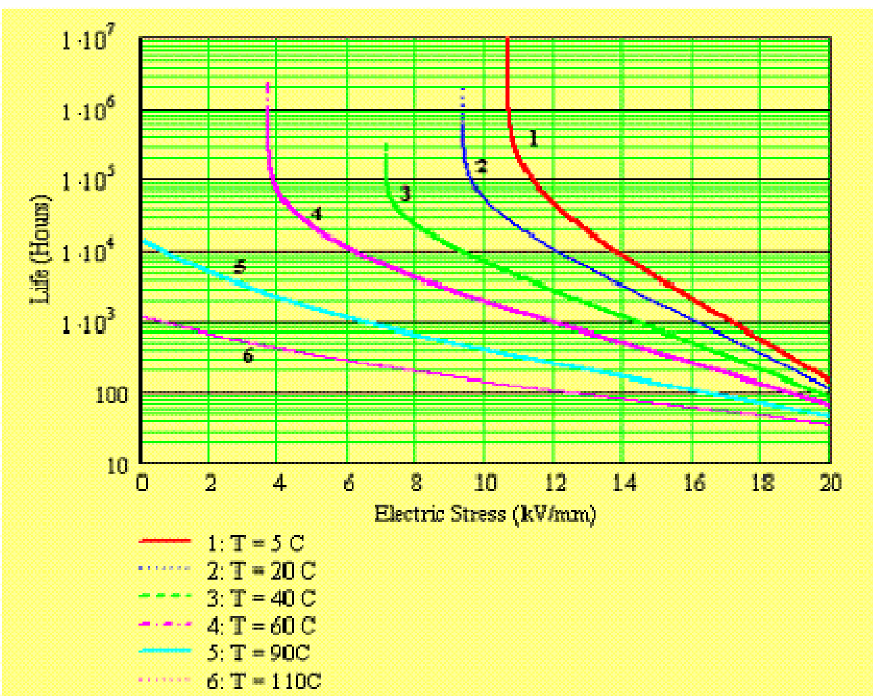


Figure 2.2. Prediction of life from multi-stress model-Electric Life Lines [39]

2.4 A Broader Perspective on Aging Models

The models for investigating the electrical, thermal and multi stress endurance of insulating materials are mainly of a phenomenological nature and are empirical. These models provide parameters useful for the characterization of materials and insulation systems, comparison of their performance, and eventually, life and stress-design estimation. Mostly, life models provide straight or curved lines at chosen failure probabilities, in a semi log or bilog plot where each line is the plot, of the functional relationship between the applied stress and the time-to-failure.

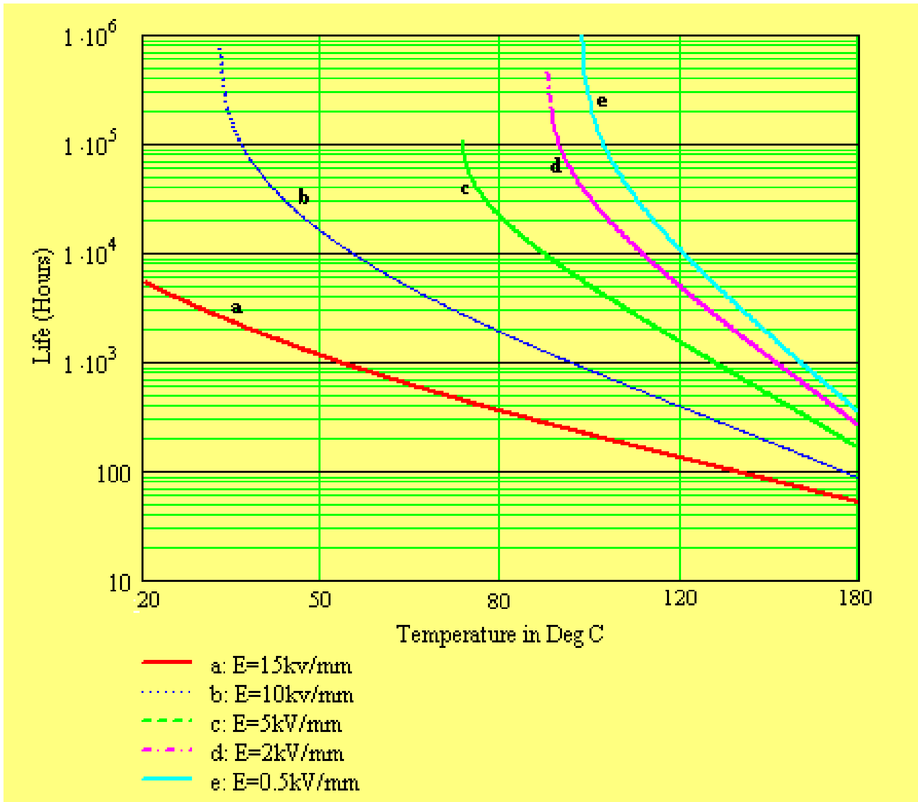


Figure 2.3. Prediction of life from multi-stress model- Thermal Life Lines [39]

The model parameters, calculated on the basis of experimental-data fitting, characterize the stress endurance of the tested material or insulation system. Model parameters like endurance coefficient, derived from the lifeline slope and the threshold, or the lowest value of stress below which in the absence of other stresses or factors of influence, aging does not significantly occur can be calculated. Designing, for instance, insulation system with an electrical field and temperature below the threshold derived from combined thermal-electrical stress life models would ensure extremely long life to the system, if voltage and temperature were the prevailing stresses expected in service conditions [42]. These facts emphasize that a life model cannot be replaced by a simple polynomial regression of the experimental points.

Thermodynamic models also have also been proposed for thermal and multiple electrical-thermal-mechanical aging. The data fitting is almost the same for two models in the test temperature ranges. Physical models, based on charge injection, Luminescence effect and trapping or treeing growth, space charge and void characterization also have been proposed for electrical aging but still lack experimental support [43-50].

2.5 Diagnostic Methods

Literature review suggests that there are two approaches to the assessment of cable insulation aging: the characterization of the cable system or the characterization of cable insulating material. In the characterization of the cable system, tests are applied in the field, while in the case of cable insulating material tests can be applied in the laboratory [51].

2.5.1 Characterization of Cable Systems

The test methods applied in the field can be divided into two groups:

- The 'go / no-go' and
- The one-parameter-type measurement tests.

The first group contains the resonant ac, dc, 0.1Hz, or Oscillatory wave tests, all of which are based on the application of voltage at a level higher than the nominal voltage for a fixed period. The mentioned tests are very simple and there is no interpretation of data involved. If the cable system passes the test, it can be concluded that cable insulation performance is still satisfactory. At the same time, passing the test does not mean insulation is without defects. These tests themselves are considered to be a potential source of degradation for the insulation.

The second group (one parameter type measurement test) contains traditional tests like dielectric losses (tan) at 60 Hz, measurement of partial discharge, polarization index and insulation resistivity (megger) [52]. These tests are simple but are not very sensitive, and even though the sensitivity of these tests can be improved, there is still no level or range of values establishing that the insulation is due for replacement.

2.5.2 Characterization of Cable Insulating Material

Characterization of cable insulating material is performed using the samples taken from cable materials that were in service. These tests are generally performed after failure or an accelerated aging test. Some of these methods are: Differential Scanning Calorimeter (DSC), Oxidation Induction Time (OIT), Infrared (IR), Ultraviolet (UV), Thermo-Mechanical Analysis (TMA), Time Domain Spectroscopy (TDS), Thermally Stimulated Current (TSC), Energy Dispersive X-ray emission (EDX) and many others [53-54]. These methods can be used to set up a database and to have a better understanding of the aging mechanisms due to singular or multiple stresses. The main concern about all of these approaches is whether or not they are representative of the whole cable or just the sample analyzed.

2.6 What is Missing?

The main concern of utility engineers is to be able to evaluate the integrity of high voltage equipment, such as transformers, switchgears and cables. There is a requirement of diagnostic technique(s) to assess any degradation of the insulating materials and 'aging criteria' and determine if and when maintenance is required [17]. Most researchers believe that there is no recognized diagnostic method, nor is there any 'aging criteria' associated with conventional testing methods used for XLPE cables. This implies that more work is necessary to find practical solutions for electrical utility engineers.

2.7 Accelerated Aging Mechanisms

It is important to find answers for important questions such as, how long does it take for the insulation to age before failure occurs? What is the life of the insulation under the stresses and factors experienced during operation of the cable? Aging tests are carried out on cables to predict their life expectancy under in-service operating conditions. Ideally an aging test should subject the cable insulating material to typical electrical, thermal and mechanical stress that are encountered in service. However, conducting life tests on cables under normal operating conditions results in unacceptably long testing times. Hence aging tests must be accelerated and be of as short duration as possible, as long as the induced aging mechanisms remain, as much as possible, similar to those occurring under actual service conditions. The most effective means to carry out accelerated aging is by subjecting the cable to enhanced stresses. This justifies the need of accelerated aging test procedures, in which, the stresses applied at higher than the normal operating values. The importance of accelerated electrical aging test methods has been already recognized for more than half a century. The most severe test included is load cycling between 130^0C and room temperature for 30 days (emergency condition). The purpose of this work is to produce a simple test, which will provide aging data relative to the polymer.

Early accelerated aging tests were performed on dry cable samples. Water was recognized as a source of concern for XLPE since the early 1970's. Since then, for polymeric power distribution cables, accelerated aging procedures have been developed emphasizing the formation of water trees. The AEIC test [69] has been the most widely used test in North America. In this test all important and known cable structural factors which affect the performance of cable have been considered. The aging test of this specification is intended for qualification of a cable design. The most severe test included is load cycling between 130^0C and room temperature for 30 days (emergency condition) for 180 total hours at 130^0C. This is inadequate for the present purpose which is to provide a simple test which will provide aging data relative to the polymer dielectric alone. However, the validity of this test is being questioned because the parameters are not rigidly defined and the number of samples is insufficient to provide satisfactorily meaningful data.

The difficulty with accelerated aging tests is relating the life under high stress to the life under operating conditions. Since there is no firm theoretical model to convert accelerated aging test results to the life at operating stress, statistical regression techniques are used to develop empirical models that relate stress levels to insulation life [55]. Despite the development of several accelerated aging tests, there is still no simple aging test that can reliably assess and/or predict the performance of cables. The problem can be attributed to three main reasons:

(1) The basic insulation aging mechanism is still not fully understood,

(2) The simulation of what occurs in service is difficult to reproduce in the laboratory and,
(3) Various service stresses cannot be accurately defined.

3. Design of Accelerated Aging Test

For polymeric materials such as XLPE, high temperature enhances not only the chemical reaction rate but also the degree of other thermally activated processes. At temperatures greater than 90^0C, the crystalline regions melt and further oxidation occurs. It is well established that both the 60Hz and impulse breakdown strengths diminish with temperature. But this phenomenon is partly determined by hardness of the polymers, and is independent of the oxidation level. For XLPE at 90^0C, the ac and impulse breakdown values are reduced by 6 and 19% respectively from those at room temperature, with further respective reductions of 18 and 48% at 115^0C [70]. This illustrates that in the case of XLPE, the parameters which are independent of oxidation level maintains the functionality even at higher than melting (90^0C) temperatures.

3.1 Estimation of Accelerated Aging Test parameters

Accelerated aging parameters like thermal stress and time duration are calculated with the help of the well known Arrhenius equation. The Arrhenius model relates time and temperature with the deterioration of materials. Arrhenius equation is preferred for this work over the n-degree rule as it has a better theoretical foundation and has been verified for many materials. Calculations have been done assuming constant as well as different temperature cycles for the cable insulation throughout its life using 3.1

$$L=B\times e^{\phi/kT} \tag{3.1}$$

Where, L = Time to reach a specified endpoint or lifetime (Hours)
B = Constant (usually determined experimentally)
ϕ = Activation energy (eV)
k = Boltzman's constant (0.8617× 10-4 eV/K)
T = Absolute temperature (K)

Using a special form of Arrhenius equation, accelerated aging parameters were identified by using [56] by the following equation:

$$ln\left(t_s/ta\right)=\frac{\phi}{k}\left(\frac{1}{T_s}-\frac{1}{T_a}\right) \tag{3.2}$$

Where, T_s is the service temperature in Deg. K.
T_a is the actual temperature in Deg. K
t_a is the time in years for which material is at actual temperature T_a
t_s is the time in years for which material is at service temperature T_s

Equation (3.2) can be explained as follows: Heating a material or component at temperature T_a for a time t_a will produce the same amount of reaction as will be produced at the service temperature T_s over a time t_s.

Service conditions are rarely constant with respect to temperature and in general, a device will be exposed to a range of temperatures depending on the load. This variation may be regular (cyclic) or irregular. T_o simplifies the procedure, and the times at various temperature levels are summed up using a procedure given in [56]. Equivalent time spent (t_o) at each temperature ($Ti - i = 1, 2...n$) was calculated after selecting one reference temperature (T_o) using equation (3.3).

$$t_o = t_1 \times e^{\left(\frac{1}{T_o} - \frac{1}{T_1}\right) \times \frac{\phi}{k}} \tag{3.3}$$

Where, T_o is the reference temperature in Deg K.

t_o is the equivalent time in years spent at temperature T_o

After calculating the total equivalent years (t_o) at an arbitrary reference temperature (T_o), lab aging time (t_s) is considered as one week for the cases of 5, 7.5, and 10 years of field age and two weeks for the case of 12.5, 15, 17.5 and 20 years of field age. Equation (3.4) is used to find the accelerated temperature (T_a) at which cable will be stressed for the duration of t_s.

$$T_a = \left[\left(\frac{1}{T_o} - \frac{k}{\phi} ln\left(\frac{t_o}{t_s}\right)\right)^{-1} - 273\right] \tag{3.4}$$

To simulate the exact field conditions for different ages, the temperature cycles as shown in Table 3.1 were decided after discussion with utility engineers. Table 3.2 gives the results of various calculations performed using the Arrhenius model.

