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Condition Based Maintenance of Transmission Power Cables

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***Abstract*— One of the issues faced by asset managers in the electric power industry is the condition and remaining life assessment of the high voltage (HV) assets. In contrast to other power equipment, transmission power cables are mainly subjected to corrective maintenance. To support the asset management of service aged transmission power cable circuits, this paper discusses an approach of integrated knowledge rules for condition-based maintenance based on laboratory investigations and field examples. There are very few recent publications on this subject in spite of aging power cable infrastructure; therefore, this paper aims at showing practical applications of condition-based maintenance of this important component of the transmission and distribution systems.**

***Index Terms*— transmission power cable, XLPE insulation, paper-oil-impregnated insulations, cable accessories, failures, reliability, condition-based maintenance, power cables, on-site diagnostic testing, asset management.**

I. Introduction

Referring to the recently published Cigre Technical Brochures [1, 2] the following key points have drawn expert's attention:

1. At a voltage level of 60 kV and above, there are more than 30,000 circuit km of land cables and approximately 6,000 circuits km of submarine cable systems in service at the end of 2015 (AC and DC cables).
2. Land cable systems are the group with the most diversified insulation technology depending on the application (AC or DC) and voltage class.
3. In contrast to other equipment, power cables have the lowest expenditure on predictive maintenance, and the highest expenditure on corrective maintenance.
4. There are more than 700 service failures on land cables reported in the past 30 years, where 2/3 of the faults are internal of which more than 1/2 have been located to the cable itself and 1/3 in cable joints and terminations.
5. The estimation of the average outage times associated with carrying out repairs following a fault was about 3.5 months.

With regard to XLPE cable systems, [1] is reporting that most failures occur within the first 2-3 years of operation and mostly in the cable accessories. After 30 years of operation, most failures are occurring in the cable insulation.

With regard to paper-oil-insulated cable systems, [1] reports that after 30 years of operation most failures are occurring in both cable accessories and cable insulation.

Except for listing diagnostics that could be used on cable systems, none of both recent Cigre Technical Brochures [1, 2] is providing any ready-to-go solutions with regard to effective condition assessment and decision criteria to support condition-based maintenance for both the XLPE- and paper-oil-insulated cable systems.

Summarizing, the for existing cable systems there is a chance of one failure per circa 42 km circuit's length and there are, for service-aged cables, no established dedicated methods and criteria for condition-based maintenance.

The availability and reliability of power cable systems within the transmission network is an important element of the liberalization of electricity markets triggered by:

1. Reduction of the maintenance and investment costs.
2. Maximization of the service life of the existing cable networks.
3. Cost increase of power non-availability, an increase of the reliability of the power supply is required [3].

During the last 20 years, the ongoing development of new more advanced technologies for testing of new cable installations and diagnosis of the service-aged cables took place, [4-10]. In the past years, several papers have been published on the application of the diagnostic data for remaining lifetime estimation of medium voltage cables [11-14]. However, judging by the lack of newly published works dealing with the application of the condition-based maintenance to transmission power cables, it can be concluded that the CBM is not widely applied in practice, despite a great potential of increasing the reliability of the existing cable networks.

Having in mind the above-mentioned situation with shortage on progress in applying innovative solutions for transmission power cables maintenance, this paper discusses the experiences and possibilities to improve the process of condition assessment towards predictive maintenance for service-aged XLPE- and oil-filled power transmission cable systems.

Therefore, the novelty of this paper is not so much in presenting new diagnostics on experimental/laboratory level but in the evaluation of the state-of-the-art in this field and in applying the existing diagnostic techniques for condition assessment towards predictive maintenance of service aged

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transmission power cables.

II. Basic Aspects of Condition Assessment of Service-Aged Power Cable Systems

According to [7] a system or sub-system failure may lead in addition to emergency repair costs as well as to a loss of income or to claims, see Table 1.

According to [15], the cable repair costs could be around 500 €/kV in the event of a failure of a HV cable system. As a result, a repair of a failure in a transmission cable (at 150 kV) might be around EUR 75´000 only.

The average service life of transmission cable networks is 35 to 50 years. Referring to [1, 2], until now less experiences have been collected with regard to:

1. Linking the generic knowledge of insulation aging to the degradation status evaluation of the cable insulation and accessories.
2. Linking this information to the operational reliability and system availability.

TABLE 1: Basic aspects of a responsible operation and asset management of transmission power cables.

Goals of diagnostic- and maintenance testing of operational transmission cable systems	
Source of problems	**Importance**
Operational damages and electrical-, thermal- and mechanical- over-stresses	High: cannot be disregarded e.g., network transients, over-voltages, over-loading, etc.
Aging processes and its assessment	Medium: depending on various operational- and local factors e.g., presence of installation defects, constructions work, environmental conditions, etc.
Lack of knowledge about the remaining life	High: keeping CAPEX and OPEX on an optimal level is the main goal of most asset managers

The above discussion indicates that in case of oldest cables circuits in service strategic decisions have to be taken about maintenance or replacement [16-18].

Having an input of present and future asset performances e.g., technical conditions, degradation processes, decisions about condition-based maintenance and/or replacements can be planned, see Fig. 1. By setting up such approach the following aspects have to be taken in to account:

1. In case of no failures or very low number of failures, statistical predictions are more difficult [17].
2. Insulation degradation is more complicated and further investigations, including field verifications, are needed [17].
3. No general accepted diagnostics are in use for on-site condition assessment [19].

