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Time to Failure Testing of Model HV XLPE Cables in Salt Water at High Electrical AC Stress and Temperature

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SUMMARY

Installation of high voltage (66 kV) rather than medium voltage (36 kV) inter-array cables for bottom-fixed and future floating wind farms reduces the number of cable strings entering a platform, reduces system losses, reduces the overall cable length and the number of substations. All together this will result in a significant overall cost benefit. These developments in offshore renewables as such have called for new cost-effective and reliable high voltage subsea cable designs. The new designs include so-called wet designs allowing water molecules to enter the cable core during service. Time to failure (TTF) testing can provide data to empirically model the service lifetime of the cables at a lower service stress. For high voltage cables, the needed electrical stress during TTF testing can be very high, and there are several challenges then to overcome when performing such testing in seawater. This includes challenges e.g. related to the test-set-up to avoid premature breakdowns at the terminations, or to avoid anomalies at the water surface due to non-radial temperature and diffusion gradients, or in the insulation due to much higher electrical stress in the insulation during testing than in service. This paper presents initial results to facilitate a TTF test set-up and program to model high voltage cable cores soaked in salt water and subjected to a very high electrical stress and temperature. A TTF test of model HV subsea cables using medium voltage XLPE cores was undertaken at a high stress of 30 kV/mm at the conductor screen. From this test it is shown that the modified termination system had a high breakdown stress and inception voltage for partial discharges which was necessary to withstand the high voltage stress of about 100 kV for a long time during the TTF test. The temperature calculations have shown that the anomalous wet ageing conditions occurring close to the hot water-air interface must be avoided as it could cause non-steady anomalous wet ageing strongly accelerating the water tree growth. The heated air system included in the set-up resulted in no anomaly temperature conditions nor any excess ageing phenomena at this interface. All breakdowns occurred in the active/wet sections of the cable, and the mean time to failure (Weibull eta) at 30 kV/mm was about 116 days. Short vented water trees appeared both at the conductor and insulation screen with about the same length and appearance despite the higher electrical field at the conductor screen. This indicate that the electrical field at the conductor screen did not accelerate the length of the vented water trees. However, a significant higher density of bow-tie trees was detected close to the conductor screen than close to the insulation screen. Future work includes TTF testing at other field stresses, where also a sudden death approach to limit the test time will be considered.

KEYWORDS

Floating wind farms, Subsea HV XLPE cables, Dynamic cables, Wet ageing, Time-to-failure testing, Water treeing

Introduction

Installation of high voltage (U_m= 72.5 kV) rather than medium voltage (U_m= 36 kV) inter-array cables for bottom-fixed and future floating wind farms reduces the number of cable strings entering a platform, reduces system losses, reduces the overall cable length and the number of substations. All together this will result in a significant overall cost benefit [1]. It has been projected that floating wind will contribute a total of 250 GW, or 2 % of the world's total electricity generation, by 2050 [2]. Floating wind farms such as Hywind Scotland (operation since 2017) and Windfloat Atlantic (operation since 2020) proves the technology is feasible. Traditionally, cables above 36 kV have been in dry service conditions protected from seawater by an extruded layer of lead. For floating wind applications lead sheathed cables are not applicable due to bad dynamic mechanical performance. These developments in offshore renewables have called for new cost-effective and reliable high voltage subsea cable designs. The new designs include so-called wet designs allowing water molecules to enter the cable core during service. Recently a CIGRE technical brochure has addressed wet ageing of high voltage cable cores to assess the long-term performance of high voltage cables up to 72.5 kV in seawater [3]. However, higher voltage ratings are causing even higher stress in the insulation system that could influence the cable system lifetime. Laminate outer sheath coverings replacing lead are not completely water-tight, allowing diffusion of water molecules to the cable core.