Table 3.1. Various Temperature Cycles for Different Field Age

Sr. No.	**Temperature**	**Total Field Age in Years**			
		5	**10**	**15**	**20**
1	$t_1 = 80^0C$	T_1 = 2 years	T_1 = 5 years	T_1 = 8 years	T_1 = 10 years
2	$t_2 = 60^0C$	T_2 = 1.5 years	T_2 = 2.5 years	T_2 = 3.5 years	T_2 = 5 years
3	$t_3 = 100^0C$	T_3 = 1.5 years	T_3 = 2.5 years	T_3 = 3.5 years	T_3 = 5 years
		Total = 5 years	Total = 10 years	Total = 15 years	Total = 20 years

Table 3.2. Results of Accelerated Aging Parameters

Sr. No.	Field Age in years	Accelerated aging temperature (T_a) in ^0C	Duration of accelerated test (t_s) in hours
1	5	155.25	168 hours
2	10	163.58	168 hours
3	15	168.97	168 hours
4	20	163.58	336 hours

3.2 Experimental Setup

A number of cable sections removed from the field were made available. New samples were obtained from two different manufacturers. To eliminate any block effects in the experiment such as of manufacturer, randomized block design is adopted during experiments. The outer jacket and the armoring were removed and samples were cut to pieces of 30 cm length for the purpose of thermal aging. A gravity convection oven was used to perform thermal aging. To increase the confidence in the results, two samples were used in each experiment based on randomized block design of experiments.

The FTIR technique is useful for studying and monitoring the structural changes in dielectric materials before and after being subjected to different kinds of stresses. In the present study a FTIR spectrometer Nicolet 205 equipped with EZ-Scope attachment (Spectra-Tech) was used. Liquid nitrogen cooled Mercury Cadmium Telluride (MCT) was used as the detector. The depth of penetration depends upon the type of crystal used, and ZnSe crystal is used for the experiments.

Slices of thickness 1 mm were prepared using a diamond saw for the FTIR measurements. For each subset of cable sample, FTIR spectrums were obtained using five different small samples. Figure 3.1 shows the average spectrums for each subset of sample found by averaging five spectrums for each case. They were kept at room temperature for at least 24 hours before performing the FTIR analysis.

3.3 Fundamentals of Statistical Analysis

The statistical modeling work was performed both at Arizona State University and Wichita State University.

Statistical methods should be used to analyze the data in such a way that the results and conclusions are objective rather than judgmental in nature. It is usually very helpful to present the results in terms of an equation which expresses the relationship between the response and the important factors. Residual analysis and model adequacy checking are also important analysis technique.

3.3.1 Statistical Hypothesis

A statistical hypothesis is a statement either about the parameters or a probability distribution or the parameters of the model. The hypothesis reflects some conjecture about the problem situation. This may be stated formally as [57],

$$\begin{aligned} &H_0 : \mu_1 = \mu_2 \\ &H_1 : \mu_1 \neq \mu_2 \end{aligned} \tag{3.5}$$

Where, μ_1 and μ_2 are the mean value for different treatments. The statement H_0: $\mu_1 = \mu_2$ is called null hypothesis and H_1: $\mu_1 \neq \mu_2$ is called the alternative hypothesis. The alternative hypothesis specified here is called a two-sided alternative hypothesis because it would be true if $\mu_1 < \mu_2$ or if $\mu_1 > \mu_2$.

To test the hypothesis, a procedure is followed of taking a random sample, computing an appropriate test statistic, and then rejecting or failing to reject the null hypothesis H_0. For the specified value of significance level test procedure is designed so that the probability of error has a suitably small value.

3.3.2 Two Sample t-Test

The appropriate test statistic for comparing two treatment means in the completely randomized design is

$$t_0 = \frac{\bar{y}_1 - \bar{y}_2}{S_p \sqrt{\frac{1}{n_1} + \frac{1}{n_2}}} \tag{3.6}$$

Where, $\bar{y}_1$ and $\bar{y}_2$ are the sample means, n_1 and n_2 are the sample size, $S_p^{\,2}$ is the estimate of the common variance $\sigma_1^{\,2} = \sigma_2^{\,2} = \sigma^2$ computed from

$$S_p^{\,2} = \frac{(n_1 - 1)S_1^{\,2} + (n_2 - 1)S_2^{\,2}}{n_1 + n_2 - 2} \tag{3.7}$$

Where, $S_1^{\,2}$ and $S_2^{\,2}$ are the two individual sample variances. To determine whether to reject H_0: $\mu_1 = \mu_2$, t_0 is compared to the t-distribution with $n_1 + n_2 - 2$ degree of freedom. If $|t_0| > t_{\alpha/2, n_1 + n_2 - 2}$, where $t_{\alpha/2, n_1 + n_2 - 2}$ is the upper α/2 percentage point of the t distribution with n_1+n_2-2 degrees of freedom, hypothesis H_0 can be rejected. In this case it can be concluded that two treatment means are different.

One way to report the results of hypothesis test is to state that null hypothesis was or was not rejected at a specified value of significance level. This statement is often inadequate because it gives the decision maker no idea about whether the computed value of the test statistic was just barely in the rejection region or whether it was very far into rejection region. To avoid this P-value is adopted where P is the probability that the test statistic will take on a value that at least as extreme as the observed value of the statistic when the null hypothesis H_0 is true. In other words P is the smallest level of significance that would lead to rejection of the null hypothesis H_0 [57].

3.3.3 Assumption during *t*-Test

While performing *t*-Test assumption of both samples being independent and normally distributed is made. This means that the standard deviation or variances of both populations are equal, and that the observations are independent random variables. The equal-variance and normality assumptions can be checked easily by Anderson-Darlington normality test.

3.3.4 Analysis of Variance (ANOVA)

The analysis of variance (ANOVA) is based on a partitioning of total variability into its component parts. The total variability measured by the total corrected sum of squares, is partitioned into a sum of squares of the differences between the treatment averages and the grand average, plus a sum of squares of the difference of observations within treatments from the treatment averages. The difference between the observed treatment averages and the grand average is a measure of the difference between treatment means, whereas the difference of observations within a treatment from the treatment average can be due only to random error. Thus total sum of squares can be expressed as,

$$SS_T = SS_{Treatments} + SS_E \tag{3.8}$$

Where, $SS_{Treatments}$ is called the sum of squares due to treatments
SS_E is called the sum of squares due to error.

Formal test of the hypothesis of no differences in treatment means (H_0: $\mu_1 = \mu_2 = ... = \mu_a$ and H_1: $\mu_i \neq \mu_j$ for at least one pair (i,j)) can be performed using F-Statistics [57]. If the null hypothesis of no difference in treatment means is true, F_0 is distributed as F with $a-1$ and $N-a$ degrees of freedom and F_0 is

$$F_0 = \frac{SS_{Treatmetns} \,/(a-1)}{SS_E \,/(N-a)} = \frac{MS_{Treatments}}{MS_E} \tag{3.9}$$

Where a is the number of treatments of a single factor
N is the total number of readings.

Equation 3.9 is the test statistic for the hypothesis of no differences in treatment means. Hypothesis H_0 can be rejected and it can be concluded that there are differences in the treatment means if

$$F_0 > F_{\alpha,a-1,N-a} \tag{3.10}$$

Where, $F_{\alpha,a-1,N-a}$ is the upper-tail, critical region value for level of confidence of α. Generally *P*-value approach is adopted to make test more adequate.

3.3.5 Assumption during ANOVA Test

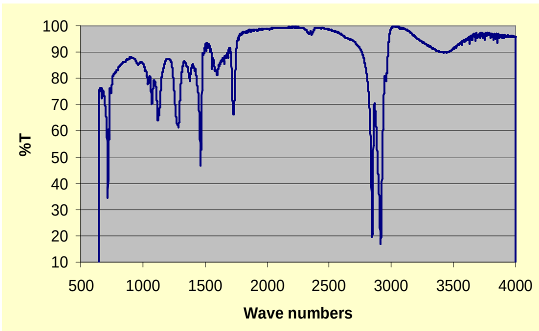
The followings are the assumptions made during ANOVA test, which needs to be verified.

- The errors are normally and independently distributed.
- The observations are also normally and independently distributed.

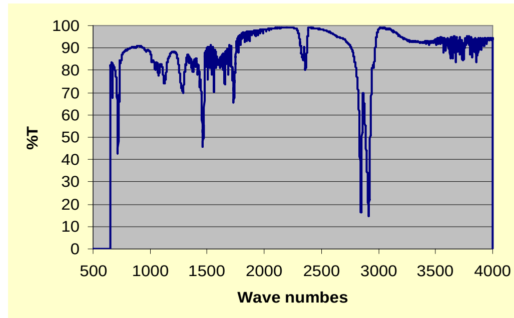
These two assumptions can easily checked by Anderson-Darlington test of normality.

3.4 Statistical Analysis

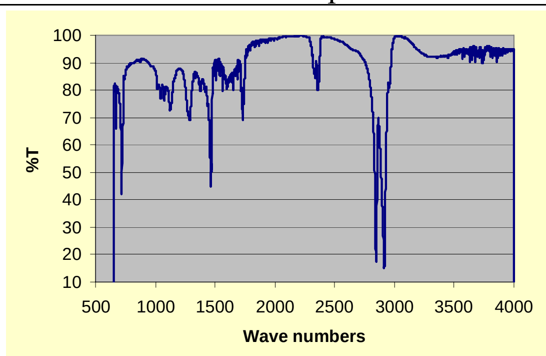
Statistical analysis was adopted to prove the significance of designed accelerated aging procedure. Comparing all the spectrums obtained as in Figure 3.1, a trend in the region of 2750 – 3000 cm^{-1} wave numbers is noticeable. The quantitative concentration of a compound can be determined from the area under the curve in characteristic regions of the IR spectrum.



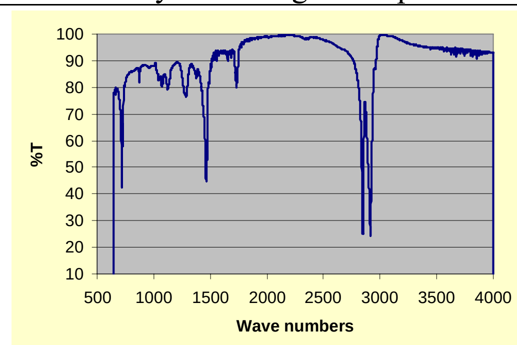
a. New Sample



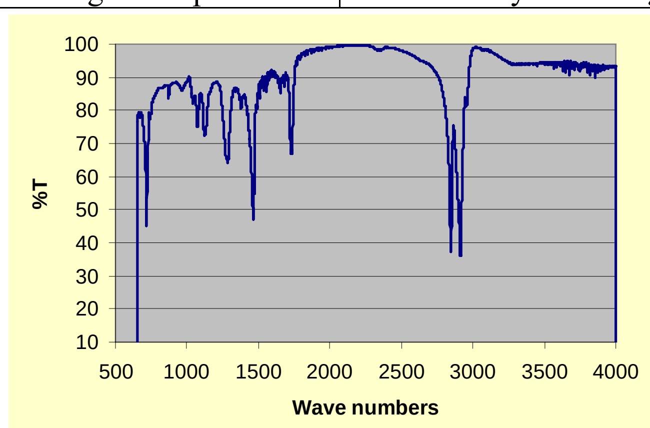
b. 5 years lab aged sample



c. 10 years lab aged sample



d. 15 years lab aged sample



e. 20 years lab aged sample

Figure 3.1. Average FTIR Spectrums after Accelerated Lab Aging for Different Years

The statistical analysis was performed for the area 2750 – 3000 cm^{-1} wave numbers region. CH_3 asymmetric stretching vibration occurs at 2975-2950 cm^{-1} while the CH_2 absorption occurs at about 2930 cm^{-1}. The symmetric CH_3 vibration occurs at 2885-2865 cm^{-1} while CH_2 absorption occurs at about 2870-2840 cm^{-1}. In general, the analyzed area under the curve (2750-3000 cm^{-1}) is representative of *–CH, -*CH_2 and *–*CH_3 carbon/hydrogen stretching vibrations. There was a trend noticeable for other group of wave numbers but it corresponds to either oxygen or hydrogen, which was not considered for the detailed analysis. To quantify the changes with the different durations of aging, the spectrum of a new cable was taken as the reference. Figure 3.2 shows the mean FTIR spectrum for each subset after subtracting the data of new cable spectrum. Table 3.3 shows the numerical values of Figures 3.2.

