Lifetime assessment of Low-pressure oil filled cables

Author: E.I. de Wolff

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Lifetime assessment of low-pressure oil-filled cables

By

E.I. de Wolff

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Supervisor:	Prof. ir. P.T.M Vaessen	
Thesis committee:	Dr. ir. D. van der Born,	TU Delft
	Dr. ir. W. Shi,	TU Delft
	Dr. ir. R. Bhandia,	TenneT TSO

TU Delft

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Abstract

In this thesis the lifetime assessment of low-pressure oil-filled (LPOF) cables is investigated. Most of the LPOF cables are already quite old but it is unknown if the degradation of these cables matches the age of the cable. Due to energy transition and the fact that not all cables can be replaced simultaneously, an estimate of the lifetime of the cable needs to be defined. This is done in this research using the following three research questions:

- What is the health level of the LPOF cables based on their historical loading profiles and their health index?
- Which LPOF cables are suitable for more loading?
- What is the remaining lifetime of cables that are suitable for more loading on this new loading levels?

These questions are answered using a thermal ageing model based on the historical loading data. From this model it could be concluded that the thermal degradation of the insulation of TenneT's LPOF cables has been very limited even after 50 years of service. This means that it might be possible cable insulation wise to let it be run continuously on the nominal loading level (maximum allowed temperature) for another 47 years. Although it must be mentioned that the accessories remaining lifetime and loading capabilities are not investigated in this research.

There are done tan delta measurements on an old cable to see if there would be any degradation visible from the 50 years of ageing of the cable. From this testing there was no noticeable degradation in the insulation paper visible. However, from this testing it could not be fully conclude that no ageing would be visible from this cable. Therefore, more testing needs to be done which could be done in the following way.

Acknowledgments

Since I started my study in Delft, I quickly became interested in the energy transition, and this interested has only grown since. Therefore, I was very excited to do my thesis within TenneT TSO and start my first (small) contribution to help the energy transition. Within this journey there have been a lot of people who helped me finalize my study so a thank you is on its place.
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1 Introduction

Cables play a vital role in the electricity transmission system. In the Netherlands, the high voltage transmission network consists of 2795 km of underground cable circuits. Of this total length, 1517 km consist of XLPE (Cross linked polyethylene) insulated cables with a rated voltage between 110 and 150 kV [1]. In the future it is expected that most cables will be XLPE insulated. Nevertheless, not all cables contain this type of insulation. Some other technologies are still in use, of which the low-pressure oil-filled insulated (LPOF) cables are the most common. For this type of insulation, 258 km of cable circuit is in the ground of which 256 km has a voltage rating between 110 and 150 kV. In the coming years, these cables are replaced by XLPE cables because, as shown in Figure 1, most of the cables are already more than 40 years old.

However, not every cable has reached its full lifetime, and not all cables can be replaced simultaneously. The latter is because the high voltage grid of the Netherlands faces a lot of challenges. The energy transition and the fact that it is already congested in a lot of areas are two of those challenges that need to be solved in the coming years. In Figure 2, the map of the Netherlands with the congested areas can is shown. This congestion gives a problem for the replacement of cables because, not all cables can be put out of service at the same time. Otherwise, there will be not enough capacity available to transmit all the electricity. Furthermore, the shortage of technical people which can do the replacement work hinder this even more.

So, to help with solving these challenges it would be useful to use the full lifetime potential of the assets involved in the electricity grid. This is where this research comes into play to see how the lifetime of the LPOF cables can be used to its full potential.

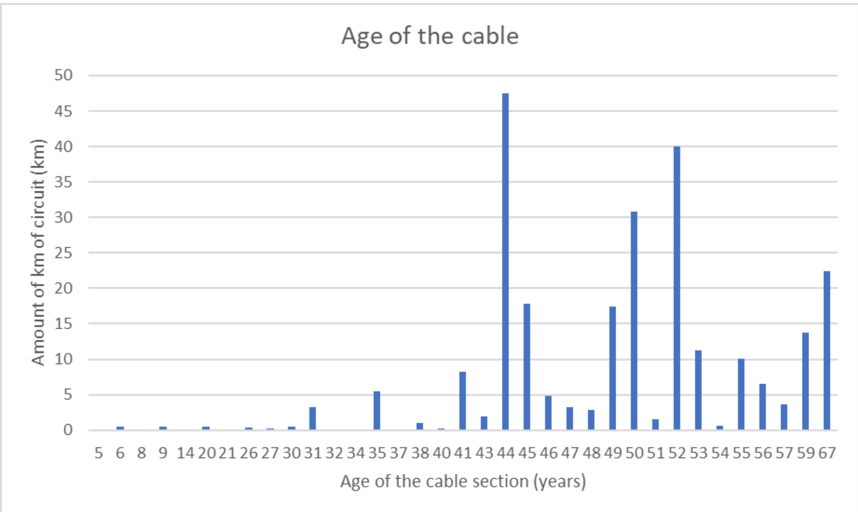

Figure 1: age of the low pressurized oil-filled cable sections.

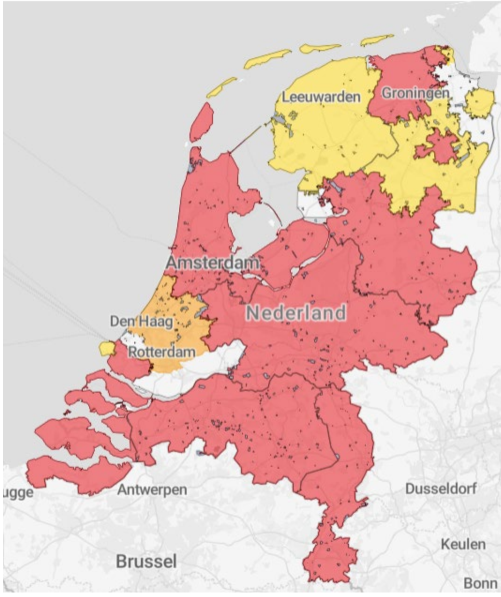

Figure 2: Grid congestion map of the Netherlands.

An oil filled cable system consists of multiple components. There are joints, terminations (air insulated or gas insulated), cable sections and oil expansion tanks. Each of these components have their own failure mechanisms, but they all have influence on the lifetime of a cable system. The focus of this research is on the lifetime of the cable itself and not on the other components in the cable system. The reason for this is that the degradation, especially thermal degradation of an LPOF cable is the worst degradation phenomena of this type of cable systems [2].

However, for TenneT 's cables the thermal degradation has not been the worst failure mechanism. This is because TenneT is not making use of the total capabilities of each cable section, due to the redundancy policy of TenneT (See Section 2.1 for a more in-depth explanation). This means that there are two circuits for each high voltage connection that can withstand the entire load if one of the circuits is not working [3]. During normal operation they are therefore only loaded to approximately half of their capacity. Which makes that the cable has a lower temperature than was assumed beforehand (See Chapter 3). Due to this the cables have seen less degradation then was assumed.

Most utilities expect their oil-filled cables to last 40-60 years which is in most cases under the assumption that the cables are fully loaded to steady state nominal values [4]. So, due to this lower degradation levels then there is assumed until this point, there is a possibility that the lifetime of this cables is a lot longer than was expected until this point. So, more load can possibly be applied to these cables to align better with the intended lifetime.

TenneT has used several types of LPOF cables over the years. This is due to changing manufacturing processes and the use of different cable manufacturing companies. Also, these cables come from a time when there were multiple owners of the 150 kV grid of the Netherlands which each had their own way of working.

In Table 1 all the different types of LPOF cables are shown. This table shows that most cables either come from Prysmian or its predecessor NKF. Most of the cables have a copper conductor and a lead sheath. There are two types (EZPAKod and VBPLKod) that have significantly more km in the ground than the rest. Figures 3 and 4 give examples of what kind of materials these cables consist of. In Chapter 3 the difference between the cables is described in more detail. The most important thing to note is that the cable differences will have an influence on the prediction of lifetime loss. In more detail, the materials that are used inside the cable as well as the manufacturing process influence the lifetime of a cable [5].

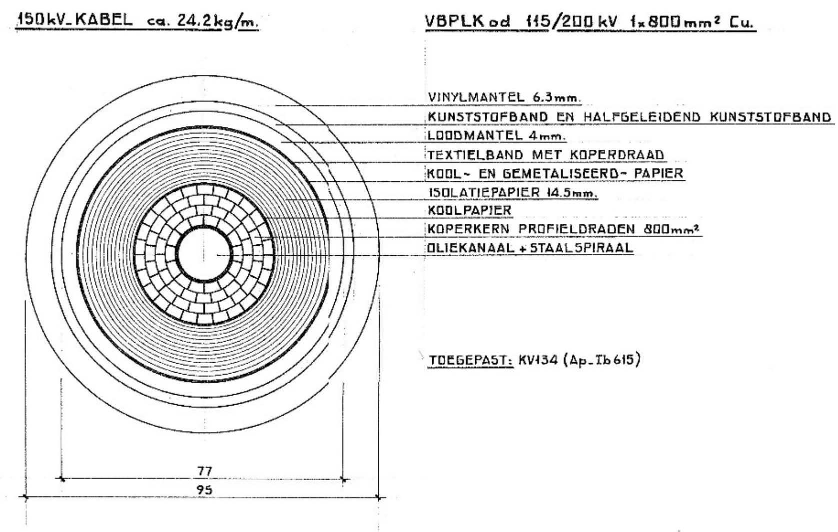

Figure 3: VBPLKod type of cable example.

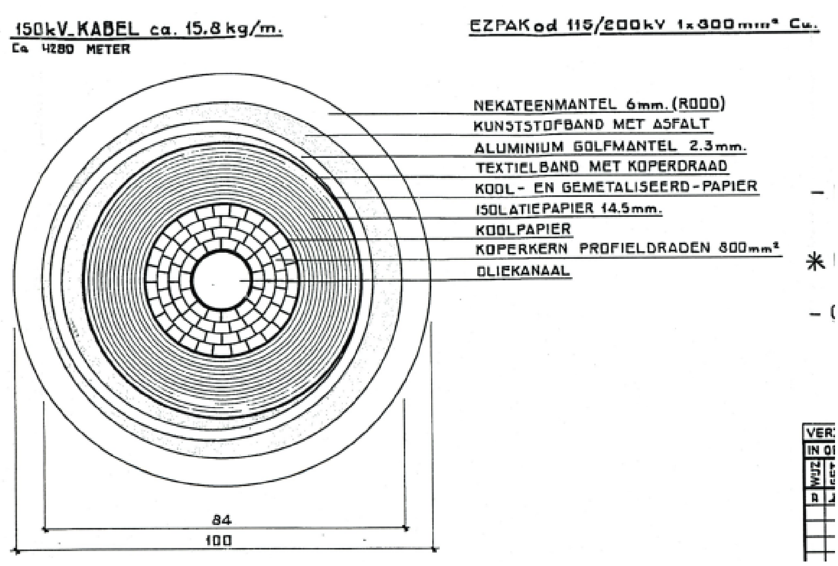

Figure 4: EZPAKod type of cable example.

Table 1: distinct types of self-contained oil-filed cables that TenneT owns.

Type of Insulation	Manufactures	Conductor material	Sheath material	Amount of km in ground
BPLKod	NKF Delft, Prysmian and Unknown	CU and AL	Lead	6.09 km
EBPLKod	Prysmian	CU	Lead	4.88 km
EP-SPLKod	NKF Delft	CU	Lead	3.25 km
ESPLKod	NKF Delft and NKF	CU	Lead	47.42 km
ESPLKodas	Prysmian	CU	Lead	1.44 km
EZPAKod	NKF Delft, NKF, Pirelli and Prysmian	CU and AL	Either lead or aluminium but it is unknown now	373.77 km
GEZPAKod	NKF and Prysmian	CU	Aluminium	3.47 km
GPLKod	NKF Delft, NKF and Prysmian	CU	Lead	9.90 km
GVBPLKod	NKF	CU	Lead	0.86 km
Oliedruk	NKF, unknown	CU and AL	Either lead or aluminium but it is unknown now	4.02 km
PLKod	Prysmian	CU	Lead	4.20 km
VBPLK_H_od	NKF	CU	Lead	1.59 km
VBPLKod	AEG, NKF Delft, NKF and Prysmian	CU	Lead	242.60 km
VGEZPAKod	Prysmian	CU	Aluminium	0.74 km
VGPLKod	NKF Delft and Prysmian	CU	Lead	15.88 km
VPLKod	NKF Delft and Unknown	CU	Lead	1.12 km
VSPLKod	NKF Delft, NKF and Prysmian	CU	Lead	50.94 km

1.1 Scientific gaps

There is already a lot of research on oil filled cables available. However, there are still a couple of gaps that need to be filled. First, there are two age ranges of oil filled cables, cables aged over 40 years old which are close to the end of their lifetime and less than 40 years old. These cables have their own failure modes and, more important, failure mechanisms. This is because the cable failure probability changes over the lifetime of the component as it follows a bathtub curve.

There is an early life period where the undetected hardware defects increase the failure probability of cables. If a cable has withstood this early life period, the failure probability has decreased and will approximately stay the same for a long time. When a cable reaches the wear out stage the aging effects will start influencing the failure probability of the cable [6]. From that period on, the older the cable, the more likely it will be to fail. However, the difference in risk when these cables are overloaded and how much health will be lost if the cables are used on high current levels is not investigated yet.

Secondly some studies [7], [8] have shown the influences of dynamic loading on a cable and the reduction of life based on that instead of using nominal loading values. Those papers did not include the historical loading of the cable. In these studies, no tests were done on a real-life cable, and it was assumed that the cable was newly installed. The studies concluded, however, that in the scenario without distributed energy resources (DER) the remaining life values using average annual loading is almost the same when dynamic loading is used.

Another effect which is often excluded, is that the load profiles have changed over the years. This has a couple of reasons. First, the consumption of electricity in the Netherlands has increased over the years. While in 1980 only 64843 GWh of electricity was used. In 2023 121330 GWh has been used, which is almost twice as much. Second, the mix of electricity generation sources has changed. In the last 15 years there has been an increase in production from renewable electricity source. In 2010 only 4049 GWh was produced with wind and solar sources while in the year 2023 49103 GWh was produced with solar and wind [9]. Due to this change in electricity generation and especially the increase of solar generation the load profile of electricity cables is not only demand dependent anymore, but also generation dependent. Which makes that the load profiles of the network have taken a different pattern. This change can be observed in Section 3.1.5.

Third, other studies [10], [11] did use physical cables and tests to find the health or remaining life values of the cable. Still, they either used nominal current levels to show the effect of future loading or the maximum temperature value that can be used to reach the desired lifetime. So, the dynamic loading profile is not included in the estimation of the lifetime.

There is a study [12] performed that includes all the data to create a health or lifetime model. Not all the data they used is available for this project. This has two causes, either the parameters they used are not part of the cable systems of TenneT or the diagnostics data is not measured in the past or properly stored.

These studies show the benefit of having a lifetime or health model for cable systems. However, they did not show the effect of dynamic loading on the used cables or used the health index model as an indicator for cables suitable for overloading.
A health index model can be used to identify the health status of a cable or other component. They use certain indicators to find out which cable is degraded the most and can be used for multiple purposes. For example, a health index can be used to identify the cables that need to be replaced the fastest as they have the highest risk of failing.

To summarise the scientific gaps in the literature. The first gap is that the ageing effect of a used LPOF cable based on its historical dynamic loading profile has not been thoroughly investigated. Next to this, the standard that should be able to calculate dynamically the temperature of a cable (standard IEC 60853-2) is not designed for this purpose and therefore another model could be more suitable to use. The last gap that can be identified is that the best fitting model for the ageing of a LPOF cable is not yet defined. So, it is unclear what the yearly degradation of an LPOF cable is.

Therefore, in this research the following questions are answered:

- What is the health status of the LPOF cables based on their historical loading profiles and their health index?
- Which LPOF cables are suitable for more loading?
- What is the remaining lifetime of cables that are suitable for more loading on this increased loading levels?

To answer these questions there a health model will be created to calculate the degradation based on the historical loading data of the system. This model will be validated using tests that have been done on a 55-year-old used LPOF cable as well as condition indicators that has been determined for different cable systems in TenneT's grid.

1.2 Outline of chapters

1.2.1 Chapter 1: Introduction

In this chapter, the subject of the thesis is introduced, and the research gaps and questions are discussed.

1.2.2 Chapter 2: Related work

In this chapter, the literature review and related work are discussed. First, the ageing phenomena of the cable are discussed. Next, the different ageing models are analysed. Lastly, the health index models are explained.

1.2.3 Chapter 3: Ageing model

In this chapter, the created health index model is discussed. First, the type of cables that are in TenneT's grid are explained in more detail. After that, the required data for each test or diagnostic is provided and discussed. Next, the created model is analysed, and the different thermal models are discussed and lastly the results of the model are provided.

1.2.4 Chapter 4: Testing of the 55-year-old Vierverlaten – Winsum Ranum black Cable

The procedure of the tan delta testing of the 55-year-old Vierverlaten – Winsum Ranum cable (Circuit "Zwart") is discussed in this chapter.

1.2.5 Chapter 5: Cables suitable for higher loading

In this chapter, the cables that are suitable for overloading, based on the health index model, are discussed. First, why these cables can be overloaded is explained. After that the laying conditions are provided.

1.2.6 Chapter 6: Discussion and conclusion

In this chapter, the recommendations from this research will be discussed as well as the conclusion of the research.

2 Related work

In this chapter the related work for this research is described. First, the most important ageing phenomena of an LPOF cable are described. After this, the ageing models that are related to thermal and electrical ageing of LPOF cables are described and last the health index models are described.

2.1 Ageing Phenomena

Ageing phenomena in all electrical high voltage equipment are based on four different mechanisms: thermal, electrical, mechanical, and ambient.
In [4] the ageing phenomena of cables are defined. Thermal ageing is caused by electrical current under normal and emergency conditions. Due to the current that flows through the conductor the cable heats up and causes degradation of the insulation material of the cable. This thermal degradation leads to a maximum operating temperature with which a specific lifetime of the cable can be reached. This maximum operating temperature depends on the insulation materials and operating conditions.

Electrical ageing is caused by the operating voltage under normal and emergency conditions and due to impulse voltages following lightning and switching [4].

Mechanical ageing is caused by the laying conditions (bending), service conditions (externally induced cyclic movements like vibrations due to a road above it) or accidental damage [4].

Ambient ageing is caused by the environmental conditions acting on the external sheaths of the cable (polymer degradation, metal corrosion) [4].
These ageing phenomena are of different importance for the different equipment, and it can be a combination of more than one phenomenon that creates a certain ageing effect. For LPOF cables, thermal ageing is the most severe ageing factor [2].

Due to thermal ageing in LPOF cables, the paper deteriorates, creating certain gasses that contaminate the oil and cause a higher dielectric loss due to an increase in the tangent delta value [2]. The types of gasses are explained in Section 3.1.2.
In addition, thermal-mechanical bending damage decreases the mechanical strength of the paper. Thermal-mechanical bending damage can occur by the cable being bent to a relatively sharp angle or flex point. During load cycling, the cable tends to bend repeatedly at the same location. Over time, if the cables are not constrained, the repeated bending can cause the cable papers to shift. This can cause local tearing and creasing of the paper tapes which softens the cable. The insulation structure is weakened, and electrical failure can occur [4].