Time to failure (TTF) testing can provide data to empirically model the service lifetime of the cables at a lower stress. For high voltage cables, the needed electrical stress during TTF testing is very high, and there are several challenges to perform such testing in seawater. This includes challenges e.g.~~,~~ related to the test-set-up to avoid premature breakdowns at the terminations, or to avoid anomalies at the water surface due to non-radial temperature and diffusion gradients, or in the insulation due to much higher electrical stress in the insulation during testing than in service. This paper presents initial results to facilitate a time-to-failure test set-up and program to model high voltage cable cores soaked in salt water and subjected to a very high electrical stress and temperature.

2. Numerical calculations

i. Temperature distribution during electrical test

The axial and radial temperature distribution in the model cables at the hot water-air interface was calculated using the material thermal data shown in Table 1.

Table 1: Data used during the temperature distribution calculations.

Cable Section	Thermal Conductivity [W/mK]	Density [kg/m3]
Metallic Cu conductor	385	- - -
Semi-conductive screens	0.34	1140
Insulation	0.23	923

The convective heat transfer coefficient of air used during the calculations was 10 W/m^2K (low speed flow of air over the cable surface), and the emissivity applied was 0.9. The geometric data was the same as listed in Table 2.

ii. Electrical field distribution in terminations

A PD free cable termination system was developed to withstand the high electrical stress during ageing at 94 kV, corresponding to 30 kV/mm at the conductor screen in the cable. A commercially available 12 kV silicone rubber (SiR) slip-on termination was used and modified. The electrical field distribution in the cable and the termination system was calculated by using Comsol. The SiR termination was placed in a polyethylene sealed tube filled with a synthetic ester with a higher relative permittivity (3.8) than XLPE/PE (2.3) and SiR (2.8). The electrically insulating tape used to increase the interfacial pressure between the XLPE cable and the SOT termination was not included in the model during calculation of the electrical field as the thickness was considered small compared to other sections.

2. Experimental work

i. Test Samples

Cable No. 1 was used during developments and modifications of the silicone rubber termination to achieve a high withstand voltage. The cable was an extruded 12 kV XLPE cable with an insulation thickness of 3.5 mm and aluminium conductor. Cable No. 2 was also a 12 kV XLPE cable but with a slightly larger insulation thickness (3.9 mm) and had a copper conductor. This cable was used for the time-to-failure test. Both cables were equipped with a standard subsea cable sealing material between the strands.

Table 2: Cable dimensions.

Cable No.	Test	Cable rating (Um)	Diameter [mm]			
			Conductor	Conductor screen	Insulation	Insulation screen
1	ACBD	12 kV	13.2	14.7	21.7	23.2
2	TTF	12 kV	13.0	15.0	22.8	24.8

ii. Test Set-Up

Cable Terminations

Silicone rubber type slip-on 12 kV terminations (SOT) were used to avoid flashover or breakdowns in the cable ends. The sheds of the termination were removed prior to installation resulting in a reduced length. The surface roughness of the XLPE after peeling the insulation screen should be very low. This was achieved by using new (and polished) knives only. Silicone grease was applied in advance to the XLPE surface to fill any remaining micro voids in the interface. To increase the inception voltage of partial discharges and the withstand voltage, an increased radial pressure on the interface between the silicone rubber and XLPE cable surfaces was applied. This was done by essentially installing several layers of an insulating vulcanisation rubber tape over the relatively soft silicone termination. The resulting interfacial pressure was not assessed. To avoid flashover, the slip-on termination was finally placed in a PE housing filled with an electrically insulating synthetic ester.

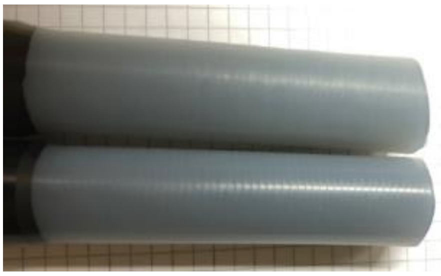

Figure 1: Cable ends after peeling of the insulation screen. Upper core: Not sufficient quality. Lower core: High quality.

Partial Discharge Testing

Two terminations were subjected to 120 kV for 14 days. Partial discharges were detected electrically with an oscilloscope according to standard [4].