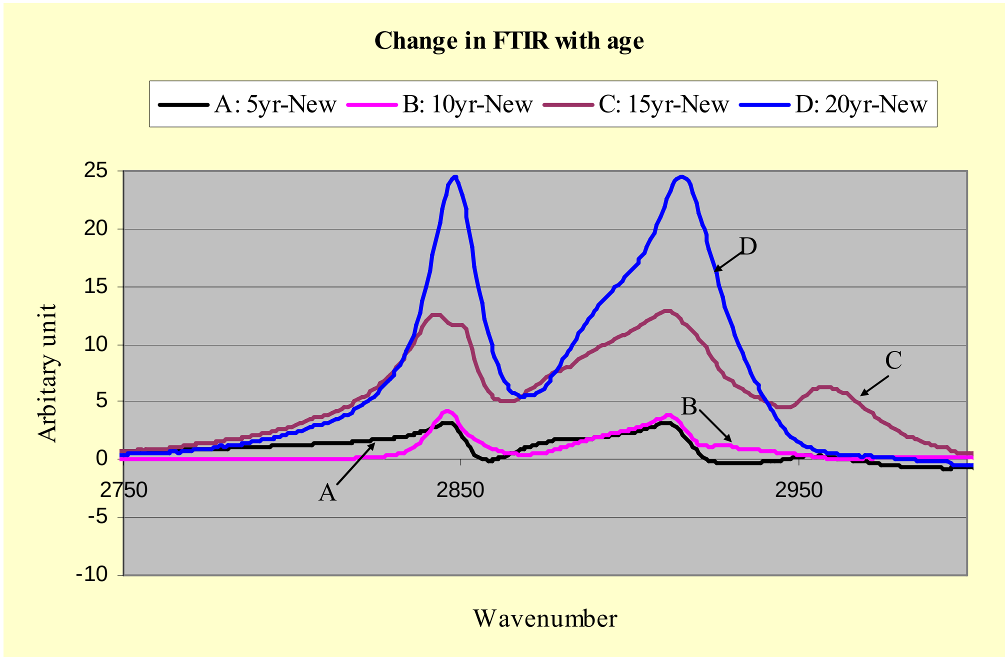


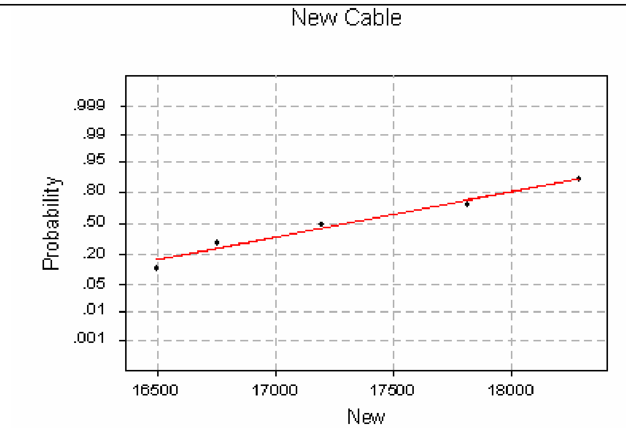
Figure 3.2. Change in FTIR Spectrums with Respect to New Cable

Table3.3. Results of FTIR Analysis for Lab Aged Samples

Run / Subset	1	2	3	4	5	Average
New	17812.1	18279.3	16493.5	16746.8	17191.7	17,304.7
5 years	17271.7	17108.9	17387.3	17807.5	18181.6	17551.4
10 years	17865.3	17107.8	17323.3	17607.2	17740.7	17,528.9
15 years	19221.2	18551.2	19054.1	18489.5	18662.8	18,795.8
20 years	19614.8	18410.9	18727.9	18709.6	20156.5	19,123.9

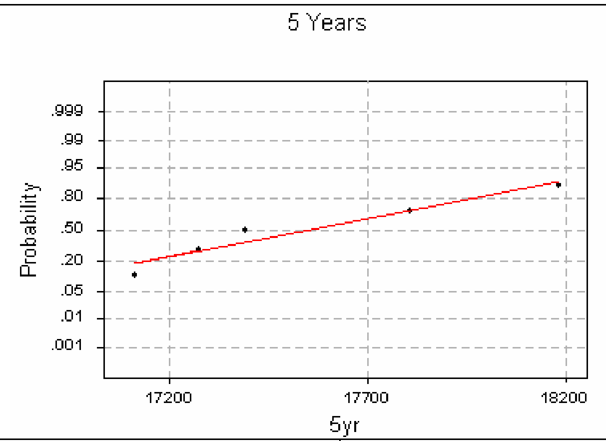
Each of five subsets was tested for conformance to normality. Each subset passed the Andersen-Darling test for normality. The *p-values* obtained with Minitab^{TM} software for these tests are shown in Figure 3.3 a-e. The Andersen-Darling test for normality was used to test the null hypothesis that the sampled distribution was normally distributed versus the alternative hypothesis that the sampled distribution was not normally distributed.

The Andersen-Darling test is a widely used statistical test for normality. If p-value exceeds 0.005 (a rule of thumb used by statisticians), the null hypothesis cannot be rejected and the data are assumed to be normally distributed.



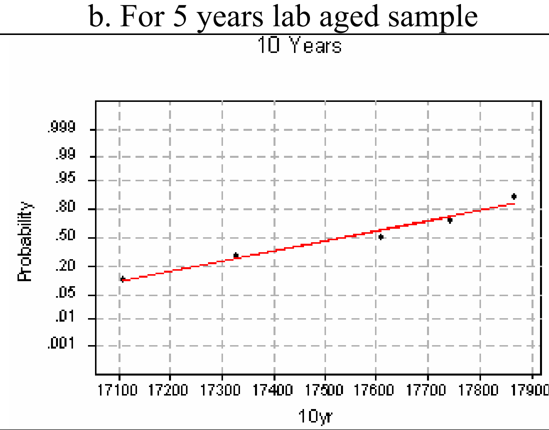
Average: 17304.7 StDev: 739.820 N: 5	Anderson-Darling Normality Test A-Squared: 0.202 P-Value: 0.742

a. For New cable



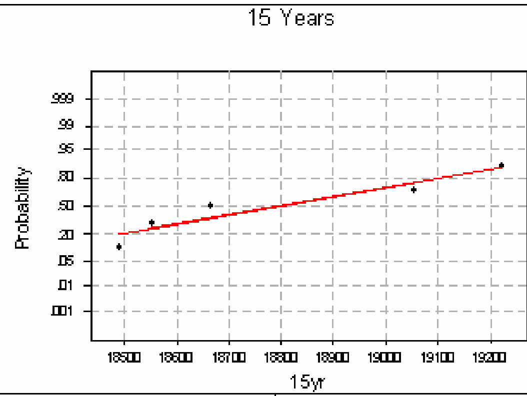
Average: 17551.47 StDev: 436.970 N: 5	Anderson-Darling Normality Test A-Squared: 0.264 P-Value: 0.518

b. For 5 years lab aged sample



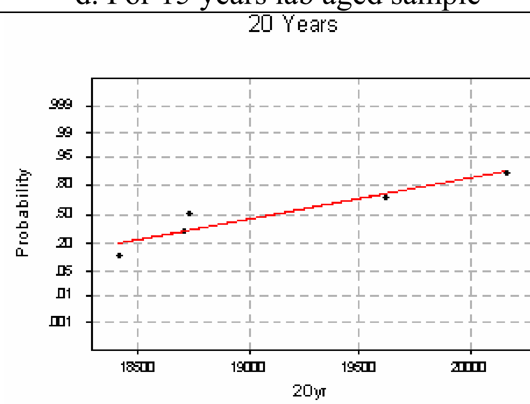
Average: 17528.9 StDev: 309.737 N: 5	Anderson-Darling Normality Test A-Squared: 0.212 P-Value: 0.702

c. For 10 years lab aged sample



Average: 18795.8 StDev: 323.68 N: 5	Anderson-Darling Normality Test A-Squared: 0.352 P-Value: 0.298

d. For 15 years lab aged sample



Average: 19123.9 StDev: 732.150 N: 5	Anderson-Darling Normality Test A-Squared: 0.369 P-Value: 0.265

e. For 20 years lab aged sample

Figure 3.3. Results of the Anderson-Darling Test for Normality

Analysis of Variance (ANOVA) was used to find how significantly subsets are different from each other. The analysis of variance (performed in Minitab™ software) is summarized in Table 3.4. It can be noted that the between-subset mean square (3480793) is many times larger than the within-subset or error mean square (295005). This indicates that it is unlikely that the subset means were equal. In addition, the F ratio is also computed and found to be 11.8. This is compared with an appropriate upper-tail percentage point of the $F_{4,20}$ distribution. If we consider 95% confidence limits, i.e. $\alpha = 0.05$, the value of $F_{0.05,4,20}$ is 2.87. As $F_0 = 11.8 > 2.87$, it is concluded that the subset means are different, indicating that the area under the curve for the region of 2750 – 3000 cm^{-1} is significantly different with respect to different years of aging in the laboratory.

Table 3.4. ANOVA Analysis for Lab Aged Samples

One way ANOVA (Analysis of Variance): New, 5 years, 10 years, 15 years, 20 years					
Source	**DF**	**SS**	**MS**	**F**	**P**
Factor	4	13923174	3480793	11.80	0.000
Error	20	5900108	295005		
Total	24	19823281			

Once the data was tested for normality and different subset means, a one-sample t-test was used to test the hypothesis that each subset other than new cable had a different area value of FTIR spectrum (2750-3000 cm^{-1}). Assuming the variance of area under the curve is approximately identical for different years of lab aging, and then the t-test can be used to compare two subset means in a completely randomized design. Taking the confidence requirement as 95% ($\alpha = 0.05$), we can reject the hypothesis of subset means being equal if $t_0 > \pm t_{0.025,\ 8}$ (2.30) or (-2.30). Table 3.5 shows the results of t-test (performed using Minitab™ software), which indicates that the subset means of 5 years and 10 years of lab aging are not different significantly from the subset mean of new cable. At the same time, subset means of 15 years and 20 years are significantly different than that of new cables. It can be concluded that accelerated lab aging experiments produce significant results for simulated age of more than 10 years.

Table 3.5. Results for hypothesis Test for Lab Aged Samples

Test of μ_0 = 17305 verses $\mu_0 \geq$ 17305						
Subset	**n**	**Average**	**STDEV (s)**	**t_0**	**$t_{0.25,\ 8}$**	**p-value**
5 years	5	17551	437	01.26	2.30	0.276
10 years	5	17529	310	01.62	2.30	0.181
15 years	5	18796	324	10.30	2.30	0.001
20 years	5	19124	732	5.56	2.30	0.005

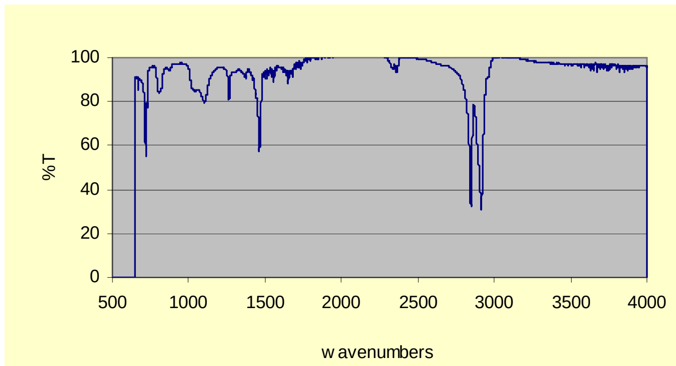
3.5 Correlation with Field Aging

The second task of this study was to prove the significance of accelerated lab aging with field aging. Cable samples of different field aging were obtained from local utility company as shown in Table 3.6. Five samples from each different field aged cable (1 and 2) are obtained from different locations.

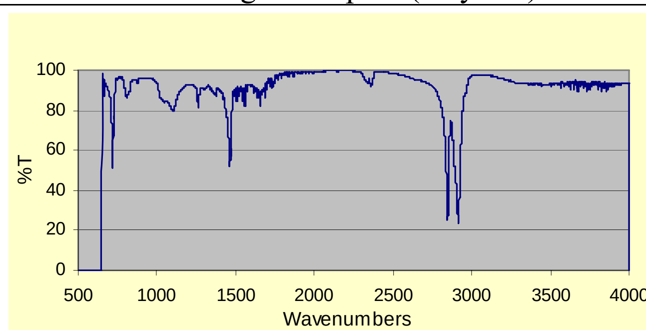
Figure 3.4 shows the average FTIR spectrum and Table 3.7 shows the area value for 2750 – 3000 cm^{-1} wave numbers for field aged samples 1 and 2. The two subsets each were tested for conformance to normality. Each subset passed the Andersen-Darling test for normality. The *p-values* obtained with Minitab™ software for these tests are shown in Figures 3.5a – 3.5b. As shown in Figure 3.5, both the samples have passed the Andersen-Darling test for normality.