To support the asset management of HV power cable circuits, there is need to develop programmes consisting of implementation of non-destructive diagnostic tools and development of dedicated knowledge rules for condition assessment and decision support, [6, 19-23].

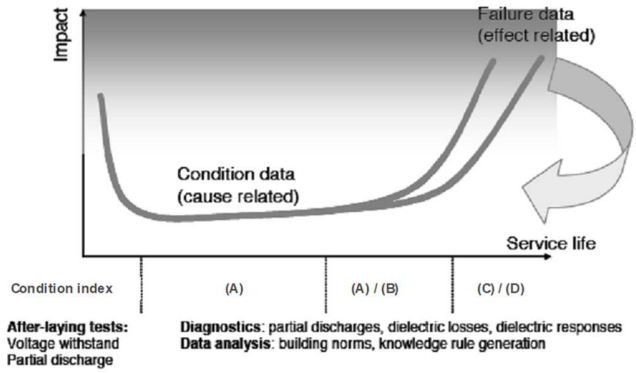

Fig. 1. Schematic behavior of the service life and the importance of condition data analysis [7].

III. Knowledge Rules Generation

If non-destructive methods are used to determine the actual condition of cable insulation, the collecting /monitoring of this data could be helpful in determining the present condition dedicating recommendations for further condition-based maintenance, see Fig. 2.

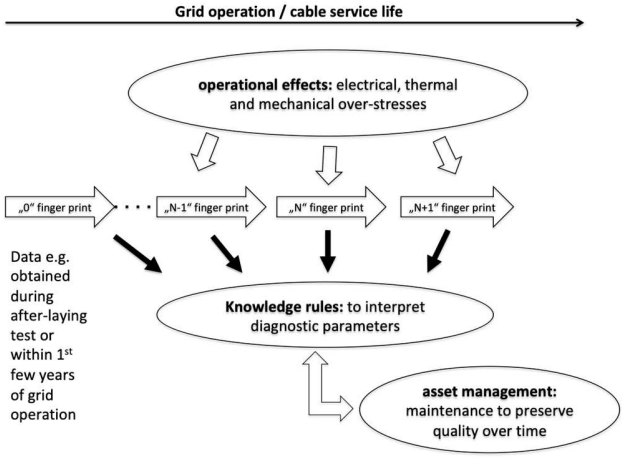

Fig. 2. Basic asset management factors determining condition-based maintenance for a safe and reliable grid operation of power cables. The "finger-print" approach means a cable system quality determination over the overall lifetime by evaluation of diagnostic parameters e.g., partial discharges dissipation factor.

The monitoring of aging processes might be helpful to get an indication about the service availability of individual assets [24]. In particular based on:

- degradation mechanisms,
- the diagnostic techniques,
- categorization of obtained information,

the asset management decision processes can be made regarding condition-based maintenance, see Table 2.

IV. Non-Destructive Diagnostic Parameters

The cable insulation failures could be the result of decreased

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dielectric strength due to ongoing aging processes and/or due to internal insulation defects.

TABLE 2: POSSIBLE CONDITION CATEGORIES AND MAINTENANCE RECOMMENDATIONS FOR POWER CABLES.

Category	Condition	Recommendation	Maintenance goals
A.	New connection Very good condition	No action re-test in 10 years	Minimal maintenance Optimal availability
B.	Health condition	Investigation and/ or re-test in 1 to 5 years	No reliability reduction Maintain optimal availability
C.	Poor condition		Reliability reduction Go to Category B Maintain optimal availability Apply periodical condition assessment
D.	Instable situation	Investigation and/ or re-test in 1 year	Reliability very low Go to Category C Apply failure risk analysis
E.	End of life cycle	Immediate action required	No operation Plan refurbishment and/ or repair and/or replacement No possibility to extend the lifetime

Moreover, independently of the type of the overstresses, whether electrical, thermal, mechanical and environmental, an insulation failure of a power cable is caused by lower dielectric strength (aging) originally initiated due to one of the above-mentioned local overstresses.

From electrical point of view, such abnormalities can be classified to three basic types of discharging sources that are occurring at low pressure-gas (atmospheric pressure):

1. Cavities and de-laminations,
2. Sharp edges,
3. Surface discharges.

Depending on their size, the local electric field and other acceleration mechanisms e.g., network transients, harmonic overvoltage, thermal cycling and mechanical overstresses, those defects may develop (degrade) till eventually a breakdown occurs, see Fig. 3.

For all those defects, the Paschen law inception mechanisms with a Paschen minimum of circa 327 V at 7.5 µm distances are valid for creating start electrons and for both the ionization- and feedback processes. The start of partial discharges is a self-supporting process.

After getting a start electron by external causes e.g., field emission, cosmic radiation, these external causes are not needed anymore to keep the discharge process active [21-23]. The stress demand for further development is defect type related. For example, after inception the demand for surface discharges is in the range of 1kV/mm. And for partial discharges at sharp edges of 50 µm, about 500 V are needed to keep the PD process ongoing.

Furthermore, higher PD intensity e.g., 100 PD pulses / cycle of 50 pC will result in a dissipation factor increase of 10 x 10^{-3} [25, 26].

Considering the aging of power cables insulation, partial discharges (PD) and dissipation factor measurements (tan δ) have to be included. It is known, that there is a frequency dependency of the loss-factor tan δ, see Fig. 4.