AC breakdown voltage testing

The modified silicone rubber model cable termination was breakdown voltage tested at room temperature by applying a step voltage test starting from 60 kV (10 U_0) and increasing the voltage in steps of 12 kV until breakdown using a 5 meter long cable sample. The other end was equipped with a 1 meter long water termination.

Time to Failure

The cables were initially installed to an inner PP tube with smaller diameter with a sufficient mutual distance to avoid damaged insulation due to any electrical breakdown of a neighbouring sample. Then the cables were placed in 5 metres long polypropylene (PP) tubes filled with 3.5% salt water and conditioned to water saturation at a constant temperature of 70 °C with (salt) water only subjected to the cable core surface. The saturation time was determined by using measured water transport coefficients for the actual insulation material system and the actual design (thickness of layers) as indicated in Table 1 during numerical diffusion calculations [5]. Two 0.5 meter long sealed tubes with feedthroughs for the 12 kV cables were installed in the end of the salt water filled PP tubes. The air volumes were heated to slightly above 70 °C, where including fans to circulate the air to obtain an even air temperature. The main purpose of these sections was to avoid high temperature gradients at the water surface (tube ends).

The set-up was energized with a high voltage resonant test system with low transient magnitudes during failure. The times to failure were recorded, and each sample was analysed with respect to water treeing.

iii. Material analysis
After the cables failed during the TTF test, 10 slices of 0.5 mm in thickness were helically cut including the breakdown site. The length of the longest vented water tree and bow tie tree in each slice were measured. In addition, the density of bow-tie trees close to the semi-conductive screens were recorded.

3. Results and discussion

i. Numerical Calculations
Temperature distribution in cable during the TTF test
Without any measures at the water-air interface, temperature gradients will occur in the cable insulation when the water temperature is 70 °C and the ambient air temperature about 25 °C. Figure 2 a) shows the axial temperature distribution for the model cable at such conditions. It can be seen that no significant axial temperature gradient occurs below the water surface. At the metallic conductor, the lower air temperature causes a reduced temperature along the conductor for about 0.5 meters below the water surface in the heated water. Close to the water surface the temperature at the conductor is about 55 °C increasing to 70 °C after 0.5 meters. Figure 2b) shows the radial temperature distribution at different axial positions for the same temperature conditions as in Figure 2a). At the water surface, there is a significant radial temperature gradient in the model cable: The temperature at the conductor screen is about 55 °C, and at the insulation screen about 65 °C. The radial gradient is reduced at positions below the water surface. At for example 20 cm below the water surface the temperature gradient across the insulation wall is reduced to values below 4 °C.