Table 3.6. Cable Samples Received from the Local Utility Company

Sample	Cable Specification	Year of Installation
1	500MCM, 15kV	1983
2	500KCMIL, 15kV	1989



a. Field aged sample 1(20 years)



b. Field aged sample 2 (13 years)

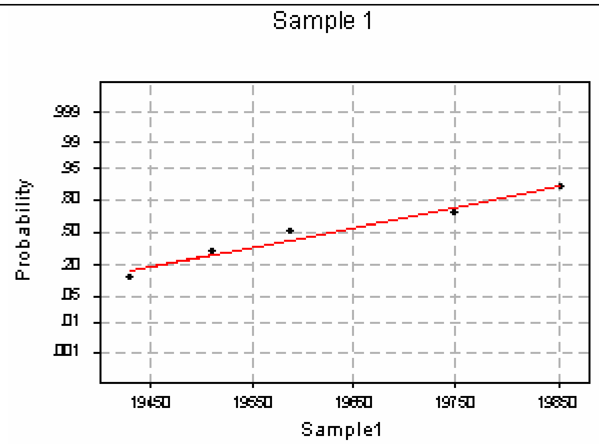
Figure 3.4. Average FTIR Spectrums for Field Aged Samples

Table 3.7. Results of FTIR Analysis for Field Aged Samples

Subset \ Run	1	2	3	4	5	Average
Sample 1 (20 years)	19851.0	19747.5	19585.9	19430.5	19511.0	19,625.2
Sample 2 (13 years)	18623	18585	18523	18783	18618	18626.4

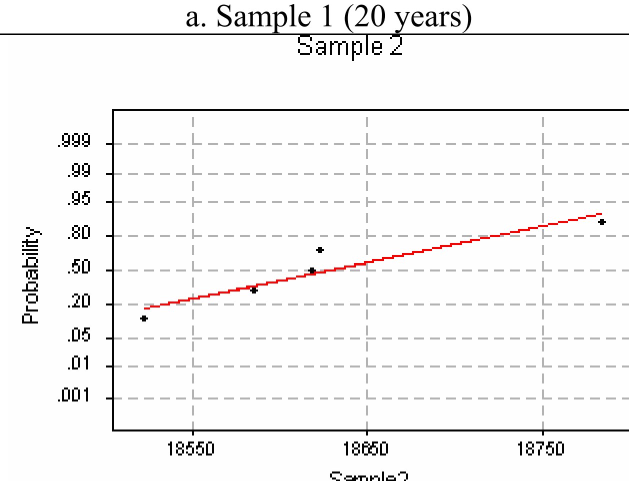
The strong correlation (as shown in Table 3.8) between lab aging and field aging is observed by comparing average value of area (for 2750-3000cm^{-1}). Statistically this correlation can be proved by performing t-test hypothesis. Taking confidence requirement as 95% ($\alpha = 0.05$), hypothesis of subset means being equal can be rejected if $t_0 > t_{0.025, 8}$ (2.30) or $t_0 < - t_{0.025, 8}$ (-2.30). Table 3.9 clearly shows that in case of sample 1 and 20years of accelerated lab aging results, hypothesis of subset means being equal can not be rejected. In case of accelerated lab aging of 5 years, 10 years, and 15 years t-values suggests that hypothesis of subset means being equal can be rejected. The same conclusion can be made based on p-value shown in Table 3.9.

For sample 2, Table 3.10 shows the result of t-test hypothesis. The hypothesis of subset means being equal can not be rejected for 15 years as well as 20 years of lab aging. In case of accelerated lab aging of 5 years and 10 years, t-values suggests that hypothesis of subset means being equal can be rejected confidently. P-values suggest that sample 2 can be correlated better with 15 years of simulated lab aging more than with 20 years of simulated lab aging.



Average: 19625.2 StDev: 172.089 N: 5	Anderson darling Normality Test A-Squared: 0.202 P-Value: 0.742

a. Sample 1 (20 years)



Average: 18626.4 StDev: 96.1915 N: 5	Anderson darling Normality Test A-Squared: 0.381 P-Value: 0.244

b. Sample 2 (13 years)

Figure 3.5. Results of the Anderson-Darling Test for Normality

Table 3.8. Comparison of Field aging and Accelerated Lab Aging

Age	Field Aged Sample	Lab Aged Sample
20 years	19624	19123
13 years	18626	18795 (Aged for 15 years)

Table 3.9. Results for Hypothesis Test for Field Aged Cable Sample 1 and Lab Aged Cables

t-test for filed aged 20 years cable with lab aged cables			
Subset	**n**	**t_0**	**p-value**
Sample 1Vs. New	5	-6.83	0.002
Sample 1 Vs. 5 years	5	-9.87	0.000
Sample 1 Vs. 10 years	5	-13.23	0.000
Sample 1 Vs. 15 years	5	-5.06	0.002
Sample 1 Vs. 20 years	5	-1.49	0.210

Table 3.10. Results for Hypothesis Test for Field Aged Cable Sample 2 and Lab Aged Cables

t-test for filed aged 20 years cable with lab aged cables			
Subset	**n**	**t_0**	**p-value**
Sample 2Vs. New	5	-3.96	0.017
Sample 2 Vs. 5 years	5	-5.37	0.006
Sample 2 Vs. 10 years	5	-7.57	0.002
Sample 2 Vs. 15 years	5	1.12	0.325
Sample 2 Vs. 20 years	5	1.51	0.206

3.6 Summary

The degradation of cable insulation material (cross linked polyethylene - XLPE) is identified and quantified in terms of concentration of –CH, $-CH_2$ and $–CH_3$ carbon/hydrogen stretching vibrations using FTIR analysis. The accelerated aging procedure is established based on well known Arrehenius equation. Strong correlation is observed between field aged samples and suggested accelerated lab aging procedure. The identification and quantification of degrading parameter in case of cable insulation material (XLPE) can help to prioritize maintenance as well as replacement schedules of in-service cables.

4. Differential Scanning Calorimetry (DSC)

It has been shown that the electrical properties of XLPE get affected by change of crystalline structure [58]. These changes consist of partial crystalline melting or re-crystallization of the structure. In crystalline polymers like XLPE, it is well known that re-crystallization occurs under heat treatment while the thermal characteristics also change. An attempt to calculate the thermal history using Differential Scanning Calorimetry (DSC) profiles is made in [58] by Kazuharu Kobayashi et al. In [58], a new procedure is discussed and validated to calculate thermal history of XLPE for the case when XLPE is under heat treatment for the time of 2-3 hours. Knowledge of thermal history of the field aged cable samples can facilitate the calculation of accelerated aging parameters. An attempt to establish the thermal history for field aged cable samples using DSC profiles was made and discussed in this chapter.

DSC is a technique to study what happens to polymers when they're heated. The principle on which measurements of DSC is taken is the following. Two pans sit on a pair of identically positioned platforms connected to a furnace by a common heat flow path. Out of two pans, one pan will be empty and other will hold the sample to be analyzed. The furnace is turned on using computer, heating both the pans at a constant specified rate. As two pans are different, one is empty and other is with the sample, it takes different heat flow to maintain the constant specified temperature rise. The difference between heat flow of two pans are plotted as output with temperature as χ axis.

The following properties and parameters can be measured and/or calculated using DSC plots.

- Heat capacity (Cp)
- Polymer's glass transition temperature
- Polymer's crystallization temperature
- Latent energy of crystallization for the polymer
- Polymer's melting temperature, and
- Thermal history of the polymer.

4.1 Experimental

Field aged cable samples were obtained from various utilities. In order to compare the results directly, samples were prepared from two different field aged samples of approximately same field age in years. DSC analysis has been performed on a sheet specimen of 0.5 mm thickness, 2 mg of specimen in air atmosphere at a heating rate of 10^0 C/minute. To compute the parameters for various calculations, obtained DSC plots were compared with figure 4.1, which displays the location of various parameters in a standard DSC plot.

4.2 Results and Discussion

Figure 4.2 and 4.3 shows the DSC plots of the two field aged cable samples of approximately 5 years of age. The detail calculation was performed on both the samples plots using equations 4.1 – 4.6 and constants mentioned in table 4.1. Appendix B shows the various steps of the calculations. Table 4.2 displays the results of the calculations.

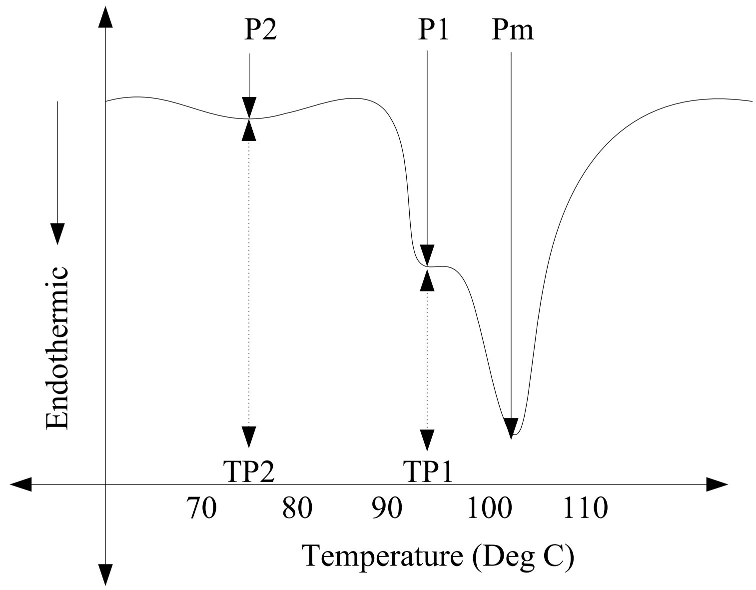


Figure 4.1. Profile of DSC output plot with various parameters

$$T_{p1}\left(T,t\right) = S_{1(T)}\, log\left(t\right) + T_{p1}\left(T,t\right) \tag{4.1}$$

$$T_{p2}\left(T,t\right) = S_{2(T)}\, log\left(t\right) + T_{p2}\left(T,t\right) \tag{4.2}$$

$$S_1\left(T\right) = A_1 T + B_1 \tag{4.3}$$

$$S_2\left(T\right) = A_2 T + B_2 \tag{4.4}$$

$$T_{p1}\left(T,t\right) = C_1 T + D_1 \tag{4.5}$$

$$T_{p2}\left(T,t\right) = C_2 T + D_2 \tag{4.6}$$

Where, *t:* Treated period
T: Treated temperature
A_1, A_2: Slope of $S_1(T)$, $S_2(T)$
B_1, B_2: Intercept of $S_1(T)$, $S_2(T)$
C1, C2: Slope of $Tp_1(T,t)$, $Tp_2(T,t)$
D1, D2 : Intercept of $Tp_1(T,t)$, $Tp_2(T,t)$

Table 4.1. Parameters for Thermal History Analysis (XLPE)

A_1	A_2	B_1	B_2	C_1	C_2	D_1	D_2
-0.056	-0.022	6.5	-0.43	1.1	1.2	-7.7	-16

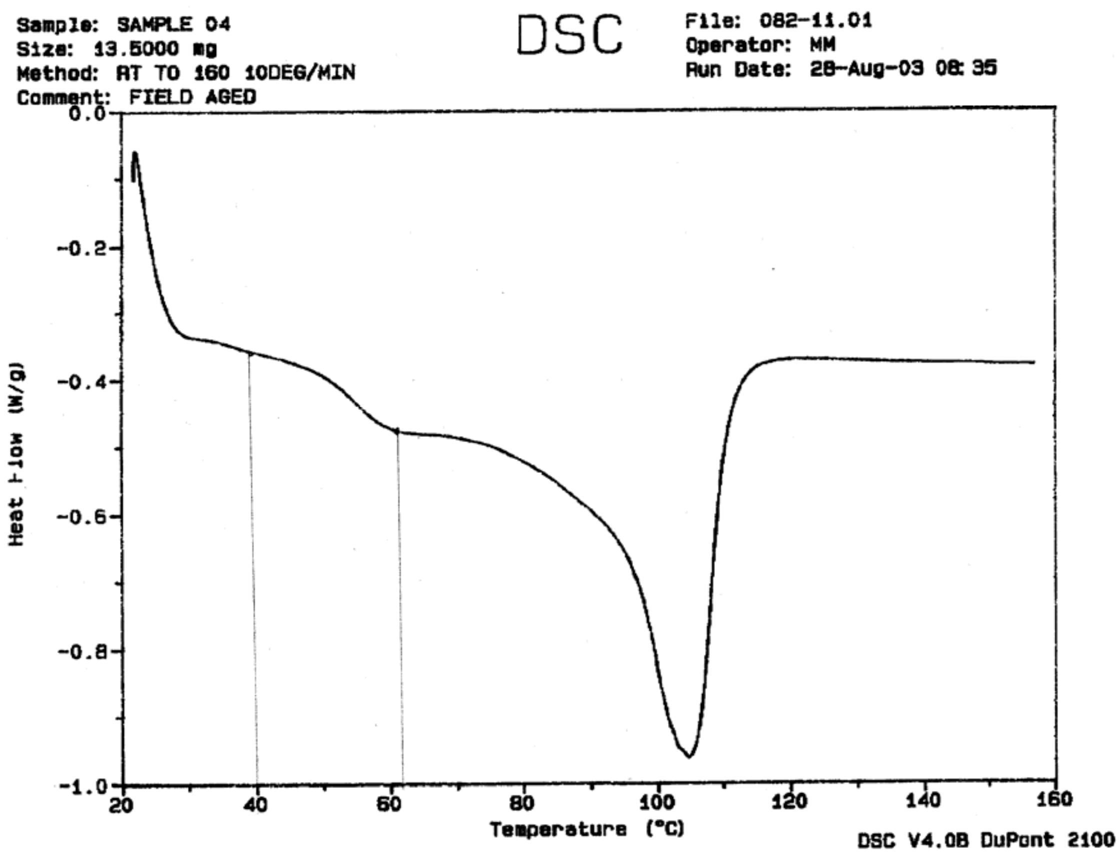


Figure 4.2. DSC Profile of Field Aged Sample 1(~ 5 yr)