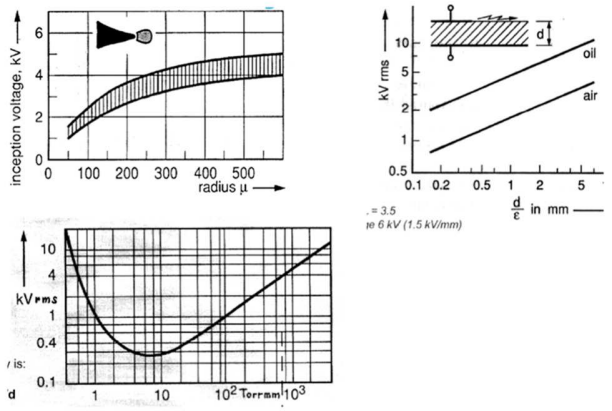

Fig. 3. Partial discharges occurrence of basic types of discharging insulation defects in function of the electric field conditions [21, 22].

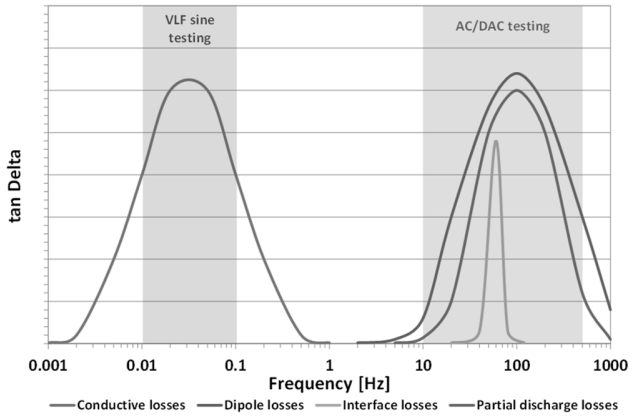

Fig. 4. Types of typical losses in relation to the voltage frequency. Dipole losses, interface losses and partial discharge losses are dominant in the frequency range of the AC and damped AC (DAC) testing (20-300Hz) and the conductive losses are dominant in the frequency range of very low frequency (VLF, below 1 Hz) sine testing.

Dielectric material is characterized by an arrangement of electric charge carriers that can be displaced by an electric field. To compensate for the electric field the charges become polarized. Moreover, insulation material has several dielectric polarization effects that contribute to the permittivity and the dielectric losses. As a result, defects related to common types of dielectric losses are:

1. Insulation ageing represented by the dipole losses (detectable with tan delta measurement above 10 Hz). Water treeing represented by conductive losses (detectable with tan δ measurement below 1 Hz).
2. Interface problems between materials represented by interface losses (detectable with tan δ at 50/60 Hz power frequencies).

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3. Partial discharges with high intensity and large amplitude cause an increase in the loss factor.
4. As the location with higher dielectric losses in power cables cannot be determined, the detection of high intensity discharging defects (producing an increase of the dissipation factor) is a valuable tool helping to accurately localize these sites at voltage frequencies above 10 Hz.

In [20, 24] the application of dissipation factor diagnosis (tan δ) is shown, to develop a model for decision support. The increase of tan δ as a function of the electrical stress e.g., during onsite testing, and increase of tan δ as a function of temperature e.g., due to the increase of cable load during operation, could be used as indicators of insulation degradation, see Fig. 5.

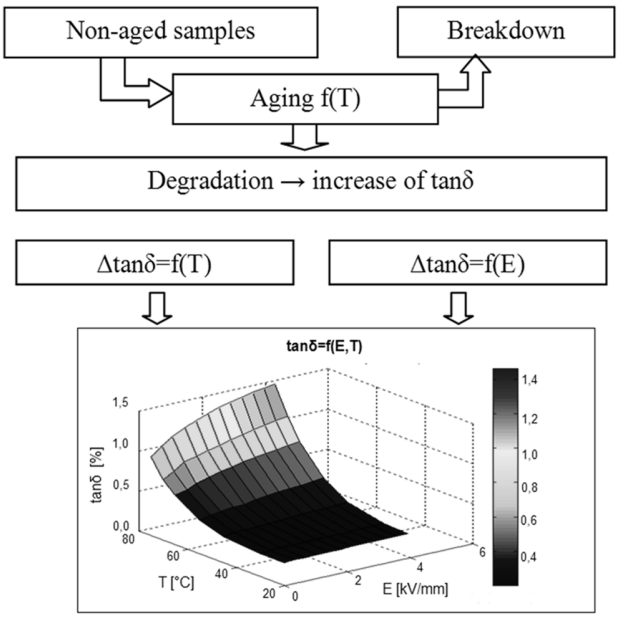

Fig. 5. Experimental results of modeling the dependence between dissipation factor tan δ and the thermal and electrical stresses for oil-impregnated aged insulation [24].

Based on this data, the dependency of relative tan δ_R on the applied voltage can be calculated by:

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

This relative tan δ is used to present different level of life consumption of the insulation, see Fig. 6.

As a result, while traditional voltage withstand testing [25-27] only indicates "passed" or "not passed" in a destructive way [18], measurement of partial discharges and dielectric properties e.g., dissipation factor are valuable indicators of the quality level of cable insulation [20, 28].

In particular:

- To prevent failures caused by local insulation defects, onsite partial discharges diagnosis based on quantities related to insulation degradation has to be used.
- To prevent failures caused by ageing of the impregnated bulk insulation properties e.g., dielectric losses measurement has to be used [24].

According to [8, 9] the results of these non-destructive diagnoses show a direct relation to the average level of quality of the insulation at the time of the diagnostic measurement. Moreover, it can be used as a trend- or fingerprint measurement. In TABLE 3 lists most known diagnostic parameters that can be used for the condition assessment of the cable insulation.