Lastly, thermal ageing also influences the dielectric fluid. The degradation is not as significant as the degradation of the paper. However, contaminants in the cable system such as water, metallic salts, particles, or oxygen can have noticeable effects on dissipation factor, breakdown strength, acidity and colour, although electrical or chemical tests of the dielectric fluid alone are unlikely to provide sufficient information for determining the cable system end of life [4].

For LPOF cables electrical failure caused by electrical ageing is mostly a localized event. The failure can occur, for example, at a hot spot, a mechanically damaged area, or at a sheath defect. If the cable dielectric fluid is not continuously maintained at or above the proper pressure within the cable, degradation of the insulation fluid and paper can occur due to high electrical stresses within the gaseous voids between or within the cellulose paper tapes. These voids can result in localized partial discharge conditions that could eventually result in electrical failure [4].

Selection of inferior materials, sheath design, cable manufacturing processes or installations could lead to accelerated mechanical ageing of the sheath and sheath failure in low-pressurized oil-filled cables. Sheath failure can result in a dielectric fluid leak, and if liquid supply and pressure become insufficient, ionisation occurs, leading eventually to electrical failure. The main causes of mechanical sheath ageing are fatigue and creep, which can occur in both lead alloy and aluminium sheaths. Thermal-mechanical cycling and vibration are common causes of fatigue and creep. Increased rate of fatigue can be caused by heavy traffic on the road above, especially on bridges. Fatigue and creep properties of lead alloys are greatly influenced by the alloy type, extrusion conditions, grain size of the alloy, and the temperature to which the sheaths are exposed [4].

Ingress of water can also speed up the ageing process of cables as water increases the local tangent delta of the cable and could result in surface tracking on the paper insulation. This can cause an increase in thermal ageing due to the higher tangent delta value or even a failure due to thermal runaway [11]. Ingress of water can happen due to degradation or damaging of the sheath, not sufficiently mounted circuits or failures in joints and terminations.

In case of low-pressure oil-filled cables from TenneT, the risk of thermal and electrical ageing is less severe than the sheath degradation of these cables. Talking to multiple cables experts within TenneT, it was observed that no oil filled cables have failed based on thermal or electrical ageing so far. The root cause of the failures was due to oil leakages because of sheath degradation or external causes that decreased the electrical breakdown stress or breakdown of the joints and terminations of the cable system.

So, if nothing is changed in the way the cables are loaded right now the ageing of the sheath is probably more important to know than that of the insulation ageing. That the insulation ages slower than other parts of the cable system make sense looking at the redundancy policy of TenneT. Cable systems are normally only utilized to 50 % of the ampacity rating. This is done because of the n-1 redundancy policy so that the cable system that lies in parallel could transfer all the load if the other cable system has a failure. This means that the nominal ampacity ratings of the cable are only reached for some moments per year or even less. Consequently, the cables become less hot and, the thermal degradation of the insulation goes slower. So, it makes sense that thermal degradation is not the most severe degradation phenomena for TenneT's LPOF cables.

When looking at the failures worldwide for LPOF cables, most of the failures for cable systems were caused by the cable and not the accessories [13]. Most of these failures were caused by external factors. For internal failures of the cable, 61% is caused by oil-leakages [13]. Thus, the condition of the sheath is one of the parameters that is important to consider when looking at the age of a cable. Especially, if the loading of the cable would not be increased. Even when the loading of the cable would be increased the sheath degradation is an important aspect to consider. In this way it can be made sure that the cable sheath will not creak due to the higher temperature of the cable.

2.2 Ageing models

In literature different definitions are proposed to define the degradation of oil-filled cables. There are models that are based only on the degradation processes inside the insulation of the cable. These degradation models are based on the Arrhenius equation and the inverse power law, to model the thermal and electrical degradation.

2.2.1 Arrhenius equation

For thermal degradation the Arrhenius equation is used.

$$L(T) = A * e^{\frac{-E_A}{R*T}} \quad (1)$$

In this equation A and E_A are parameters related to the type of material that was used, and which degradation phenomenon is described. R is the universal gas constant (8.13 J/mol*K) and T is the temperature in Kelvin. The ratio R/E_A is often taken as the parameter B. For LPOF cables it is most useful to look at the degree of polymerization but in literature more models have been proposed [2], [14], [15]. In Table 2 the different parameters for the models are given. Most of these parameters are based on cable insulation material, except for the per unit life of the winding hottest-spot temperature of a transformer. This parameter set is created for transformer oil paper which can withstand higher temperatures. So, it is to see if this model is correct to model oil paper insulation from an LPOF cable. However, in [16] they used it to model the thermal degradation for PILC cables therefore it was included.
To quantify the life loss of a cable based on the Arrhenius equation, literature has defined two options. In [14], [17] and [18] the loss of life is defined as:

$$Lifelost(t,T) = Lifelost_{t=0} * e^{-L(T)*t} \quad (2)$$

So, this would lead to the following equation:

$$Lifelost(t,T) = Lifelost_{t=0} * e^{-A*t*e^{\frac{-E_A}{R*T}}} \quad (3)$$

In this equation lifelost at t = 0 can be 1 to represent zero percent loss of life or it can represent a certain degradation phenomena value that was measured before the degradation started, t is the time, and the rest is the Arrhenius equation. To define when the lifetime of the cable has ended depends on the degradation mechanism. However, in literature for the degree of polymerization 30% of life left has been set as a limit for when the paper is degraded as well as 50% is the limit for tensile strength [14].

In the other definition, as described in [15] and [16], a reference temperature (nominal loading conditions) is compared to the actual temperature at every time step to create a certain acceleration factor. So, a certain lifetime is assumed which would be reached if the cable operated under reference temperature and this is adjusted depending on the actual temperature. This other definition gives the following equation:

$$D_t(T_{c,n}) = \frac{\frac{\sum_n^m e^{\left(\frac{B}{T_{ref+273}} - \frac{B}{T_{c,n+273}}\right)}}{x_n} * t * 100}{t_{ref}} \quad (4)$$

x_n stands for the amount of time steps that have been taken. t is the time since the start that has happened and t_{ref} is the assumed lifetime of the cable under reference temperature. TenneT assumes for the reference lifetime 50 years under nominal loading conditions for an LPOF cable. This means for LPOF cables a reference temperature of 85 degrees Celsius, even though the limit for certain cables has been set to 65 degrees Celsius. The reason for this lower maximum temperature is not because of the paper that has been used (which is the same paper), but it comes from the fact to the cable has no pressure banding. This pressure banding makes sure that on higher temperatures no voids can be created. So, if the cable does not have pressure banding there is an increased risk for occurrence of discharges that could lead to breakdown on higher temperatures [19].

Table 2: parameters of oil filled paper for the Arrhenius equation.

Model	A parameter	B parameter	Paper, it comes from
Degree of polymerization	$2.98 * 10^{13}$ h^{-1}	15288 ± 440 K	[2]
Burst strength	$1.71 * 10^{13}$ h^{-1}	15288 ± 440 K	[2]
Tensile strength	$1.29 * 10^{13}$ h^{-1}	15288 ± 440 K	[2]
Elongation at break	$2.25 * 10^{13}$ h^{-1}	15288 ± 440 K	[2]
Fold strength	$1.16 * 10^{14}$ h^{-1}	15288 ± 440 K	[2]
Tear strength	$4.40 * 10^{13}$ h^{-1}	15288 ± 440 K	[2]
Tensile strength	$2.05 * 10^{-49} * e^{0.1885T}$	13892	[14] this one is per week
Per unit life of the winding hottest-spot temperature of a transformer	$9.8 * 10^{-18}$	15000	[15]

2.2.2 Montsinger law

From the Arrhenius equation, Montsinger defined that for oil paper insulation the degradation doubles every time the temperature increases with 8 degrees. This degradation behaviour is noted for transformers but if the same decrease happens in oil-filled cables is not clear. Other sources have defined the yearly degradation using Montsinger law for external pressurized cables and paper insulated lead covered (PILC) cables, but the LPOF cables are not defined in that way [20] [21]. Montsinger's law is:

$$D_{year}\,(T_{conductor}) = D_{to} * 2^{\frac{T_{conductor-15}}{T_d}} \quad (5)$$

D_{year} is the yearly degradation, D_{to} is the degradation rate at 15 degrees Celsius, T_d the temperature difference to get double degradation and $T_{conductor}$ is the cable temperature. In Table 3 the values for the external pressure cables and PILC cables are added.

Table 3: Parameters of Montsinger law

Cable type	T_d	D_{to}	T_{max}	Paper it is from
External gas-pressure mineral oil cable	13° C	1%	60° C	[20]
External gas-pressure synthetic oil cable	21° C	1%	85° C	[20]
PILC cable	6.5° C	0.5%	43° C	[20]
Transformer hottest spot winding temperature	8° C			[21]

2.2.3 Inverse power law

Another way to define the insulation degradation is finding out if the thermal degradation has influence on the electrical breakdown strength of the insulation. The electrical life of the insulation of a cable can be described by the inverse power law:

$$L(E) = \frac{1}{K * E^{-n}} \quad (6)$$

Were K and n being parameters that are found during the experiment and E is the electric strength that is applied. Both [22] and [23] have shown the influence of thermal ageing on the electrical breakdown strength of the insulation and found out that this strength decreases if the cable is thermally aged.

In [22] there is found that non-aged oil-impregnated paper insulation is better at withstanding voltage than thermally aged oil-impregnated paper. In Table 4, the difference between aged and non-aged paper can be seen.

In [23] it was also found that thermally aged paper had a reduction in the electric strength. These parameters of the inverse power law have also been added to the table and there can be noted that the n parameter decreases due to thermally ageing of the cable. However, note that [23] uses oil-impregnated paper insulation from external pressure oil filled cables and not low-pressure oil filled cables. Hence, these values may be different for the low-pressure oil filled cables.

Table 4: parameters for the power law

K parameter	n parameter	Paper it is from
Log(K) = 0.3043 * T – 39.43	18.24 – 0.0402026 * T – 0.001394 * T^2	[23]
$9.28 * 10^{-17}$	16.11	[22] The aged paper
$1.13 * 10^{-24}$	24.74	[22]the non-aged paper

2.2.4 Other models

Another option to get an estimate of the age and remaining life is to use the dissipation factor. [10] used the dissipation factor to quantify how much life was lost. To determine this lost in life, they defined the following equation:

$$ILC = \left(\frac{0.9}{U_2 - U_1}\right) * \left(1.1^{\frac{U_1}{0.09}}\right) * \tan\delta_R \quad (7)$$

ILC is the insulation life consumption in percentage, U_2 is the upper testing voltage, U_1 the lower testing voltage and tan δ_R is the relative tan delta. Where the relative tan delta is defined by the following equation:

$$\tan\delta_R = \frac{\tan\delta\,(U_2) - \tan\delta\,(U_1)}{\tan\delta\,(U_1)} \quad (8)$$

They also calculated the life reduction based on the Arrhenius equation and then used both to define the total degradation of the cable. Depending on the difference between the two values a certain percentage was used to get to the final degradation state of the cable which then can be used to see which cable has to be replaced the fastest.

There are also models that take two degradation phenomena into account. In most cases both the thermal and electrical degradation phenomena. These models were mentioned in [23]. However, it was difficult to find any values for these models that could be used for this research. As well as shown in Section 2.1 the temperature is the most important degradation mechanism. So, they are not considered.

2.3 Health index model

As shown in Section 2.1 the degradation of a cable is not only dependent on the temperature degradation of the cable insulation. Other factors also need to be considered for looking at the degradation of a cable system. Therefore, some papers have taken a combination of different degradation aspects of a cable to give it a certain health index to figure out which cable should be replaced the fastest. According to [24], [25] a health index can be calculated using the following equation:

$$HI = \sum_{i=1}^{n} w_i * HI_i \quad (9)$$

In this equation, each health index value gets a weight that corresponds to the importance of that health index value on the degradation of the total system. How the weights and the health indices are determined differs in literature.

[24] has made an overview of all the test and diagnostics that can be used to record useful data to create a good health index. They use four different health indices for the health index: maintenance, age, failures and failure mode effect, and criticality analysis (FME(C)A). They suggest that assigning the highest weight to the FMECA health indicator is the best option given that the availability and reliability of this data is most likely the most sufficient one in the data system. How to assign values to the different condition indicators is defined in the report using the IEEE std 400.2. Then a condition indicator is assigned a value from 1 to 5 where 1 indicates a good condition and 5 a bad condition. The highest value of this set of condition indicators then determines the value of the health indices. The weighing factor of the health indices are not defined in this report.

In [26], [27] and [28] the weighting factors are defined or the health indices they have used but they didn't explain in their papers how they calculated the value of the different health indices. They defined the degradation of the oil-filled cables in thermal, electrical, mechanical and environmental (ambient) factors and gave the maximum score of each index respectively 60, 20, 15 and 5. Based on these parameters they plotted it over time to see what the health index of a certain cable system was. Based on this, they defined the expected life using a Weibull CDF and determined the number of years the cable systems had left. To simulate the expected lifetime, they used a Monte Carlo simulation to define the risk of failing of the cable as well as the effect of operating stress.

Another study [12] proposed a health index for a cable system. This model gives a value for the cable, joint, termination, manhole, and duct bank and they also give an operating factor to the cable system. This operating factor gives an indication on the service life of the cable. Then they define the final health index by multiplying the health index calculation times this operating factor. To get a remaining useful life estimation they estimate the age curve using a Weibull distribution and determine the apparent age and then they subtract this apparent age form the expected end of life.

2.4 Conclusion of chapter 2

From this chapter the following things can be concluded. First, it is important to know that thermal degradation is the most severe ageing mechanism of an LPOF cable. However, when looking at the cables of TenneT no cables have failed based on thermal ageing. It can be concluded from TenneT's data as well as data from elsewhere that oil leakages are the most recorded failure causes. This means that the sheath degradation is a more important failure mechanism than the thermal degradation.

It makes sense for the TenneT LPOF cables that they do not fail on thermal degradation. This is caused by the redundancy policy of TenneT. Which makes that the average temperature is lower than what they can handle, and thus degradation will be slower.

To still see what the current effect is of the thermal degradation on the insulation, a degradation model had to be chosen. The best equation that can be used for LPOF cables is the Arrhenius equation to describe the thermal degradation. For other models any parameters for LPOF cables there could not be found, or they did not describe thermal ageing. So, these models are not used to find the effect of thermal ageing. The results of this ageing model are explained in Chapter 3.

Next to this, the ageing of a cable can be estimated using tan delta measurements. Which is used as the basis for the testing of the LPOF cable in Chapter 4.

The last thing that can be concluded from this chapter is that creating a health index can bring insight in which cables need to be replaced earlier. However, what the best model (weighting factors and health indices) will be for LPOF cables is not defined in literature as this also depends on the risk management of an organization and on which condition indicator has higher importance for this organization.

3 Ageing model

The degradation mechanisms of an LPOF cable have been described in Chapter 2. This information is used to develop an ageing model that can give the health status of an LPOF cable. In this chapter this ageing model is described.

TenneT has 104 cable systems that still have LPOF cables inside. For these cable systems parts of the following data is available:

- Gas in oil analysis back to 2000
- Historical loading data back to 2011
- Current rating of the cables
- Installation conditions
- Cable type
- Condition indicators of the oil pressure, pressure alarm, propagation resistance, condition of the sheath and visual inspection

This data is considered inside the ageing model, and which is described in the sections below. First, the data that is used is described after that the proposed model will be explained and finally the temperature model is validated.

3.1 Available data

In this section, the available data used for the ageing model is described.

3.1.1 Cables

In this part, the types of cables are explained in more detail. A cable consists of a conductor, conductor screen, insulation material, insulation screen, sheath, armour (sometimes), and a jacket. All these components have their own function in the cable.

The conductor size depends on how much current needs to flow through the cable (ampacity). How much insulation material is needed depends on the voltage the cable needs to withstand. The sheath/screen gives the earth path of the cable as well as the protection layer to prevent water ingress to the insulation of the cable. The jacket protects the sheath from water ingress or other hazards that can damage the sheath. TenneT has 17 types of LPOF cables installed inside their network as already mentioned in chapter 1. The things that can vary for the 17 types of LPOF cables are:

- Different jacket materials: PE, compounded jute and fibrous materials, PVC and bitumen on corrugated aluminium sheaths.
- Different sheath materials: corrugated aluminium sheath or a lead sheath is used.
- Different allowed maximum temperature which can either be 65 degrees or 85 degrees Celsius. Depending on the application of pressure banding [19].
- The conductor material can either be aluminium or copper.

- The conductor area can be different as this depends on the amount of allowed current that needs to be flowing through the cable.
- Some cables have concentric wires for example the types BPLKod, GPLKod, VGVPLkod.

These different materials influence what a cable can handle. The different jacket materials have different thermal resistivity, and the volumetric specific heat differs which makes that thermal behaviour of the cable is different when a different jacket is used [29].

The different sheath materials have different electrical and thermal properties. Lead sheaths are not commonly installed anymore as it is toxic for the environment while aluminium is still used a lot.

The difference in conductor material has an influence on the size of a cable. When aluminium is used the cable needs to be bigger to transfer the same amount of current than when copper is used. This is because the electrical conductivity of aluminium is lower than that of copper [5]. Concentric wires are sometimes added to reduce the electromagnetic interference of a cable.

All these variations have an influence on the design of the cable system, and it could be the case that it has an influence on the lifetime of the cables. However, it is very difficult to be sure that this is true as the failure data for LPOF cables of TenneT is not recorded.

3.1.2 Dissolved Gas Analysis (DGA)

Gas in oil analysis is one of the tests that are recorded for the LPOF cables within TenneT. There is data available back to 2000. The DGA is documented with two different formats, but the same levels were used to identify the condition. In Figures 5 and 6 the formats are shown. The condition indicators for the different measurements were already specified in the recorded data where three states were presented. There is good, slightly higher or lower (depending on what is the worser condition) and bad.

For each test that is done in the provided sample, an indication is given for that value. The different gases can be produced by different degradation phenomena. According to [30], four groups can be separated based on the gases found by doing a DGA:

- Partial discharges in butt gaps or areas of minor disturbance of the insulation papers produces a large amount of hydrogen and a small amount of methane.
- Overheating of the cellulose with temperatures above 100 degrees Celsius for a extend period creates carbon monoxide, carbon dioxide and a small amount of hydrogen.
- Overheating of the dielectric fluid above 200 degrees Celsius creates an amount of ethylene that is larger than the other hydrocarbon gases.
- Arcing in the dielectric fluid between metallic components creates acetylene. If acetylene is created this shows that either arcing is active or that some type of fault had already taken place.

Note that dissolved gas analysis can give a very limited picture of the cable as it can be location depended. To find trends with the DGA data, the sampling of it needs to be done in both summer and winter as well as the loading history can be relevant to changes in gas concentrations [30]. For the data of TenneT there is too little information available to see these trends, as only for eight circuits multiple measurements have been taken over the years.