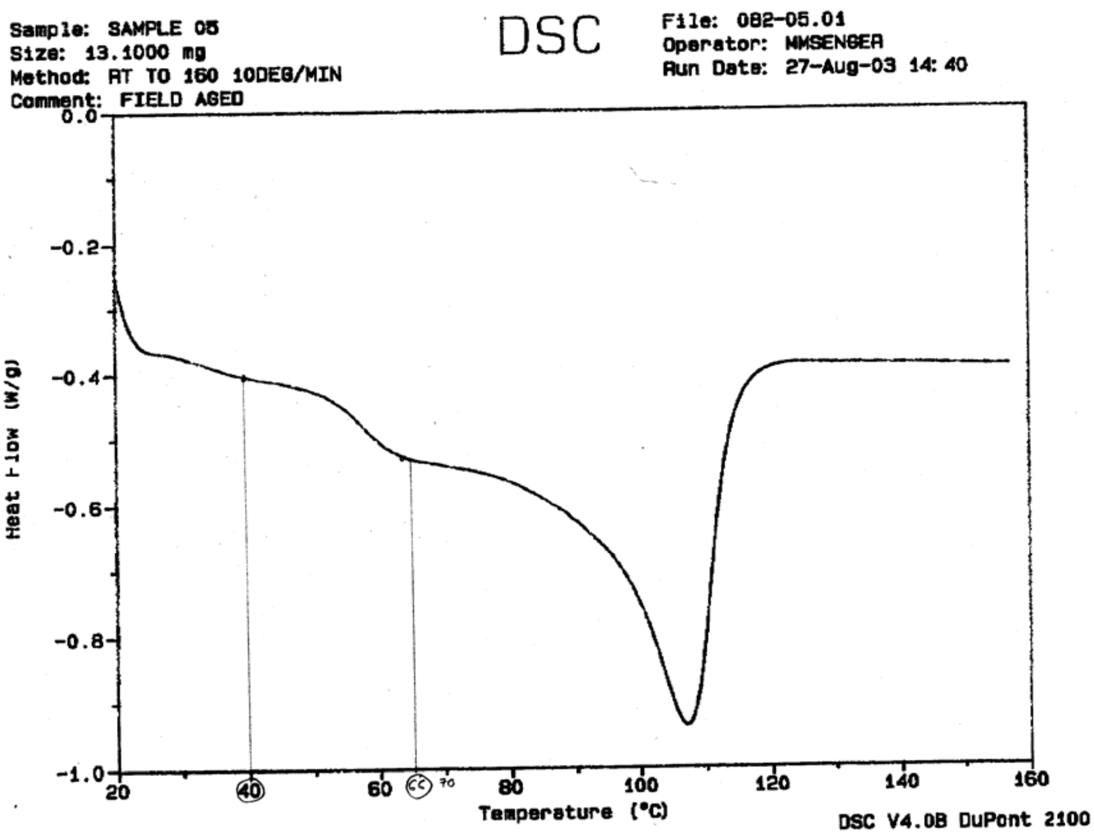


Figure 4.3. DSC Profile of Field Aged Sample 2 (~ 5 yr)

Table 4.2. Calculated Thermal Histories

Sample	Tp_1[1]	Tp_2[1]	Temp. T in Deg C	Treatment time in Hours
Sample 1	66	40	52.56	8.08
Sample 2	62	40	51.39	1.19

Estimation method described in [58] is very sensitive to identification of hump (P_1) and small concave (P_2) observed in DSC profile. Small variation (even 1^0C) in either P_1 or P_2 results in a large variation of calculated temperature and treated time. When applied to field aged samples, it is very difficult to understand results obtained. Application of this method to approximately 5 years field aged sample suggests that heat treatment is performed on cable at 52.5^0C for 8 hours.

4.3 Summary

An attempt is made to apply the method described in [58] to the case of filed aged cable samples of approximately 5 years. The method described is successfully used by K. Kobayashi et al for the thermal history of few hours (~ < 5 hours). It can be concluded

[1] These values are obtained from DSC plot (shown in figure 4.2 and 4.3 for sample 1 and 2 respectively)

that this method is not suitable for establishing the thermal history of 5 years field aged cable sample.

5. Condition Monitoring of Cable Insulation

Accidental failures in cables causing outages in power supply are one of the major sources of concern for utilities. As in the case of any electrical equipment, in cables also, it is the dielectric or insulating material which degrades over a period of time and eventually fails. The reliability of distribution network is therefore intimately tied to the state of the cable insulation. Many XLPE insulated power distribution cables have been operating for more than 20 years and are approaching their designed 30 years of expected life. Some these cables have started to have accidental failures resulting in outages of electricity.

There are two major reasons for inability to prevent these failures; lack of complete understanding about aging and, lack of reliable and cost effective insulation monitoring techniques. A good amount of work has been performed towards understanding the aging process of insulating material, but still it's far from being completely understood. What causes the aging and, which parameters can be used to quantify aging, are not easy questions to answer. Years of experience has shown that the degree and the rate of aging of insulation depend on the physical and chemical properties of the material, nature and duration of applied/induced stresses, material processing and subsequent use in the device [17]. Good progress has been made in terms of electro thermal modeling of cable insulation [59] and some models can predict life under certain conditions. It is difficult to reproduce whatever happens in the field in terms of intermittent value of various stresses and other conditions, and this could be one of the reasons for a lack of accuracy in aging models.

It is important to detect the problems in its incipient stages to avoid costly shutdowns. This can be achieved by identifying and monitoring key properties related to degradation if any of the cable insulating medium. This is the major challenge in establishing decision making tools for replacement and maintenance schedules. In case of having robust methodologies to monitor the condition of insulation, decisions can be made regarding replacement or continuation of some existing cable network without compromising the reliability of the system.

Condition monitoring is defined as a technique or a process of monitoring the operating characteristics of electrical equipment in such a way that changes and trends of the monitored characteristics can be used to predict the need for maintenance before serious deterioration or breakdown occurs. The reliable condition monitoring techniques enabled the change of the maintenance from periodic to condition based. There are two different approaches adopted to assess the condition of cable insulation: the characterization of the cable system or of cable insulating materials as explained in chapter 2.

Various techniques and features are used to characterize different stages of the aging process in order to assess the condition of the cable insulation. These techniques can briefly be classified as [60]:

1) Micro-structural:
The measureands like crystallinity, Amorphous content Lamella and crystal domain size, to name a few, have been successfully used by researchers for condition monitoring of the cable insulation. Techniques like Differential Scanning Calorimetry (DSC), Raman and Micro-Raman Spectroscopy, FTIR, Atomic Force Microscopy (AFM), are mainly adopted to perform the analysis.

2) Electrical:
Electrical breakdown strength and traps are one of the main measureands for quantifying electrical properties. Techniques like Pulsed Electro-Acoustic space charge measurements (PEA), and Charging-Discharging currents are used to measure the electrical property of the cable insulation.

3) Physical:
Properties like chain reconfiguration, nano to micro voids and traps are used successfully to characterize the physical condition of the cable insulation. To achieve this characterization, techniques like FTIR and Optical microscopy to name a few, are used extensively.

4) Cable Stability:
Parameters like oxidation, chemical changes, and additives are measured to check the cable stability. For these, techniques ranging from FTIR to break down voltage are used.

There is a requirement of a diagnostic and /or condition monitoring technique(s) to assess any degradation of the insulating materials and to decide whether or not to do any maintenance on equipment [17]. Most researchers believe that there is no recognized diagnostic method, condition monitoring technique, nor any ‘aging criteria’ associated with conventional testing methods used for XLPE cables. This implies that more work is necessary to find out practical solutions for electrical engineers dealing with utility. This work establishes a new approach for condition monitoring of the cable insulating material XLPE.

The basis of the new approach is in the author’s belief that the knowledge of insulation condition coupled with real life data on end-of-life should enable the information to be presented in a manner that would make it more valuable for practicing engineers. If data indicative of the condition at any given time can be obtained, then it would be possible to predict the condition at a future time and estimate remaining life as well. This feedback from the actual working condition is possible only if we can measure the changes occurring in service.

Field aged cable samples have been obtained during the course of study from various utilities. The obtained samples are from all the utility companies, which mainly have operations in hot and dry type of atmosphere as that of the state of Arizona, USA. Table 5.1 shows the details of field aged samples analyzed during this study. Figure 5.1 shows cable sample A, specified in Table 5.1, which was removed from the service after 5 years due to failure.

Table 5.1. Cable Identification of Various Field Aged Samples

Cable	Age in the Field	Reason for removal
A	5yr	Failure
B	13yr	Replacement
C	20yr	Replacement
D	26yr	Replacement
E	40yr	Replacement

Figure 5.1. Cable Sample A

5.1 Experimental

In this study, two different techniques are selected for detailed analysis based on their applicability and importance to monitor the condition of the cable insulation.

5.1.1 FTIR Analysis

FTIR spectrums can be used

- To characterize and identify material.
- To monitor chemical reactions.
- To determine the absence/presence of specific chemical groups.

FTIR analysis is able to assess mainly condition monitoring agents like micro-structural, physical and cable stability. In the present study a FTIR spectrometer Nicolet 205 equipped with EZ-Scope attachment (Spectra-Tech) is used. Liquid nitrogen cooled Mercury Cadmium Telluride (MCT) is used as the detector. The depth of penetration depends upon the type of crystal used, and ZnSe crystal was used for the experiments. A very thin slice of 1mm is obtained using diamond saw.

For preliminary analysis, FTIR spectrums are compared for new cables and field aged cables of approximately 10 years. Figure 5.2 shows a noticeable trend in FTIR spectrums, with respect to age in case of field aged samples which were removed due to replacement. Table 5.2 shows comparisons between transmittance peaks for healthy new cables, healthy aged cables, failed new cables and failed aged cables. The wave shape of transmission bands is proportional to the concentration of material of different chemical groups at different wave numbers. The reduction of CH_2 bond (2926 cm^{-1}) is approximately 66%, 82% and 85% for healthy aged cables, failed new cables and failed aged cables respectively with respect to new cables. Side chain absorption bands made up of -CH_2 at 1460 cm^{-1} also decreases and reaches higher transmittance level.

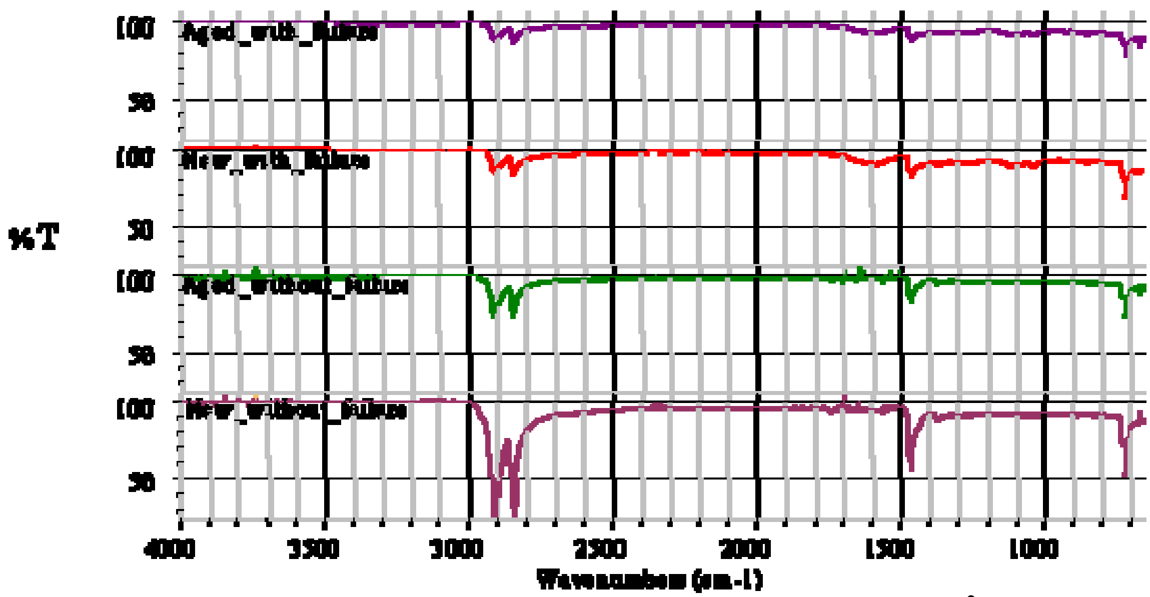


Figure 5.2. FTIR Spectra of New and Aged XLPE Cables[2]

[2] Spectrums are averaged for 6 to 7 different places of each sample with 10 samples of each type.

Table 5.2. Wave Numbers of Different Cables Spectra

Wave number cm^{-1}	Bond	Transmittance %				
		1	2	3	4	5
2926	Asymmetric stretching of C-H	22	73.5	86	88.5	66.5
2850	Symmetric stretching of C-H	24	74	85	88	64
1460	Symmetric deformation of C-H	57	83	83.5	88.75	31.75
720	Asymmetric deformation of C-H	52	74	74.5	79	27
1 - New_without_failure 2- Aged_without_failure 3 – New_with_failure 4 - Aged_with_failure 5 - Range						

5.1.2 Electrical Breakdown Strength

Electrical breakdown tests using needle plane geometry was used to gauge the electrical breakdown strength of the cable. The electrical breakdown strength of the cable insulation can be influenced by rough interfaces, foreign particles or contaminants and small voids or cavities within the insulation.

Initially to prove the significance of electrical breakdown strength as a quantifiable parameter of degradation, breakdown strength was performed on new as well as 10 years field aged cables. The outer jacket and the armoring were removed and samples were cut in 30 cm pieces for the purpose of the electrical breakdown test. The schematic and setup of the electrical breakdown test is shown in figure 5.3 and 5.4 respectively.