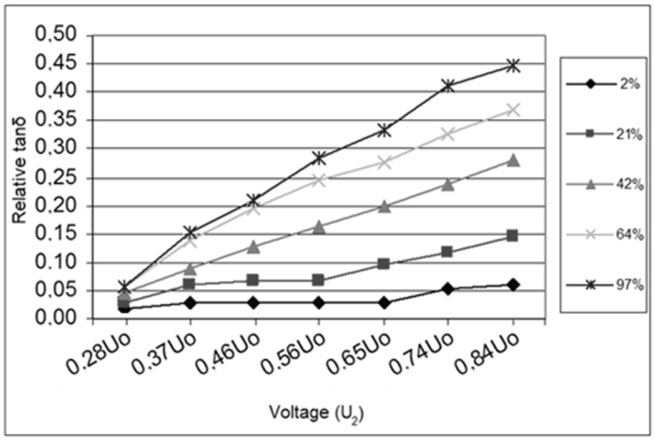

Fig. 6. An example of relative tan δ parameters as measured in function of the electric stresses at different stages of the life consumption in % [28].

TABLE 3 CHARACTERIZATION OF ON-SITE DIAGNOSTIC PARAMETERS FOR POWER CABLES.

Condition assessment	Type of diagnosis	Important parameters
Weak spots in cable insulation and in cable accessories	Partial discharges [IEEE 400.3, IEC 60270, IEC 60885-3, Cigre TB 502, IEC 62478, Cigre TB 444, Cigre TB 662]	PD inception voltage (PDIV) PD extinction voltage (PDEV) PD magnitude at voltages up to e.g., 1.7 Uo PD intensity and PD location PD patterns
Cable section integral condition of the insulation	Dielectric losses [IEC 60141, IEEE 1425, Cigre TB 627]	Tan δ at voltages up to e.g., 1.7 Uo Δ tan δ (tan δ increase) up to the maximum test voltage level

In the following section, based on experiences as collected for both the XLPE- and paper-oil-insulated cable systems, these parameters will be discussed and used to support decision about condition-based maintenance.

V. BACKGROUND OF CONDITION ASSESSMENT AND ASSET MANAGEMENT OF SERVICE AGED CABLES

Remaining life management of transmission power cables (e.g., 132kV, 230kV, 400kV) deals with a complex issue, consisting of a combination of technical, strategic and economic factors. The process of service ageing depends on the operating mode of the power cable and on the local environment; the so-called TEAM-factors (temperature, electrical stress, ambient conditions, mechanical stress) [29].

Various characteristics may indicate that a component will reach its technical end of life because of:

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- Increased measured deterioration.
- Increased number of failures.
- Failures of similar components with the same age.

The degradation of the solid insulating materials is influenced by individual cable service conditions such as: cable load, the number and the type of the existing insulation defects developing during service life, maintenance quality and environmental influences such as soil thermal resistivity, over-voltage conditions.

Failures triggered by service aging are the result of cable service stresses such as (as shown in Fig. 7.):

- Electrical stresses
- Thermal stresses
- Mechanical stresses
- Environmental stresses.

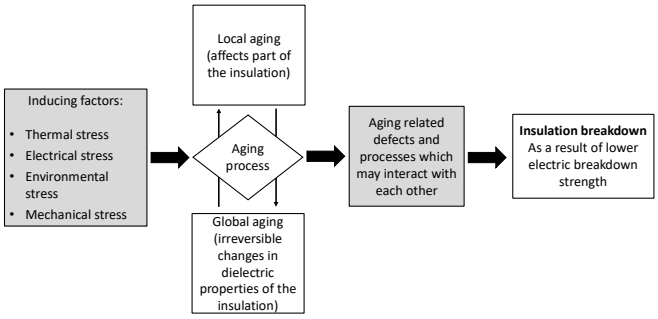

Fig. 7. Aging factors of (Extra) High Voltage cables

Three types of degradations can describe degradation of cross-linked polyethylene (XLPE):

- Chemical changes of insulation and/or trapped charges,
- Physical changes (irreversible degradation of the dielectric insulation structure),
- Electrical aging (tracking, cracks, electrical treeing).

At the normal operating maximum temperature, below 90° C XLPE and EPR insulated cables are not affected by thermal degradation [37]. When XLPE insulation is exposed to temperatures above 130°C (e.g., due to overloading) gasification might occur. However, this will not directly affect the insulation breakdown strength [33]. The degradation due to increased operational temperatures might take place when XLPE insulation will be subjected to thermal cycling at high temperatures. Such thermo-mechanical stresses will be generated by the expansion and the contraction of the insulation.

Aging of the paper-oil insulated cables is related to thermal, electrical and mechanical stresses. This aging process is related to a combination of the different stresses acting during the cable service life such as thermal aging, oxidation and hydrolytic degradation.

For paper-oil insulated power cables, degradation due to moisture is the major mechanism leading to irreversible lowering of the breakdown strength of the paper-oil insulation. The above-described insulation ageing processes are generally also applicable to cable accessories (joints, terminations). The ageing mechanisms of cable accessories are mainly related to:

- Electrical stresses, leading to discharging defects,
- Moisture ingress,
- Mechanical stresses,
- Thermal stresses.

To obtain the overall technical condition of the cable circuits and to evaluate the ageing factors for paper-oil insulated cables (as far as detectable with electrical tests), the following diagnostic test should be performed and the results evaluated in relation to international guidelines [23, 33-37]:

- High voltage testing;
- Partial discharge measurement with localization;
- Dielectric losses by the dissipation factor (tan δ).

