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Monitoring the Oil of Wind-Turbine Gearboxes: Main Degradation Indicators and Detection Methods

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Abstract: Oil condition monitoring is a common practice in the wind industry. However, the published research about oil degradation in wind turbine gearboxes is limited. This paper aims at providing new information on the oil degradation process by analyzing wind turbine gearbox oils aged in the laboratory and in the field. Oil samples were analyzed in the laboratory and two sensors were used to determine the oil condition by means of dielectric constant and conductivity measurements. Additionally, micropitting tests were carried out for three oils with different base stocks. The results of this study show that viscosity changes of the oils from the field were not significant.Extreme pressure additives depletion and the increase of the iron content are among the most relevant degradation indicators. The oil sensors used in this study provided limited information on the oil degradation process. The accuracy of the sensors was affected by the oil type and its measurement range. The results of the micropitting tests showed that even aged oils exhibited a high micropitting resistance.

Keywords: wind turbines; oil condition monitoring; gearboxes; oil sensors; oil analysis; oil degradation; oil sampling

1. Introduction

According to WindEurope [1], wind energy has become the second largest form of power generation capacity in Europe, with a total installed power of 153.3 GW, corresponding to 17% of the European power generation capacity. Larger wind turbines are being installed and the reliability of the main components has been the focus of several research initiatives. In [2,3], two gearboxes were used to validate drive train models and test different condition monitoring systems (CMS). In [4], a study of downtime and failure rate of the different wind turbine components was carried out. The results indicated that major replacements in gearboxes cause significant downtime. As a gearbox failure implies significant downtime, the reliability of this component is of vital importance to reduce the operation and maintenance costs (O&M) of wind turbines. Early bearing failures due to white etching cracks (WEC) have been affecting wind turbines and have been the focus of several studies [5–8]. The influence of additives and oil type on WEC has also been investigated [9]. It is important to consider that, independent of the failure mode, the oil plays an essential role in reducing friction and wear, allowing for proper operation of the gearbox. Therefore, the oil condition and its degradation have a direct impact on the reliability of this component.

CMS have become a standard solution in modern wind turbines. Condition monitoring (CM) is carried out based on two different approaches. The first approach, known as offline-CM, means that the parameters are obtained without the necessity of continuous measurements during the operation of the turbine, for example, gearbox oil sampling. In contrast, online-CM is based on permanently installed systems providing continuous signals to perform fault detection and diagnosis, such as the classical vibration-based CMS in the drive train. Some other approaches focus on the utilization of

Supervisory Control and Data Acquisition (SCADA) system data to perform condition monitoring and maintenance management [10,11]. Model-based CM can be carried out by creating a model of the wind turbine behavior and identifying faulty conditions. In [12,13], a benchmark model was used to test several fault detection approaches, such as Kalman filters, support vector machine algorithms, state space set membership consistency tests, and others. This approach allows for performing fault identification and isolation only with standard measurements of the wind turbine control system and offers the possibility of studying sensor faults, such as faulty pitch position measurements, actuator faults such as faults in hydraulics of the pitch system, or system faults such as drive train faults indicated by an increased friction coefficient in the gearbox. This benchmark model also offers the possibility of testing fault-tolerant control methods by simulating sensor and actuator faults [14]. In [15], two fault-tolerant torque control methods were tested based on fuzzy modeling and identification, where actuator faults were simulated with a passive (without knowledge of the faults nor of a fault detection system) and an active approach (with automatic signal correction) showing good results for the analyzed scenarios compared with classical control system methods. Oil condition monitoring (OCM) has been implemented in wind turbines to help identify gearbox faults and define oil change intervals. Depending on its size, a wind turbine gearbox needs an oil quantity between 200 and 800 L. Therefore, extending oil change intervals by using the maximum achievable life span of the oil leads to a reduction in the O&M costs. OCM is conducted mainly by oil sampling and in some cases by sensors measuring parameters such as oil cleanliness and wear debris production [16]. Other studies related to OCM focused on the validation of a sensor to detect developing faults and provide information about additive depletion and oil degradation [17,18]. In [19], a detailed review of different OCM approaches for wind turbine gearboxes was performed. The review shows the different forms of oil degradation caused by oxidation, water contamination, temperature and viscosity changes, as well as different methods to perform oil analysis. Additionally, the author proposed a combined approach of several OCM methods such as fluorescence spectroscopy, Fourier transform infrared spectroscopy, photoacoustic spectroscopy and viscosity measurements in order to improve the robustness of the oil-based CMS performing a multivariate analysis from the obtained measurements. For further information about CMS for wind turbines, the reader is referred to [20–25].

Even if OCM is current practice in the wind industry, there is limited published information about the degradation of the oil in wind turbine gearboxes. In [26], a study showing changes of some oil properties due to the operation of the gearbox with a significant amount of oil samples was carried out. However, the study comprised only one oil brand and limited information about the operating condition of the wind turbines was provided. Mineral oil degradation and its additives have been studied for several years, especially for internal combustion engine (ICE) applications [27]. In view of the important role of the oil condition in determining an oil change, this paper aims to provide a better understanding of the oil degradation process in wind turbine gearboxes.

This paper can be divided into three main sections. The first section reviews the characteristics of oil for wind turbine gearboxes and provides an overview of additives, oil degradation, and OCM. The second section explains in detail the approach used to recreate and assess oil degradation and the objective of the experiments. The third section presents the results of the tests and provides new information to better understand the degradation process of the oil. Finally, we summarize the main results and point out the most important aspects for further research.

2. State of the Art

2.1. Oils for Wind Turbine Gearboxes

The use of high-performance synthetic oils for wind turbine applications is gaining more acceptance within the industry, as reflected by the large variety of synthetic products currently available for wind turbine gearboxes. Even if synthetic oils are more expensive than mineral oils, their good thermal stability, lower pour points, and higher viscosity indexes (VI) make them very attractive for operators and manufacturers of wind turbines [28]. The VI describes the changes of the oil viscosity with temperature: the higher the VI, the lower the changes in the viscosity with increasing temperature, which leads to better lubrication for variable operating conditions. Oils are composed of a base stock and additives. For the sake of simplicity, the oils in this paper will be designated only by their base stock. The most typical base stock used in wind turbine gearboxes is poly-alpha-olefin (PAO). PAOs are synthetic oils consisting of a straight hydrocarbon chain with an unsaturated carbon at one end of the chain. Even if there is a significant amount of turbines still operating with mineral oil, newly installed turbines tend to be filled with synthetic oils. Another oil base stock used recently in wind turbines is poly-alkylene-glycol (PAG). PAGs are also synthetic oils and have a higher VI than PAOs. PAOs have a VI between 140 and 180, while PAGs have a VI between 180 and 260. This high VI provides a better temperature viscosity behavior than mineral oils, which only have a VI around 90 (no hydrocracked oils). The viscosity grade (VG) for wind turbine gearbox oil is 320, which means that the kinematic viscosity of the oil at 40 °C lies between 320 $mm^2/s \pm 10\%$. All the oils for wind turbines comply with the requirements of DIN 51517-3 [29]. The IEC 61400-4 provides an overview of the minimal requirements for oil in wind turbines [30]. These requirements comprise tests of gear and bearing wear, as well as the assessment of fatigue and mixed friction lubrication conditions in FE-8 and FZG test rigs [31,32]. Additionally, tests are available to assess oil corrosion and shear stability [33,34]. The oil compatibility with elastomers can also be assessed based on [35]. As the tests in the standards are only minimal requirements; commercial oils can exhibit superior performance characteristics. This means that two oils complying with all the requirements stated in the norms can show very different behavior and performance in the field. In addition, gearbox manufactures can have additional or different requirements, which also limits the list of lubricants that can be used in the gearbox. Commercial oils must meet demanding requirements before being used in the field. However, their performance above the limits of the standards is the deciding factor in the life span of the oil.

2.2. Additives Used in Oils for Wind Turbine Gearboxes

The additive content and formulation play a decisive role in the performance of the oil. Their composition and interaction is very complex and partly unknown due to the vast number of patents and the know-how of each oil manufacturer. However, some general knowledge is available in the literature. In [36], an extensive description of various types of additives for different applications is provided. For wind turbines, the most common types of additives are anti-wear (AW) and extreme-pressure (EP) additives. Other type of additives such as antioxidants, anti-foam, and corrosion protection additives are also part of the oil formulation. Some formulations could include detergents. The most relevant type of additives for wind turbines are presented in the following.

Antioxidants: These additives act as a protection against the effect of oxygen and high temperature. These additives can also be used as corrosion protection additives. Antioxidants can contain aromatic compounds, such as amines and phenols [37,38], which are typical for turbine oils and lubricating greases [39]. Some tests with molybdenum mixed with zinc dithiophosphates (ZDDP) provided good oxidation stability [40]. Molybdenum as an antioxidant additive has also been investigated [41]. This additive, in combination with an aromatic amine, has shown antioxidant properties in oxidation tests [42]. Sulfur–phosphorus (S–P) compounds can act as antioxidants [43–46]. They can be used for several base stocks and can be found in commercial oils [36].