	Meting						Classificatie		
	1	2	3	4	5	6			
Olieanalyse - diëlektrisch							Goed	Licht verlaagd	Verlaagd
doorslagwaarde [kV/2,5mm]	75	75	69				≥ 50	50 > x > 30	≤ 30
							Goed	Licht verhoogd	Verhoogd
tan δ bij 40°C [·10^4]	81	66	48				≤ 80	80 < x < 125	≥ 125
tan δ bij 60°C [·10^4]	115	125	93				≤ 170	170 < x < 275	≥ 275
tan δ bij 80°C [·10^4]	220	225	148				≤ 350	350 < x < 550	≥ 550
tan δ bij 100°C [·10^4]	373	323	148				≤ 460	460 < x < 750	≥ 750
Olieanalyse - gas-in-olie							Goed	Licht verhoogd	Verhoogd
waterstof	703	98	62				≤ 650	650 < x < 1100	≥ 1100
koolmonoxide	5	7	2				≤ 50	50 < x < 80	≥ 80
methaan	4	4	4				≤ 15	15 < x < 35	≥ 35
ethaan	2	2	6				≤ 10	10 < x < 20	≥ 20
etheen	1	4	3				≤ 5	5 < x < 10	≥ 10
ethyn	0	0	0				≤ 2	2 < x < 5	≥ 5
propaan	1	1	2				≤ 15	15 < x < 30	≥ 30
propeen	0	1	2				≤ 5	5 < x < 15	≥ 15
iso-butaan	0	0	2				≤ 30	30 < x < 60	≥ 60
n-butaan	0	1	2				≤ 30	30 < x < 60	≥ 60
kooldioxide	535	613	593				≤ 500	500 < x < 800	≥ 800
Waarden gelijk aan 0 betekent beneden de detectiegrens. Als gevolg van hercalibraties zijn kleine wijzigingen mogelijk									

Figure 6: New DGA format used for oil samples form cables.

	Meting			Classificatie		
Olieanalyse - diëlektrisch	1	2	3	Goed	Grijs	Slecht
doorslagwaarde [kV/2,5mm]	67	80	70	1, 2, 3		
tan δ bij 40 °C [·10^4]	46	67	66	1, 2, 3		
tan δ bij 60 °C [·10^4]	114	162	193	1, 2	3	
tan δ bij 80 °C [·10^4]	228	330	402	1, 2	3	
tan δ bij 100 °C [·10^4]	259	275	110	1, 2, 3		
Olieanalyse - gas-in-olie						
zuurstof						
stikstof						
waterstof	107	204	83	1, 2, 3		
koolmonoxide	10	6	6	1, 2, 3		
methaan	3	2	2	1, 2, 3		
ethaan	2	1	2	1, 2, 3		
etheen	4	1	1	1, 2, 3		
ethyn	1	0	0	1, 2, 3		
propaan	3	0	1	1, 2, 3		
propeen	2	1	1	1, 2, 3		
iso-butaan	0	0	0	1, 2, 3		
n-butaan	0	0	1	1, 2, 3		
kooldioxide	199	335	231	1, 2, 3		

Figure 5: Old DGA format used for oil samples from cables.

3.1.3 Tan delta measurements

Tan delta measurements of the oil are recorded regularly and are done on the same cables and samples as the DGA measurements. Tan delta measurements are useful to see if the paper has degraded. Because the degradation of paper creates gasses as mentioned before which increase the dielectric losses of a cable resulting in a higher tan delta value. This increase in losses makes it potentially more dangerous for hot spots as these places will be heated up more than the rest of the cable and could lead to breakdown. These tan delta measurements are, however, different then performing tan delta measurements on the entire insulation material which is done during the testing of the cable in Chapter 4. In this case it is only done on the oil sample and not on a paper oil sample.

3.1.4 Breakdown strength of the oil

The breakdown strength of the oil is also recorded regularly, and these measurements are done on the same cables and samples as the DGA measurements. This value gives an indication of the contamination of the oil. If the breakdown strength becomes too low the cable cannot withstand the electric field that is necessary, and a breakdown could occur.

3.1.5 Historical loading data

For the historical loading data, it was possible to get for all the circuits that are still in service the loading data of the last 14 years. This loading data is then used to determine the temperature of the cable which can be used to determine the loss of life of the insulation. How this temperature is determined is explained in Section 3.3.1.1.

Figure 1 shows that most of the cable sections are older than 14 years. Therefore, these other years should be considered to determine the insulation life loss of the cable. So, first, the available loading data is analysed. In Figures 7, 8, 9, and 10 the loading profiles of two different cables systems can be seen in the year 2011 and 2024. As one can see these profiles have changed.

The reason for this change has been explained in Section 1.1. Before 2011 there was even less renewable electricity generation [31]. So, for least the Dodenwaard Ede black (DOD-EDE Z) circuit it would be more useful to use the loading data of 2011. However, to verify that this change in loading profile influences the degradation rate the ageing model needs to be run.

For the ULW-SOS W circuit it was in 2011 already difficult to see what the day to day loading profile looked like. Therefore, in contrary to DOD-EDE Z the only option is to use the estimated temperatures over the years and take the average degradation rate for the years which no historical loading data is available for.
So, in both cases the degradation rate needs to be investigated to see how much influence this change in loading profile has.

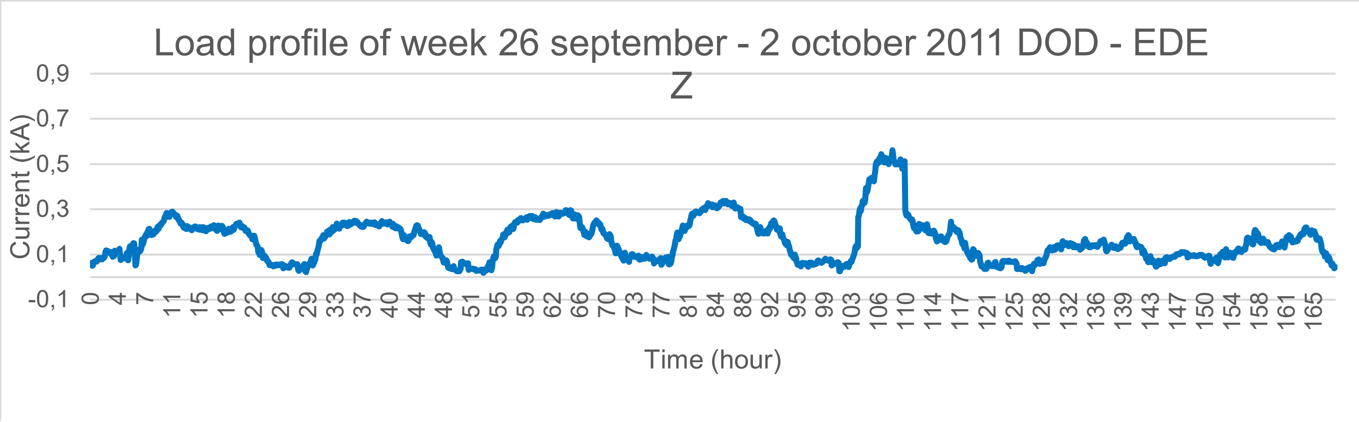

Figure 7: Load profile of DOD-EDE W week 26 September - 2 October 2011

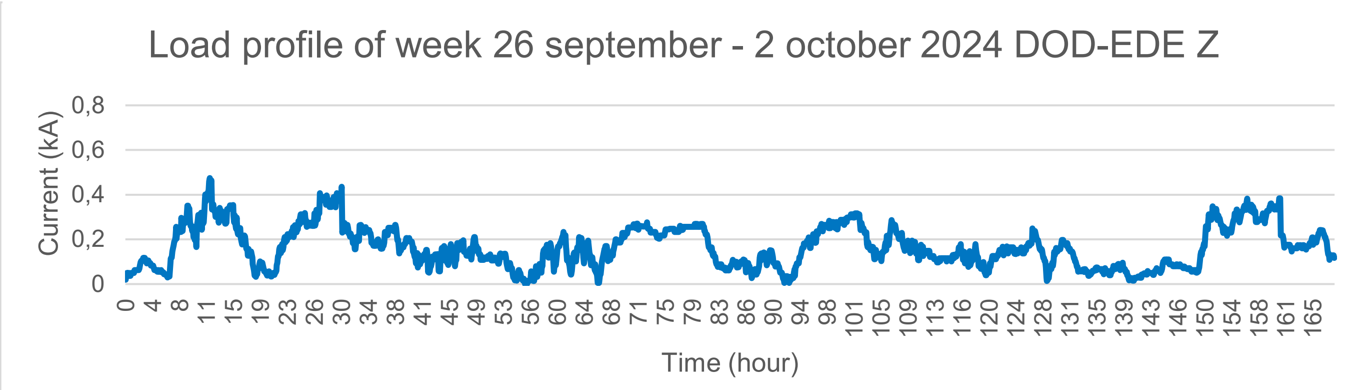

Figure 8: Load profile of DOD EDE week 26 September - 2 October 2024

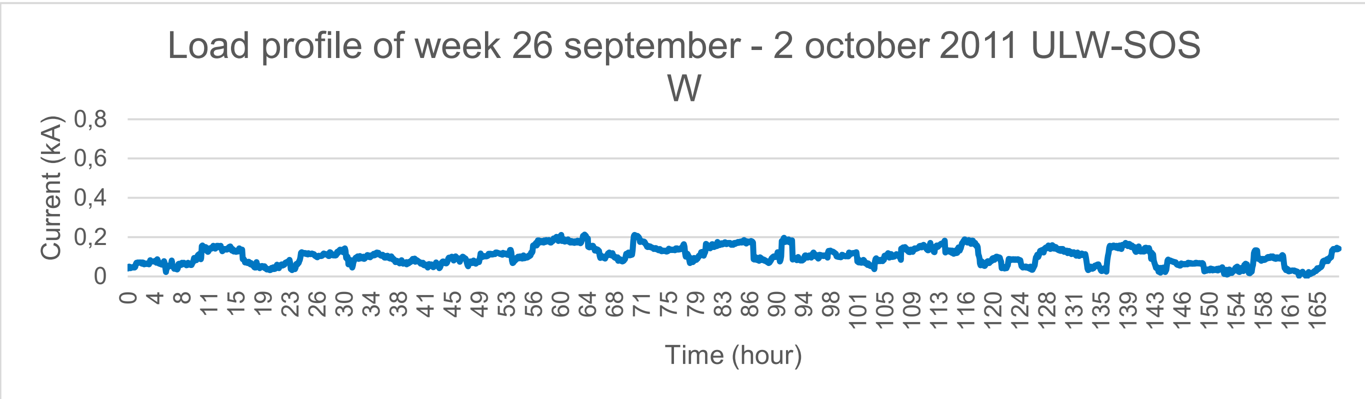

Figure 9: Load profile of ULW-SOS W week 26 September - 2 October 2011

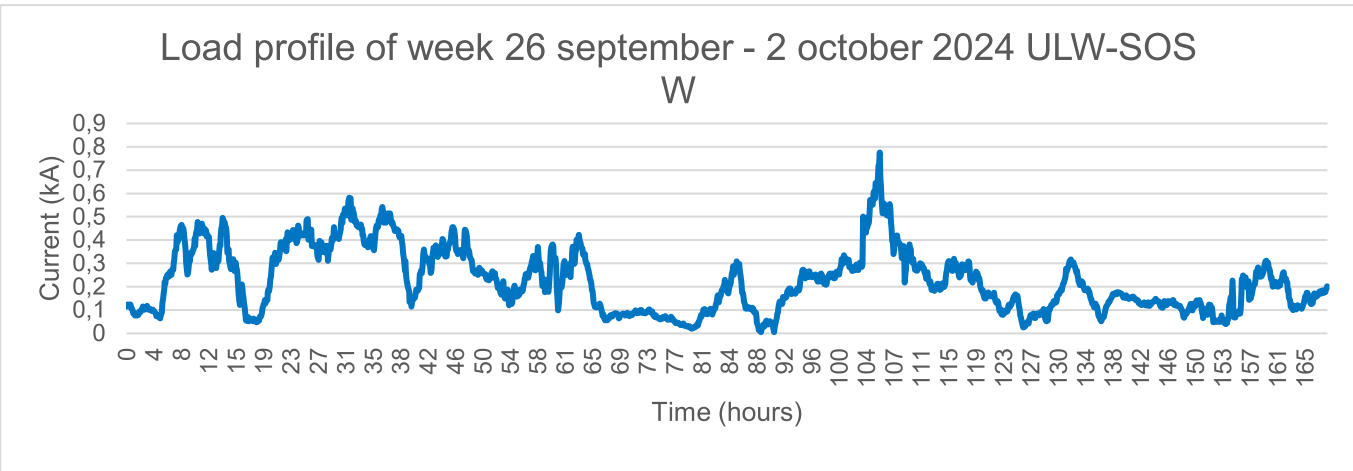

Figure 10: Load profile of ULW-SOS W week 26 September - 2 October 2024

3.1.6 Condition Indicators

For the condition indicators, it is important to note that not to every cable system all the condition indicators were assigned. In Table 5, the number of circuits a certain condition indicator is assigned to, can be observed. These numbers show that for not all the 104 circuits there is condition indicator data available. For 27 circuits no condition indicator is known, for 44 no DGA measurements have been done but there are some other condition indicators, and for 34 have both DGA measurements and some other condition indicators.

This incompleteness makes it complicated to give a health index value to all the circuits. When using Equation 6 directly this could result in a bias for the condition of the circuit if not all condition indicators are known. So, it is decided to sum up the weighting factors of which a condition indicator is available and divided the health index by this summed value. In this way the range of values will be in the same range. Despite this normalization, due to some unknown indicators it is still possible that the cable does not get the right health index. Therefore, for the cables with incomplete condition indicators, the unknown condition indicators are written down such that the user knows that this condition indicator is not considered when calculating the health index.

Table 5 : Number of circuits for a condition indicator

Condition indicator	Number of values	Condition indicator	Number of values
Breakdown strength of the oil	34	Pressure alarm	56
Tan delta measurements of the oil	30	Propagation resistance	51
DGA measurement of the oil	34	Visual inspection data	12
Oil pressure	11	Sheath condition	38

3.2 Ageing model

The ageing model consists of two parts. First, the temperature based on the historical loading data is determined. Using this temperature the different Arrhenius equations are calculated to see the degradation of the cable insulation. Then the other known condition indicators are added to the give a status to the health of the cable.

3.2.1 Temperature model

There are multiple ways to determine the temperature of a cable. The most accurate option would be to place temperature sensors on the cable. These sensors give for those spots the temperature of the cable. However, this is not available for most LPOF cables of TenneT. Only one LPOF cable circuit has these sensors, so another method had to be used to determine the temperature of these cables. The cable systems with sensors are the Utrecht Lage Weide - Soest circuits. Both the black and white circuits have temperature sensors.

Another way to determine the cable temperature is using the load profile of the cable. In this research, three different models are used to determine the cable temperature. The model of the Cymcap software, the temperature model of the IEC 60853-2 standard, and a thermal numerical model made by Ype Wijnia have been used. The models are described below, and the downsides and upsides of every model are discussed. The models are verified with the temperature measurements of the Utrecht Lage Weide - Soest circuits. This validation is done in Section 3.3.1.

In literature other models have been described to develop a better estimation of the transient temperature behaviour of cables. [32] made an overview of the existing papers that have looked at the thermal dynamic rating of cables in 2022. The papers that were reviewed mentioned the limitations of the IEC 60853-2 thermal model and have proposed their own model to reduce the error for the problem they were facing. However, due to time these models have not been considered when creating the thermal model for this cable.

IEC 60853-2

The IEC 60853-2 standard is used to calculate the cyclic ratings, emergency rating and the transient responds of cables whose internal thermal capacitance cannot be neglected. The first option for a temperature model has been made using the IEC 60853-2 standard as this standard is the only standard that deals with dynamic loading.

This standard was designed for daily load cycles that look substantially the same [29]. Furthermore, if a step function transient was applied to the cable this increase in temperature could also be calculated. Using this daily load cycle, the temperature transient response for the emergency ampacity rating can be calculated.

This model makes a lumped parameter thermal model of the cable and ground to calculate the transient. To calculate the total transient the following equation is used:

$$\theta(t) = \theta_c(t) + \alpha(t) \cdot \theta_e(t) \quad (10)$$

Where θc is the transient response of the cable, α is the attainment factor for the transient temperature rise between the conductor and the outside surface of the cable and θ_e is the transient temperature rise of cable surface above ambient of the ground surrounding the cable.

There two versions of how these parameters are calculated. This is different for the duration of the transient. For the dynamic model it was decided to use the transient with a duration of 1/3 T*Q or less. As the change in load could be measured for each 5 min and there was a change in this load often enough in this time frame that it was necessary to do this. Besides this in literature for the usage of dynamic cable rating this was also the model that was used [33].

For transients with a duration of 1/3 T*Q or less the following equations are used to calculate the transient response.

$$\theta_c(t) = W_c[T_a(1 - e^{-at}) + T_b(1 - e^{-bt})] \quad (11)$$

$$\alpha(t) = \frac{\theta_c(t)}{W_c(T_A + T_B)} \quad (12)$$

$$. \ \theta_e(t) = \frac{\rho_t W_1}{4\pi}\left\{\left[-Ei\left(\frac{-D_e^2}{16*t*\delta}\right)\right] + \sum_{k=1}^{k=N-1}\left[-Ei\left(\frac{-(d_{pk}^2)}{4*t*\delta}\right)\right]\right\} \quad (13)$$

In these equations: $T_A = 0.5*T_1$, where T_1 is the thermal resistance of the insulation in (K*W/m).
$T_B = 0.5*T_1 + q_s * T_3$, where q_s is the ratio of sheath losses compared to the conductor losses and T_3 is the thermal resistance of the external serving (K*W/m).
The W_c is the power loss per unit length in a conductor, based on the maximum conductor temperature.
$T_a = \frac{1}{a-b}\left[\frac{1}{Q_A} - b*(T_A + T_B)\right]$ and $T_b = (T_A + T_B) - T_a$,
$a, b = \frac{M_0 \pm \sqrt{M_0^2 - N_0}}{N_0}$,

$N_0 = Q_A T_A Q_B T_B$ and $M_o = 0.5(Q_A(T_A + T_B) + Q_B T_B)$, $Q_A = Q_c + p^* Q_{il}$, and
$Q_B = p^* Q_{i2} + (1 - p^*)Q_{i1} + \left[(1 - p^*)Q_{i1} + \frac{Q_s + p' Q_j}{q_s}\right]\left(\frac{q_s T_3}{0.5T_1 + q_s T_3}\right)^2$

In these formulas Q_c is the thermal capacity of the conductor, Q_{i1} is the thermal capacity of the first half of the insulation, and Q_{i2} is the thermal capacity of the second half of the insulation. The $p^* = \frac{1}{\ln\left(\frac{D_i}{d_c}\right)} - \frac{1}{\left(\frac{D_i}{d_c}\right) - 1}$, $p' = \frac{1}{2\ln\left(\frac{D_e}{D_s}\right)} - \frac{1}{\left(\frac{D_e}{D_s}\right)^2 - 1}$, and q_s is the ratio of the sheath losses compared to the conductor losses.

The ρ_t is the thermal resistivity of the soil. The δ is the soil thermal diffusivity, D_e is the external diameter of the cable, and t is the time that has passed since the moment of application of heating. The D_s is the diameter of the sheath, and D_i is the diameter of the insulation

Unfortunately, daily load cycles that look substantially the same is not the reality anymore. This is already shown in Section 3.1.5. Therefore, the cable heating does not match this profile. This can be clearly seen in Section 3.3.1. So, if another model can have a smaller error this would be preferred.