To evaluate the operational conditions of the cable, the historic cable loading data as well as the failure statistics are taken into consideration. The overall evaluation flowchart is shown in Fig. 8.

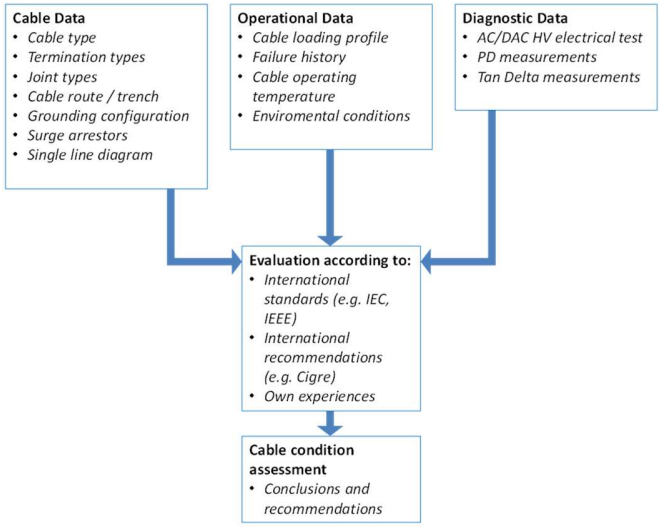

Fig. 8. Evaluation flow chart to obtain the cable condition

For the condition assessment non-destructive testing is required that provides deterministic values of partial discharge (PD) activities in the cable system as well as the dissipation factor (tan **δ**) of the overall cable system. Those technical parameters provide the main indicators for the overall cable condition assessment.

The different PD and tan **δ** properties can be taken into account for the determination of the insulation quality of all cable components like cable insulation, cable terminations and joints.

The obtained diagnostic values (PD and tan **δ**) will be evaluated by taken into account the following rules for PD:

- Is internal PD present in the cable insulation or in the cable accessories?
- Is the PD concentrated at a location?
- What is the PD inception voltage?
- What is the PD magnitude, in calibrated pC values?
- What is the PD increase in function of the test voltage?
- How does the phase resolved PD look like (defect characterization)?

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And for tan **δ**:

- How are the measured tan **δ** values in relation to the values known for new paper-oil insulation?
- Can an increase of tan **δ** values (tip-up) be seen in relation to the increasing test voltage level?
- How are the measured values in relation to the other phases and circuits?
- Based on the maintenance history, the operational- and insulation- life consumption what is the future life estimation?

The overall approach of the diagnostic tests and the evaluation of diagnostic parameters will be evaluated and combined for the insulation condition assessment in one of three classes, in line with Table 2:

- Good (No action):
  - No breakdown occurred during diagnostic testing.
  - No internal PD activity has been observed up to the maximum test voltage level.
  - The tan **δ** values are below 0.1% and stable in relation to the applied test voltage level.
  - It is advised to evaluate the cable condition again within 10 years.
- Medium (Investigation):
  - No breakdown has been observed.
  - Internal PD activity has been observed with an inception voltage above Uo and a level below 100 pC in one or more phases and/or,
  - Tan **δ** values higher than 0.1% have been measured in one or more phases and/or,
  - Tan **δ** an delta tip-up up to 0.05% has been seen with increasing test voltage level in one or more phases.
  - It is advised to monitor the cable condition and measure again within 1 - 5 years. If the PD inception voltage is only slightly above Uo and/or the tan delta is higher than 0.2% together with a tip-up of more than 0.05%, it is advised to test again within a 1-year period.
- Bad (action required):
  - Internal PD activity has been observed with an inception voltage below or equal to 1.0 Uo in one or more phases and/or,
  - Tan **δ** values significantly higher than 0.2% have been measured in one or more phases and/or,
  - Significant tan delta tip-up of more than 0.05% has been seen with increasing test voltage level in one or more phases.
  - It is advised to schedule maintenance / replacement actions.
- Bad (immediate action required):
  - Insulation breakdown has been observed
  - Internal PD activity has been observed with an inception voltage below or equal 1.0 Uo in one or more phases and/or,
  - Tan delta values significantly higher than 0.2% have been measured in one or more phases and/or,
  - Significant tan **δ** tip-up of more than 0.05% has been seen with increasing test voltage level in one or more phases.
  - Repair and more dedicated maintenance / replacement assessment.

As a result of the above information a basis can be defined to support the condition-based maintenance (CBM), see Fig. 9.

The measured partial discharge values and the PD evaluation together with the tan **δ** values are used as input for statistical analysis to obtain, for a particular type of cable insulation, the boundary values. These boundary values can be used for cable condition indexing.

Based on these boundary values, a five-level condition index is composed. The boundary values are used to provide a condition index that is indicated with a number and color:

- ✓ Index 9; very good (green)
- ✓ Index 8; good (light green)
- ✓ Index 6: moderate (yellow)
- ✓ Index 3: poor (orange)
- ✓ Index 1: very poor (red)

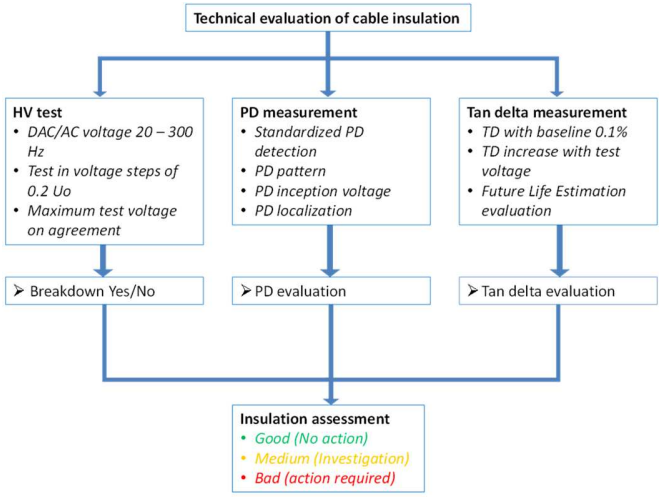

Fig. 9. Cable insulation condition assessment approach.