Anti-wear (AW) and extreme-pressure (EP) additives: These types of additives are active during mixed friction lubrication. They form a reaction layer to avoid or reduce direct metal-to-metal contact. AW additives are effective for moderate loading and temperature in the contact. In contrast, EP additives are effective under high loading. The complexity and variety of this type of additive are large. One of the most common combinations for wind turbines are the S–P compounds. ZDDPs can act not only as antioxidants but also as AW/EP additives [36]. The presence of ZDDP compounds in wind turbine oils is not common, however, oils containing zinc–molybdenum compounds can also have an effect as AW/EP additives and they can be found in some oil formulations [47].

Detergents: This type of additive removes deposits and aging products from the contact surface. Detergents are typical for internal combustion engines. Calcium compounds, such as calcium sulfonates, usually have detergent effects and are found in some oil formulations in wind turbines [47]. Due to their increased polarity, oils with high additive content can suffer from additive fallout due to water ingress. The use of detergents then becomes necessary to reduce this effect [47].

Antifoam additives: This type of additive acts on the surface tension of the oil, leading to a faster bursting of bubbles and avoiding excessive foaming. One example of antifoam additives is silicon compounds [36]. Silicon antifoam additives can be found in wind turbine gearbox oil.

Corrosion protection additives: This type of additive protects the oil from water or acids by neutralization. This additive also creates a layer to protect the metal surface. Some corrosion protection additives can also act as antioxidants (metal deactivators).

The combination of different type of additives can also be detrimental to the lubrication. Corrosion protection additives can affect AW/EP additives. Detergents can also affect the generation of the protective film in the surface of the contact. Therefore, the additive formulation and the type of application are essential to understand oil degradation.

2.3. Oil Degradation

Oil degradation can be defined as the negative changes in the oil properties until the oil cannot fulfill its lubricating function anymore, which leads to wear and consequential damage. This degradation is influenced by numerous parameters, such as temperature, loading, environmental conditions, external contaminants, type of oil, additive package, etc. ICEs operate under high temperatures and contact with oxygen is a catalyzer, leading to high oxidation rates. This type of oil degradation with high temperature and oxygen can be described as thermal–oxidative aging. Oil oxidation can occur due to auto-oxidation, metal catalysis and high temperature [48]. Oxidation leads to a thickening of the oil and subsequently to an increase in the viscosity. High oxidation causes formation of sludge and varnish. Therefore, antioxidants are necessary to slow down this process [27]. As wind turbines operate under a lower oil temperature than ICE (under 80 °C), the gearbox oil oxidation process also occurs at a very lower rate. Oil degradation and its influence on the oil load carrying capacity were studied by several scientists [49–51]. They performed tests in mineral oil and PAO. The results indicate that the reduction of the remaining useful life of the oil is doubled per 10 °C increment at temperatures higher than 60 °C. In this aging process, the antioxidant additives play an essential role. In [36], a study showed that different synthetic base stocks without antioxidants did not exhibit any difference in their performance in oxidation tests. However, when additives were used, their performance showed different results with an increased life span.

2.4. Oil Condition Monitoring

Oil sampling and subsequent offline analysis is the most widely applied method to provide an indication about the oil condition. This method allows for determining several parameters, such as viscosity, metallic elements, particles, additives, water content, etc. On-site devices and online oil sensors are also used to monitor the oil and the gearbox condition in the wind turbine. The gearbox condition is mostly monitored by means of inductive wear sensors giving an indication of ferromagnetic and non-ferromagnetic particles in the oil [52]. Additionally, the cleanliness of the oil can be monitored by means of optical particle counters [53]. As we are not directly assessing the wear of the gearbox, particles and wear debris counting are outside the scope of this paper. Relevant for this paper are oil quality and oil properties sensors. These types of sensors detect oil degradation based on the hypothesis that the dielectric constant and the conductivity of the oil are related to oil degradation [17,54–56]. As the conductivity of the contaminants, broken oil molecules, or acids is different from the oil, these substances cause changes in the conductivity, which can be measured to give an indication of oil degradation. Additionally, the additive changes can be related to the changes in the dielectric constant, which provides information about additive depletion. Some authors have shown the effectiveness of oil sensors to detect damage in bearings of wind turbine gearboxes [18]. However, the accuracy of the sensors is highly dependent on the learning phase, the interpretation of the data, and the robustness of the sensor. Conductivity and the dielectric constant are temperature-dependent. This means that a temperature compensation algorithm is required to isolate the changes related to additive depletion or oil degradation to a change in the dielectric constant and the conductivity, respectively. The temperature compensation is carried out during a learning phase. In this process, the sensor creates a curve to compensate for the variations in the measurements due to temperature, in some cases, based on a polynomial approximation with an operating temperature used as reference [57]. Therefore, this compensation is very oil-specific and can induce some errors due to the approximation of the polynomial coefficients.

3. Materials and Methods

In order to understand the degradation of wind turbine gearbox oil, two different oil aging processes were analyzed for three different oil types: PAO, mineral oil, and PAG. The oils used for this test campaign have a VG of 320 and S–P additives. The oils from the first aging process were obtained from accelerated aging on a FZG back-to-back test rig in the laboratory [58]. The oils from the second aging process were obtained by extracting oil from wind turbines in operation. The oils obtained from these two aging processes were analyzed with three different methods:

- **Oil Sampling**: Analysis of the measurements of the oil properties in the laboratory;
- **Online Sensors**: Analysis of the electrical properties of the oil in an oil sensor test bench;
- **Micropitting tests**: Analysis of the micropitting resistance of the oil by performing tests in a FZG back-to-back test rig.

For all these analysis methods, fresh oil was tested and used as a reference. An additional method to assess the degradation of oil was also carried out for a PAO with high additive content, named PAO II. This analysis combined the results from the oil sampling in the laboratory with SCADA data of the corresponding wind turbine to assess the effect of the operating conditions on the oil degradation. Table 1 shows the methods of analysis and the oils used for each method.

Table 1. Methods of analysis.

Oil Type	Oil Condition	Oil Sampling	Online Sensors	Micropitting Tests	SCADA-Data
PAO I	Fresh	x	x	x	
	Laboratory aging	x	x	x	
	Field aging	x	x	x	
Mineral oil	Fresh	x	x	x	
	Laboratory	x	x	x	
	Field aging	x	x	x	
PAG	Fresh	x	x	x	
	Laboratory aging	x	x	x	
	field aging	x	x	x	
PAO II	field aging	x			x

3.1. Oil Aging

The aging in the laboratory was carried out by the FZG. As stated in Section 2.3, one of the most relevant parameters causing oil aging is temperature. Therefore, accelerated oil aging can be carried out by intensifying the effect of temperature. The drawback of carrying out thermal oil aging is that this process does not represent the same conditions as in the field, where the operating temperature of the wind turbines is clearly lower. Furthermore, thermal aging mostly activates antioxidants and does not directly affect other types of additives, such as EP/AW additives. By comparing the changes in the additives obtained from accelerated thermal aging and field aging, the effect of temperature on the oil can be assessed.

3.1.1. Laboratory Aging

This approach consisted of an accelerated thermal aging process in a FZG back-to-back test rig. The oil was aged in the slave gearbox of the test rig. The temperature of the tests was initially 120 °C. However, the temperature was increased up to 135 °C for some tests.

The oil aging stages were determined based on the experience of the FZG of the Technical University of Munich, Fraunhofer IWES and OELCHECK GmbH. Aging stage I corresponds to an oil showing signs of degradation, but still suitable for further use. Aging stage II is a degraded oil that was not suitable for further use. The parameters defining each aging stage are summarized in Table 2. The aging process was completed when two or more parameters in Table 2 were reached. As the changes of these parameters do not follow any sequential behavior, the highest priority was given to the total acid number (TAN), followed by the viscosity and, with lowest priority, by the antioxidant and EP/AW additives (S–P compounds). The aging tests were carried out first for PAO I then for mineral oil and last for PAG. As the time to reach the corresponding aging stage was unknown, the FZG started the test for each oil at 120 °C for aging stage II. Based on the duration of the test to reach this aging stage, the test conditions for aging stage I could be redefined if necessary.

Table 2. Parameters defining the condition of aged oils.

Aging Stage	Description	Changes in TAN	Changes in Kinematic Viscosity	Changes in the Additive Concentration
Aging Stage I	aged, but suitable for further use	Minimum increase of 0.3 mgKOH/g	+5% to +10%	decrease of additive concentration of >−10%
Aging Stage II	aged and deteriorated, not suitable for further use	Minimum increase of 0.5 mgKOH/g	+10% or more	decrease of additive concentration of >−20%

3.1.2. Field Aging

Field aging is defined as the operating time of a turbine filled with the oil under analysis without oil change. The accessibility of the wind turbines was a limiting factor. For this reason, the duration of the aging process of each oil is different. An oil sample of 20 L of PAO I, mineral oil, and PAG could be obtained from three different wind turbines. This oil quantity was enough to carry out the measurements with the sensors and the micropitting tests. For PAO II only a sample of 200 mL could be obtained, which was only enough to carry out the laboratory analysis. The operating hours of each oil sample from the field are summarized in Table 3.