Cymcap model

Cymcap is a software program made by Eaton. It is fully compliant with IEC 60287, IEC 60228 and IEC 60853. The software is developed in such a way that one can define the cable and its installation conditions. After that, the software can already preform the steady state ampacity calculation using IEC 60287.

For the dynamic loading, there are multiple ways it can be defined in the software. First, a loading profile can be added and the temperature during this load profile will be calculated and vice versa. The assumption before the transient load profile calculation is started, is that the cable was operating on steady state ampacity. But, as shown in Section 3.1.5, the cables do not see a steady state nominal loading condition. All the historical loading profiles used in this thesis did not show a steady state ampacity for the cable.

Therefore, the assumed heat that is now in the ground surrounding the cable first needs to dissipate to get a more accurate dynamic temperature responds. Consequently, before the model can run there needs to be included a cooldown of approximately 4000 hours. This is done by applying a load of 0.001 Per unit (PU). After this cooling down, the historical loading data can be applied to get an estimation of what the temperature of the cables would have been.

The downside of using this software was that the running time to go through a whole year of loading data already took an hour to complete even when using time steps of 1 hour (instead of 5 minutes) as a higher resolution was not possible. Doing this slow method for multiple circuits each having 14 years of historical data would not be realistic. This made that Cymcap was used to verify the different models using a small part of the data, but not to run all the data through it.

Numerical model

The IEC standard 60853-2 suggest that the thermal transient can also be calculated by a numerical method [29]. They refer to a model approach by a Cigre paper [34]. So, Ype Wijnia has taken this as a basis to create a numerical model for TenneT. He created a model to calculate the temperature based on its dynamic rating for the Utrecht Lage Weide - Soest cable system. He wanted to make an easy model that could quickly calculate the temperature of the cable for a year. He divided the cable and ground in different concentric cylindrical elements that heat up [35]. The cable is divided into two layers: the core and the rest of the cable. The ground is divided into 20 layers. For these three groups there is for each group a formula used to calculate the temperature of the layer. The three formulas are:

$$T_c(t) = T_c(t-1) + \Delta t * \frac{P_{loss}(t-1) - \frac{\left(T_c(t-1) - T_j(t-1)\right) * 2 * \pi * \lambda_j}{\left(g_c * ln\left(\frac{R_{2depth}}{R_{1depth}}\right)\right)}}{R_1^2 * \pi * C_{pvc}} \quad (14)$$

$$T_j(t) = T_j(t-1) + \Delta t * \frac{\frac{\left(T_c(t-1) - T_j(t-1)\right) * 2 * \pi * \lambda_{jacket}}{\left(g_c * ln\left(\frac{R_{2depth}}{R_{1depth}}\right)\right)} - \frac{\left(T_j(t-1) - T_{g1}(t-1)\right) * 2 * \pi * \lambda_{g1}}{g_j * ln\left(\frac{R_{g1depth}}{R_{2depth}}\right)}}{(R_2^2 - R_1^2) * \pi * C_{pvj}} \quad (15)$$

$$T_{gn}(t) = T_{gn}(t-1) + \Delta t * \frac{\frac{\left(T_j(t-1) - T_{gn}(t-1)\right) * 2 * \pi * \lambda_{gn}}{\left(g_j * ln\left(\frac{R_{gndepth}}{R_{gn-1depth}}\right)\right)} - \frac{\left(T_{gn}(t-1) - T_{gn+1}(t-1)\right) * 2 * \pi * \lambda_{gn+1}}{g_{gn} * ln\left(\frac{R_{gn+1depth}}{R_{gndepth}}\right)}}{(R_{gn}^2 - R_{gn-1}^2) * \pi * C_{pvgn}} \quad (16)$$

The different Ts represent the corresponding temperature of each layer.
The Δt is the time step of 300 seconds (5 min).

P_loss is the power loss generated by the conductor and other losses of the cable P = R_ac * I^2. Here, is R_ac the ac resistance of the cable calculated with the following formula:

$$R_{AC}(T_c) = R_{acmaxT} * (1 + T_c - 65) * \alpha \ (17)$$

In this equation R_acmaxT is the thermal resistance of the cable corrected for the losses that occur due to the dielectric losses and the sheath losses at the maximum temperature of the cable (in this case 65 degrees Celsius). T_c is the conductor temperature at that time step and alpha is the temperature coefficient at 20 degrees Celsius.

The Lambdas are the thermal conductivity of the jacket or ground layers. The thermal conductivity of the jacket is determined using the summation of the thermal resistivity in parallel over all layers of the cable except the conductor so $\lambda_j = \frac{1}{T_{insulation}} + \frac{1}{T_{sheath}} + \frac{1}{T_{jacket}}$ that gives the total conductivity of the jacket layer. For the 20 ground layers it is determined using the following equation:

$$\lambda_{gn} = \frac{R_{gndepth} - R_{gn-1depth}}{\frac{R_{gn-1} - R_{gn-1depth}}{\lambda_{gn-1}} + \frac{R_{gndepth} - R_{gn-1}}{\lambda_{gn}}} \ (18).$$

The C_pv is the volumetric specific heat of the material that the temperature is being considered for.

The R_j, R_c and R_{gn} are the thicknesses of the layers that are considered. R_{cdepth}, R_{jdepth} and $R_{gndepth}$ are the penetration depths that the heat will flow to. This is needed to correct for the fact that not in every point of a layer the heat will be the same. The geometric factors (g) correct for the fact that the heat transfer from the cable to the ground does not happen over the entire outer surface to one point. Instead, approximately one-third of the cable surface transfers its heat to a certain point, which is considered by this factor. It depends on the cable formation when this geometric

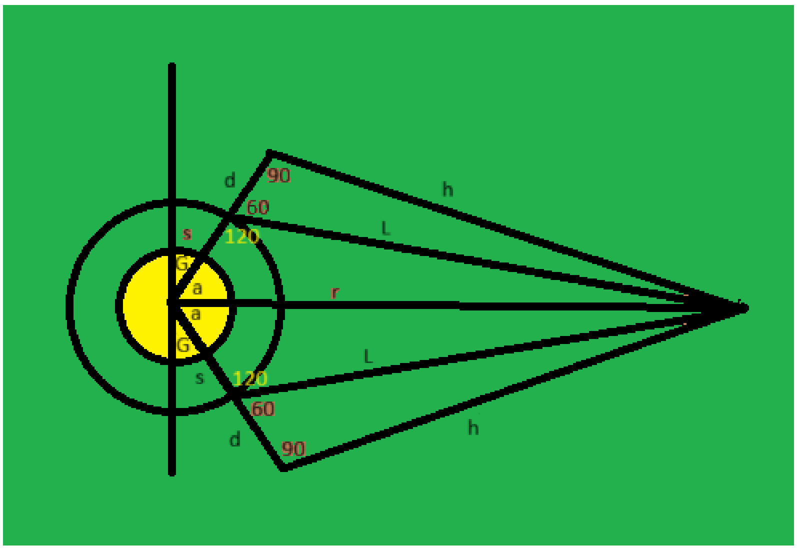

Figure 11: Situation to determine the geometric factor

factor starts playing a role. For flat formation it only happens for layers that are more than half of the length between two cables away. While for a trefoil formation this geometric factor applies for all ground layers. In Figure 11, the situation in which the geometric factor is determined is shown. Using this figure and some rewriting the G can be determined with the following equation:

$$G = 90 - \cos^{-1}\left(\frac{\frac{6*\frac{S}{2} \pm \sqrt{\left(-6*\frac{S}{2}\right)^2 - 16*(3*(\frac{S}{2})^2 - r^2)}}{8}}{r}\right) \quad (19)$$

Where s is the distance between two cables, r is the distance until the point and the core of the cable. Then, to determine the geometric factor the following equation is used:

$$g = \frac{1}{\frac{G}{90}} \quad (20)$$

Next to the information that is directly put into these three formulas, some other information is also needed to run this model. That is the ambient ground temperature and the dimensions of the cable.

All these parameters need to be known for the bottleneck (hottest part of the cable system). Even though this model is not perfect, it is more accurate than the IEC 60853-2 model and way faster than the Cymcap model. It only takes 20 minutes to run through 14 years of data. Furthermore, the ageing model can be applied directly to it as it is written in python, so adding another formula is not a problem. The downside is that it does not follow a standard so to be able to be used for other types of cables than LPOF cables is for this moment unknown. That would require a new validation using measurement data for a cable from that specific cable type.

3.2.2 Degradation model

As explained in section 2.2 the kind of model that gives the best estimation of the health degradation of a LPOF cable is unclear. So, it was decided to use all the models based on the Arrhenius equation to see the difference and to get a range of what the degradation of the insulation of the cable could be. Both methods (equations 3 and 4) have been used to determine the degradation per step.

3.2.3 Health indicators

The health index is calculated based on the known condition indicators to see if the cable would be suitable for higher loading. As the thermal degradation of the insulation could still be low it is also important that the rest of the cable is able to withstand a higher load. So, if any of the condition indicators is not in good shape it will be wise to check if this condition indicator will be influenced when the temperature of cable reaches higher values.

3.3 Results

3.3.1 Validation of the temperature model

The temperature model is validated with the use of the Utrecht Lage Weide - Soest white (ULW-SOS W) case. This cable is 55 years old. For this cable, the location of the hotspot and thus the limiting part of the circuit has been identified. In Tables 6 and 7 the laying conditions and cable parameters of an point close to the hotspot location of this cable can be found (Orinocodreef) and a point from which the measurement data is still available (Houstondreef). Unfortunately, the hotspot location data could not be found anymore. The cable that is in place is a VBPLKod 115/200 kV 1x500 mm^2 CU cable.

Table 6: Laying conditions of Utrecht Lage Weide - Soest white circuit.

Place	Formation	Distance between cables	Thermal resistance of the soil	Laying depth of the cable	Ambient temperature	Far earth distance
Orinocodreef	Flatbed	0.35 m	1.26 K*W/m	1.2 m	15 Celsius	2.5 m
Houstondreef	Flatbed	0.35 m	1.05 K*W/m	1 m	15 Celsius	2.5 m

Table 7: Cable parameter of the Utrecht Lage Weide - Soest white circuit

Cable type	Conductor area	Conductor diameter	Conductor screen thickness	Insulation thickness	Screen thickness
VBLKod	500 mm^2	0.0304 m	0.0004 m	0.01545 m	0.0004 m
Jacket thickness	**Conductor material**	**Sheath material**	**Jacket material**	**Cabble diameter**	**Sheath thickness**
0.00498 m	Copper	Lead	PE	0.083 m	0.00505 m

For the three models that have been created, the loading profile of the year 2022 was given as an input for the model to estimate the temperature. In Figures 13, 14, and 15 the results can be seen for the three models. All models are created assuming the ambient temperature of the ground (the temperature without the extra heat from the cable) stayed 15 degrees Celsius for the entire year. However, in real life this is not the case. So, while comparing the measured data with the model data this simplification must be considered. In Figure 12, the measured data can be seen. This figure shows that there is a mismatch due to the ground temperature not being 15 degrees for the entire year. However, from these figures there can be concluded that the numerical model follows the temperature the best. The reason behind the numerical model outperformance is that both the IEC 60853-2 and the Cymcap model overestimated the impact of the load increase during peaks. Nevertheless, the numerical model gives an error which should be considered. Especially, when looking at the higher temperature peaks the model does not match completely with the measured data. This mismatch can have a large effect on the lifetime of the cable as the impact on the loss increases exponentially with the temperature.

The extension of this error for all the models can be seen in Figures 16, 17, 18, 19, 20, and 21, where the box plots of the errors can be observed. Were the absolute temperature difference being the absolute value of the difference. From these figures, it can be concluded that indeed the numerical model has the smallest error range. Besides that, the error becomes smaller for all the models if the measured data has 15 degrees as ground/ambient temperature all the time. To observe the effect this error has on the degradation of the cable, the ageing model needs to be run which is done in Section 34.
For the Cymcap model the need to first cool down the cable and surrounding ground before applying the desired load profile can be seen. Without cooling down, the temperature first starts to match again after approximately 2000 hours with the cooled

down one and when comparing it with the measured data it can be clearly seen that without cooling down the first 2000 hours have a too high temperature.

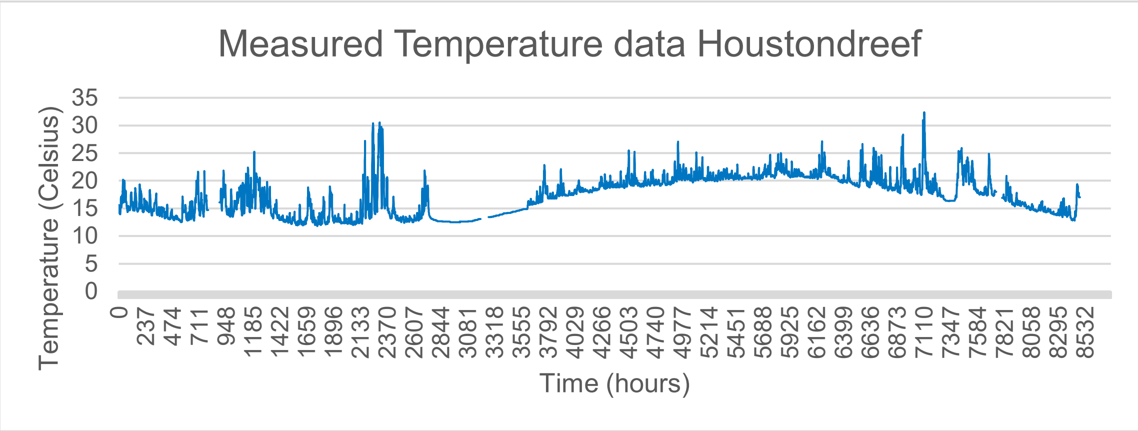

Figure 12: Temperature measurements at Houstondreef for ULW-SOS W cable system

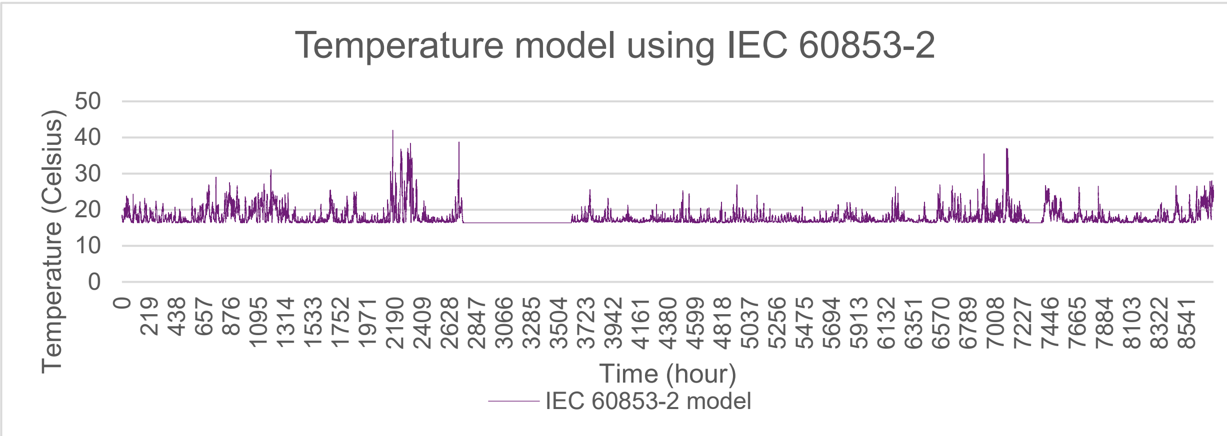

Figure 13: Temperature model using IEC standard 60853-2.

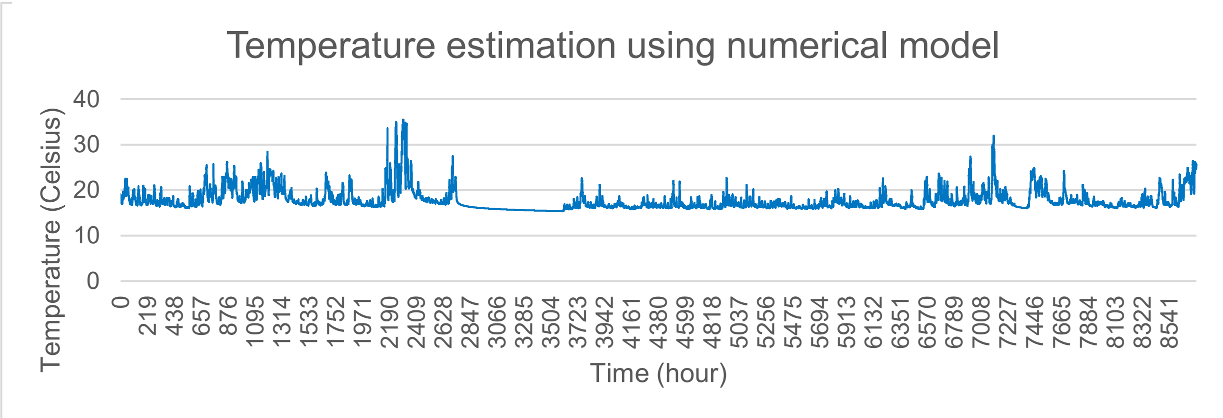

Figure 14: Temperature estimation using the numerical model.

