Operations and Maintenance Recommended Practices

Chapter 8 Condition Based Maintenance

version 2017

ACKNOWLEDGEMENTS

The American Wind Energy Association (AWEA) Operations and Maintenance (O&M) Recommended Practices (RP) are developed through a consensus process of interested parties by AWEA O&M Committee. These RPs represent decades of experience from the members of the AWEA O&M Committee. This expertise, often gained from other industry sectors, helps inform, train and support wind energy technicians and managers in their efforts to improve reliability and project performance. These are, in general, the nuts and bolts of wind energy power plant maintenance and operations. As the industry matures, additional maintenance strategies and operations philosophies will certainly come to the fore, however, these basics will always be required knowledge for new technicians and asset managers expanding their areas of responsibility.

Development of the AWEA O&M RPs started in 2009, with the first edition publication in 2013. The current version is the result of hundreds of hours of volunteer time by many people and we, the AWEA O&M Committee Chairperson, Kevin Alewine, and Vice Chairperson, Krys Rootham, wish to thank all of the individuals who have participated in the AWEA O&M Committee to develop these documents and the companies that continue to allow those efforts, as well as, sharing their technical know-how.

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- AWEA O&M Steering Committee
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- Condition Monitoring Subcommittee
- Data Collection and Reporting Subcommittee
- End of Warranty Subcommittee
- Gearbox Subcommittee
- Generator Subcommittee
- Operations Subcommittee
- Tower Subcommittee
- Tower Auxillary Subcommittee

Again, thanks to everyone for their continued support for development of these recommended practices. Please contact any of us if you have questions or comments (OM@awea.org) regarding the Committee or these documents.

Thanks again for the efforts and accomplishments,

Kevin Alewine, Shermco
Chairperson, AWEA O&M Committee

FORWARD

The AWEA Operation and Maintenance Recommended Practices are intended to provide establish expectations and procedures to ensure all personnel performing service and maintenance on wind turbines have a minimum knowledge base.

The AWEA Operation and Maintenance Recommended Practices (O&M RPs) are not “best” practices nor the only procedures that should be followed. They represent suggestions from experts in the field who have refined their procedures over time. The preferred procedures in the future will no doubt change with improved communications, technology, materials and experience. These AWEA O&M RPs will be revised as needed.

The AWEA O&M RPs were initiated in 2009 and created by members of the AWEA O&M Committee to ensure that the future wind industry benefits from the experience gained from the past. Individual members donated their time and expertise to document these procedures.

The AWEA O&M RPs are organized into “chapters” to address the major functions of a wind turbine and its operation. Individual recommended practices address specific procedures used in each of those areas.

Many other organizations have developed consensus standards, recommended practices, best practices, etc. that also offer excellent supporting information for effective wind farm operations and maintenance. IEEE (Institute of Electrical and Electronic Engineers), NETA (International Electrical Testing Association), SMRP (Society for Maintenance and Reliability Professionals), AGMA (American Gear Manufacturer’s Association) just to name a few. These sources should be reviewed in developing sound maintenance strategies.

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The wind energy industry is covered by OSHA regulations for worker safety and health practices. §29 C.F.R 1910.269 is the OSHA standard that regulates employee safety in the operation and maintenance of electric power generation, transmission and distribution facilities and installations, which covers the wind energy industry and §29 C.F.R 1926, for construction activities.

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Chapter Eight: Condition Based Maintenance

*These RP's did not require updates from the original 2013 version.

RP 801 Condition Based Maintenance (CBM)

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chair: Junda Zhu, Ph.D., Senior Data Scientist, NRG Systems
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Purpose and Scope

The scope of “Condition Based Maintenance (CBM)” provides an overview of the condition based maintenance strategy along with examples of some of the existing technologies utilized to perform condition monitoring on wind turbines. This document serves as the introduction and foundation for the rest of the 800 series of recommended practice chapters. For further detail on any of the specific technologies mentioned in this chapter, please look into the rest of the RP 800 series.

Introduction

Following in the footsteps of other industries, the wind energy industry operations and maintenance have been evolving towards predictive maintenance strategies to maximize the turbine availability while minimizing the production interruption due to operational failures. A conventional event-based maintenance strategy is recognized to be not as optimal due to unexpected shutdowns and potential safety concerns related to the catastrophic failures with no early warnings. On the other hand, scheduled based maintenance, while significantly improves the turbine availability, still falls short on cost optimization since failure occurs in between the maintenance cycles.

Introduction
(continued)

As the wind industry is exploring territories that are much more remote, drive train operational situation awareness is considered crucial for turbine availability and maintenance cost optimization. Predictive maintenance strategy based on condition monitoring technologies are considered the direction where the industry is moving towards. Predictive maintenance is to schedule maintenance action based on the actual or the projected condition of a single component or the overall turbine operational health condition. Hence, this is also referred to as condition based maintenance. The maintenance activities at the site are only carried out when it is necessary or convenient. The condition of the component can be assessed through a variety of condition monitoring technologies like commonly seen vibrations analysis and particle counters among others.

With the help of properly instrumented condition monitoring hardware and algorithms, the operator will have full situation awareness and overview of the operational condition down to critical components of the turbine. With the information available from these systems, the maintenance team can optimize the maintenance activity and decide the right time to service the right component. Hence, the maintenance cost along with the turbine downtime can be greatly reduced. Establishing the right maintenance strategy and practices for your fleet can make the difference between a profitable operation versus one that is not.

Traditionally speaking, a properly deployed condition monitoring system involves many aspects including hardware instrumentation, data collection and storage system configuration, fault detection, diagnostic, severity assessment, prognostics, action recommendation, inspection/repair, and knowledge preservation. It is important for the end user of a condition monitoring system to understand these aspects in order to select a system that is capable and effective when deployed. The following list provides the end user a checklist to go over when choosing a system that fits their budget and needs.