Table 3. Operating years of the oil samples extracted from the field.

Oil Designation	Wind Turbine Power Range (MW)	Operating Time (h)
PAO I	1 to 2	76,548 (8.7 years)
Mineral oil	1 to 2	50,216 (5.7 years)
PAG	1 to 2	28,300 (3.2 years)
PAO II	3 to 4	30,904 (3.5 years)

It is important to note that the viscosity and additive content of the oils were analyzed after oil filling to verify that the oil was not mixed with the rest of the flushing oil. For PAO I, mineral oil, and PAG, an oil change took place after taking the oil sample. Therefore, the operating time give an indication of the duration of the oil change interval. We observe that the oil change intervals varied between 3.2 and 8.7 years, which can be larger if we consider the time that the turbine was not producing power.

3.2. Analysis Methods

In this paper we considered three methods of analysis. The first method was the typical laboratory analysis of oil samples, which is current practice in the wind industry. The second method consisted in measuring the dielectric constant and the conductivity of the oil by means of sensors to obtain information about oil degradation. The third method consisted of combining oil sampling with SCADA-data from the respective wind turbine to correlate operating conditions with changes in the oil properties. The three analysis methods are introduced in more detail in the following.

3.2.1. Oil Sample Analysis

This method provides detailed information about different oil parameters with high precision and accuracy. In this study, we performed three different types of measurements:

- **Viscosity and Viscosity index**: Measurement of the kinematic viscosity at 40 °C and 100 °C with the corresponding calculation of the viscosity index according to DIN 51659-3 [59].
- **Element analysis**: Determination of the element content in the oil based on inductively coupled plasma (ICP) mass spectrometry according to DIN 51399-1 [60]. The elements covered by this method are aluminum, barium, lead, boron, chromium, iron, potassium, calcium, copper, magnesium, molybdenum, sodium, nickel, phosphorus, sulfur, silicon, zinc, and tin. We will focus on phosphorus, sulfur, magnesium, molybdenum, and zinc, as these elements are contained in the additives of the oil under analysis. Iron will also be included to observe possible increase of chemically bounded iron during the wind turbine operation.
- **Neutralization number or total acid number (TAN)**: Determination of the oil oxidation, the breakdown of oil additives, and increase in the acidity of the oil. This method determines the required quantity of potassium hydroxide (KOH) to neutralize the oil by means of titration. The measurements are carried out according to DIN ISO 6618 [61].

3.2.2. Online Sensor Measurements

An oil sensor test bench, which is described in [62], was used to carry out the measurements with two oil properties sensors of the same manufacturer. The oil sensor test bench allows for analyzing the detection capability and quality of different types of sensors. This is achieved due to the well-defined and reproducible operational characteristics of the test bench. The main goal is to measure the oil properties for fresh and aged oils with reproducible test procedures. This test procedure is carried out only for PAO I, mineral oil, and PAG, as the oil quantity of PAO II was not sufficient for this test. The oil sensor test bench consists of an oil circuit in which several sensors can be installed in horizontal and vertical positions. Several adapters are used to install the sensors at different positions in the test pipe. The test bench has a heat exchanger to control the oil temperature and a pump to control the oil flow. A contamination unit with a rotor–stator system for homogenization is used to artificially contaminate the oil with particles or water if desired. The test bench is illustrated in Figure 1.

For this study, a stepped temperature profile ranging from 40 °C to 80 °C with three flow rate steps at 5, 10, and 15 L/min was used to record the measurement of the sensors. The sensor measurements were recorded inline during the temperature profile with the changes in the flow rate. Two oil properties sensors as well as reference temperature and pressure sensors were installed in the horizontal and in the vertical pipe of the test bench. The reference temperature sensors controlled the temperature of the oil of the test bench ensuring a homogenous temperature in the pipes and reservoir. The oil properties sensors used for this study measure temperature, water saturation, dielectric constant, and conductivity. However, we will only focus on the dielectric constant and conductivity measurements. As mentioned in Section 2.4, these parameters can give indication of oil degradation.

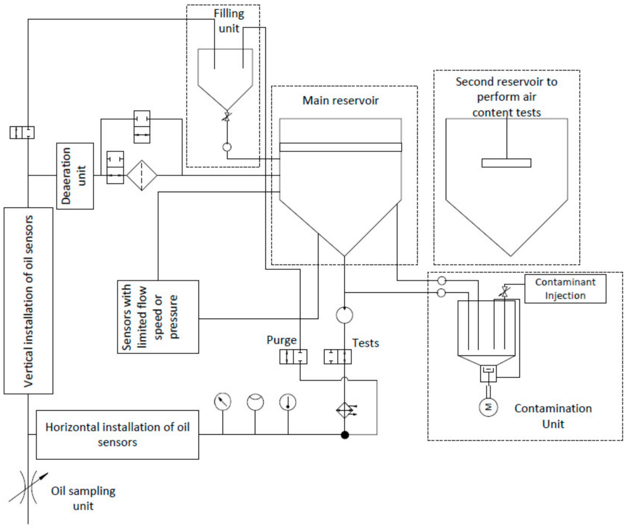


Figure 1. Layout of the oil sensor test bench at Fraunhofer IWES.

3.2.3. Micropitting Tests

This test procedure was carried out by the FZG. These tests were run only for PAO I, mineral oil, and PAG, as not enough oil from PAO II was available. Micropitting refers to a type of mid-cycle surface contact fatigue, in which, due to asperities and microcracks, shallow "pits" (up to 20 µm) are generated on the surface when the lubrication film is not thick enough in comparison with the roughness of the surface [63,64]. In order to assess the capability of the oil to withstand micropitting, short tests according to DGMK 575 were carried out in a FZG back-to-back test rig [65]. The main objective of these tests was to assess the micropitting resistance of oils aged in the laboratory and in the field. Additionally, the test was intended to show whether oil degradation due to depletion of AW/EP-additives or oil oxidation could have an effect on the micropitting resistance of the oil. It is important to note that the test method proposed in DGMK 575 serves only as a screening test to classify the lubricant into different GFKT classes (low, medium, or high). Therefore, the effect of oil degradation and the depletion of AW/EP additives on the micropitting resistance have to be very significant to be identified with GFKTs.

3.2.4. Combined Analysis from Oil Samples and Wind Turbine SCADA Data

As mentioned in Section 2.3, temperature can accelerate oil aging processes. However, the oil in wind turbines experiences variable temperature due to the fluctuating wind speed. Between two samplings, a wind turbine operates in very different regimes: full load, partial load and idling. These different operating conditions affect the loading of bearing and gears [2], which can involve operation under mixed friction lubrication regime, high loading, or increased temperature. Therefore, the rate of oil degradation and depletion of additives is also variable. In order to get insight into the operating conditions of wind turbines, SCADA data from a 3.4 MW wind turbine with PAO II were analyzed. Several oil samples taken in time intervals of 4–10 months were used to perform a trend analysis. An analogy of the power bin concept is implemented to analyze power production and gearbox temperature. The power bin concept is usually used to relate vibration measurements to a defined power bin. A description of this method can be found in [66]. As we are interested in temperature, we attributed the temperature of the bearings and gearbox oil sump to bins of the active power generated by the turbine. An additional trend analysis of oil samples from other turbines with PAO I was carried out in order to better understand the degradation process of this type of oil. Moreover, a statistical analysis of oil samples was carried out to assess the variability of the viscosity for mineral oils and PAOs.

4. Results

4.1. Oil Sample Analysis

The results of the oil sampling correspond to the measurements at the end of the laboratory and field aging. The criteria defining the end of each test in the laboratory are described in Section 3.1.1. It is important to note that the extreme temperature tests in the laboratory aim at understanding the reaction of the oil under accelerated thermal stresses and do not represent the real operating conditions in the field.

4.1.1. Laboratory Aging

The results of the laboratory aging are summarized in Table 4. For PAO I and mineral oil, it was necessary to increase the oil aging temperature to accelerate the aging process in order to limit the duration of the test.

Table 4. Results of the laboratory aging.

Oil Designation	Oil aging Stage	Changes in the TAN	Changes in the Kinematic Viscosity	Changes in the Additive Content
PAO I	Aging stage II (882 h [1])	+0.54 mgKOH /g	+6.5%	P: −26% S: −42%
PAO I	Aging stage I (539 h, 135 °C)	+0.41 mgKOH/g	+10.5%	P: −32% S: −50%
Mineral oil	Aging stage II (1080 h, 130 °C)	+0.94 mgKOH/g	+21%	P: −76% S: −24%
Mineral oil	Aging stage I (912 h [2])	+0.35 mgKOH/g	+10%	P: −64% S: −20%
PAG	Aging stage II (314 h, 130 °C)	+1.23 mgKOH/g	+10%	P, S: less than 10%
PAG	Aging stage I (150 h [3])	+0.77 mgKOH/g	+7%	P, S: less than 15%

[1] Increase from 120 °C to 135 °C after approx. 500 h. [2] Increase from 120 °C to 135 °C after approx. 400 h. [3] Decrease from 130 °C to 60 °C after approx. 70 h.