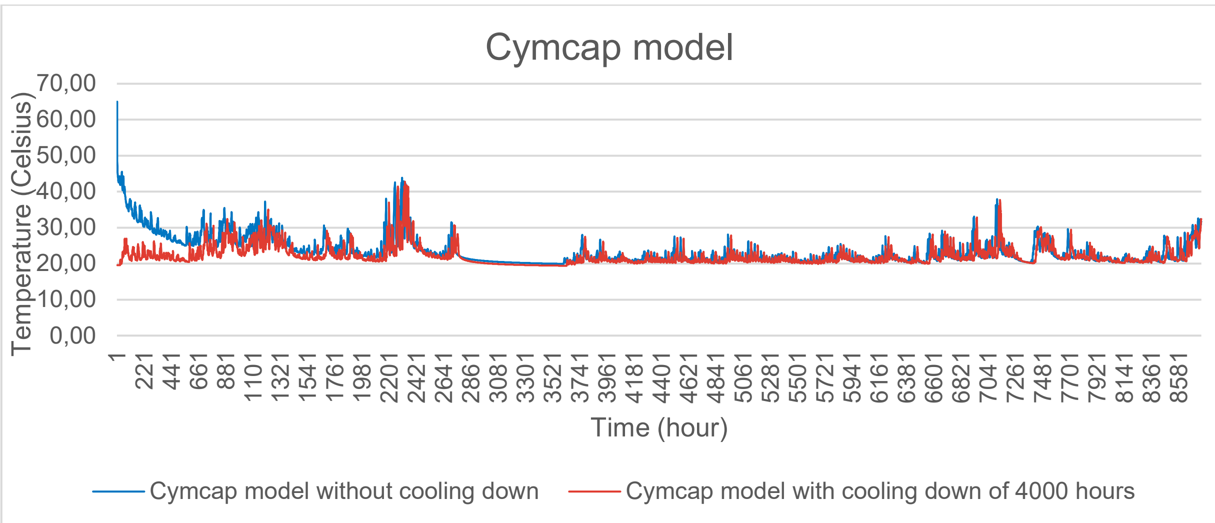

Figure 15: temperature estimation using Cymcap

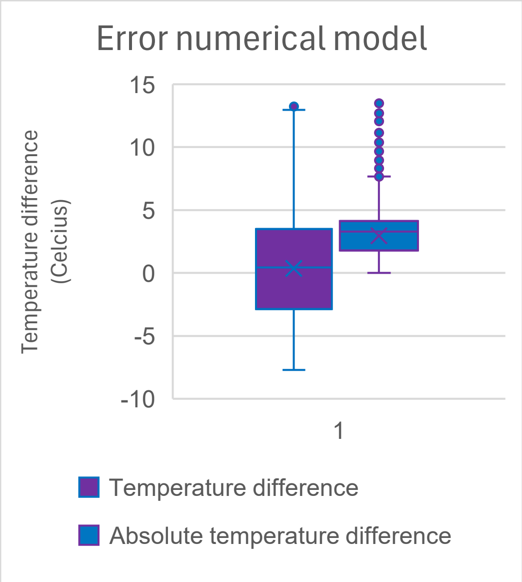

Figure 17 Error of the numerical model compared with the temperature measurements

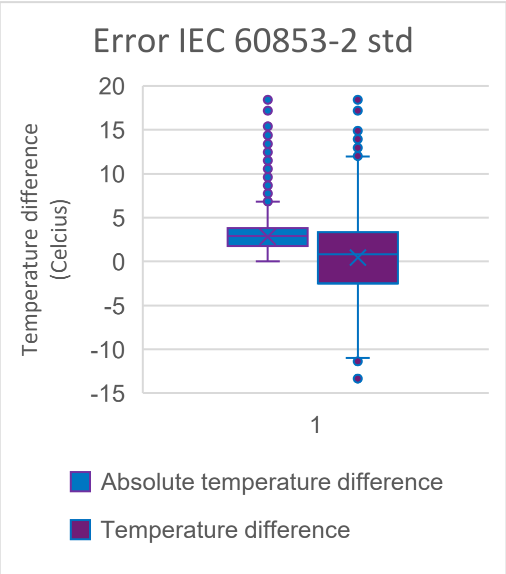

Figure 18: Error of the IEC 60853-2 model compared with the temperature measurements

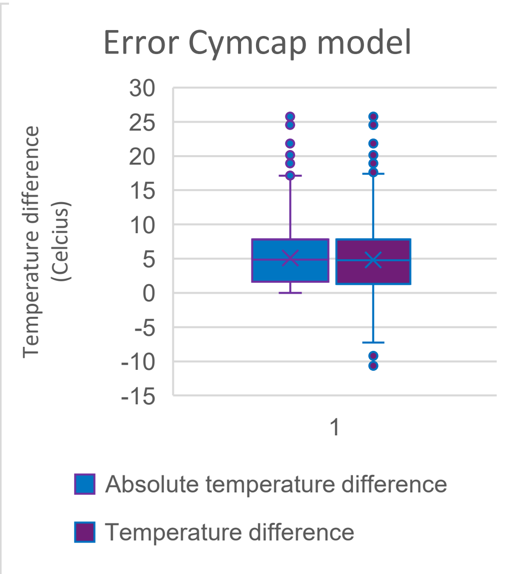

Figure 16: Error of the Cymcap model compared with the temperature measurements .

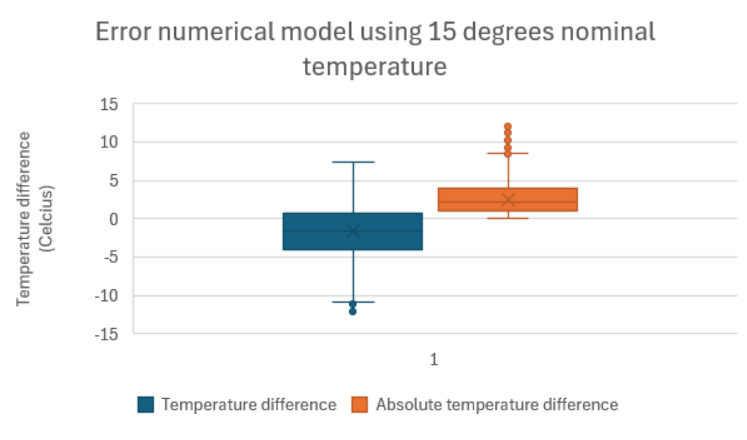

Figure 21: Error of the Cymcap model compared with the temperature measurements.

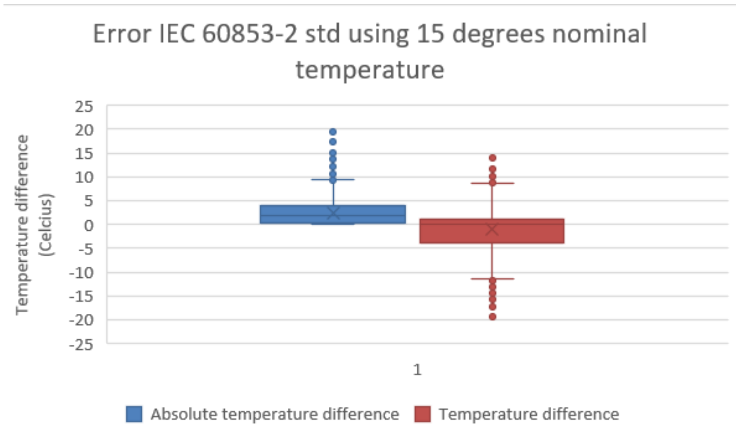

Figure 20: Error of the IEC 60853-2 std model compared with the temperature measurements when the ambient temperature is always 15 degrees Celsius

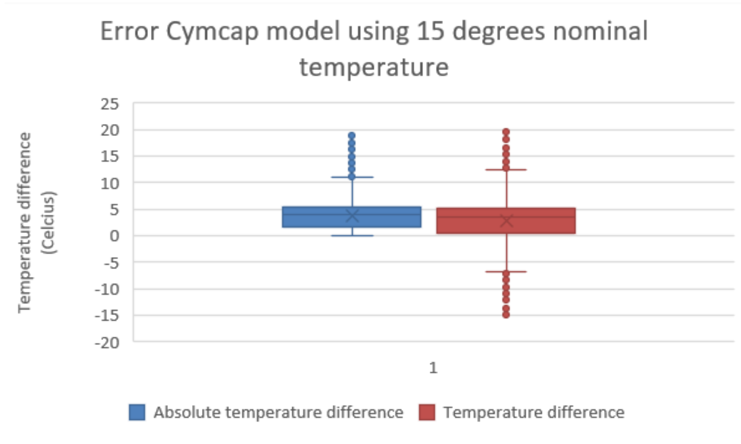

Figure 19: Error of the Cymcap model compared with the temperature measurements when the ambient temperature is always 15 degrees Celsius

3.3.2 Ageing model for ULW-SOS W

In this section, the ageing model results are described for the ULW-SOS W cable. Based on section 3.2.1 the numerical model is the best model to predict the temperature of the cable. Since this model still has an error, this needs to be considered in the degradation model. To see the extent of the error the measured temperature data of 2022 is used as a reference. The measured temperature data has timesteps of one hour, but with some points missing. Therefore, instead of the entire period, the longest period without missing time points was used to investigate the difference in degradation. This period is from 17-5 00:00 until 19-11 19:00.

Next to this measured data, the numerical model has been used on the ULW-SOS W cable. In Tables 6 and 7, the laying conditions of the cable at the measurement location (Houstondreef) and the cable parameters can be found.

In Table 8, the results can be seen for both models. It can be concluded that the degradation is a bit underestimated when using the temperature model. It is now on average 1.66 times lower than it should be. So, to compensate for this difference, the degradation values of the ageing model are multiplied with 1.66 to get a value closer to reality. To verify if the degradation rate difference is only an effect of the difference in ground temperature, the measured data is put to 15 degrees for the entire time and then run through the aging model. This result can also be seen in Table 8. From this table, it can be concluded that this result is approximately the same as when the normal ground temperature is taken it is only 2 percent higher. So, this change in ground temperature does not influence the total ageing over a year a lot.

Table 8: Degradation rate error

	Degree of polymerization	Burst strength	Tensile strength 1	Elongation at break	Fold strength	Tear Strength	Tensile strength 2	Hotspot winding transformer
Using measured temperature data	1.54E-05	8.86E-06	6.69E-06	1.17E-05	6.01E-05	2.28E-05	0.00181	0
Using estimated temperature data	9.30E-06	5.34E-06	4.03E-06	7.02E-06	3.62E-05	1.37E-05	0.00112	0
difference	6.15E-06	3.53E-06	2.66E-06	4.64E-06	2.39E-05	9.08E-06	0.000685	0
Difference in %	166	166	166	166	166	166	161	0
Using ambient temperature of 15 degrees for measurement data	1.56E-05	8.96E-06	6.76E-06	1.18E-05	6.07E-05	2.3E-05	0.0018	0
Difference	6,31E-06	3,62E-06	2,73E-06	4,76E-06	2,45E-05	9,31E-06	0,000679	0
Difference in %	168	168	168	168	168	168	161	

Now that the error of the temperature model is known, it is important to consider that the numerical model is fitted to the ULW-SOS W cable. Therefore, the difference between the fitted and unfitted model should be compared. Such that this extra error can be considered for other circuits which don't have temperature measurements to validate. There are three fitted values: the lambda for the jacket layer, and both the volumetric specific heat for the conductor and jacket layers.

The lambda of the jacket layer was set to a lower value from 0.48 to 0.3. Furthermore, the specific heat of the jacket and the conductor are fitted. They both were 2 $*10^6$ while it is known that copper has a volumetric specific heat of 3.45 $*10^6$ and the one of the jackets is probably also not entirely correct as it consists of multiple layers which not all have the same specific heat.

In Tables 9 and 10, the results can be observed for the unfitted and fitted model. From these results, it can be concluded that the difference on average is 6 % lower degradation when using the unfitted model. However, when the average degradation over all these years is used to find out how much degradation has happened after 55 years, there is in the worst case only 1 % lower degradation for the unfitted model and that is only for model 7 (second tensile strength model). The rest of the models has only a difference of 0.01 %. Hence, this error is very small compared to the error of the temperature model and therefore is not considered.

Now that all the errors are quantified, the model can be run to see what the total degradation is for the ULW-SOS W circuit. In Table 10, the results compensating for all these errors are provided. Besides that, the 41 years of which no loading data is available are estimated using the average degradation rate over the available 14 years.

In Table 11 these results are shown and it can be concluded that the cable insulation degradation has been extremely low using these ageing models except for the tensile strength equation of paper [14]. However, in this paper it was mentioned that the degradation is three times as fast as normal ageing behaviour as during the tests they could not excluded oxygen from effecting the insulation. This also means that it makes sense that the degradation has been higher. However, this shows that for the purpose of this study the degradation behaviour does not match with the lifetime of the cable and therefore will not be considered. Next to this, the hotspot transformer winding equation does not show any degradation whatso ever using equation 3.

This shows that that equation is not a good fit for the hotspot transformer winding model. Because, when looking at the results of the ageing models using the other Equation 4 there was degradation visible for the model of the hotspot transformer winding. The results using equation 4 for all the models were approximately 3 % degradation after 55 years. This is a bit higher than the results of equation 3. However, in equation 3 the reference of what is the end of life is not yet determined. While using equation 4 this is determined. So, the difference between the two can be explained using the fact that they use a different reference.

The result of the model for all other Arrhenius models was expected when noticing that the temperature of the cable does not often reach higher values than 25 degrees Celsius. As this cable was rated for 65 degrees nominal temperature level and the temperature degradation is an exponential function it is logical that the degradation is limited over these 55 years.

So, to validate the model, some tests on a cable have been done to see if there has been any noticeable degradation on the insulation. This is not done on the ULW-SOS W cable, but on the old Vierverlaten - Winsum Ranum black (VVL-WSMR Z) cable. In Chapter 4, the tests can be found and in the next subsection the degradation for the VVL-WSMR Z cable based on the aging model will be described.

Table 9: unfitted model values of ULW-SOS W circuit insulation degradation per year

	Degradation phenomena using the Arrhenius equation							
Year	Degree of polymerization	Burst strength	Tensile strength 1	Elongation at break	Fold strength	Tear Strength	Tensile strength 2	Hotspot winding transformer
2011	2.25E-5	1.29E-5	9.74E-6	1.70E-.5	8.76E-5	3.32E-5	3.00E-2	0
2012	2.26E-5	1.30E-5	9.79E-6	1.71E-5	8.81E-5	3.34E-05	2.96E-2	0
2013	2.32E-5	1.33E-5	1.00E-5	1.75E-5	9.01E-5	3.42E-05	2.90E-2	0
2014	2.61E-5	1.50E-5	1.13E-5	1.97E-5	1.02E-4	3.85E-05	2.89E-2	0
2015	2.78E-5	1.60E-5	1.20E-5	2.10E-5	1.08E-4	4.11E-05	2.85E-2	0
2016	2.39E-5	1.37E-5	1.03E-5	1.80E-5	9.29E-5	3.53E-05	2.76E-2	0

2017	2.48E-5	1.42E-5	1.07E-5	1.87E-5	9.65E-5	3.66E-05	2.72E-2	0
2018	2.09E-5	1.20E-5	9.04E-6	1.58E-5	8.12E-5	3.08E-05	2.62E-2	0
2019	2.17E-5	1.25E-5	9.39E-6	1.64E-5	8.45E-5	3.20E-05	2.99E-2	0
2020	2.26E-5	1.30E-5	9.79E-6	1.71E-5	8.81E-5	3.34E-05	2.96E-2	0
2021	2.72E-5	1.56E-5	1.18E-5	2.05E-5	1.06E-4	4.02E-05	2.96E-2	0
2022	3.52E-5	2.02E-5	1.52E-5	2.66E-5	1.37E-4	5.20E-05	2.99E-2	0
2023	4.09E-5	2.34E-5	1.77E-5	3.09E-5	1.59E-4	6.03E-05	3.00E-2	0
2024	3.78E-5	2.17E-5	1.64E-5	2.85E-5	1.47E-4	5.58E-05	2.99E-2	0
Total degradation	3.77E-4	2.16E-4	1.63E-4	2.85E-4	1.47E-3	5.57E-04	4.05E-1	0

Table 10: fitted model values of ULW-SOS W circuit insulation degradation per year

Year	Degree of polymerization	Burst strength	Tensile strength 1	Elongation at break	Fold strength	Tear Strength	Tensile strength 2	Hotspot winding transformer
2011	2.29E-05	1.31E-5	9.91E-6	1.73E-5	8.91E-5	3.39E-5	3.01E-2	0
2012	3.10E-05	1.32E-5	9.96E-6	1.74E-5	8.96E-5	3.40E-5	2.96E-2	0
2013	2.08E-05	1.36E-5	1.02E-5	1.79E-5	9.21E-5	3.49E-5	2.91E-2	0
2014	2.71E-05	1.56E-5	1.17E-5	2.04E-5	1.06E-4	4.00E-5	2.90E-2	0
2015	2.92E-05	1.68E-5	1.26E-5	2.21E-5	1.13E-4	4.30E-5	2.87E-2	0
2016	2.46E-05	1.41E-5	1.06E-5	1.84E-5	9.53E-5	3.62E-5	2.77E-2	0
2017	2.56E-05	1.47E-5	1.11E-5	1.93E-5	9.94E-5	3.77E-5	2.73E-2	0
2018	2.11E-05	1.21E-5	9.13E-6	1.59E-5	8.20E-5	3.10E-5	2.62E-2	0
2019	2.22E-05	1.27E-5	9.59E-6	1.68E-5	8.63E-5	3.27E-5	3.00E-2	0
2020	2.34E-05	1.34E-5	1.01E-5	1.76E-5	9.08E-5	3.45E-5	2.96E-2	0
2021	2.89E-05	1.66E-5	1.25E-5	2.17E-5	1.12E-4	4.27E-5	2.98E-2	0
2022	4.08E-05	2.34E-5	1.78E-5	3.09E-5	1.59E-4	6.04E-5	3.02E-2	0
2023	4.75E-05	2.72E-5	2.06E-5	3.59E-5	1.84E-4	7.01E-5	3.04E-2	0
2024	4.30E-05	2.47E-5	1.86E-5	3.25E-5	1.68E-4	6.34E-5	2.95E-2	0
Total degradation	4.08E-04	2.31E-4	1.74E-4	3.04E-4	1.57E-3	5.94E-4	4.07E-1	0

Table 11: average degradation and total degradation of the insulation of ULW-SOS W cable

	Degree of polymerization	Burst strength	Tensile strength	Elongation at break	Fold strength	Tear Strength	Tensile strength
Average degradation per year non fitted parameters	2.69E-5	1.55E-5	1.17E-5	2.03E-5	1.07E-4	3.98E-5	2.89E-2
Total life (%) over 55 years non fitted parameters	99.85	99.91	99.94	99.89	99.42	99.78	-59.17

Average degradation per year fitted model	2.87E-05	1.65E-5	1.25E-5	2.17E-5	1.12E-4	4.25E-5	2.91E-2
Total life left (%) over 55 years fitted model	99.84	99.91	99.93	99.88	99.38	99.77	-60.09

3.3.3 Ageing model results for VVL-WSMR Z

The VVL-WSMR Z does not have any temperature sensors placed on it. Therefore, the temperature model has been made based on the available data. This cable was laid in 1970 and is probably taken out in 2020, as then the new cable circuit was put into place. For this cable, there is historical loading data from 2011 until the end of 2019. The laying conditions and cable parameters can be found in Tables 12 and 13. Due to the lack of information, it was not entirely clear what exactly the g value of the ground would have been at the bottleneck of the circuit. However, a study was performed for the new circuit that has found the g value of 1.82 for the worst piece of the circuit. So, it is assumed that this was g value was the same for the old circuit. In Table 14, the results for VVL-WSMR Z can be seen. From this table, it can be concluded that the degradation of the cable has been very low and that the paper should not show any signs of degradation once looking at the paper.