This is done for the PD and for the tan **δ** evaluations. For each phase of a cable circuit at the different voltage levels, the condition indexing can be obtained for the four main PD and tan **δ** parameters. Eventually, these values are combined to obtain an overall condition index per phase, Fig. 10.

	Phase		
Condition parameter	**L1**	**L2**	**L3**
Concentrated PD	9	6	1
PDIV ≤ Uo	9	9	1
PD amplitude at PDIV	9	6	3
TD evaluation	8	8	8
Overal cable rating	**9**	**6**	**3**

Fig. 10. Example of statistically obtained condition indices for the PD and tan **δ** evaluation for the condition indexing levels for a XLPE 220 kV cable.

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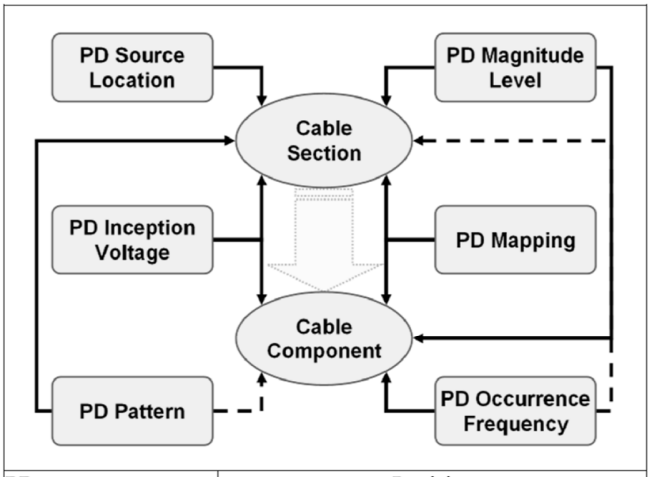
A. Example of PD & tan δ evaluation XLPE cable incl. future life estimation

Determination of the life consumption and future life estimation of an XLPE insulated cable can be based on the parameters also used for the condition indexing. As XLPE insulation is not sensitive to the thermal ageing, as long as the maximum conductor temperature is not exceeded, this parameter does not play a role in the life consumption, which is the case with paper-oil insulation. If XLPE insulated cables are overheated, this can lead to a deformation of the insulation layer and eventually resulting in a breakdown of the polymer chains, baking and carbonizing of the insulation.

Ageing of XLPE insulation is more dependent on local defects in cable insulation or cable accessories that can be represented by partial discharges. If the insulation has any defects caused by deterioration, additional stresses imposed by over-voltages can initiate the breakdown in the entire thickness of insulation. The PD properties, as indicated in Fig. 11, are evaluated to obtain the condition index that can be further used to obtain the current degradation rate. In Fig. 12, examples are shown how the CBM parameters can influence the degradation rate of a XLPE insulated cable.



PD property	*Decision*	
PD inception voltage	*< experience norm*	*> experience norm*
PD source location	*cable accessories*	*cable insulation*
PD mapping	*concentrated PD*	*scattered PD*
PD magnitudes level	*> experience norm*	*< experience norm*
PD intensity	*> experience norm*	*< experience norm*
PD pattern	*symmetric*	*a-symmetric*

Fig. 11. The direct and in-direct derived PD properties obtained from a cable system that are taken into account for the determination of the degradation rate

In this example from Fig. 12, it can be seen what the past degradation rate is up to the current service age of the cable and what the expected degradation rate will be in the future taking into account the different outcomes of the diagnostic parameters evaluation scenarios.

The first part of Fig. 12 is a single red line (squares) that shows at the moment of the 10th service life the past degradation of the cable. This line is based on a linear degradation over a period of the total lifetime of 30 years. After performing condition-based maintenance, the actual condition of the cable can be obtained.

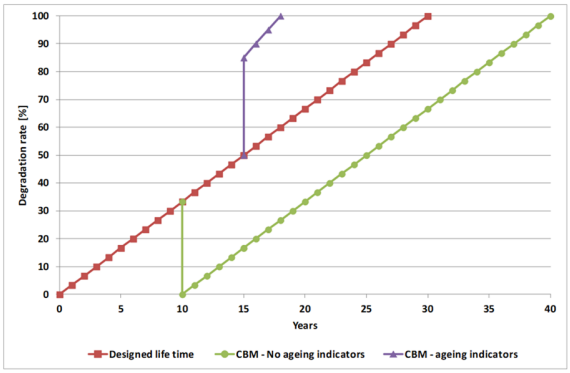


Fig. 12. Practical example of future life estimation of a 220 kV XLPE power cable (length about 1 km, age 15 years) based on a technical lifetime of 30 years. At the moment condition-based maintenance is performed, the future life estimation is adjusted based on the diagnostic parameters.