The test for aging stage II of PAO I started at 120 °C. However, the changes necessary to achieve stage II were not achieved after approx. 500 h. Therefore, the temperature was increased from 120 °C to 135 °C. The necessary changes in the TAN and viscosity were reached after 882 h. This process led to an increased TAN of +0.54 mgKOH/g and a slight oil thickening, indicated by a viscosity increase of 6.5%.

In order to reduce the duration of the test to reach aging stage I of PAO I, this test was carried out entirely at 135 °C. However, we observed a higher increase in the viscosity and a more significant additive depletion than for aging stage II in a shorter test time (539 h). This confirms the acceleration effect of temperature on oil degradation.

In the case of mineral oil, we observed that the oil required a longer time to achieve the values defining the oil aging stages. Similarly to PAO I, reaching stage II of mineral oil required an increase in the temperature, this time to 130 °C. The values obtained in stage II of mineral oil were far over the defined thresholds. This is explained by the accelerated changes in the oil properties caused by the increased temperature during the entire test (130 °C).

The aging stage I of mineral oil was also carried out initially at 120 °C and then increased to 135 °C to avoid the same results obtained for stage I of PAO. The required viscosity of at least 5% was achieved, but the required TAN of at least 0.3 mgKOH/kg required more time and the viscosity continued to increase up to 10%. These tests show the effects of hightemperature, where acids are characterized by an increase in the TAN and the formation of high molecular weight products resulted in an increased viscosity [36]. Very interesting was the reaction of the PAG to the thermal aging. As the test duration was defined based on the previously observed behavior of PAO and mineral oil, the test started at a high temperature of 130 °C. However, after taking a sample to verify the condition of the stage II of PAG, the values indicated that the oil was aging much faster than expected, reaching a change of 1.23 mgKOH/kg and a viscosity change of 10% after only 314 h. Therefore, the time to verify the oil condition during the test at 130 °C for stage I of PAG was reduced to 70 h. As not all the parameters were reached, the temperature was reduced from 130 °C to 60 °C until the TAN and viscosity required changes were achieved. The reduction of phosphorus and sulfur for the PAG was not as significant as for PAO I and mineral oil.

4.1.2. Field Aging

The results of the field aging are summarized in Table 5.

Table 5. Results of the field aging.

Oil Designation	Oil aging Duration (h)	Changes in the TAN	Changes in the Kinematic Viscosity	Changes in the Additive Content
PAO I	76,548 (8.7 years)	No significant changes	Less than 3%	P: −40% S: −27%
Mineral oil	50,216 (5.7 years)	No significant changes	Less than 3%	P: −28% S: −19%
PAG	28,300 (3.2 years)	+0.61 mgKOH/g	Less than 3%	P: −33% S: −33%
PAO II	30,904 (3.5 years)	−1 mgKOH/g	Less than 3%	P, S: −5%

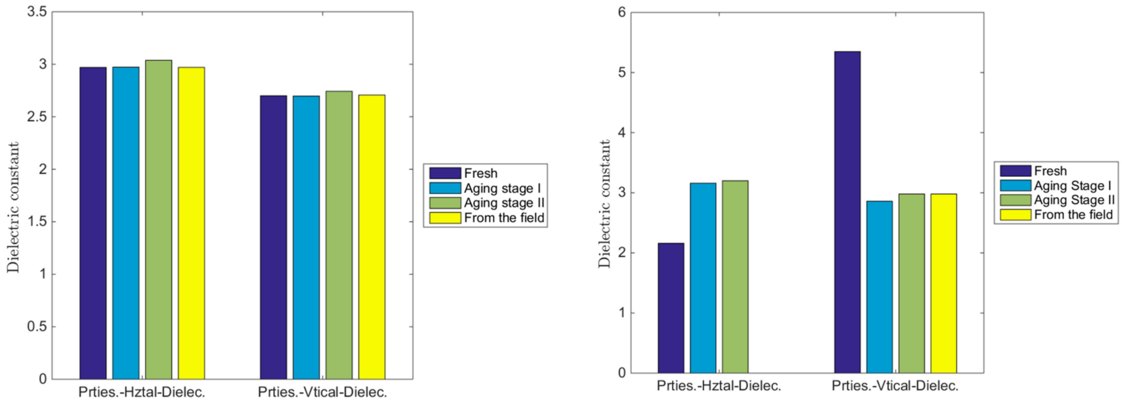
Table 5 shows that all field-aged oils did not exhibit any significant change in their viscosity. Additionally, PAO I and the mineral oil did not show important variations in their TAN. In the case of PAG, an increase in the TAN of 0.61 mgKOH was observed. In contrast to the laboratory aging, the field aging showed changes in the P–S additives. As mentioned in Section 2.2, these compounds act as EP/AW additives and are reduced due to the operation of the wind turbine. A stable viscosity is expected, as the oil temperature is low and oil thickening due to the formation of high molecular weight products caused by thermal aging did not take place. PAG showed an increase in the TAN, indicating a slightly increment in the acid content of the oil. As the PAG chemistry works very differently from the other two oils, a better understanding of this behavior will require more testing. In contrast to all other analyzed oils, the field-aged PAO II showed a decrease in the TAN. The changes in the TAN are also affected by the type of additive package. It is important to note that PAO II does not only contain P–S compounds, but other types of additives, such as molybdenum, magnesium, zinc, and calcium, and the changes in TAN can also be related to the changes of these additives.

4.2. Online Sensor Measurements

The test bench described in Section 3.2.2 has been used to measure the dielectric constant and the conductivity of oils from the laboratory and field aging, as well as of fresh oil. These measurements were carried out for PAO I, mineral oil, and PAG, as shown in Table 1. Before starting the measurement with the sensors, a learning phase for each oil was necessary, including the temperature range in which the sensor will be operating. For these tests, the learning phase was carried out between 20 °C and 80 °C at a constant flow rate in the oil sensor test bench. This learning phase is necessary to provide temperature-compensated values, as conductivity and dielectric constant are very sensitive to temperature changes [17]. As the temperature in wind turbine gearboxes is variable, it is expected that the sensor only relates the changes in the conductivity and the dielectric constant to oil degradation and not to a temperature change. However, small changes in the conductivity occurred. Therefore, the values provided for this analysis are the average values of conductivity measurements obtained from the stepped profile described in Section 3.2.2. The measurements of the dielectric constant remained constant during the entire profile.

4.2.1. Dielectric Constant Measurements

The measurements of the dielectric constant have shown very different results for the oils under test. In the first place, the results of PAO I were not very conclusive. The sensor did not exhibit any change in the dielectric constant neither for the laboratory-aged oil nor for the field-aged oil. In the case of mineral oil, as observed in Figure 2a, the measurements of the dielectric constant of the oil only showed an increase for aging stage II.



(**a**) (**b**)

Figure 2. Measured dielectric constant of (**a**) mineral oil and (**b**) PAG oil during the stepped profile described in Section 3.2.2.

The measurements of the horizontal and vertical sensor showed a systematic deviation. In order to verify that the position of the sensor in the pipes does not have an influence on the measurements, we switched the positioning of the sensors and repeated the measurements. The new measurements of each sensor were identical. After repeating the tests several times, we realized that this offset was constant and did not change during the tests. According to the sensor manufacturer, the difference in the measurements was due to the tolerance range used for the calibration procedure. Therefore, this offset in the measurements is attributed to the sensor itself and does not represent any real change in the oil condition.

During the measurements with PAG, no comparable measurements were obtained from both sensors. The sensors provided very different results for fresh oil, as observed in Figure 2b. Furthermore, the horizontal sensor did not provide any measurements during the test with the PAG from the field. Due to the poor comparability of the sensor measurements, it was not possible to obtain information about additive degradation based on the dielectric constant measurements of the sensors.

4.2.2. Conductivity Measurements

During the learning phase with PAO I, which has a particularly low conductivity, we observed that the sensor provided negative conductivity values. This is caused by the temperature compensation/correction procedure: When the sensor measures a conductivity smaller than 1 nS/m, the temperature compensation curve cannot be properly generated, as the sensor accuracy is ±0.5 nS/m full scale. This means that the error does not change with the measured value. Therefore, for large conductivity measurements during the learning phase, for example 50 nS/m, the value used for compensation after the learning phase will be between 49.5 and 50.5 nS/m. However, in the case of a measurement of 0.5 nS/m, the value used for compensation could be between 0 and 1 nS/m. For this reason, the values used to compensate for the conductivity measurements could lead to a negative number for very low conductivity values.

During the learning phase with PAG, the sensor was unable to generate a compensation curve. After external measurements of the conductivity of the oil, it was confirmed that the PAG had a conductivity larger than 100 nS/m, which is beyond the upper limit of the sensor measurement range. Plausible conductivity measurements could only be obtained for mineral oil. These measurements are illustrated in Figure 3.