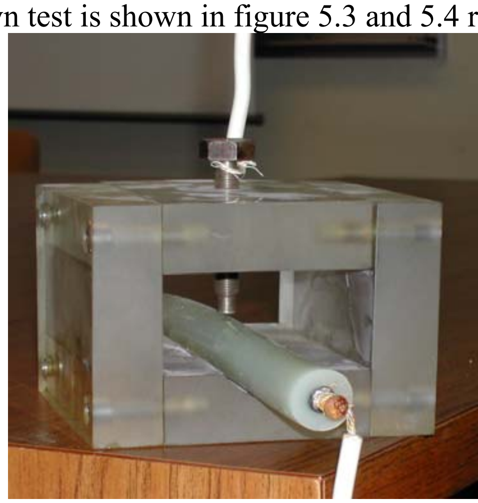


Figure 5.3. Experimental Setup for Electrical Breakdown Test

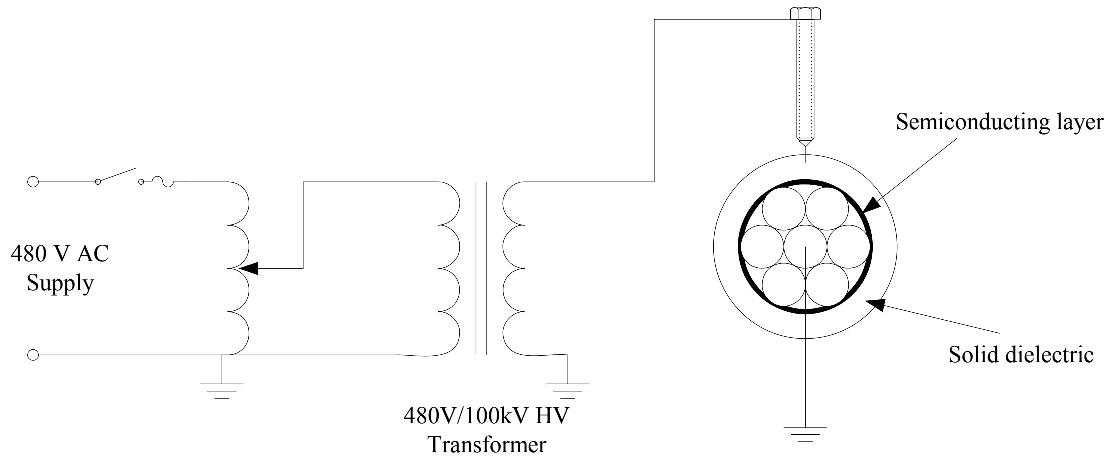


Figure 5.4 Electrical Setup for the Breakdown Test

During these experiments, the depth of the needle was varied and voltage-time product was compared for new as well as field aged samples. Figure 5.5 gives the electrical breakdown test data; the following conclusions can be made for new and aged cables [61]:

- Aging of around 10 years in dry weather resulted degradation in cable performance by at least 25%.
- Equal slope for new and aged cables indicates linear dependency of kV-time product with respect to depth of penetration.
- A different depth of penetration is required to get zero kV-time product for aged and new cables (5.9mm for new versus 3.8 mm for aged). This clearly indicates that the aged cables are more susceptible to failure due accidental dig-ins.

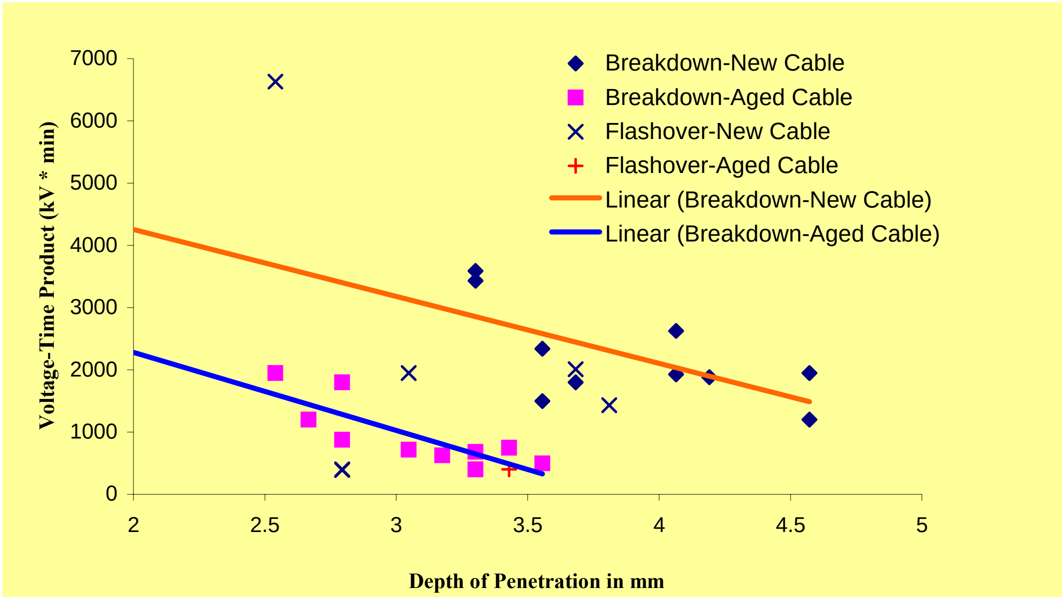


Figure 5.5: Electrical Breakdown Test Data
(To obtain these results 10 samples of each cable type (new and aged) have been used)

5.2 Results

5.2.1 FTIR Analysis

Detailed FTIR analysis was performed on these cables, as explained in the previous section. A trend in the region of 2750 – 3000 cm^{-1} wave numbers is noticeable, as shown in figure 5.2. The quantitative concentration of a compound can be determined from the area under the curve in characteristic regions of the IR spectrum. The statistical analysis was performed for the area 2750 - 3000 cm^{-1} wave numbers region. CH_3 asymmetric stretching vibration occurs at 2975-2950 cm^{-1}, while the CH_2 absorption occurs at about 2930 cm^{-1}. The symmetric CH_3 vibration occurs at 2885-2865 cm^{-1}, while CH_2 absorption occurs at about 2870-2840 cm^{-1}. In general, the analyzed area under the curve (2750-3000 cm^{-1}) is representative of –CH, -CH_2 and –CH_3 carbon/hydrogen stretching vibrations. There was a trend noticeable for other groups of wave numbers, but it corresponds to either oxygen or hydrogen, which was not considered for the detailed analysis. Table 5.3 displays the results of FTIR analysis, which is the area of the spectrum from 2750-3000 cm^{-1} wave numbers.

To perform statistical analysis like t-test, ANOVA, it is very important to check the assumption of normally distributed data, made for performing these mentioned tests. Each of the five subsets was tested for conformance to normality. Each subset passed the Andersen-Darling test for normality. The *p-values* obtained with Minitab™ software for these tests are shown in Figure 5.6 a - e. The Andersen-Darling test for normality was used to test the null hypothesis that the sampled distribution was normally distributed, versus the alternative hypothesis that the sampled distribution was not normally distributed.

The Andersen-Darling test is a widely used statistical test for normality [62]. If the p-value exceeds 0.005 (a rule of thumb used by statisticians), the null hypothesis cannot be rejected and the data is assumed to be normally distributed.

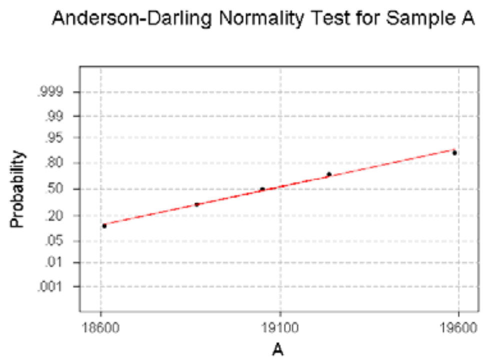
Table 5.3. Area of FTIR Spectrum (2750 – 3000 cm^{-1})

Cable	Value of Area of FTIR Spectrum				
A	19589	18866	18608	19050	19237
B	18623	18585	18523	18783	18618
C	19851	19747	19585	19430	19511
D	20368	22324	19931	20071	18636
E	21203	20771	20712	20556	20904

Analysis of Variance (ANOVA) is used to find how significantly subsets are different from each other. The analysis of variance (performed in Minitab™ software) is summarized in Table 5.4. It can be noted that the between-subset mean square (39364741) is many times larger than the within-subset, or error, mean square (399909). This indicates that it is unlikely that the subset means were equal. In addition, the F ratio is also computed and found to be 9.84. This was compared with an appropriate upper-tail percentage point of the $F_{4,20}$ distribution. If we consider 95% confidence limits, i.e. $\alpha = 0.05$, the value of $F_{0.05,4,20}$ is 2.87. As $F_0 = 9.84 > 2.87$, it can be concluded that the subset means are different, indicating that the area under the curve for the region of 2750 – 3000 cm^{-1} was significantly different with respect to different years of field aging [8].

Table 5.4. One way ANOVA Analysis for Field Aged Samples for FTIR Spectra

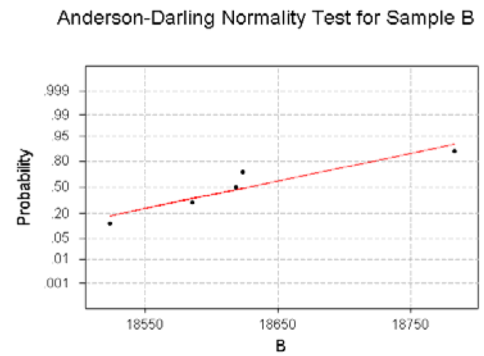
One way ANOVA (Analysis of Variance): A, B, C, D, E					
Source	**DF**	**SS**	**MS**	**F**	**P**
Factor	4	15745884	39364741	9.84	0.000
Error	20	7998181	399909		
Total	24	23744065			



Average: 19070
StDev: 371.72
N: 5

Anderson-Darling Normality Test
A-Squared: 0.140
P-Value: 0.926

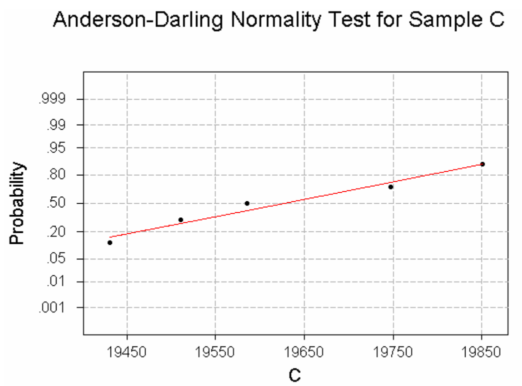
a. For Sample A



Average: 18626.4
StDev: 96.19
N: 5

Anderson-Darling Normality Test
A-Squared: 0.381
P-Value: 0.244

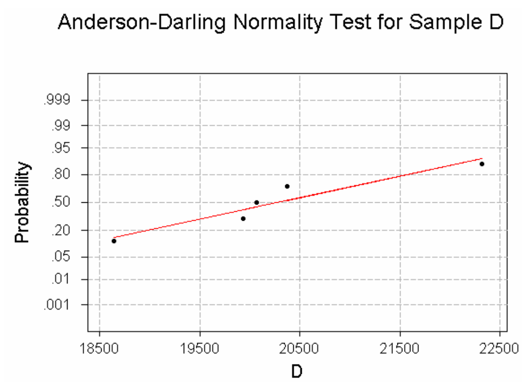
b. For Sample B



Average: 19625.2
StDev: 172.08
N: 5

Anderson-Darling Normality Test
A-Squared: 0.202
P-Value: 0.742

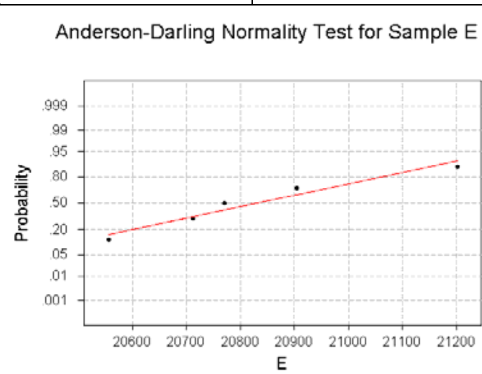
c. For Sample C



Average: 20266
StDev: 1327.87
N: 5

Anderson-Darling Normality Test
A-Squared: 0.331
P-Value: 0.343

d. For Sample D



Average: 20829.2
StDev: 243.45
N: 5

Anderson-Darling Normality Test
A-Squared: 0.225
P-Value: 0.0.648

e. For Sample E

Figure 5.6. Normality Test for Aged Samples for FTIR Analysis

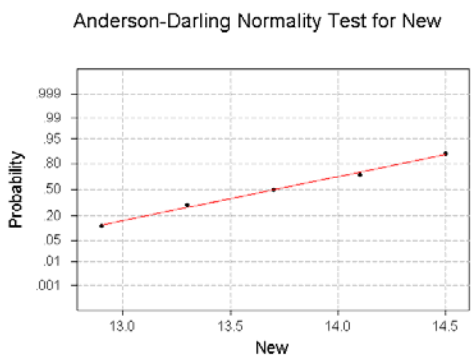
5.2.2 Electrical Breakdown Analysis

Electrical breakdown tests were performed on all the field aged samples listed in table 5.1, as shown in figures 5.3 and 5.4. Table 5.5 displays the results of electrical breakdown strength for new as well as field aged cables. Each of the five subsets was tested for conformance to normality. Each subset passed the Andersen-Darling test for normality. The *p-values* obtained with Minitab^{TM} software for these tests are shown in Figure 5.6 a - f. The Andersen-Darling test for normality was used to test the null hypothesis that the sampled distribution was normally distributed, versus the alternative hypothesis that the sampled distribution was not normally distributed.