The green line (dots), shows the future life estimations when the partial discharge and tan delta evaluation would be performed after 10 years of service operation. The condition index based on these parameters shows a very good cable condition. In that case, the cable is defect free and can be considered as in new condition. The actual insulation degradation is lowered to the level of a new cable. The degradation line can be redrawn (green) similar to the line of a new cable, which means that the lifetime is extended to 30 years, calculated from the actual age of the cable. When the CBM is repeated again after e.g., 15 years, the degradation line can be adjusted according to the outcomes of the condition evaluation.

The purple line (triangles) shows the future life estimations after the partial discharge and tan delta evaluation have been performed after 15 years of service operation. The condition index shows a poor cable condition. In that case, the cable has shown localize concentrated PD activity in one of the termination, which indicates a defect in the cable accessory that is active under normal operating conditions. The cable can be considered to have a higher degradation rate as the assumed 50% after 15 years of service operation. The actual insulation degradation is increased to the level of an older cable, e.g., with a lifetime of 25 years, and it can be expected that because of the insulation degradation, the cable cannot reach its designed lifetime. The degradation line is drawn from that point with a steeper slope compared to the line of the new cable. This means that the lifetime is shortened to only 18 years, which is 3 years calculated from the actual age of the cable. In this case, it is advised to monitor the situation or to take the adequate action.

B. Example of PD & TD evaluation oil-filled cable incl. future life estimation

An aging model can be used to determine parameters such as the estimated life consumption and the future remaining life estimation of oil-impregnated paper insulated cables [37, 38]. The relative tan **δ** changes linearly with the test voltage and hence the life consumption. As a result, the relative tan **δ** value, which is measured at ambient temperatures during the on-site

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diagnosis, is used to estimate the life consumption of the oil-impregnated paper insulation. Secondly a method is used based on thermal aging and the Arrhenius Law to diagnose the operational life consumption of the insulation.

The thermal degradation and the result of the life consumption calculated by the relative tan **δ** values is incorporated for the future life estimation. Fig. 13 shows the flow chart of the data analysis structure to estimate the future life. The insulation life consumption (ILC), which is obtained from the measured tan δ values and the operational life consumption (OLC), obtained analyzing the yearly degradation based on the cable loading, are used to obtain the current total life consumption (TLC).

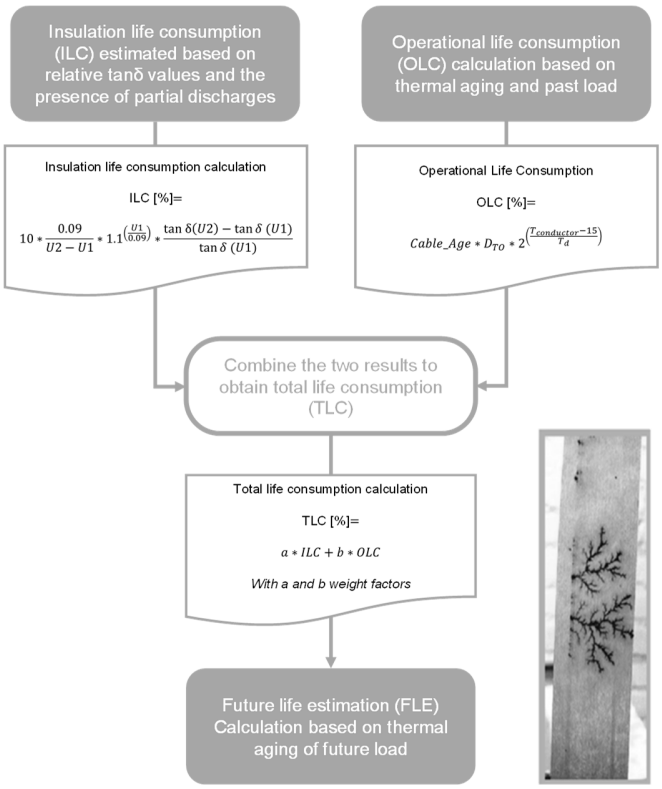

Fig. 13. Principal process to determine the life consumption and future life estimation calculations

Using both relative tan **δ** value and thermal aging the calculation of the life consumption can be done. Then the two results can be combined by giving different weights to the results. At the end, the life consumption result and thermal degradation are used to calculate future life estimation. The complete procedure is shown in the flow chart in Fig. 14.

An example of a future life estimation where the insulation degradation rate based on the tan delta evaluation together with the cable loading in relation to the cable age is shown in Fig. 15, in the case of a cable in bad condition. In this example, it can be seen what the past degradation rate is up to the current service age of the cable and what the expected degradation rate will be in the future considering different cable loading scenarios.

Measurements have been performed on several service aged power cables to obtain the diagnostic parameters. One of them is a paper-oil insulated cable that has been in service for 35 years. The average loading on this cable circuit has been estimated based on the measurements performed during its operation. This resulted in an average past loading of 40% of the maximal designed value.

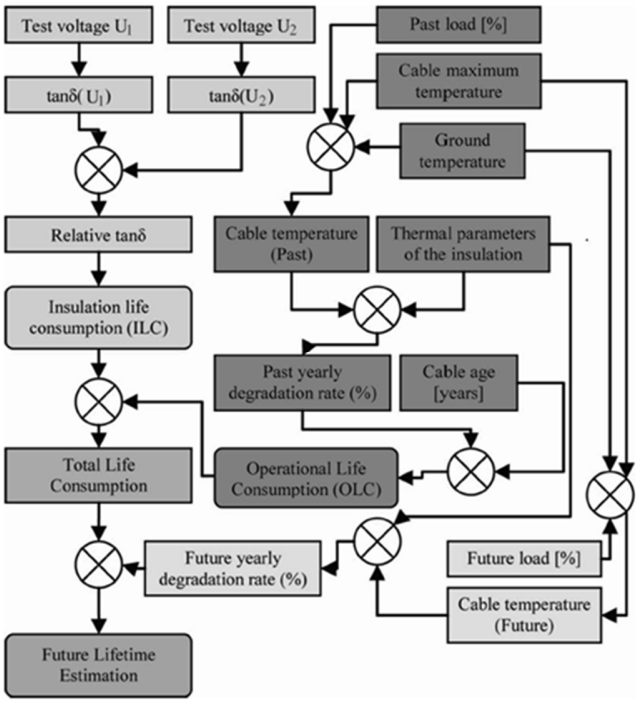

Fig. 14. Flowchart of the estimation of future (remaining) service lifetime based on insulation- and operational- life consumption.