Table 12: Laying conditions of VVL-WSMR Z circuit

Formation	**Distance between cables**	**Thermal resistance of the soil**	**Laying depth of the cable**	**Ambient temperature**	**Far earth distance**
Flatbed	0.4 m	1.82 W/m	1.14 m	15 Celsius	2.5 m

Table 13: Cable parameters of VVL-WSMR Z circuit

Cable type	**Conductor area**	**Conductor diameter**	**Conductor screen thickness**	**Insulation thickness**	**screen thickness**
VBLKod	800 mm^2	0.0405 m	0.00028 m	0.00974 m	0.00042 m
Jacket thickness	**Conductor material**	**Sheath material**	**Jacket material**	**Cabble diameter**	**Sheath thickness**
0.00467 m	Copper	Lead	PVC	0.082 m	0.00466 m

Table 14: degradation of the VVL-WSMR Z cable

	Degradation phenomena using the Arrhenius equation							
Year	Degree of polymerization	Burst strength	Tensile strength 1	Elongation at break	Fold strength	Tear Strength	Tensile strength 2	Hotspot winding transformer
2011	2.67E-5	1.53E-5	1.16E-5	2.01E-5	1.04E-4	3.94E-5	3.07E-2	0
2012	2.77E-5	1.59E-5	1.20E-5	2.09E-5	1.08E-4	4.09E-5	3.03E-2	0
2013	2.83E-5	1.62E-5	1.22E-5	2.14E-5	1.10E-4	4.18E-5	2.98E-2	0
2014	2.80E-5	1.61E-5	1.21E-5	2.12E-5	1.09E-4	4.14E-5	2.92E-2	0
2015	2.81E-5	1.61E-5	1.22E-5	2.12E-5	1.09E-4	4.15E-5	2.86E-2	0
2016	2.79E-5	1.60E-5	1.21E-5	2.10E-5	1.08E-4	4.11E-5	2.81E-2	0
2017	2.86E-5	1.64E-5	1.24E-5	2.16E-5	1.11E-4	4.22E-5	2.77E-2	0
2018	2.92E-5	1.68E-5	1.27E-5	2.21E-5	1.14E-4	4.32E-5	2.72E-2	0
2019	2.81E-5	1.61E-5	1.22E-5	2.12E-5	1.09E-4	4.15E-5	2.66E-2	0
Total degradation over 2011-2019	2.53E-4	1.45E-4	1.09E-4	1.91E-4	9.83E-4	3.73E-4	2.58E-1	0
Average degradation rate	2.81E-5	1.61E-5	1.21E-5	2.12E-5	1.09E-4	4.14E-5	2.87E-2	0
Total life left after 50 years [%]	99.86	99.92	99.94	99.89	99.45	99.79	-43.44	0

3.3.4 Condition indicators

For the condition indicator data, first, the DGA measurements were evaluated. For these measurements it can be concluded that none of the measured cable systems showed signs of high degradation levels. This was even the case when a measurement was taken from a place close to a failure location. In three cases that were measured there is mentioned that it looked like the cable had experienced higher temperature levels. For one of these 3 cases, it was noted after a failure and for the other 2 cases this higher temperature levels had happened during the soldering of the cable cover.

As already mentioned in Section 3.1.2, it is very difficult to conclude much from these DGA tests as there are not many DGA measurements done. However, what can be concluded is that to see the trends of ageing in the cables based on these measurements, TenneT needs to follow the policy they have written. Because in the policy it is stated that every 3 years a DGA measurement must be done on an oil-filled cable. Unfortunately, from the data that was provided for this research it can be concluded that this policy is not followed as only 34 out of the 104 circuits have had an DGA measurement done. From these 34 circuits only 8 circuits were tested in the last 3 years. This could also mean that the test has been performed, but the data is not stored properly. In both cases the policy is still not met.

For the other condition indicators, it is very hard to conclude things about it but what can be concluded is that this data and tests also need to be done more often, or the data needs to be stored better.

3.4 Conclusion of Chapter 3

The most important finding is that the ageing of the LPOF cables has been very limited considering the time the cables have been in the ground.

Furthermore, the numerical model gives the most accurate results for the ULW-SOS W cable even though the temperature model is not validated by any standard from the measured data. However, to ensure that this model is the best option, it should be validated on other cables which have temperature measurements. Moreover, other temperature models can be evaluated to see if those would be a better fit than the now chosen model. These other models can be interesting as even the numerical model still includes an error which leads to an 66% lower ageing compared to the measured data.

The last conclusion which can be drawn from this chapter is that it is very difficult to use the condition indicator data to say something about the status of the cables, as the data is very limited. So, it is important that the policy of TenneT concerning these condition indicators is followed, as either the data is not stored, or the measurements are not preformed. The lack of data makes the group of LPOF cables that misses condition indicator data bigger than for the group for which this condition indicator data is available.
However, looking at the DGA data it could be concluded that there were no signs of high degradation.

4 Testing of the 55-year-old VVL-WSMR Z cable

In this chapter the testing of the old VVL-WSMR Z cable is described. To figure out the remaining lifetime and degradation of the cable tan delta measurements are done. Only these tests were done as there was limited time.

4.1 Sample preparation

The cable was delivered in 6 sections of 0.5 meters. Each cable section has been cut from the same longer cable. This cable is an old cable that has been in service for 50 years. It has been taken out of the ground in 2020 and after that it has been stored for 5 years on a reel under 1 bar pressure. The cable sections then were opened to get samples out of it.

The size of the paper varied from 0.03 mm (most inner layer paper) to 0.25 mm thickness (most outer layer paper). The width of the paper variated from 25 mm to 30 mm. The length of the paper samples could be anything as the paper itself was several meters long. It was important that all the samples where approximately the same size. So, that the test set up could be used for all of them.

The samples were taken form the most outer layer of insulation, halfway the insulation and the layers closest to the conductor. Of each layer 20 sample were taken to perform tan delta measurements at 23 degrees Celsius. Eight samples of the outer layer material, 4 samples for the halfway layer and 4 samples of the inner layer material were tested by increasing temperatures. One sample of the outermost layer material is tested while increasing the voltage level.

4.2 Test set up

For the test set up an IDAX 300 is used This device can measure the dissipation factor, complex capacitance, capacitance, tan delta and moisture DFR. The tested object was placed between two electrodes. The high voltage electrode has a diameter of 30 mm. The ground electrode had a diameter of 25 mm. The whole test set up was placed in an oven and an extra temperature sensor was placed on top of the high voltage electrode. In this way it was made sure that the sample had the desired temperature while doing the tan delta measurements at a higher temperature. This temperature sensor was not connected when testing was done on the higher voltage levels.

In Figure 23 the test set up can be seen. Note that it is not placed in the oven yet. As the first 60 measurements were done at room temperature so there was no need to place it in the oven yet.

The IDAX 300 can supply by itself 200 V to the sample and using a voltage amplifier (Box above the IDAX 300 in Figure 23) the voltage can go up to 2 kV. When the voltage is applied to the sample a current will flow through the sample which will be measured by the IDAX. In Figure 22 the schematic of the setup can be seen.

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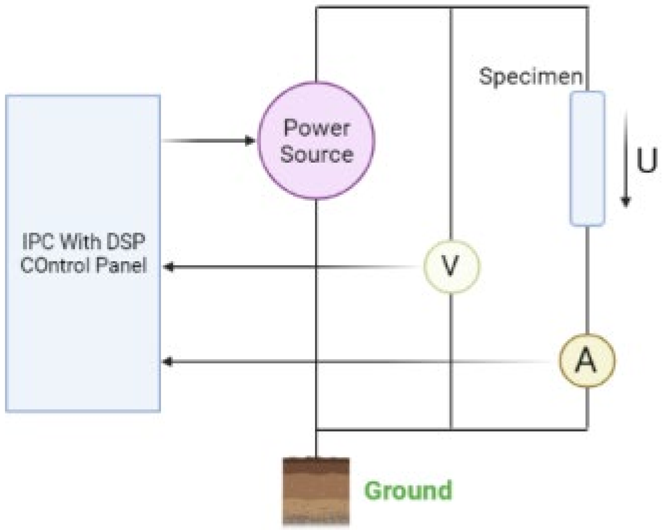

Figure 22: Schematic of setup of the tan delta measurements [23]

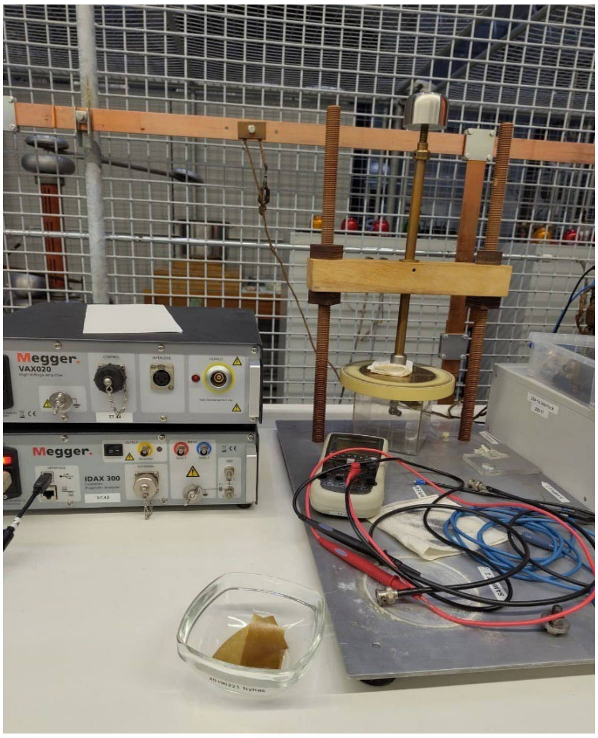

Figure 23: test set up for the tan delta measurements.

4.3 Tan delta measurement results

The tan delta measurements are done on different frequencies. The IDAX 300 determines the tan delta of the sample using the description of the insulation impedance as a capacitance combined with a dissipation factor, tan delta or a power factor. The capacitance, tan delta and power factor are defined as follows [36]:

$$C' = RE\left\{\frac{1}{j\omega Z}\right\}$$

$$PF = \cos(\varphi) = \frac{RE\{Z\}}{|Z|}$$

$$\tan\delta = -\frac{RE\{Z\}}{IM\{Z\}}$$

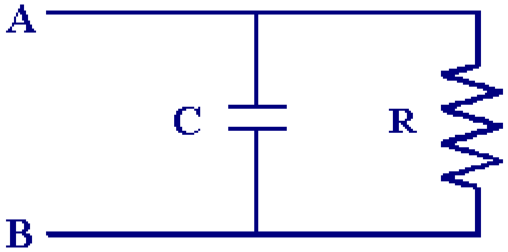

Figure 25: dielectric impedance using a parallel network

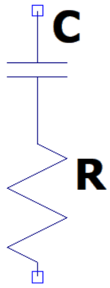

Figure 24: dielectric impedance for using a series network

Were j is the imaginary unit, Z is the insulation impedance that can be either modelled by a capacitor and resistor in series or parallel (See Figures 24 and 25). which can be calculated using Ohm's law:

$$Z = \frac{U}{I}$$

Z, U and I are complex quantities. Where in most cases the tan delta can be described as the angle between the resistive current component of the insulation and the purely capacitive current. Such that using the equivalent circuit of the dielectric the tan delta can be described as:

$$\tan\delta = \frac{1}{\omega RC}$$

There are three effects that create these losses in the dielectric. There is dielectric loss due to conduction, dielectric loss due to polarization and dielectric loss due to partial discharges [37]. So, the tan delta can also be expressed as:

$$\tan\delta = \frac{\frac{\sigma_0}{\omega\varepsilon_0} + \varepsilon''(\omega)}{\varepsilon'(\omega)}$$

Where the $\frac{\sigma_0}{\omega\varepsilon_0}$ represent the conduction dielectric losses and $\varepsilon''(\omega)$ represent the polarization dielectric losses. The conduction losses have a minor effect compared to the polarization losses [37]. So, the behaviour of the polarization dielectric losses is the most important to investigate to understand what is happening with the tan delta.

For the polarization processes of the insulation, it is known that when the frequency decreases more polarization processes can be completed which leads to a higher dielectric loss. While with a higher frequency not all the processes can be finished so a lower loss will be happening [23]. There is however a peak when the highest amount of polarization processes are finished before it becomes higher again. So, it more behaves as a peak. Conduction dielectric losses happen due to charge carriers that respond to an electric field and can overcome a potential barrier between a localized trap. This results in the real part of the permittivity decreasing while the frequency is increasing [23]. However, this effect is smaller for the lowest frequencies than the polarization losses there is however a frequency range in between were the conduction losses have more influence which is clearly shown in chapter 9 of the work of D. Basu and in the work of M. Dong [23] [38].

4.3.1 Results of the tan delta measurements at 23 degrees Celsius

For the different layers of paper, the tan delta is measured to see if there is any difference visible for the degradation of the cable. As the layers closer to the conductor have become hotter than the most outer layers. So, there is expected that the layers closer to the conductor have seen more degradation than the layers farther away.

In Figures 26, 27, 28, 29, and 30 the results can be observed. Each colour represents samples taken on the same day. For the halfway layers it is uncertain if the layers are exactly the same, as an estimate was made when rolling down the paper of what exactly halfway the insulation was. From the results it can be concluded that there is quite a difference in the tan delta even when the same layer is used. One of the reasons for this difference is that not all the tests are done on the same day, but the insulation was exposed to air as the cable was opened when taking the samples during this time which could have let to moisture ingress. From these figures it can be concluded that the outermost layer has the highest tan delta value. Which is probably caused by moisture ingress as the lowest tan delta values are measured at the most inner layer. However, it is not possible to concluded form these test that that some layers of the insulation have seen more degradation than other layers.

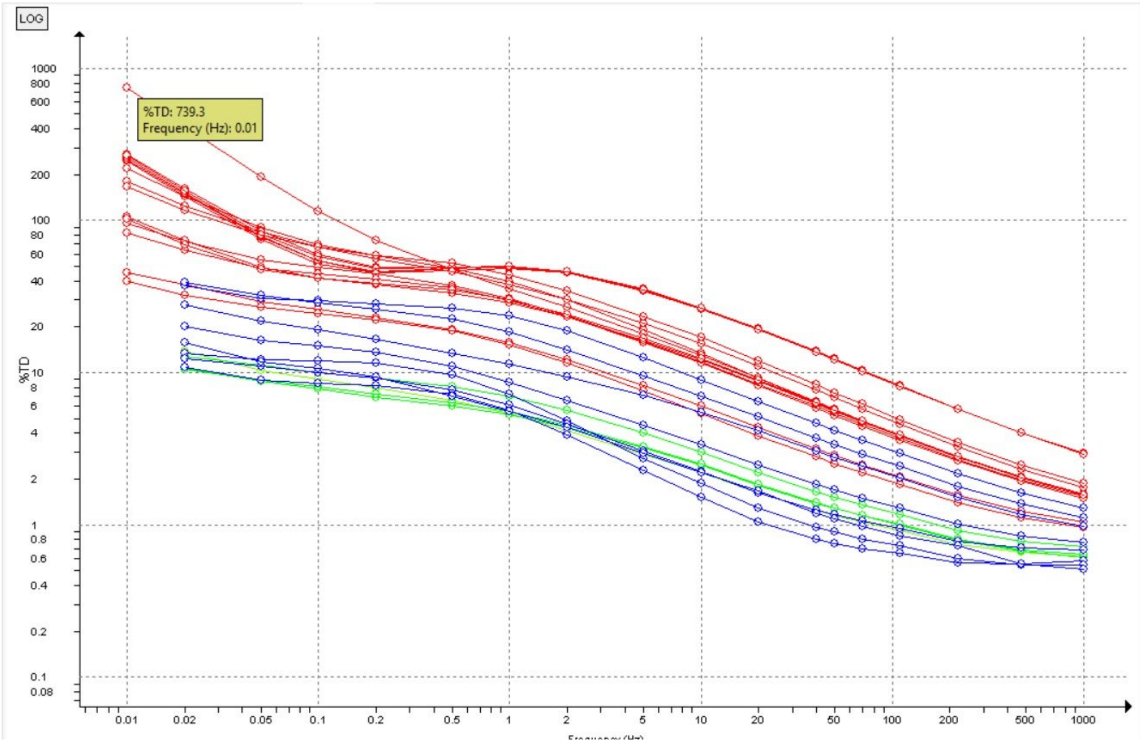

Figure 26: Outermost layer sample 23 degrees

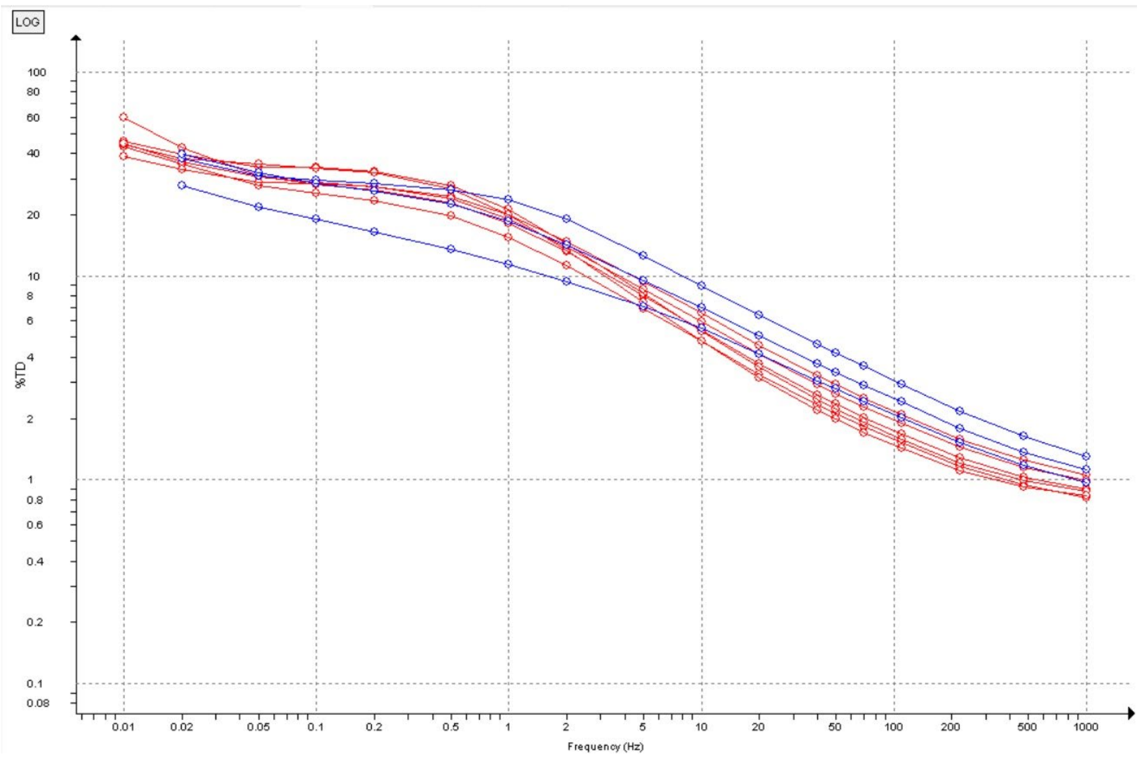

Figure 27: One layer below outermost layer samples at 23 degrees.