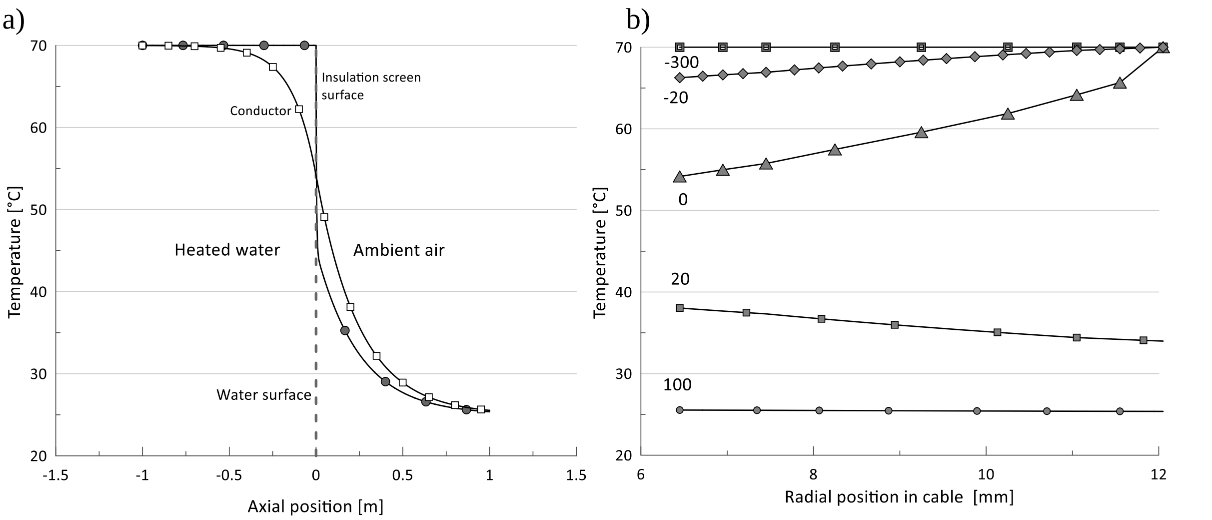

Figure 2: Temperature gradients at the end section of the water-filled tube. a) Axial temperature gradients along the cable and across the water surface. b) Radial temperature gradients at different locations along the cable: 0: At water surface, 20 or 100: 20 or 100 cm above water surface (in air), -20 or -300: 20 or 300 cm below water surface (in water). The radial positions are taken from the metallic conductor to the insulation screen surface.

At cable sections above but close to the water surface, the radial temperature gradient is negative, with the highest temperature close to the conductor screen and slightly lower temperatures at the insulation screen.

During water conditioning the water molecules will diffuse into the insulation following Fick's law of diffusion. The amount of absorbed water will be determined by the partial pressure of water at the surface of the insulation screen. The temperature gradient in the XLPE insulation at the water surface can cause increasing supersaturation of water in the middle of the insulation [6]. During condensation an excess hydrostatic pressure can be established in liquid water. This pressure can exceed the strength of the XLPE insulation and microscopic water-filled cavities can be formed. The extent of this degradation is determined by the magnitude of the temperature gradient and the temperature of the insulation as that the stiffness is steadily reduced with increasing temperature up to 95 °C [7]. This process can continue for a very long time as no steady state level has been reported for such water diffusion conditions. When an electrical field is applied to the insulation during such conditions, a huge number of very long bow-tie trees can be developed in the region of water supersaturation [6]. This anomaly temperature condition cause accelerated ageing and reduces the breakdown strength of the cable insulation in this section and could provide bad data for the TTF test and models. It is worth noting that essentially this is the same water diffusion situation occurring when water is being present between the strands in the conductor of a current loaded cable. Note that this does not include the ageing mechanism where the degradation of the conductor screen material and corrosion of the Al conductor cause a high supply of water and ions to the interface between the XLPE cable and conductor screen (stress induced electrochemical degradation) [8].

Normally during wet ageing tests, the end section is removed prior to any other electrical tests such as breakdown voltage step testing. However, in case of time-to-failure test this is not possible, and it is important that the temperature across the water surface is maintained constant to avoid ageing anomalities at this position. Therefore, another short pipe section of 0.5 meter was installed at both water-filled pipe ends and heated to slightly above the water temperature (72 °C) prior to electrical ageing. Then the same temperature as the water temperature occurred in the air above the water surface, resulting in no positive radial temperature gradients in the insulation system of the cable. Then any ageing anomalies causing unwanted failures at this section should be avoided.