We observed that the conductivity increased for the two aging stages of the mineral oil. This indicates that increased acid content and broken molecules reflected by the increased viscosity and TAN of the oil lead to a change in the conductivity measurements. As the oil from the field did not have significant changes in TAN or viscosity, only a slight increase in the conductivity was observed. The offset of the sensor in the vertical pipe was also observed in this test, which is related to the calibration process of the sensor itself, as explained in Section 4.2.1.

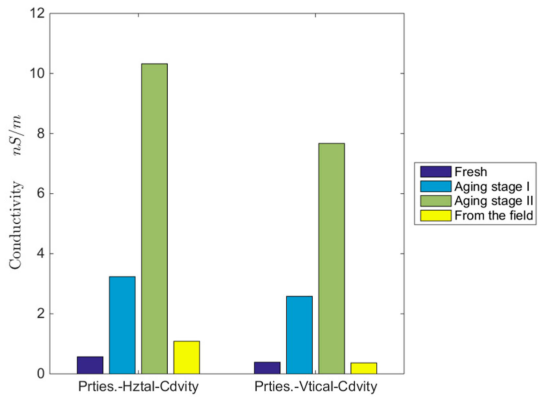


Figure 3. Conductivity measurements of fresh and aged mineral oil.

The results of the testing with the oil properties sensors showed that the measurement range of the sensor and the accuracy are not sufficient. This is caused by the large variability of the oil electrical properties, as shown bythe very low conductivity of PAO I and the very high conductivity of PAG. Moreover, the robustness of the sensor is limited due to the compensation algorithm. The sensor is very sensitive to changes in the conductivity, even after temperature compensation. In [67], three oil sensors measuring dielectric constant and two measuring conductivity were tested with a low-viscosity gear oil. The results of the tests with these sensors showed that, even after temperature compensation, the sensors also exhibited variation in the conductivity measurements. These measurements with fresh oil support the results obtained during this study, as we also observed changes in the conductivity measurements during the stepped temperature profile with fresh oil. Additionally, the sensors showed considerable difference in the absolute values of their conductivity measurements. During the tests carried out in [67], measurements with aged oil from oxidation test were performed. In these tests a conductivity increase was also observed with increased aging hours. It is important to note that the oil used for the oxidation tests in [67] was also a mineral oil. This confirms that oil sensors can correlate the oxidation and the thermal aging with a change in the conductivity for oils with a mineral base stock. However, the absolute conductivity values can only be considered a qualitative degradation indicator, as a good accuracy and repeatability of the measurements with different sensor manufactures could not be confirmed. As a result, the robustness of the sensors needs to be improved by implementing more appropriate compensation algorithms to deal with operation outside the temperature used for the learning phase and changes in the oil properties due to refills or oil changes.

4.3. Micropitting Tests

As shown in Table 1, these tests were carried out for all fresh, laboratory, and field-aged samples of PAO I, mineral oil, and PAG. The results of the tests demonstrated that all the oils exhibited a high micropitting resistance, achieving a GFTK-class larger than 9. Each oil was tested two times, once per flank side. The average profile deviation of the flank (ffm) from the test with fresh oil, laboratory-, and field-aged samples as a function of the load stage is illustrated for PAO I in Figure 4. Similar results were obtained for all fresh oils and all aging stages. The dotted red line denotes the maximum allowed deviation of 7.5 µm at load stage 9. After a test with a lubricant, in which a lower deviation than 7.5 µm was measured, the lubricantcan be classified with GFTK-class larger than 9, implying high micropitting resistance. It is important to note that this test method can only be seen as a screening test. This means that the changes in the micropitting resistance have to be very sharp to be seen in the profile deviation. As the test results indicate, it was not possible to correlate the changes in the EP/AW additives due to the oil aging in the laboratory and in the field with a change in the micropitting resistance (Section 3.2.3).

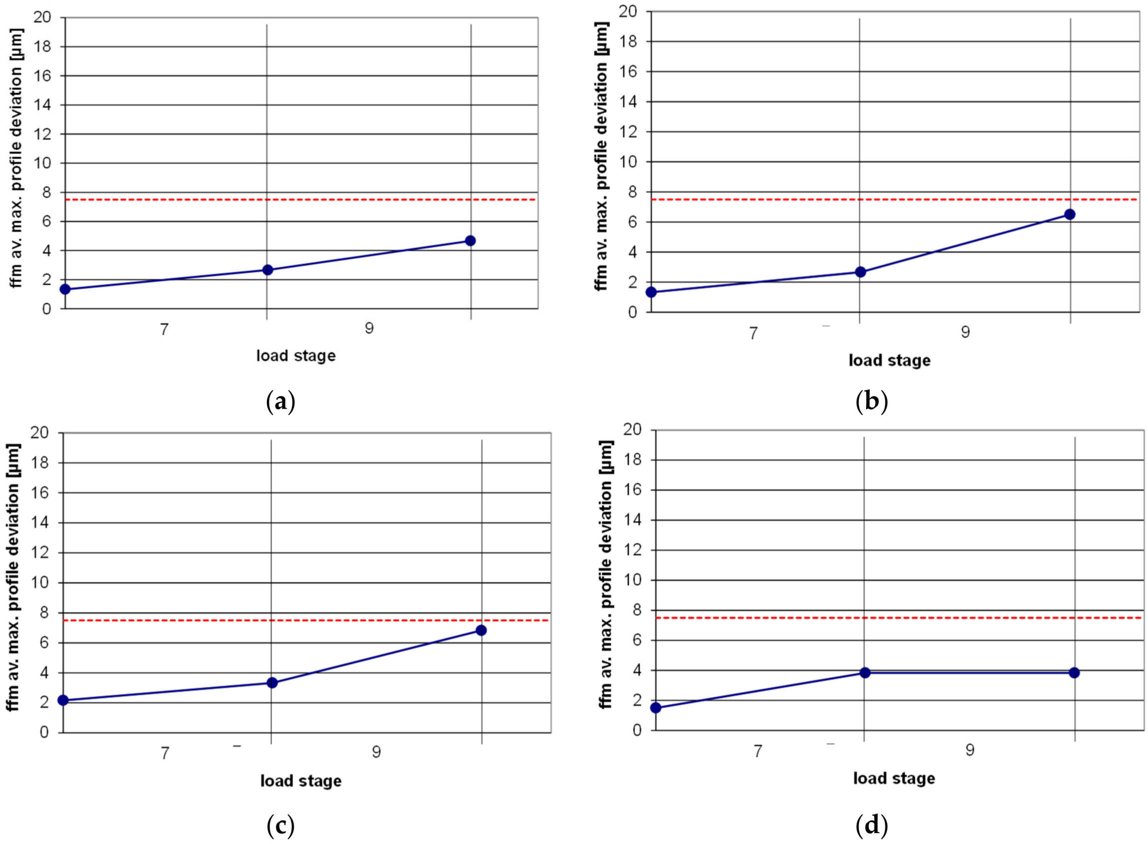


Figure 4. Micropitting test results for PAO: (**a**) fresh oil; (**b**) oil aging stage I; (**c**) oil aging stage II; (**d**) oil from the field.

4.4. Combined Analysis from Oil Samples and Wind Turbine SCADA Data

SCADA data from a 3.4 MW wind turbine with PAO II were analyzed to obtain information about the changes in the oil properties in respect to the operating conditions of the wind turbine. The operating time during three calendar years was analyzed. This means that only positive active power bins were considered ($P_{act} > 0$). The operating time of the turbine divided in 17 active power bins of 200 kW is illustrated in Figure 5.

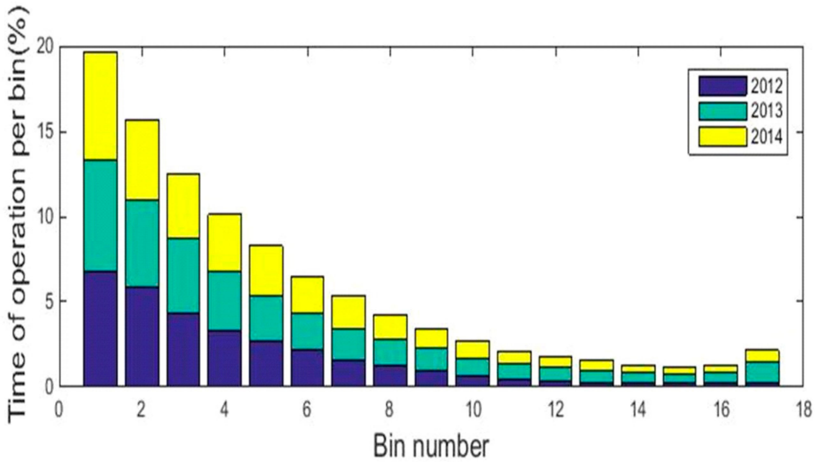


Figure 5. Power bins of 200 kW for the total operating time of the wind turbine with PAO II.

As shown in Figure 5, this turbine operated mostly in partial load during the three calendar years considered in this analysis. During approx. 60% of the operating time throughout the three calendar years, the turbine produced power below 1000 kW and around 35% below 400 kW. Oil samples were collected during the operation of the wind turbine and analyzed in the laboratory with the methods described in Section 3.2.1. The viscosity change, TAN, additive, and iron content are shown in Figure 6. It is worth noting that the operating hours of the turbine ($P_{act} > 0$), as shown in Table 5, do not correspond to the calendar time, as the wind turbine produces power only after achieving the cut-in wind speed and the turbine is also turned down during maintenance activities. Therefore, the calendar time can be larger than the operating time.