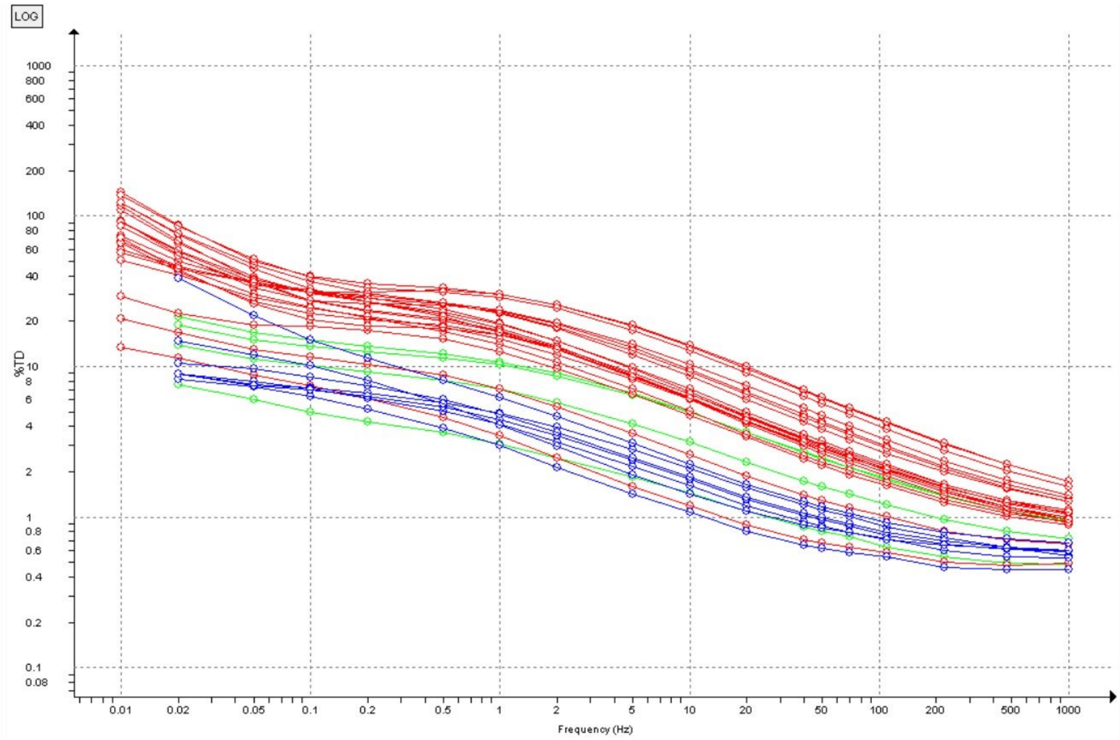

Figure 28: Halfway layers samples at 23 degrees

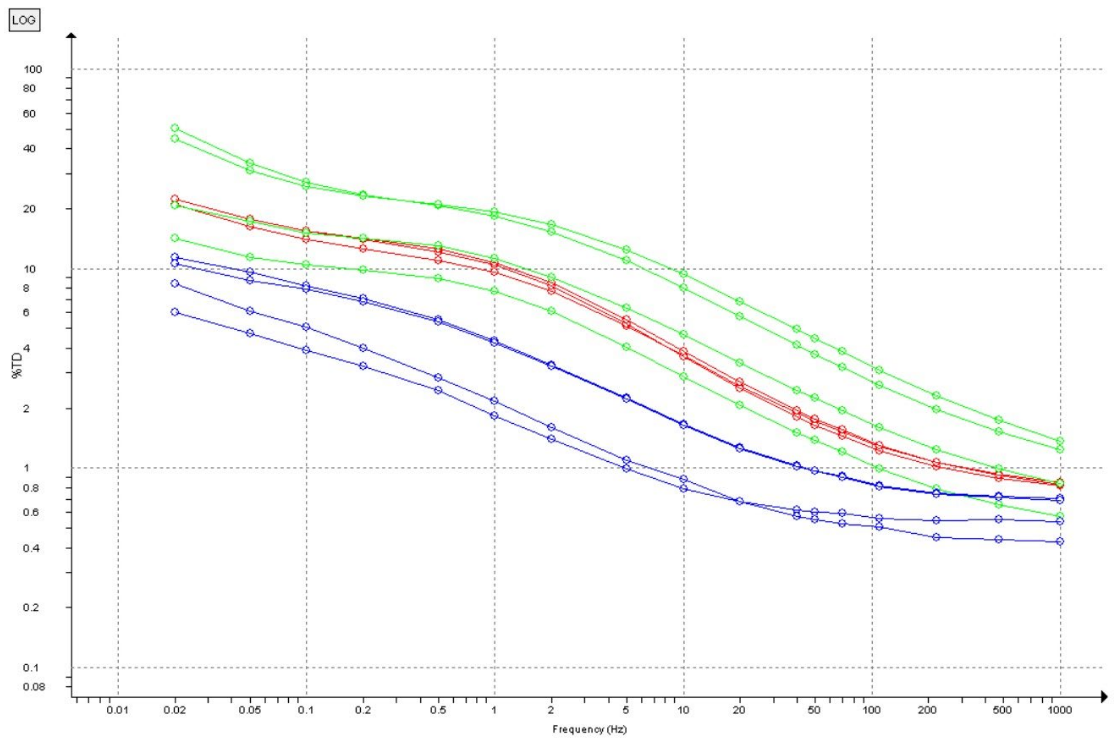

Figure 29: Two layers below innermost layer samples at 23 degrees

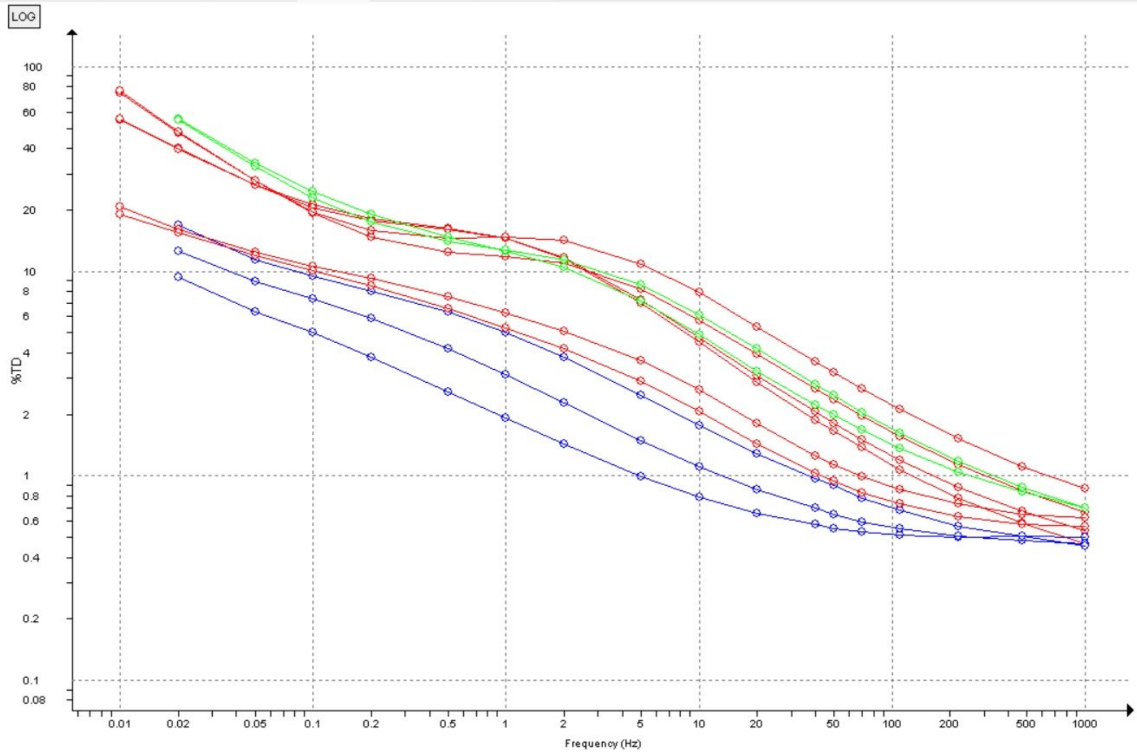

Figure 30: Innermost layer samples at 23 degrees

4.3.2 Results tan delta measurements on elevated temperature

In this section, the results of the tan delta measurements at different temperatures are discussed. All samples were measured at 22 degrees (dark blue lines), 40 degrees (orange lines) and 65 degrees (light blue lines) and the outermost layer samples were also measured at 85 degrees (red lines).

In Figures 31, 32, 33, 34 and 35 the results of the different measurements can be seen. From these figures, it can be concluded that each layer behaves differently when the temperature increases. For some layers the increase in temperature creates higher tan delta values. While for others there is first an increase and after that a decrease in tan delta with an increase in temperature. Another possibility is first a decrease and after that an increase in tan delta. This first behaviour was expected. This is because the oil viscosity becomes lower, which leads to higher ionic motion in the oil, this causes the increase of dielectric loss [39].

This last behaviour can be explained due to free radicals that are in the oil. Free radicals are particles with impaired electron on the last orbital: they can be electrically conductive and contribute to dielectric losses. Their reactivity increases with temperature, and they react with other conductive particles, thus the number of conductive particles decreases [39].

Next to this, there can be noted that the steepness of the graphs starts at a higher frequency when the temperature is higher. This is because there is more energy in the system so the conduction process can be easier completed, so it also has an effect on higher frequencies.

Lastly, there can be noted that the most inner paper behaves a bit different than the other paper layers. This make sense as this paper is different (more transparent) then the other layers. However, from these tests there cannot be concluded that degradation has had an influence on the measurements.