<u>Electrical field distribution in cable terminations</u>

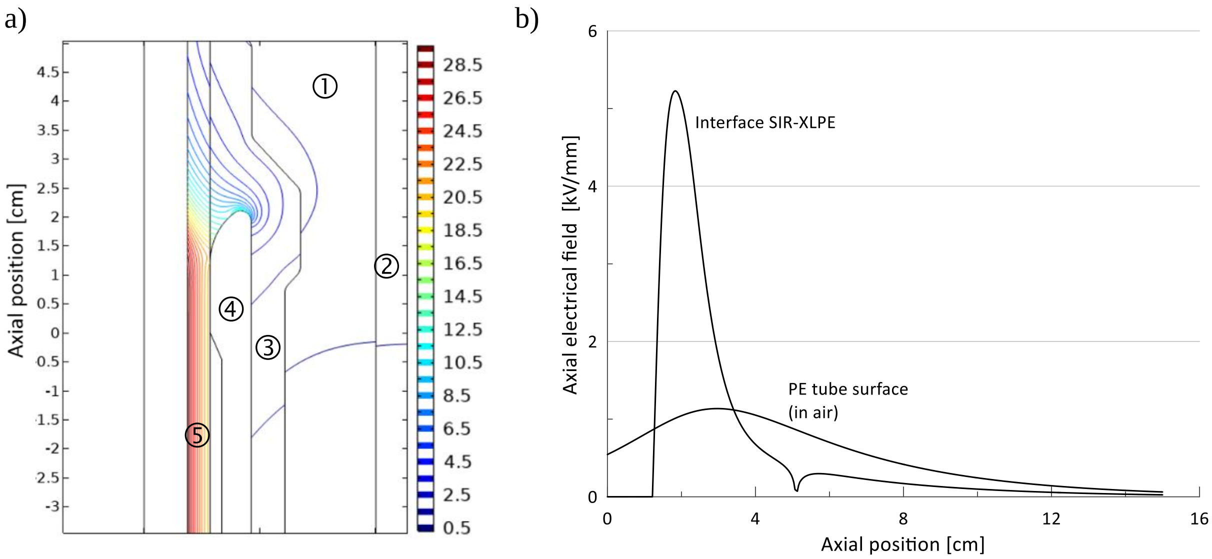

Figure 3: a) Electrical field distribution in the 12 kV SOT termination during the TTF test. 1: Synthetic ester, 2: PE tube wall, 3: SiR rubber, 4: Field grading, 5: XLPE insulation. b) Electrical field component in the axial direction (parallel to the metallic conductor) at 94 kV.

The electrical field at the cable conductor screen and close to the geometric field grading in the termination was 30 kV/mm and at the insulation screen 20 kV/mm during the TTF test at 94 kV. Figure 3 a) shows the calculated electrical field distribution in the SiR slip on termination during the test.

The axial electrical field component at the same direction as the interface between the cable and termination, is shown in Figure 3b). This field is higher than 5 kV/mm with its peak located to about 20 mm ahead of the end cut of the insulation screen of the cable. The breakdown strength and inception of partial discharges of this interface is critical. It is likely that very thin (sub-micro sized) but elongated cavities or channels could be formed in this interface, making inception of partial discharges due to the axial field component possible [9]. The electrical field at the surface of the synthetic ester-filled PE tube is at maximum slightly above 1.5 kV/mm which is well below the inception of corona discharges.

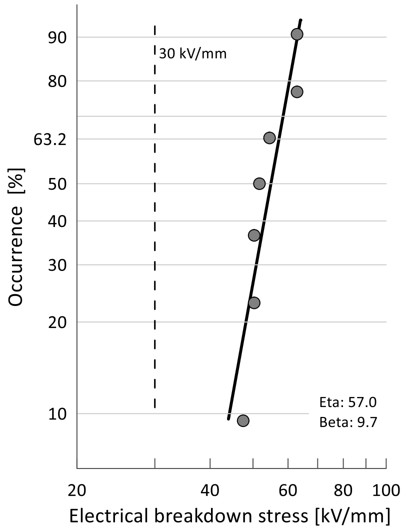

Figure 4: Results from AC breakdown testing of 12 kV slip-on terminations.

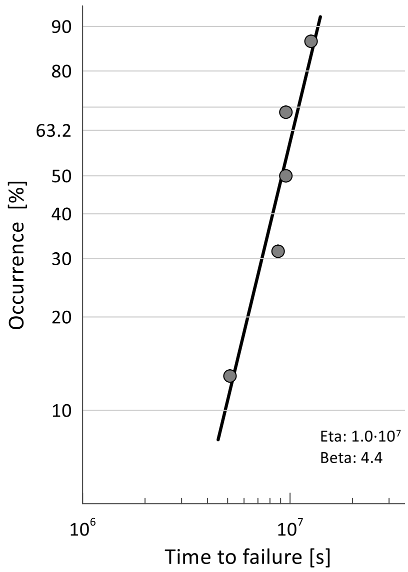

Figure 5: Time to failure of 12 kV XLPE cables wet aged at 30 kV/mm.

ii. Breakdown stress of modified termination

Partial Discharge Testing

No continuous partial discharges were detected originating from the cable slip-on termination during the 14 days at 120 kV (38.2 kV/mm at the conductor screen of the cable). However, some rare spurious discharges were detected, most likely generated by moving particles in the synthetic ester. After completion of the test, microscopy examinations showed no visible discharge patterns at the surfaces of the SiR termination or the XLPE.