The Andersen-Darling test is a widely used statistical test for normality [7]. If the p-value exceeds 0.005 (a rule of thumb used by statisticians), the null hypothesis cannot be rejected and the data is assumed to be normally distributed. Analysis of Variance (ANOVA) is used to find how significantly subsets are different from each other. The analysis of variance (performed in Minitab^{TM} software) is summarized in Table 5.6.

Table 5.5. Electrical Breakdown Strength Using Needle Plane Geometry

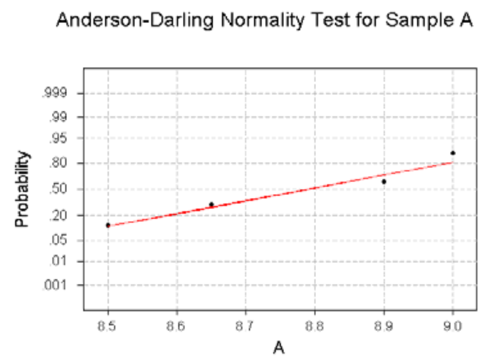
Cable	Electrical Breakdown Strength in kV				
New	14.1	13.3	13.7	12.9	14.5
A	8.9	8.5	8.65	8.90	9.00
B	9.80	9.10	9.55	9.40	8.90
C	8.70	9.00	8.90	9.30	9.20
D	9.10	8.50	8.65	9.20	8.90
E	8.45	8.25	8.80	8.70	8.10



Average: 13.7
StDev: 0.632456
N: 5

Anderson-Darling Normality Test
A-Squared: 0.144
P-Value: 0.0.920

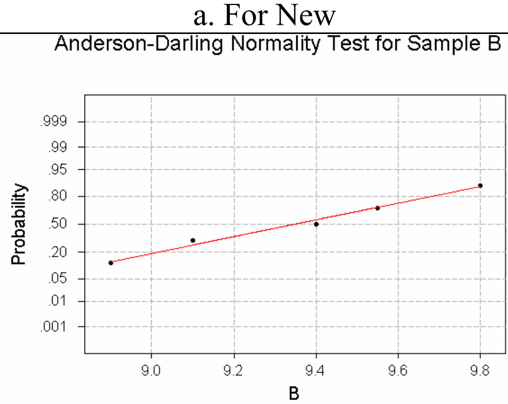
a. For New



Average: 8.79
StDev: 0.207364
N: 5

Anderson-Darling Normality Test
A-Squared: 0.0.352
P-Value: 0.297

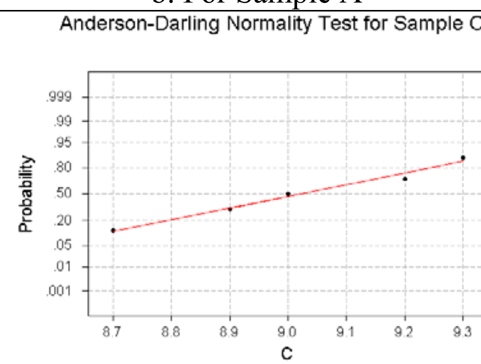
b. For Sample A



Average: 9.35
StDev: 0.357071
N: 5

Anderson-Darling Normality Test
A-Squared: 0.161
P-Value: 0.885

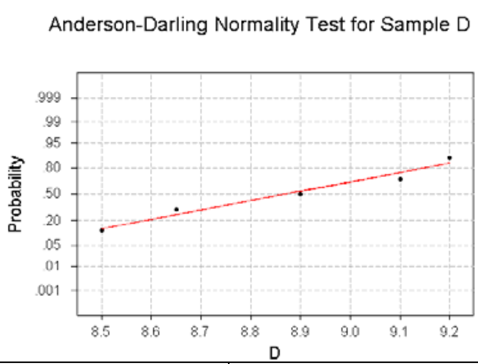
c. For Sample B



Average: 9.02
StDev: 0.238747
N: 5

Anderson-Darling Normality Test
A-Squared: 0.170
P-Value: 0.860

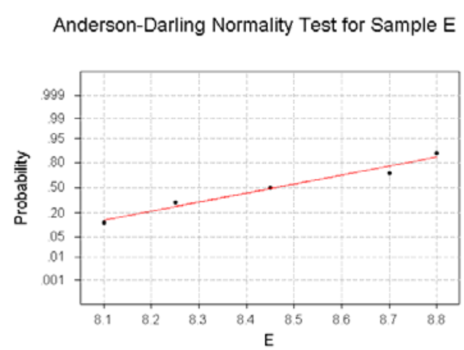
d. For Sample C



Average: 8.87
StDev: 0.297958
N: 5

Anderson-Darling Normality Test
A-Squared: 0.211
P-Value: 0.707

e. For Sample D



Average: 8.46
StDev: 0.294534
N: 5

Anderson-Darling Normality Test
A-Squared: 0.205
P-Value: 0.730

f. For Sample E

Figure 5.7. Normality Test for Aged Samples for Electrical Breakdown Test

Table 5.6. One way ANOVA Analysis for Electrical Breakdown Test Data

One way ANOVA (Analysis of Variance): New, A, B, C, D, E					
Source	**DF**	**SS**	**MS**	**F**	**P**
Factor	5	98.19	19.63	147.07	0.000
Error	24	3.20	0.134		
Total	29	101.40			

It can be noted that the between-subset mean square (19.63) is many times larger than the within-subset or error mean square (0.134). This indicates that it is unlikely that the subset means were equal. In addition, the F ratio is also computed and found to be 147.07. This is compared with an appropriate upper-tail percentage point of the $F_{4,20}$ distribution. If we consider 95% confidence limits, i.e. $\alpha = 0.05$, the value of $F_{0.05,4,20}$ is 2.87. As $F_0 = 147.07 > 2.87$, it is concluded that the subset means are different, indicating that the electrical breakdown voltage was significantly different with respect to different years of field aging [63].

5.3 Summary

In the case of XLPE insulated distribution cables for uniform weather conditions of hot and dry atmosphere, degradation can be identified and quantified by certain parameters. These parameters, namely the area of FTIR spectrum and the electrical breakdown strength, can be used to assess the condition of the cable insulation, irrespective of its' chronological age. These parameters can also be used to gauge the future performance of the cables in consideration.

6. Design of New Aging Model

6.1 Introduction

In the case of 15kV XLPE insulated distribution cables'; aging is mainly contributed to thermal and electrical stress along with moisture ingression if present. In a hot and dry atmosphere like that of Arizona, USA, thermal stress plays a major role. The goal of this chapter is to design and validate an aging model with real-time feedback using multiple quantified degrading parameters. The model in consideration [64] can best be expressed by (6.1) and (6.2),

$$L = \frac{U - P}{R \times f} \tag{6.1}$$

And R is

$$R = \frac{I - P}{Time} \tag{6.2}$$

Where,

L = Remaining useful life of the cable,
P = Present value of quantified degrading parameter
U = Ultimate value of quantified degrading parameter, which represents end of life and/or alarming situation.
R = Rate of change in degrading parameter.
f = Factor of safety.
I = Initial value of identified parameter for new cable.
$Time$ = Field age of the cable in years.

Among all the parameters listed, the present value of identified parameter 'P' and the rate of change in identified parameter 'R' are to be calculated with the help of real-time feedback from the field.

6.2 Design of Aging Model Parameter

In (6.1) and (6.2) the parameters to be designed are *U*, *f* and *C*. Experimental results were used to design aging model parameters. The significance of linear dependency of identified parameters is explained in [66-68] by the same author.

6.2.1 FTIR Analysis

FTIR analysis was performed on various field aged samples. The quantitative concentration of a compound can be determined from the area under the curve in characteristic regions of the IR spectrum. CH_3 asymmetric stretching vibration occurs at 2975-2950 cm^{-1} while the CH_2 absorption occurs at about 2930 cm^{-1}. The symmetric CH_3 vibration occurs at 2885-2865 cm^{-1} while CH_2 absorption occurs at about 2870-2840 cm^{-1}. In general, the area under the curve for wave number 2750-3000 cm^{-1} is representative of –CH, $-CH_2$ and $–CH_3$ carbon/hydrogen stretching vibrations. Table 6.1 shows the worst five values (out of ten readings obtained for each) for the area under FTIR spectra for new cables as well as for failed cables from the field. The computed average values are 19070 and 17104 for failed cables and new cables respectively. The value of U in aging model can be taken as 19625.2, while to compute C, respective parameter value can be taken as 17104.

Table 6.1. Area of FTIR Spectrum for Wave number (2750-3000 cm^{-1})

Failed Cable	New Cable
19851.0	17812
19747.5	17279
19585.9	16493
19430.5	16746
19511.0	17191

6.2.2 Electrical Breakdown Strength

Table 6.2 shows the worst five values (out of ten readings) for electrical breakdown strength for new cables as well as for failed cables. The computed average values are 8.67 and 13.74 for failed cables and the new cables respectively. The value of U in the aging model can be taken as 8.67, while to compute C, parameter value for the new cable can be taken as 13.74.

Table 6.3 gives the parameters of the designed aging model with FTIR as well as electrical breakdown strength.

Table 6.2. Electrical Breakdown Strength Results

Electrical Breakdown strength in kV	
Failed Cable	**New Cable**
8.11	14.55
8.51	12.94
9.32	13.74
8.91	13.34
8.51	14.15

Table 6.3. Designed Parameters of Aging Model

Parameter	FTIR	Electrical Breakdown Strength
U	19070	8.67
I	17104	13.74
f	1.2	1.2

6.3 Validation of the Aging Model

To validate the designed model, three different field aged samples were obtained from utility companies. Table 6.4 shows the calculation of remaining useful life with value of f as 1.2. It is to be noted that, field aged cable sample of 5 years was failed in field. Analysis by utility engineers attributed premature failure to bad workmanship at one of the cable joints.

Results of Table 6.4 indicate discrepancy in the computed remaining useful life for the case of 13 and 7 years age for each parameter. This can be attributed to different sensitivity of identified parameters for various field ages of the cables. For the case where cable failed in five years, both the parameters gave an alarming situation as estimate of remaining useful life.

Table 6.5 displays sensitivity of both the identified model parameters with respect to the age of the cable. The percentage change is noticeable in results with the previous reading of the same category as a reference. FTIR spectrums are more sensitive for the age of more than 10 years. At the same time electrical breakdown strength is more sensitive for the age of less than 10 years. Both these parameters can compliment each other for estimation of remaining useful life of the cable insulation.

Higher sensitivity of electrical breakdown strength for the age of less than 10 years can be attributed to macroscopic changes in cable insulation during early age period.

Table 6.4. Calculation of Remaining Life using Designed Aging Model

	Using FTIR		Using Electrical Breakdown	
Age	**P**	**L**	**P**	**L**
13	18624	7.14	9.2	1.67
5[3]	19070	1.18	8.9	0.34
7	17450	36.67	11.8	9.92

Where,
P = Present value of quantified degrading parameter
L = Remaining useful life of the cable

[3] This data point is of field aged cable, which failed in 5 years instead of anticipated 20-25 years of life.

Table 6.5. Percentage Changes in Aging Model Parameters

Age in Years	Mean Area of FTIR Spectrum	% Change	Mean EBV (kV)	% Change
0	17305		13.8	
5	17398	0.54	11.8	-14.3
10	17704	1.76	9.6	-18.7
15	18466	4.3	8.9	-7.3
20	19485	5.52	8.6	-3.0

Where,
EBV = Electrical breakdown voltage
Mean area of FTIR spectrum = Average value of area of FTIR spectrum for wavenumber group 2750-3000cm^{-1}.

As the age of the cable increases, microscopic changes occur, which can be quantified by changes in FTIR spectrums. In this study, as expected, FTIR analysis is more sensitive for the cable age of more than 10 years. During the remaining life estimation, for the age of less than 10 years, result of electrical breakdown voltage can be given more weight than the FTIR spectrums. At the same time for the approximate age of more than 10 years, the FTIR spectrum can be given more weight than the electrical breakdown voltage.

6.4 Summary

A new aging model which uses intermittent values from field was designed for the case of distribution cables. Validation of designed aging model gives a satisfactory estimate of remaining life of the cable. A failed cable after 5 years of service, gives good co-relation with designed model theory. In this cable, the rate of degradation was much higher than normal field aged cables. The rate of degradation for each field condition varies and establishes the fact that it is very difficult to reproduce what happens in the field.

7. Discussion

7.1 Accelerated Aging Procedure

Accelerated aging tests are used to obtain timely information on performance degradation over time. Test units are subjected to higher than usual levels of accelerating variables like temperature and voltage. The results are used, through appropriate statistical models, to predict the performance at normal working parameters like voltages and temperatures. The extrapolative predictions inherent in the use of accelerated aging test raise serious concerns [71]. Appropriate use of accelerated aging tests requires careful considerations (theoretical and experimental) of the underlying failure mechanisms. A good amount of research is done establishing various accelerated aging procedure. In this work, instead of attempting to design an accelerated aging procedure applicable in general, a simple accelerated aging procedure for one particular type of weather condition is designed and validated.