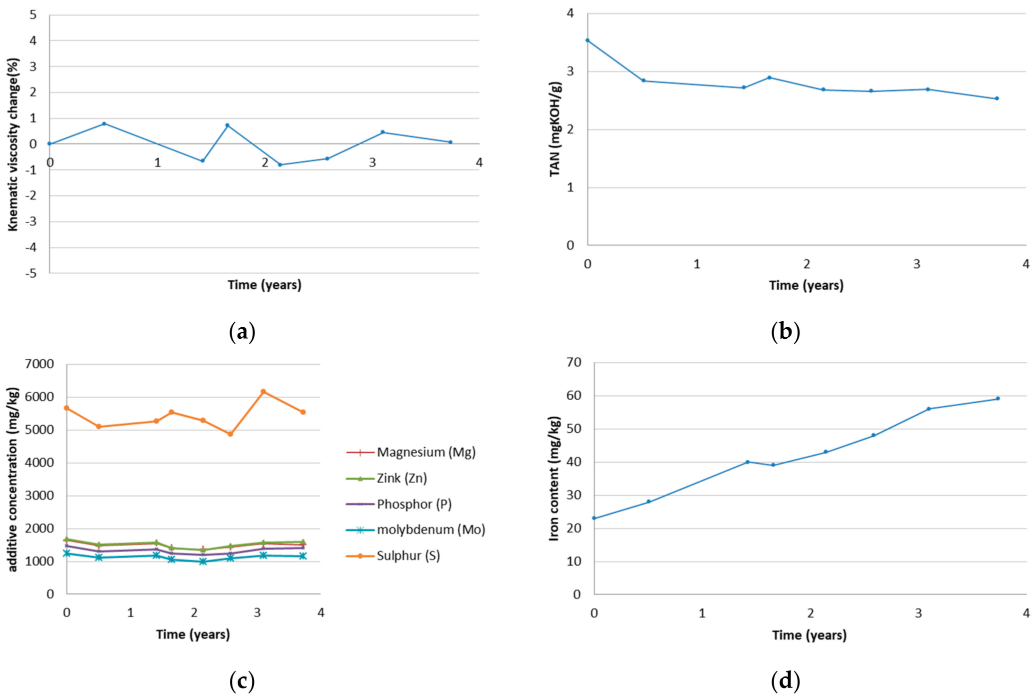
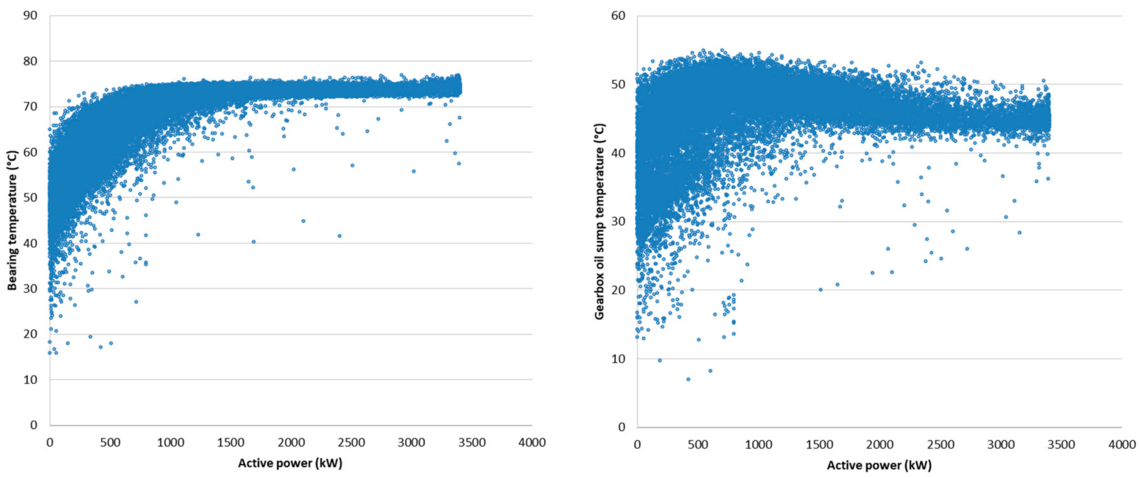


Figure 6. Sampling results of PAO II during the period of analysis. (**a**) Changes in the kinematic viscosity; (**b**) TAN; (**c**) additive content measured by the ICP method; (**d**) iron content measured by the ICP method.

We observed that the viscosity did not show any significant change. The measured values vary between ±1%. This variation is associated with the accuracy of the method and is not related to the operating condition of the turbine or any tribological process. TAN shows a decrease during the period of analysis. TAN is affected by the additives and oil oxidation. The decrease in TAN is caused by the slight decrease of additives. In some cases a slight increase from one sample to the other can be observed. This can have several reasons. One of them is that a small amount of oil (20–50 L) might have been poured into the gearbox during service, providing fresh additives. Another reason can be the sampling point and the difference in the concentration of the additives in the sample. Sulfur showed higher variations than the other elements. Even if the ICP method provides a good accuracy for most of the elements, in the case of sulfur, the method has a larger variability. The characteristic wavelength of sulfur obtained to perform the ICP measurements is similar to that of daylight. This similarity in the characteristic wavelength can cause a larger uncertainty in the measurements than for other elements. Due to the variability in the sulfur measurements, changes in the sulfur content should only be considered an auxiliary measurement to perform qualitative analyses.

The measurements of the iron content show a progressive increase. It is important to note that this measurement is related to dissolved iron, which is chemically bounded to the oil. The iron content does not give an indication of abrasion wear characterized by the production of bigger particles, which cannot be detected by the ICP method. However, if the measured iron is not ferromagnetic, the iron content gives an indication of ferrous oxides typical for corrosion products. The amount of ferromagnetic iron can be quantified by the particle quantifier (PQ) index, which in this study was very low and therefore not taken into consideration. The particle size of chemically bounded iron is typically smaller than 5 µm. Therefore, the iron content is unlikely to be removed by filtration. Consequently, a reduction of this value is usually achieved only by changing the oil or by pouring fresh oil into the gearbox. Thus, a significant decrease in the iron content also provides information about a possible oil change or refill, so an increase of the additives concentration can be attributed to one of those possibilities. In this particular case, a refill does not appear to be the reason behind the increase in the additive measurements, as the iron content increased constantly. One possible reason could be the different concentration of additives in the gearbox. In order to relate the changes in the oil and the operating condition of the wind turbine, the temperature power functions of one gearbox bearing and the gearbox oil sump during the first oil-sampling interval of approx. six months is shown in Figure 7.



(**a**) (**b**)

Figure 7. Gearbox temperature power functions during the first oil sampling interval of approx. six months. (**a**) Bearing temperature as a function of the active power ($P_{act} > 0$); (**b**) gearbox oil sump temperature as a function of the active power ($P_{act} > 0$).

The plots in Figure 7 show that a high temperature of the bearing and the gearbox oil sump is also achieved at power lower than 1000 kW and not only at high power production. The temperaturepower analysis was also carried out for other sampling intervals showing similar behavior. This indicates that for partial load the bearings also have a high temperature. Mixed lubricating conditions and loading of bearings and gears activate additives; therefore, a reduction in the additives during this period is expected. As additives deplete, the TAN decreases, as clearly observed in sampling interval 1 in Figure 6b,c. For the next sampling intervals the number of operating hours was variable, but also showing high temperature at low power. As the operating hours of each interval were different, it was not expected to obtain a linear decrease of the additives or TAN. However, we observed that even if sampling interval 2 was longer, TAN and the additives decreased more slowly than in intervals 1 and 3. This is explained by the fact that the turbine operated with a higher power range and higher temperature in intervals 1 and 3, as shown in Table 6. This analysis shows that the higher changes in the additives correlate with the intervals with higher average power, higher bearing temperature, and higher wind speed.

We observed that under these operating conditions and after almost four years, the oil showed only slight signs of degradation and was suitable for further use. Therefore, no detrimental effects on the gearbox due to oil degradation were expected in this particular case. As this wind turbine operated mostly at partial load, it will be meaningful to assess the oil properties' changes due to combined high temperature and high loads at full power or the effect of extreme temperatures (cold/hot environment) by including more turbines in a similar analysis. However, the oil sampling laboratory results together with SCADA data are mostly confidential and no further data were available to perform an extended analysis.

Table 6. Average power, bearing temperature, and wind speed during the first three sampling intervals.