AC breakdown voltage testing

Figure 4 shows results from testing of the modified slip-on silicone rubber 12 kV terminations. Only one breakdown occurred that was located to the SiR termination (51.7 kV/mm). All other breakdowns occurred either in the cable or in the water termination (62.9 kV/mm). The eta value deduced from the Weibull plot of the breakdown values as seen in Figure 4 was 57 kV/mm, and the shape factor beta was 9.7. Note that no censoring of the data was done. All these breakdown stress values were well above the minimum needed stress levels during the TTF test.

ii. Time to failure

The times to failure of the test samples are shown in Figure 5. All breakdowns occurred in the wet section of the cable in the salt water-filled pipe, and none close to the water surface (end section) or in the modified terminations. One of the samples (Position No. 2) did not suffer from breakdown during the test period. The ageing was therefore terminated, and an AC breakdown voltage step test as for the termination was subjected to the sample without removing the cable from the ageing set-up. The breakdown of this cable occurred at 148 kV and was located to the wet section of the cable. The simple inverse power law model assumes that $E^n \cdot t = C$, where *E* is the electrical field at the conductor screen, *n* the endurance coefficient, *t* time and *C* a constant [10]. Using these assumptions, *n* in this test is in the range of 2.9 to 3.4 using the shortest and longest times to breakdown, and a minimum lifetime of 40 years is assumed at a service maximum stress of 6 kV/mm. It has previously been suggested that *n* is in the range of 3.8 for wet cables but higher than 22 for dry cables [11]. Essentially water trees are "dynamically sized" contaminants that increase in length during wet ageing. Most likely, the endurance coefficient depends heavily on whether the ageing is dominated by bow-tie trees or vented water trees. Bow-tie trees stop growing after some time with a length dependent on the size of the water soluble contaminant but also the ion concentration [12]. This would result in a threshold stress below which an electrical breakdown is unlikely to occur. Also, vented water trees bridging the insulation wall do not necessarily cause an immediate breakdown, and a threshold stress but of lower magnitude than for an insulation with length-saturated bow-tie trees can also be the case for such situations. The simple inverse power law model fails to include such a threshold, unless E^n is replaced by $(E - E_0)^n$ where E_0 is the threshold stress [10]. This stress is challenging to determine, as it require long test times. To reduce this test time, an alternative approach called "sudden-death testing" can be applied. This includes testing of n_1 identical groups of n units until the first failure in each group occurs. When the first sample in a group fails, the rest of the remaining samples in the same group are suspended, and then the next group is being tested [13]. Weibull analysis can be used to determine the characteristic features (eta and beta) of the total population.

iii. Material analysis

In addition, another issue when testing at accelerated electrical field magnitudes, is if anomalous ageing features appear in the insulation. This has been examined in this paper by performing water tree analysis of the 5 cable samples as shown in Table 3 and Figure 6. The results show that both vented and bow tie trees were detected in all cables. The average length of the bow-tie trees was 144 µm bridging 3.7% of the insulation wall only. The average length of the vented water trees was shorter and about 107 µm. The lengths from the conductor screen and the insulation screen were about the same. This indicates that the higher field at the conductor screen (30 kV/mm) did not cause any significant longer trees than those grown from the insulation screen at a lower field stress (19.7 kV/mm). However, the average density of bow-tie trees close to the conductor screen was $12 \cdot 10^{-7}/\mu m^3$ and significantly higher than the same number recorded close to the insulation screen ($5 \cdot 10^{-7}/\mu m^3$).