Any accelerated aging procedure can be defined by three criteria: quick, accurate and cheap. The balance between these three aspects needs to be achieved based on requirement of the concern agencies. What this work gives is, a quick and cheap method which can help in a decision making process of cable replacement and schedules. Even the estimation of degradation with 6~12 months of error can optimize the cable replacement and maintenance schedule and save huge amount of dollar spent. The established accelerating procedure can be used to gauge the condition of cable insulation.

7.2 New Approach for Condition Monitoring

Electrical breakdown strength using needle plane geometry and area under the FTIR spectrum (2750-3000 cm^{-1}) are quantified as the data indicative for the condition of the cable insulation. Figure 7.1 shows the variation of data points for FTIR spectrums. For samples B, C, D and E, the area of the FTIR spectrum is linearly dependent on the field age of the cable. In case of the sample A, which was failed after 5 years in service, the area of FTIR spectrum does not relate to 5 years of normal field age of the cable but instead it relates to approximately 26 years of field age. Table 7.1 shows the results of two sample t-test between sample A and other samples. The p-value in table 7.1 is the probability of two subsets being equal. It can be observed that in case of sample A, it gives the highest probability of being equal to sample D. This can be attributed to excessive thermal-electrical stress experienced by that particular section of the cable. As electrical stress value does not a vary by considerable amount during normal operation of the cable, it is believed that in the case of sample A, it was the thermal stress that played major role for the immature failure of the cable. This proves the differences in degradation of the cable insulation for different field conditions. It can be concluded that the degradation of cable insulation depends on mainly on the stresses experienced by the cable insulation and the failure of the insulation does not depend on chronological age, but the rate by which cable is degrading.

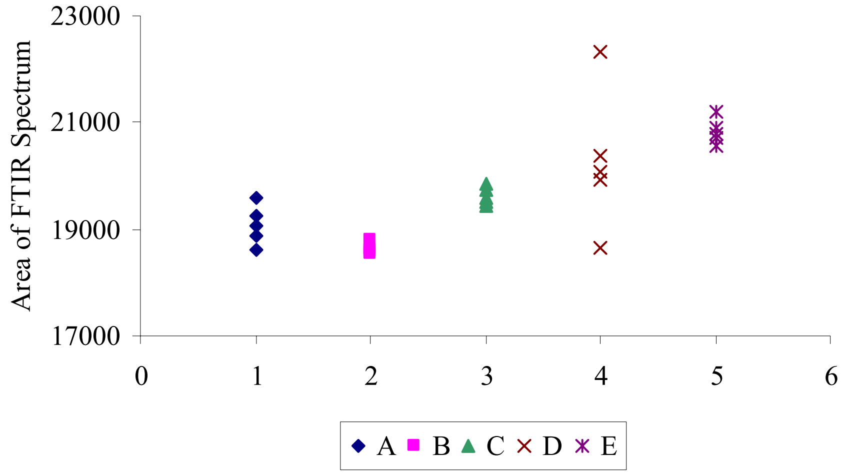


Figure 7.1. Experimental Results of FTIR Spectrum Analysis

Table 7.1. Two-Sample t-test for sample A and other samples

A	FTIR Spectrum		Electrical Breakdown Strength	
Vs	t	P-Value	t	P-Value
B	2.58	0.061	-3.03	0.023
C	3.03	0.029	-1.63	0.148
D	-1.94	0.124	-0.5	0.635
E	8.85	0.001	2.05	0.080

It can be observed in the figure 7.1 that the spread of the data points for the case of 26 years of field aged cable sample is large compared to other samples. The wide spread of data may be attributed to the presence of moisture as all other samples mainly being from a dry and hot atmosphere. Reasons for the wide spread of data points for the case of sample D might be the presence of moisture which needs further investigation.

Figure 7.2 shows the variation of data points for the electrical breakdown strength test. All the data points except sample A, give good co-relation with respect to the field age of the sample. It seems that the spread of data points for electrical breakdown test is not affected by the presence of moisture (if any). The life of cable insulation with respect to electrical breakdown strength and area of FTIR spectrum can be divided in three broad categories. These categories can be named as green, yellow and red in line with the traffic light as shown in figure 7.3 for area of the FTIR spectrum and in figure 7.4 for the electrical breakdown strength.

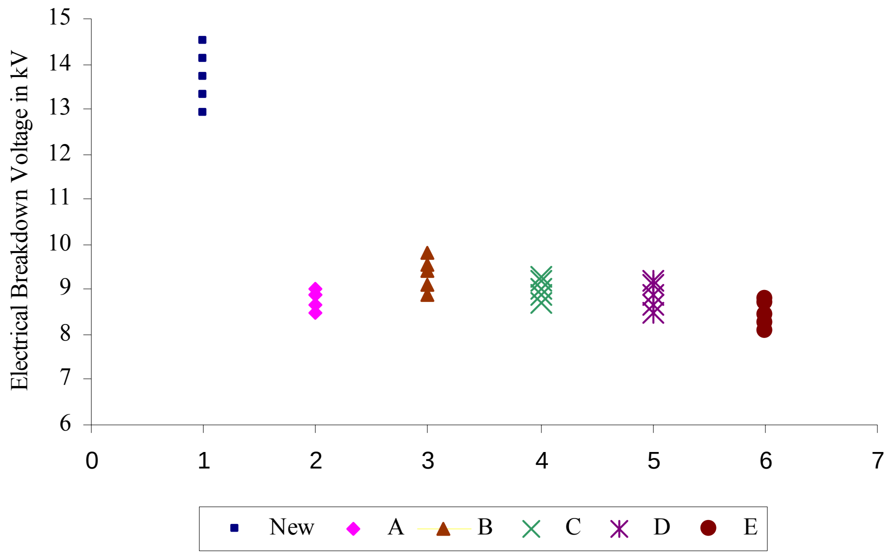


Figure 7.2. Experimental Results of Electrical Breakdown Test

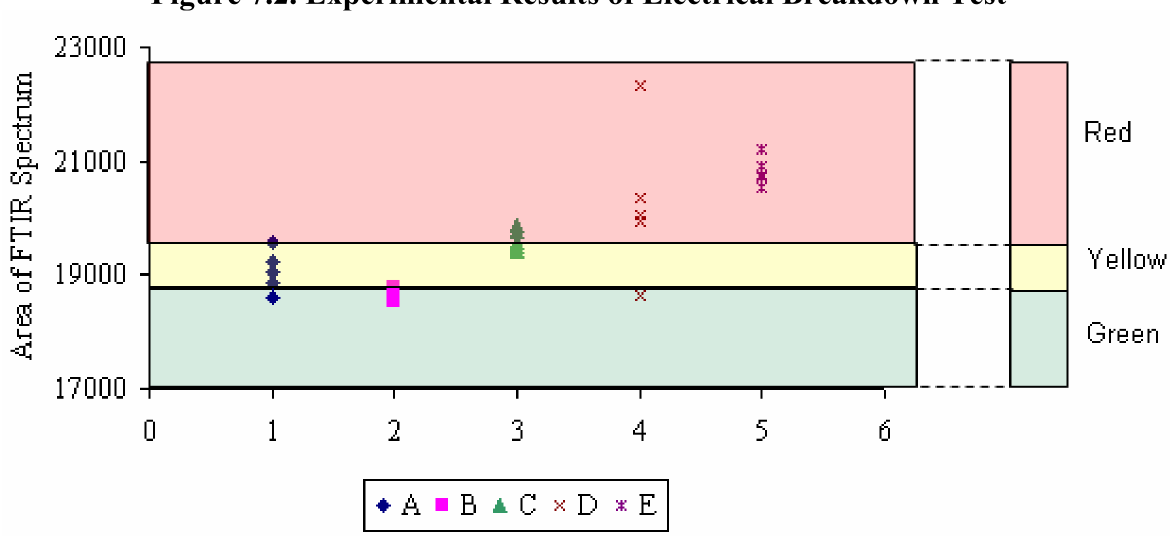


Figure 7.3. Traffic light Analogy for FTIR Spectrum Data

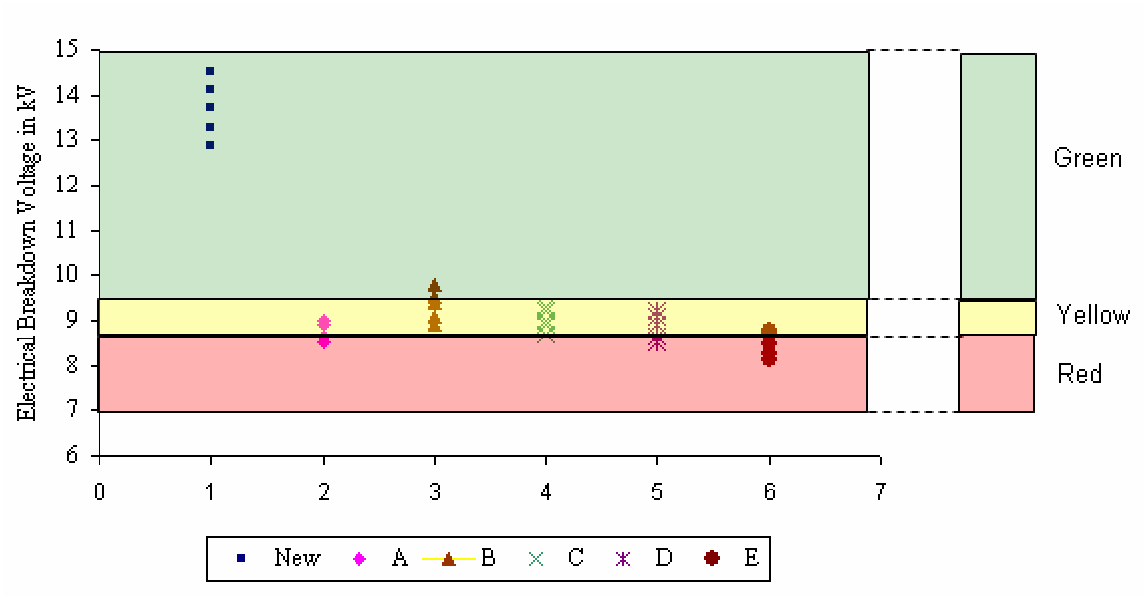


Figure 7.4. Traffic Light Analogy for Electrical Breakdown Strength Data

In figure 7.3 and 7.4, the green zone indicates no maintenance is required, the yellow zone indicates keep under observation and the red zone indicates act immediately. Maintenance and replacement schedules can easily be optimized using this kind of approach. As in this approach more than one parameter is used for decision making, it conveys more confidence to all concerned agencies.

8. Conclusions and Recommendations for Future Work

8.1 Conclusions

In hot and dry atmosphere as that of Arizona, USA, thermal stress plays prominent role for degradation of polymer. Degradation of polymer is quantified eliminating minor effects of other stresses like electrical and mechanical. The 15kV XLPE insulated distribution cables have been characterized successfully with the help of the accelerated aging procedure. It has been shown that, similar to the field (hot and dry); degradation can be produced by a suitably planned accelerated thermal aging testing in the laboratory. The Arrhenius equation is used for establishing the accelerated aging test parameters. The procedure is validated using different modes of statistical analysis namely analysis of variance (ANOVA), Andersen-Darling test for normality, F-test and t-test.

An attempt is made to apply the method described in [58] to the case of filed aged cable samples of approximately 5 years. It is concluded that this method is not suitable for establishing the thermal history of field aged cable sample of more than 2~3 years.

In case of FTIR spectrums, the reduction of CH_2 bond (2926 cm^{-1}) of approximately 66%, 82% and 85% for healthy aged cables (~10 years), failed new cables and failed aged cables (~10 years) respectively with respect to new cables is measured.

Aging of approximately 10 years in dry weather resulted degradation in cable performance by at least 25% in terms of electrical breakdown strength. The aged cables are more susceptible to failure due to accidental dig-ins with compared to new cables.

In the case of XLPE insulated distribution cables for weather conditions of hot and dry atmosphere, degradation is identified and quantified by certain parameters. These parameters, namely the area of FTIR spectrum and the electrical breakdown strength, is used to assess the condition of the cable insulation, irrespective of its' chronological age. These parameters are also used to gauge the future performance of the cables in consideration. A simple traffic light approach (Red, Yellow and Green) is also designed to assess the condition of the cable insulation.

A new aging model which uses intermittent values from field was designed for the case of distribution cables. A failed cable after 5 years of service, gives good co-relation with designed model theory. In this cable, the rate of degradation was much higher than normal field aged cables. The rate of degradation for each field condition varies and establishes the fact that it is very difficult to reproduce what happens in the field.

8.2 Recommendations and Future Work

The designed approach is for hot and dry weather conditions. There are huge number of utilities for whom, water treeing and moisture is the major source of concern. To design the suitable condition monitoring approach for such utilities involves the identifying sensitive parameters for the cable insulating material, which quantifies the degradation. A primary motivation for future research remains the minimization of the loss of money due to accidental failures, and to optimize the cable replacement and maintenance schedules. This venture may be performed by collecting number of field aged samples from same weather conditions as far as possible and by performing experiments in the laboratory.

Another potential research avenue is the probe toward finding any other parameter (if any) which can quantify the degradation for the case of hot and dry atmosphere. This research is envisioned to be from the increasing confidence in adopting the work established for decision making process.

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