	Power (kW)	Bearing Temperature (°C)	Wind Speed (m/s)
Sampling interval 1	881	61.9	5.7
Sampling interval 2	787	60.6	5.4
Sampling interval 3	1094	64.8	6.2

Even if the analysis with PAO II provided some indications of oil degradation related to the operating conditions of the wind turbine, oils have diverse additive packages that can react differently. In order to better understand the changes in the oil parameters and observe similarities with other oils with the same base stock but a different additive package, a trend analysis was carried out for 14 wind turbines filled with PAO I. For the turbines under analysis, no oil change has taken place. However, the possibility of small refills cannot be totally discarded, as these minor refills are not always documented. The turbines under analysis are divided into two groups:

- four-year group: This group corresponds to seven turbines with an operating time around four years with two different ranges of the rated power.
- eight-year group: This group corresponds to seven turbines with an operating time around eight years.

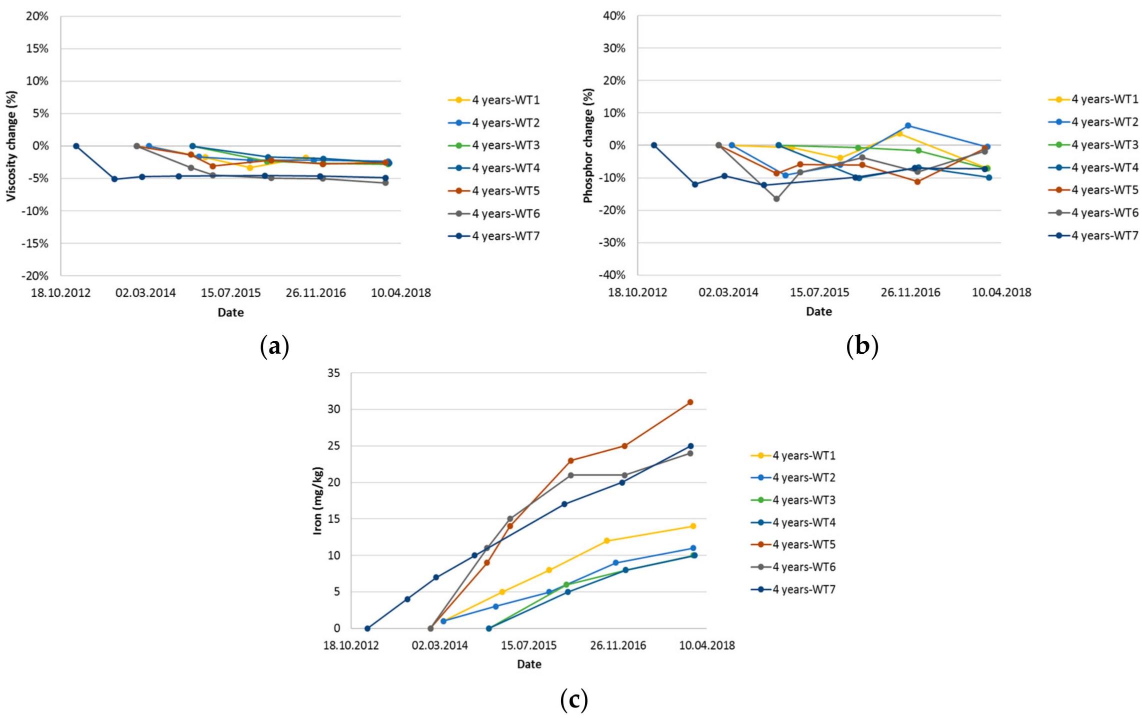
The operating years and the power range of each turbine of the four-year group are shown in Table 7. The results of the trend analysis are shown in Figure 8.

Table 7. Turbine data of the four-year group for trend analysis with PAO I.

Turbine Designation	Operating Time (years)	Power Range (MW)
4 years-WT1	4.0	3 to 4
4 years-WT2	3.7	3 to 4
4 years-WT3	3.1	3 to 4
4 years-WT4	3.1	3 to 4
4 years-WT5	4.0	3 to 4
4 years-WT6	4.0	2 to 3
4 years-WT7	4.9	2 to 3

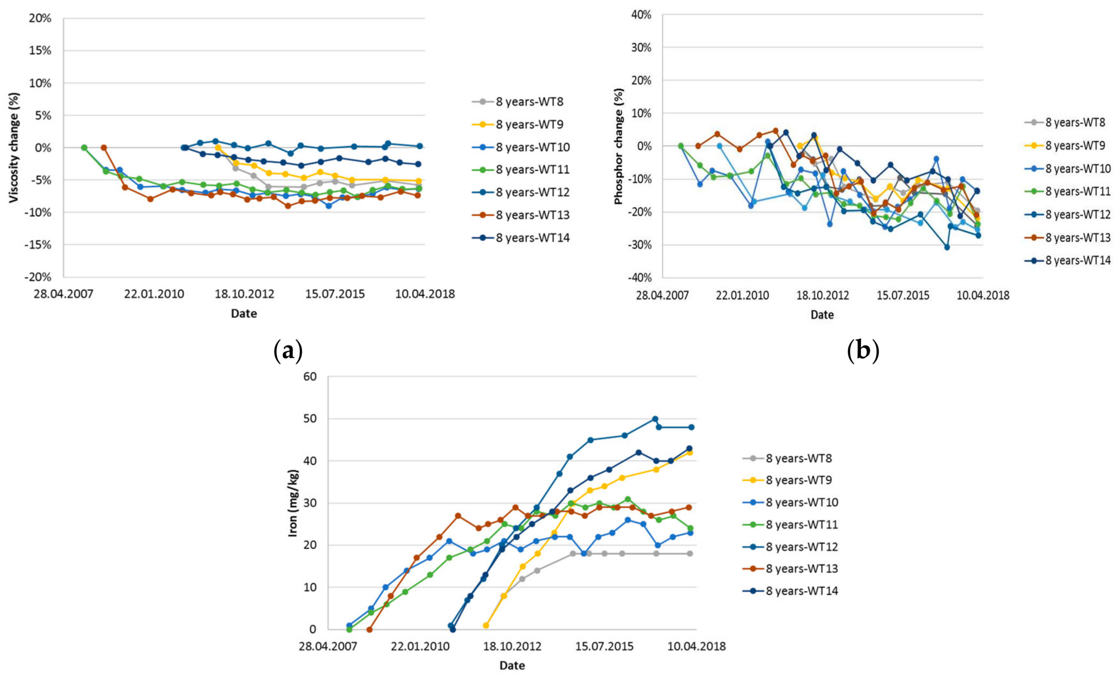
As illustrated in Figure 8, the viscosity tends to decrease at the beginning of the period of analysis. It is important to note that gearboxes are usually filled with a lower-viscosity fluid to be cleaned out. The rest of this fluid could cause this minimal change in the viscosity. After this first slight decrease, the viscosity remains almost constant within the accuracy of the method around $\pm1\%$. Similar behavior is observed in the phosphorus content. However, the measured values tend to oscillate and after the end of the analysis period no significant decrease is observed. Concerning the iron content, we observe a progressive increase of chemically bounded iron. The viscosity behavior is similar to that of the turbine filled with PAO II. In contrast to PAO II, the TAN did not show any significant change and is therefore not illustrated in Figure 8. It is important to note that four-year and eight-year designations are related the operating time (active power larger than zero) and not to the calendar time. Therefore, there could be turbines with a longer calendar time than the operating time, as the turbine did not operate continuously throughout the years under analysis.

The operating years and the power range of each turbine of the eight-year group are shown in Table 8. The results of the trend analysis are shown in Figure 9.



(a) (b) (c)

Figure 8. Trend analysis for the four-year turbine group with PAO I. (**a**) Changes in the kinematic viscosity; (**b**) changes in the phosphorus content measured by the ICP method; (**c**) iron content measured by the ICP method.



(**a**) (**b**) (**c**)

Figure 9. Trend analysis for the eight-year turbine group with PAO I. (**a**) Changes in the kinematic viscosity; (**b**) changes in the phosphorus content measured by the ICP method; (**c**) iron content measured by the ICP method.

The viscosity tends to decrease at the beginning of the period of analysis, as observed for the four-year analysis. As discussed before, the rest of the flushing oil could cause this minimal change in the viscosity. After this first slight decrease, the viscosity values remain almost constant with a variation smaller than 5%. The phosphorus content shows a general trend to decrease. As mentioned previously, the values of phosphorus can vary due to small refills or due to the variation of the concentration of the sample compared to the bulk concentration in the gearbox. Concerning the iron content, we observe a progressive increase of chemically bounded iron, as expected from long normal operation. The TAN did not show any clear trend and no signs of degradation could be seen directly.

This analysis also pointed out that the oil viscosity did not change significantly, even after eight years of operation. In order to verify that the oil viscosity remains relatively constant in wind turbine gearboxes, the viscosity measurements of approx. 200,000 oil samples from the last 10 years were analyzed. As the amount of samples from PAG and the operating time of turbines with this oil were small compared to the other oils, we did not consider PAG for this analysis. Table 9 shows the amount of samples used for the calculation of the oil viscosity at 40 °C and its corresponding standard deviation.

Table 8. Turbine data of the eight-year group for trend analysis with PAO I.