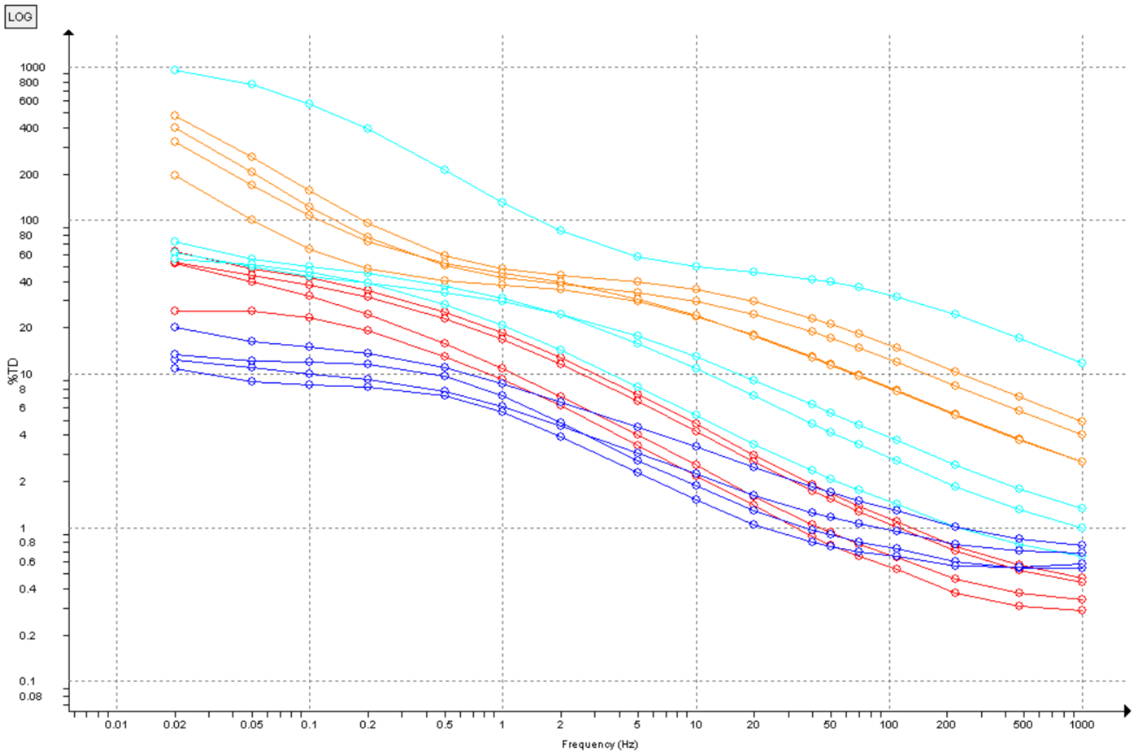

Figure 31: Outermost layer sample at elevated temperatures

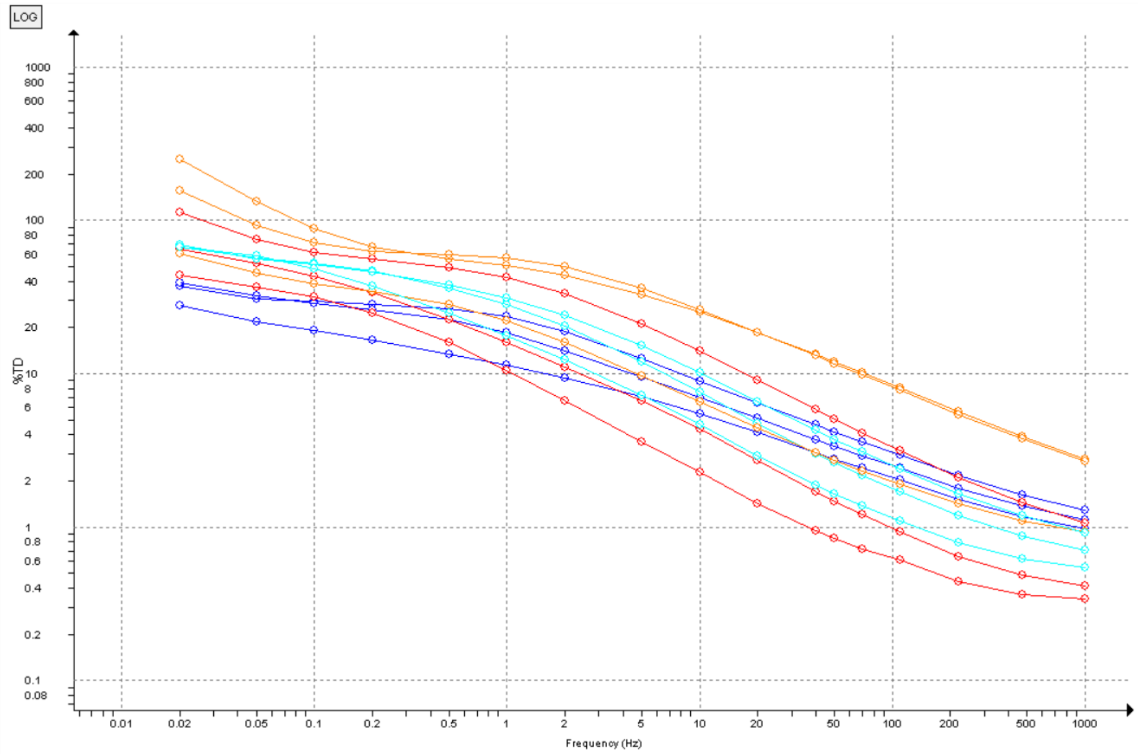

Figure 32: One layer below outermost layer samples at elevated temperatures

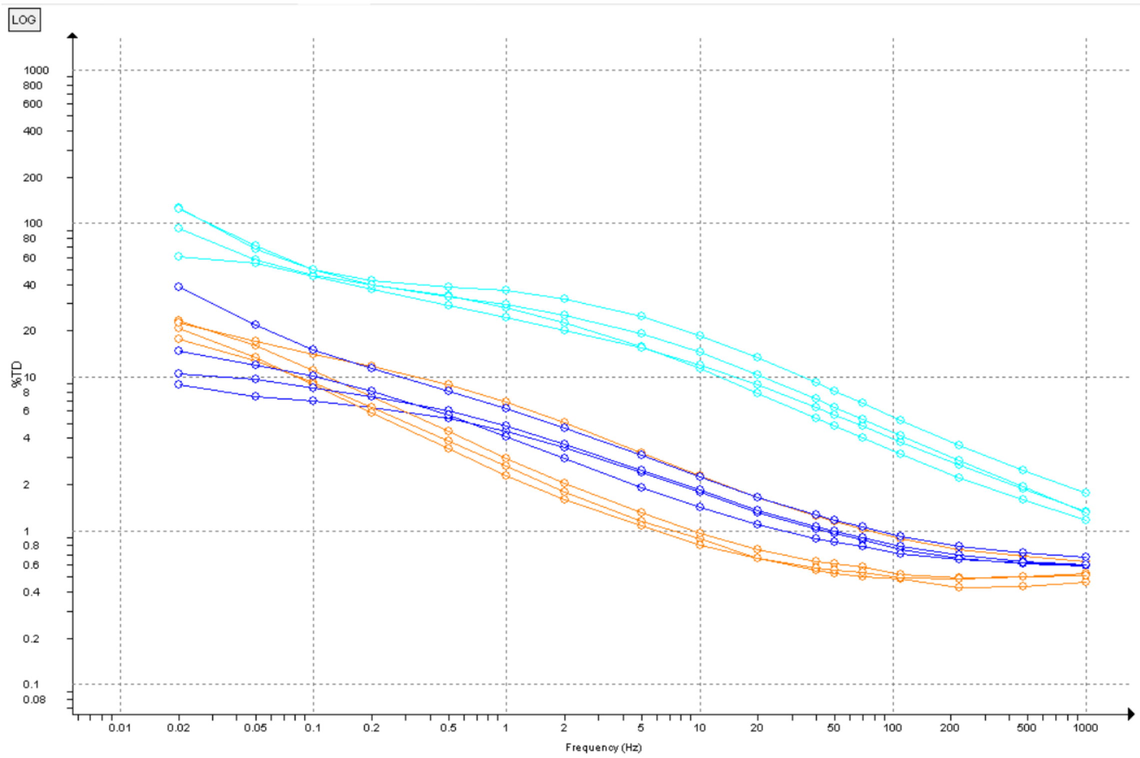

Figure 33: Halfway layers samples at elevated temperatures

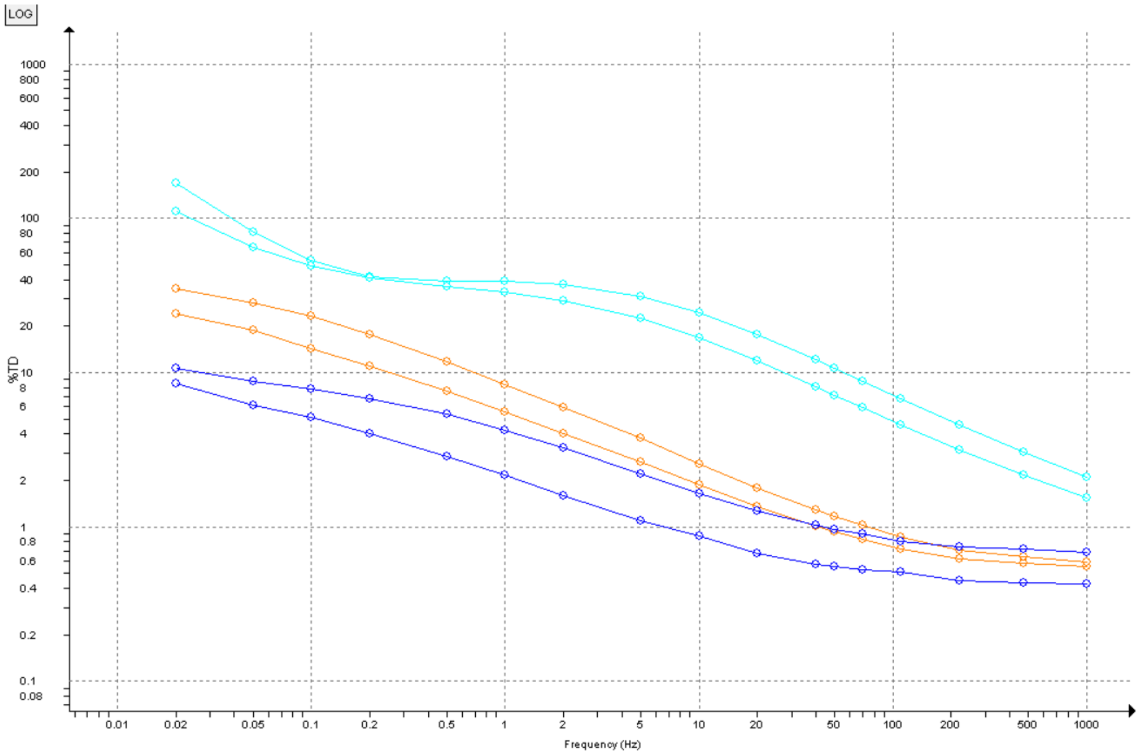

Figure 34: Two layers below innermost layer samples at elevated temperatures

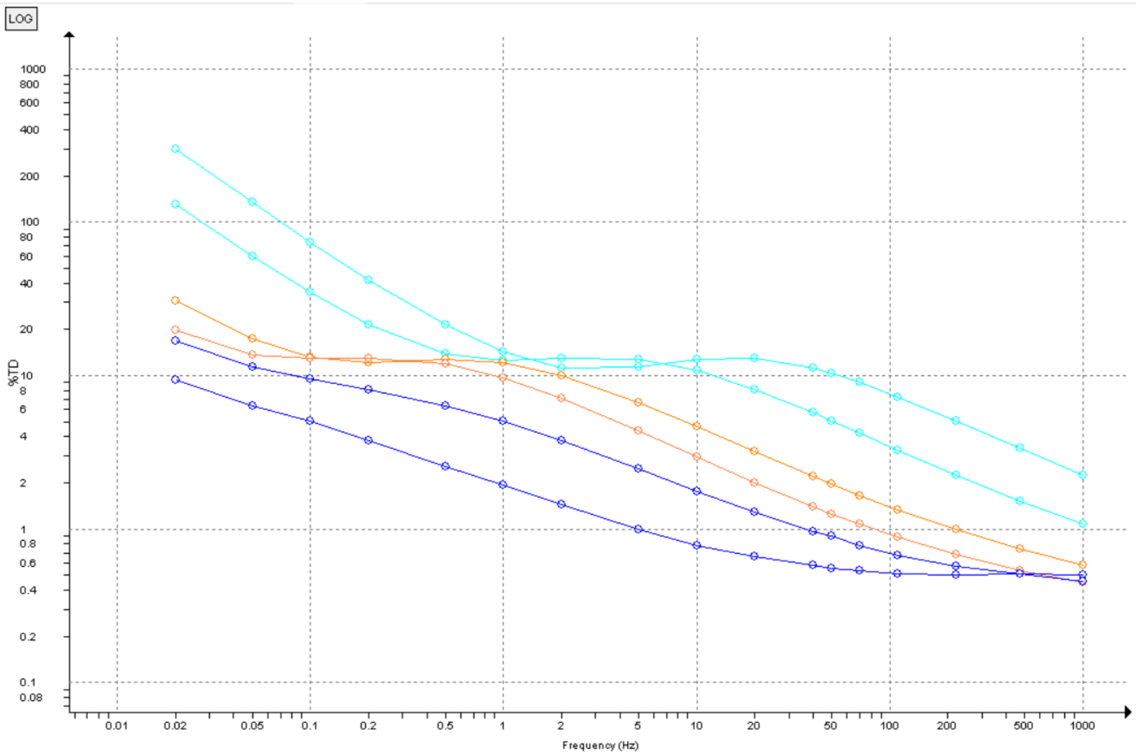

Figure 35: Innermost layer samples at elevated temperatures (transparent paper)

4.3.3 Results tan delta measurements at increasing voltage levels.

The dissipation factor is measured at 0.3-0.6 U_0. This was done to measure the insulation life consumption, as [10] had developed a method to measure the insulation life consumption based on the dissipation factor.

Equation 6 is the equation they developed for this type of measurements and to give an estimation on the percentage of lost life. In Figure 36 the result can be seen for the single sample test that is done on this cable. From this figure it can be concluded that this insulation sample does not show any big difference in tan delta value when the voltage is increased. This was also expected as for non-aged insulation the effect of increase in tan delta should be limited when the electric field is increased [10]. So, using Equation 6 what the insulation loss of this cable would be -0.208 %. This is a negative number so it is not clear if there is something that did go wrong with the measurements or that some of the values need to be between absolute values such that the degradation would become 0.208 %. Even then the degradation would be quite low. And what was stated in the formula is that for less than 10 % the results were not quite accurate. Which can be seen. However, to conclude based on this one sample that the degradation is limited is not appropriate. Thus, some more tests need to be done to verify this result.

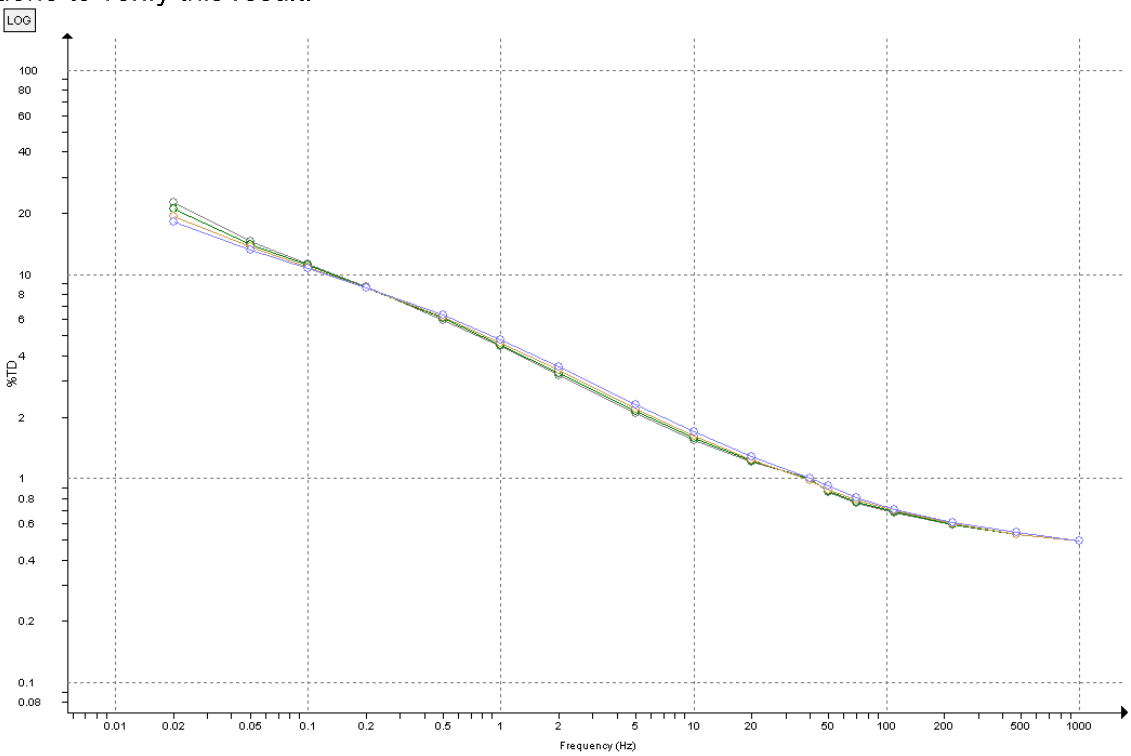

Figure 36: tan delta measurements increasing voltage levels blue lowest voltage level grey highest voltage level.

4.4 Conclusions chapter 4

Even though not much testing could be done, from the performed tests there can be concluded that nothing shows that the cable has degraded very much. However, to be sure that these results are correct more tests should be done. Due to the limited time of the project that was left when testing could be done this was not possible anymore.

What could be done to become more confident of the degradation of the cable are tests that determine the properties used in the Arrhenius equation ageing models (Table 2). Also, an ageing study could be done to see how fast this degradation is happening on the cables and if it still matches the outcomes of earlier research even when using older paper. Instead of the new kraft paper that was used in this paper [2] This would help with getting a better estimation of the degradation of LPOF cables.

5 Cable suitable for extra loading

Now, the ageing model created in Chapter 243 is run for other circuits so that the cables that are suitable for more loading can be identified. Those circuits will be discussed in this chapter.

5.1 Results cable degradation different cable systems

5.1.1 Condition indicators

To look at the influence of condition indicators. It would be wise to check all the condition indicators that could be influenced by higher temperatures to make sure that the cable system will not break due to one of the condition indicators being bad. One thing that could already be noted from Chapter 2 is that a cable that is suitable for extra loading needs to have at least a good sheath as this is one of the indicators that is known to have been a potential hazard for breakdown (See Chapter 2). However, the condition indicator that is being used for the sheath will not tell if the sheath is degraded.

5.1.2 Degradation model

For only 4 circuits both the laying conditions as well as the data sheets of the cable were known. It was discussed what TenneT uses as laying conditions which mostly met the IEC 60287-3-1 standard for laying conditions in the Netherlands. They only sometimes use a lower depth of 1.8 meters, but 1.2 meter is also fine. So, this is used as laying conditions for the cables that have no laying condition information.

There are in total 7 circuits for which the ageing model is run. These circuits are: Vierverlaten – Winsum Ranum, Utrecht Lage Weide – Soest Z and W, Zoetermeer – Leiden W and Z (ZT-LD W and Z), Amstelveen – Bijlmer W (AMV – BZ W) and Amstelveen – Diemen Z (DIM – AMV Z). In Figure 37 the place of these cables can be seen. All the orange lines are the circuits mentioned.

Figure 37: Circuits that the ageing model has run for.

In Table 15 the degradation after the years the cable has been used is shown. From this table there can be concluded that all the circuits can be used for more loading as the degradation has been quite low up until now.

To see how many years they have left at nominal capacity the degradation rates for 85 or 65 degrees Celsius are observed for all the Arrhenius equations are used. Both methods (equation 3 and 4) are used to calculate the degradation. For equation 4 it is only calculated for 85 degrees. The starting value of the life left would then be the degradation determined by the ageing model (so the values in Table 15). The results can be seen in Table 16. From this table it can be concluded that most cables still have at least 93% of their insulation life left. Which gives the same result as was given in Chapter 3. Which means that the cables based on their insulation levels can withstand still at least 47 years even when nominal capacity is applied. However, if the hydraulic system of the cable is also capable to withstand this higher load is still up for debate. Next to this it is also uncertain how the system will react to higher temperature changes over the day, as the cable becoming bigger and shorter due to this cyclic change has another effect on the cable system than a constant temperature.

Table 15: amount of life left (in %) at current age of the cable

Circuit First using the exponential equation of time (method 1) then the reference time equation is used (method 2)	Degree of polymerization Life left (in %)	Burst strength Life left (in %)	Tensile strength Life left (in %)	Elongation at break Life left (in %)	Fold strength Life left (in %)	Tear Strength Life left (in %)	Hotspot winding transformer Life left (in %)
AMV-BZ W 1	99.85	99.91	99.93	99.88	99.41	99.77	-
AMV-BZ W 2	95.89	95.89	95.89	95.89	95.89	95.89	95.11
DIM – AMV Z 1	99.83	99.91	99.93	99.88	99.36	99.76	-
DIM-AMV Z 2	97.02	97.02	97.02	97.02	97.02	97.02	96.42
ULW-SOS W 1	99.84	99.91	99.93	99.88	99.38	99.77	-
ULW-SOS W 2	95.70	95.70	95.70	95.0	95.70	95.70	94.83
ULW-SOS Z 1	99.85	99.91	99.93	99.88	99.41	99.77	-
ULW-SOS Z 2	95.88	95.88	95.88	95.88	95.88	95.88	95.04
VVL-WSMR Z 1	99.88	99.93	99.95	99.91	99.53	99.82	-
VVL- WSMR Z 2	96.75	96.75	96.75	96.75	96.75	96.75	96.07
ZT-LD W 1	99.81	99.89	99.92	99.86	99.28	99.73	-
ZT-LD W 2	95.00	95.00	95.00	95.00	95.00	95.00	93.99
ZT-LD Z 1	99.81	99.89	99.92	99.85	99.25	99.72	-
ZT-LD Z 2	94.81	94.81	94.81	94.81	94.81	94.81	93.78

Table 16: remaining lifetime (in years) of the circuits at nominal loading conditions

Circuit First using the exponential equation of time (method 1) then the reference time equation is used (method 2) and then method 1 at 65 degrees	Degree of polymerization Life left (in years)	Burst strength Life left (in years)	Tensile strength Life left (in years)	Elongation at break Life left (in years)	Fold strength Life left (in years)	Tear Strength Life left (in years)	Hotspot winding transformer Life left (in years)
AMV-BZ W 1	30.97	53.99	71.58	41.03	7.94	20.97	-
AMV-BZ W 2	47.95	47.95	47.95	47.95	47.95	47.95	47.55
AMV-BZ W 1 65 degrees	387.60	675.66	895.72	513.44	99.38	262.43	-
DIM – AMV Z 1	30.97	53.99	71.58	41.03	7.94	20.97	-
DIM-AMV Z 2	48.51	48.51	48.51	48.51	48.51	48.51	48.21
DIM-AMV Z 1 65 degrees	387.58	675.64	895.70	513.42	99.36	262.41	-
ULW-SOS W 1	30.97	53.99	71.58	41.03	7.94	20.97	-
ULW-SOS W 2	47.85	47.85	47.85	47.85	47.85	47.85	47.41
ULW-SOS W 1 65 degrees	387.59	675.65	895.71	513.43	99.37	262.42	-
ULW-SOS Z 1	30.97	53.99	71.58	41.03	7.94	20.97	-
ULW-SOS Z 2	47.94	47.94	47.94	47.94	47.94	47.94	47.52
ULW-SOS Z 1 65 degrees	387.60	675.66	895.72	513.44	99.38	262.43	-
VVL-WSMR Z 1	30.98	54.00	71.58	41.03	7.95	20.97	-
VVL- WSMR Z 2	48.38	48.38	48.38	48.38	48.38	48.38	48.03
VVL- WSMR Z 1 65 degrees	387.65	675.71	895.78	513.49	99.44	262.48	-
ZT-LD W 1	30.97	53.99	71.57	41.02	7.94	20.97	-
ZT-LD W 2	47.50	47.50	47.50	47.50	47.50	47.50	47.00
ZT-LD W 1 65 degrees	387.54	675.60	895.67	513.38	99.33	262.37	-
ZT-LD Z 1	30.97	53.99	71.57	41.02	7.94	20.97	-
ZT-LD Z 2	47.41	47.41	47.41	47.41	47.41	47.41	46.89
ZT-LD Z 1 65 degrees	387.53	675.59	895.66	513.37	99.31	262.36	-

5.2 Conclusions

There are two things that are important to take away from this chapter and that is. All the cables insulation that has been under investigation have at least 93 % of their lifetime left. Which means that they can withstand still almost 45 years at maximum loading or temperature before the end of the lifetime should be reached. However, to be sure that the cable systems can do this the status of the hydraulic system (the sheath and accessories) must be checked. Next to this, it is also uncertain how the system will react to higher temperature changes over the day, as the cable becoming bigger and shorter due to this cyclic change has another effect on the cable system than a constant temperature.

6 Recommendations and Conclusions

6.1 Conclusions

This thesis investigates the lifetime of a low-pressure oil filled cable. This is done by trying to answer the research questions. The first question is: What is the health status of the LPOF cables based on their historical loading profiles and their health index? First, the ageing mechanisms of an LPOF cable were defined. There could be concluded that the most important ageing mechanisms is the thermal ageing of the insulation. However, when looking at the cables of TenneT no cables have failed based on thermal ageing. It was concluded from TenneT's data as well as data of the from other sources that oil leakages are the most noted failure mode. This means that sheath degradation or degradation of the hydraulic cable system is a more important failure mechanism then the thermal degradation for the failing of an LPOF cable system. It makes sense for the TenneT LPOF cables that they don't fail on thermal degradation. This is caused by the redundancy policy of TenneT. Which makes that the cables were not heavily loaded and thus also did not heat up to their nominal values.

To still see what the current effect of the thermal degradation is on the insulation, of the LPOF cable a degradation model has been chosen. The best model that can be used for LPOF cables to describe the thermal degradation is the Arrhenius equation. Other models could not be found with parameters for LPOF cables, or they did not describe thermal ageing.

To be able to use the thermal degradation model the temperature of the cable needs to be estimated. From the three models that have been used in this thesis there could be conclude that the numerical model gives the most accurate results for the ULW-SOS W cable (temperature sensors have been place on this cable). However, to be sure that this model is the best option to use more validation must been done on other cables which would have temperature measurements.

Also, other temperature models can be evaluated to see if those would be a better fit to use than the now chosen model. Because even for the numerical model there is still an error which leads to a 66 % difference in ageing. This is corrected for by multiplying the ageing of the numerical model with this 66%. Using this temperature model with as input 14 years of historical loading data the average degradation rate over these years could be found. Also, an estimation could be made for the total degradation of the cables, even for the years for which no loading data was available.

Using the created ageing model the second research question could be answered. This question is: Which LPOF cables are suitable for more loading?
From this model there could be concluded that the thermal degradation of the insulation of 7 LPOF cables from TenneT has been very limited maximum 7 % even after 50 years of service. However, there are other factors that have influence if a cable is suitable for more loading. One of these is that at least there must be made sure that the

hydraulic system and the sheath of the cable is in a good condition such that it can withstand this higher temperature.

The last question that is answered in this research is: What is the remaining lifetime of cables that are suitable for more loading on this new loading levels? The answer to this question is partly met. As there is given an estimation of what the reaming lifetime is for the insulation of the cable when it would be run continuously on nominal loading levels so that the cable temperature is either 65 or 85 degrees Celsius. This showed that most cables still have a lifetime of almost 50 years within them. However, to say that the entire cable system can do this cannot be concluded from this research.

6.2 Recommendations

From this research a couple of recommendations can be made for future research. First, the temperature model that was used to estimate the temperature based on historical loading data could be investigated using other models. As the model that has been used still gives an error of 66% lower degradation. This could be done in two ways. Either improve the numerical model that was used or use other models that have been found in literature to see what kind of degradation will be happening when these models are used.

To verify in the future if the used temperature model is kind of okay it should be tested on more than one cable system with temperature measurements taken. Also, other types of cables could be tested using this model to see how good the model is.

To verify the ageing model more tests on an aged cable can be done. In this research only the tan delta measurements were done to figure out the degradation of this cable. What could be done to become surer of the degradation of the cable are tests that determine the properties which have been used in the Arrhenius equation ageing models (Table 2). There could then be an ageing study done to see how fast this degradation is happening on the cables. And if it still matches to outcomes of earlier research even when using older paper. Instead of the new kraft paper that was used in this paper [2] This would help with getting a better estimation of the degradation of LPOF cables.

Next to this, there is recommended to make sure that the policy around inspections for the cable systems is followed. For example, it is stated that every 36 Months DGA measurements shall be done on the cable sections. Only for 34 of the 104 circuits that have low pressure oil filled cables DGA measurements were performed. Even for the circuits for which DGA data is available the latest measurements were not done in the last 3 years. It could be the case that the policy is followed but that the data is not properly stored as there are more data quality issues.

When the quality of this data becomes better the trends of degradation could become visible and there would be a possibility to make a better health index. As was concluded, most of the cables still have a lot of life left. So, it would be a good thing to investigate the limits set to the maximum loading levels. To see how hot the cables really become if a certain loading profile is applied to it, even within the limits set by the redundancy policy.

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