The past degradation, during 35 years of operation, at 40% is shown in Fig. 15 as a single brown line (dots). This line represents the operational degradation resulting from the past cable loading obtained from the law of Montsinger (see the calculation of the OLC in Fig. 13) and the degradation of the cable insulation based on the measured tan **δ** values obtained from the diagnostic measurement. A temperature of 60°C is considered to be the maximum allowable operating temperature for paper-oil cable insulation and the average ground temperature is 15 degrees Celsius. With these parameters the expected service lifetime (or 100% life consumption) at this temperature is around 10 years [37].

Starting from the 35th operational year, different future loads options are considered for the future life estimations and are shown for 25%, 40%, 50%, 75% and 100% future loads.

To estimate the future life only the thermal aging is considered, as the tan δ values in the future are unknown. Those values can be incorporated in the model if the values are measured again after a certain period of additional service life. If the load will be kept at 40%, as before, the future life estimation will be around 64 years. It can be seen that based on the thermal ageing; the degradation rate will slightly increase resulting in a slightly steeper curve in Fig. 15. If after, for example, 10 years, the diagnostic measurement is repeated, the

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tan δ values measured can be used as a new input in the model and the future life estimation can be adjusted accordingly.

After 35 years, if the average load on the cable will be reduced to 20%, of the past value, the future life estimation will be around 88 years. If the load will increase to 50%, the future life estimation will be around 51 years. If the load will increase to 75% or 100%, the future life estimation will be 22 and 7 years, respectively. This example shows that the diagnostic data of a measurement obtained on a service aged paper-oil insulated cable can be applied to determine the actual life consumption, which is subsequently used in the condition-based maintenance strategy of this cable circuit.

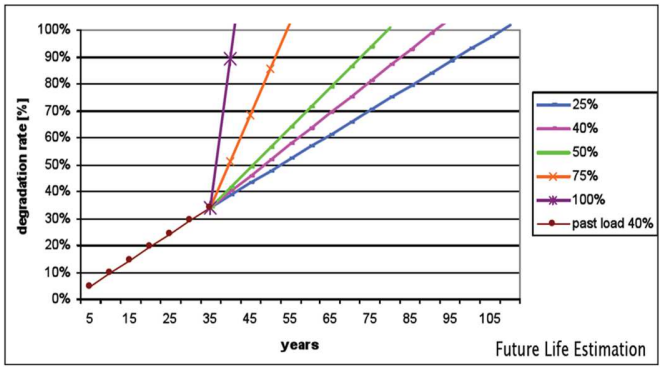

Fig. 15. Practical example of future life estimation of a 230 kV oil-filled insulated cable (length 27 km) based on actual technical life of 35 years and different options of future load estimation.

VI. Conclusions

In this contribution, based on the state-of-the art and supported by practical use, several aspects regarding condition assessment of service aged XLPE and oil-filled insulated transmission power cables are discussed. In particular the following can be concluded:

1. In contrast to distribution power cable networks with a wide scope of condition assessment experiences, to support CBM asset management by transmission power cable not much field-applied solutions have been reported in last ten years.
2. The existing transmission cable system networks have a chance of one failure per 42 km circuit's length and there are no established dedicated methods and criteria for condition-based maintenance for service-aged cables.
3. The average operational life of transmission power cables is between 45-50 years, whereas in some networks more than 50% of oil-filled power cables are in operation for more than 50 years.
4. The application of non-destructive measurements to on-site diagnosis of transmission power cables would be able to provide essential information to evaluate actual insulation condition of a service aged cable system.
5. Partial discharge measurement is a suitable method to obtain information about discharging insulation defects in both XLPE and paper-oil insulated cable insulation and cable accessories.
6. The measurement of dissipation factor (tan **δ)** at various voltage levels provides valuable information regarding the overall paper-oil insulated cable insulation ageing.
7. The diagnostic information as obtained using onsite testing contributes in the overall cable condition assessment.
8. The obtained experiences in the past years provided the information to develop knowledge rules to support maintenance and replacement activities of transmission power cables.

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VIII. BIOGRAPHIES

Edward Gulski (Fellow IEEE) received the M.Sc. degree in information technology in 1982 from Dresden University of Technology in Germany.
In 1991 he received the Ph.D. degree from Delft University of Technology in the Netherlands. In 2004 he received the Doctor Habilitatus degree from Warsaw University of Technology in Poland.
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Rogier Jongen graduated in 2004 with a M.Sc. degree in Electrical Engineering at Delft University of Technology.
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He has over 10 years' experience in on-site testing of medium- and (extra) high voltage power cables as well on performing partial discharge measurements including the data evaluation and analysis.
He has been active in several Cigré working groups as well in the completion of the IEEE 400.4 guide on field-testing of power cables with damped AC.

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