Turbine Name	Operating Time (years)	Power Range (MW)
8 years-WT8	6.1	2 to 3
8 years-WT9	6.1	2 to 3
8 years-WT10	9.9	2 to 3
8 years-WT11	10.2	2 to 3
8 years-WT12	6.7	2 to 3
8 years-WT13	9.0	2 to 3
8 years-WT14	6.8	2 to 3

Table 9. Mean and standard deviation of the viscosity at 40 °C from a database of oil samples.

Oil Designation	Approx. Number of Samples	Mean Viscosity at 40 °C (mm^2/s)	Standard Deviation (mm^2/s)
PAO I	76,000	326.2	11.7
PAO II	40,000	325.8	8.6
PAO III	7500	319.9	9.9
Mineral oil	31,000	321	9.1
Mineral oil II	44,000	319.3	8.8

The results show a standard deviation corresponding to less than 4% of the mean viscosity for all oils. The samples exhibited a normal distribution, as shown in Figure 10. Therefore, we can state that 95% of the samples have a variation in viscosity lower than 10% of the mean viscosity. Hence, 95% of the oils under analysis have a viscosity within the limits of the VG 320. This confirms that viscosity in wind turbine gearboxes does not exhibit significant changes during normal operation.

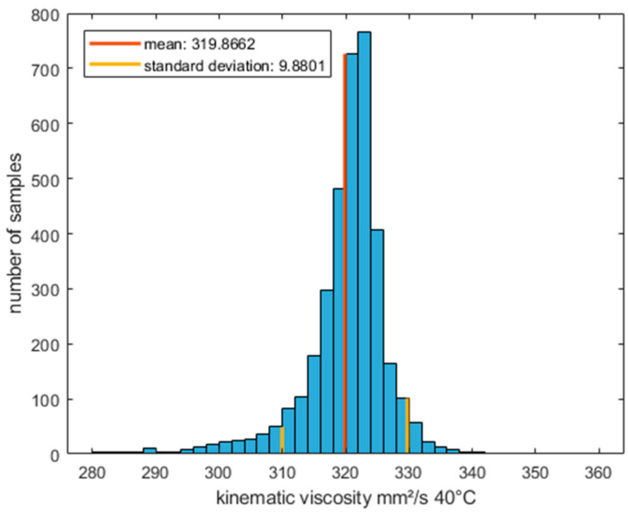


Figure 10. Distribution of the kinematic viscosity at 40 °C of PAO III.

5. Discussion

5.1. Oil Aging in the Laboratory and in the Field

Based on the results of the laboratory oil aging process, we confirmed that oil thickening due to thermal aging took place for all the oils, as can be seen by an increased viscosity of the oil. An increase in the TAN also indicated oil oxidation, as we expected. The behavior of the PAG showed an increase in the TAN, but few changes in the S–P additives. This indicates a difference in the antioxidant content of the PAG. We also observed that the S–P additives in the mineral oil and PAO are highly reduced. According to the review in Section 2.1, S–P could also act as an antioxidant; however, for PAG this was not the case.

The field aging showed, as expected, insignificant changes in the viscosity of the oil and the TAN. A reduction of the TAN for the PAO II was observed, which can be attributed to the slight additive depletion. PAG showed an increase in the TAN, with no increase in the viscosity. However, the changes in the TAN cannot be explained based on this study, as the operating conditions of the wind turbine with the PAG are unknown.

5.2. Combined Analysis from Oil Samples and Wind Turbine SCADA Data

The combined analysis of oil sampling with SCADA data showed that the wind turbine under analysis was operating with high gearbox bearings temperatures at a very low power level. During the operation of the turbine, zinc, molybdenum and phosphorus decreased by around 5%. Even if 5%

does not seem that significant, PAO II is an oil with high content of additives compared with PAO I. For example, in PAO II, molybdenum has a concentration around 1200 ppm and phosphorus around 1500 ppm, while PAO I has no molybdenum and the phosphorus concentration lies around 400 ppm. Therefore, 5% phosphorus in PAO II corresponds to approx. 75 ppm, while for PAO I, 5% corresponds to only 20 ppm. This slight degradation in PAO II is reflected in the TAN, which showed a progressive decrease. To obtain more information about the changes in the oil properties, samples from PAO I were analyzed in trend, without oil change. The results of the analysis showed that the TAN measurements were not providing a clear trend of oil aging; however, the phosphorus content decreased up to 30%. For all the samples under analysis, the iron content showed a progressive increase. This value is a good indicator of the production of ferrous oxides and its presence in the oil can only be strongly affected by an oil change. Therefore, iron content gives a good indication of the degradation process of the gearbox and the oil. It is important to note that the turbine under analysis did not exhibit any problems with increased water content, oil cleanliness, mix of lubricants, or extreme damage of bearings or gears. These factors directly affect the oil and reduce the life span of bearings. Other elements like copper or zinc and the PQ index were not considered in this study. However, these parameters can also provide valuable information about wear and corrosion processes in the gearbox and should also be monitored.

A statistical analysis was performed to determine if the viscosity is significantly affected by the operation of the wind turbine. After the analysis of almost 200,000 samples, we observed that around 95% of the viscosity measurements for PAO and mineral oil remained within the limits of the VG 320.

6. Conclusions

Several tests were carried out to analyze the degradation of wind turbine gearbox oils. Oil samples, oil sensor measurements, and micropitting tests were carried out on fresh and aged oils of different base stocks. Oil sampling provided reliable information about viscosity, TAN, and additives. The TAN was a degradation indicator only under strong thermal aging of the oil. Concerning the oils from the field, the TAN only decreased for one oil with high content of additives (PAO II) due to the depletion of these additives. PAG showed very different behavior as it has a very different composition compared to PAO and mineral oil. The element analysis provided evidence of additive depletion, mainly based on phosphorus, molybdenum, zinc, and magnesium. Depletion of sulfur was difficult to observe due to the higher uncertainty in the measurements. The iron content was shown to be a reliable indicator related to production of ferrous oxides and can be easily monitored with a trend analysis. The viscosity of the oils from the field did not show any significant change during the operation of the wind turbine. This result was verified with approx. 200,000 samples of mineral oil and PAOs, which confirmed that approx. 95% of the analyzed samples had a viscosity within the acceptable range of the VG 320. Further studies correlating the effect of extreme ambient temperature, high power production, and loading of wind turbines with changes in the oil properties will contribute to determining further oil degradation drivers for wind turbine gearboxes.

The results of the oil sensor testing indicated that the oil sensors considered have a limited capability to identify oil aging and depletion of additives. However, there are other sensors in the market with higher resolutions and different features, which may show different results. As the applicability of the sensor depends on the oil type, its measurement range, and its accuracy, further tests are required to validate the sensors for this type of application.

The micropitting tests showed that all the oils in all aging stages had very high micropitting resistance. Based on these screening tests, we could not relate the depletion of AW/EP additives to significant changes in the micropitting resistance.

Based on the results of this study, we can state that oil sampling is still a very valuable method for monitoring the oil condition. The conductivity and dielectric constant measurements carried out in this study provided limited information on oil degradation and did not exhibit direct advantages compared to oil sampling. Even if oil sensors provide continuous measurements, in contrast to oil sampling, this approach implies more costs and the accuracy of the sensors is not always validated with standardized procedures. The added value of OCM lies in its capability to reliably detect unexpected faults in the gearbox and not only negative changes in the oil properties. This means that the sensors and oil sampling should provide support for the currently implemented vibration-based CMS, acting as a complement in an integrated approach. Furthermore, oil sensors should also be robust enough to operate continuously for years, providing reliable measurements, and should be able to associate measurement signals with negative changes in the oil properties and gearbox faults. Numerous sensor manufacturers and new sensor technologies are available and standardized test procedures will facilitate the validation and integration of oil sensors in the current CMS of wind turbines.

Author Contributions: Conceptualization, D.C.; Methodology, D.C. and J.W.; Validation, D.C.; Formal Analysis, D.C. and J.W.; Investigation and literature review, D.C.; Resources, D.C. and J.W.; Data Curation, D.C.; Writing-Original Draft and Preparation, D.C.; Writing-Review & Editing, D.C. and J.W.; Visualization, D.C.; Supervision, D.C. and J.W.; Project Administration, D.C. and J.W.; Funding Acquisition, D.C. and J.W.

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Conflicts of Interest: The authors declare no conflict of interest.

Acronyms

AW	Anti-wear
CM	Condition Monitoring
CM	Condition Monitoring System
DIN	German Institute for Standardization
DGMK	German Society for Petroleum and Coal Science and Technology
EP	Extreme Pressure
FZG	Gear Research Centre
GFKT	Micropitting Short Test
ICP	Inductively Coupled Plasma
ICE	Internal Combustion Engines
IEC	International Electrotechnical Commission
KOH	Potassium Hydroxide
OCM	Oil Condition Monitoring
O&M	Operation and Maintenance
PAG	Poly-alkylene-glycol
PAO	Poly-alpha-olefin
PQ	Particle Quantifier
SCADA	Supervisory Control and Data Acquisition
TAN	Total Acid Number
VG	Viscosity Grade
VI	Viscosity Index
WEC	White Etching Cracks
ZDDP	Zinc Dithiophosphates

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