No water treeing was detected close to the end of the tube indicating that the high air temperature above the water surface caused a partly drying of the XLPE insulation close to the water surface. However, at positions 50 mm from the water surface, lengths and densities of water trees were in the same range as those detected close to the breakdown sites of the cables.

Using a digital microscope with a magnification of 100X revealed no difference in vented water tree morphology of trees growing either from the conductor screen or the insulation screen even the local electrical field is

Table 3: Length of water trees in percent of the insulation wall and density measured close to the conductor and insulation screen.

Cable No.	Length of trees [%]			Density of trees - CS [$\cdot 10^{-7}/\mu m^3$]	Density of trees - IS [$\cdot 10^{-7}/\mu m^3$]
	BT	V-CS	V-IS		
1	3.8	1.7	2.4	10,4	3,2
2	2.6	3.5	3.2	9,8	5,8
3	3.2	3.5	2.3	11,8	6,8
4	2.3	2.4	3.6	9,6	5,0
5	3.2	2.0	2.6	19,0	4,2
5*	7.1	3.3	2.6	15.1	- - -

Notes: BT: Bow-tie, V-CS: Vented water trees at Conductor Screen, V-IS: Vented water trees at Insulation Screen. Density of trees: Number of BT trees in a 160X160 µm^2 area close to the cable screens. *: Axial position at the water surface.

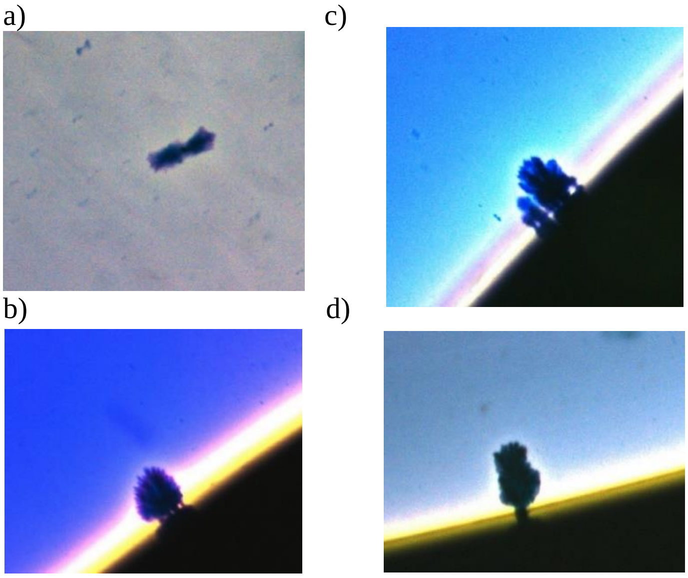

Figure 6: a) 138 µm long vented water tree growing from the conductor screen (Cable No. 2). b) 130 µm long vented water tree with inception site close to the end section for Cable 5. c) Bow-tie tree growing in the insulation of Cable No. 2 with a length of 123 µm. d) 140 µm long vented water tree growing from the insulation screen in Cable No. 4.

about 50% higher at the conductor screen. The dark colour of the trees after staining as shown in the micrographs in Figure 6 indicate a high number of voids and channels.

4. Conclusions

A TTF test of model HV subsea cables using medium voltage XLPE cores was undertaken at a high stress of 30 kV/mm at the conductor screen. From this test it is shown that

- The modified 12 kV termination system had a high breakdown stress and inception voltage for partial discharges which was necessary to withstand high voltage stress of about 100 kV for a long time during the TTF test.
- Temperature calculations have shown that the anomalous wet ageing conditions occurring at the water-air interface should be avoided. The heated air system included in this work resulted in no anomaly temperature conditions nor any excess ageing phenomena at this interface.
- All breakdowns occurred in active/wet sections of the cable, and the mean time to failure at 30 kV/mm was about 116 days.
- Short vented water trees of about 100 µm in length appeared both at the conductor and insulation screen with about the same length and appearance despite the higher electrical field at the conductor screen
- A significantly higher density of bow-tie trees was detected close to the conductor screen than close to the insulation screen.

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