1. Hardware Instrumentation

The hardware deployed should be carefully selected so that they are right for the section of components which the condition monitoring system is supposed to cover. The mounting location is also crucial for effective and accurate diagnostics. Orientation of the sensor, sensitivity of the sensor along with the measurement capability (e.g. spectrum range) should all be well selected for wind application.

2. Data Collection, Transfer, and Storage

Modern condition monitoring systems take measurements much more frequently than ever before. On one hand, data can provide insight of fault location and modes. On the other hand, if not careful, data accumulates in an uncontrolled manner and will result in high data storage cost. Collecting data more frequently than necessary will also increase the load on the data bus which potentially can affect other critical information from being transmitted.

3. System/Sensor Configuration

The sensor needs to sample at the right frequency for the component it is monitoring and have sufficient resolution for the proper analysis. The configuration should also take into account the component kinematic if the information is needed for further analysis. The data collection triggering condition sometimes needs to be predefined as well.

4. Fault Detection

Early fault detection is one of the major advantages of instrumenting condition monitoring systems. To be able to achieve early fault detection, the proper algorithm needs to be integrated to capture early signs of degradation. The algorithm implemented should be designed specifically for wind applications that cope with the operational characteristics of a wind turbine. The correct fault detection algorithm should be able to provide consistent and stable readings of the fault signature in advance allowing the operator enough time to react.

5. Diagnostics

Diagnostics, commonly referred to as fault localization and fault mode identification, is the analysis procedure to find the fault location as well as the type of fault. There are multiple algorithms developed using a variety of instruments to determine the fault mode. Different fault modes result in different maintenance priorities. For example, widespread scuffing damage should be treated more carefully compared to localize spalling. The user of the CMS system should also contact the supplier on what type of fault the systems is capable of detecting.

6. Severity Assessment

Upon successful detection of the fault, the next question that one should answer is the severity of the fault. There are multiples ways to assess the degradation level of the component. Some of the CMS suppliers use absolute references like ISO 10816 while others set up statistical thresholding methodology among the fleet. The choice of methodology for severity assessment should be evaluated together with the corresponding measurement and it characteristics.

7. Prognostics

Prognostics or remaining useful life prediction is considered one of the most challenging topics in the industry and academia. Given the fault mode and severity, to predict the end of life for a component is always a difficult task. Various kinds of faults develop dramatically differently. While some of the faults may be existing for years without interrupting production, others do fail catastrophically in a very short period of time resulting in massive asset damage. Some algorithms that specialized for prognostics are Kalman/particle filtering algorithm among other statistical intensive methodologies. The prognostics algorithms are also subject to various measured parameters along with frequency of measurements.

8. Action Recommendation

The actionable information is one of the most valuable outputs a condition monitoring system can provide to the operator of a wind farm. Once the fault mode, severity, and the predicted remaining useful life have been estimated, it is the job of the CMS or the analyst to offer the operator some recommended action. Commonly given suggestions include, keep monitoring, inspection when convenient, inspection soon, etc. If the degraded component is not accessible for inspections, then repair or replacement should be considered.

9. Inspection/Repair

Once a recommendation is offered, the site team should inspect or service the affected component, if inspection is not possible. This is normally done at the site level. The only item that needs to be addressed is if the component was replaced, it is sometimes quite helpful to let the CMS supplier know the make and model of the new component that was installed. On top of that, inspection pictures on the failed components can be very helpful for the fine tuning of the condition monitoring system.

10. Knowledge Preservation

No condition monitoring system is perfect, the diagnostics, as well as the severity assessment, should have the option to be fine-tuned using the feedback from the site team. Therefore, the inspection report along with the input from the inspection team ought to be reviewed in detail. Only by working with the maintenance team and communicating with the operator can a CMS be harnessed to its full potential.

10. Knowledge Preservation
(continued)

Condition monitoring solutions, when applied in the wind energy industry, must address some unique issues. Due to the stochastic nature of the wind, the incoming wind speed and direction are almost always changing. This leads to fluctuating drive train speed and load. Combined with the complicated design of turbine components such as gearbox planetary section, it is crucial that a deployed condition monitoring solution can overcome such issues and provide accurate and consistent readings that can be interpreted to evaluate the health of the component. There are multiple commercial condition monitoring solutions available. RP 801 focuses on some of the key technologies in the wind energy industry.

Condition Monitoring Technologies

1. Vibration Analysis

Vibration analysis is one of the most commonly available condition monitoring solutions in the industry. The technology of using vibration to perform non-destructive evaluation has been implemented by a selection of industries since the 1960's. The hardware along with the algorithm has been refined over the years. Typical measurements are acceleration and velocity. The collected signal will be processed by time, frequency, or time-frequency domain analysis techniques to extract mechanical fault signatures. The conventional vibration signal processing method is designed for stationary machinery. When applied to the wind energy industry, it is crucial that the system compensates for the drivetrain speed fluctuation in order to obtain consistent results. RP 811 "Vibration Analysis for Wind Turbines focuses on vibration based condition monitoring techniques" explains vibration analysis in detail.

2. Acoustic Emission

Acoustic emission or AE is the phenomenon of transient elastic wave generation due to a rapid release of strain energy caused by structural alteration in a solid material under mechanical or thermal stress. It was a solution for incipient fault detection using much higher sampling rate than vibration signals. There are also quite a few publications proven that this technology can provide early fault detection when compared with vibration analysis. However, due to the cost and high data sampling induced storage cost, the AE is not as widely implemented.

3. Debris Monitoring

Oil debris counter is one of the most commonly encountered CMS solutions. Recently, these measurements are normally taken in real-time. When fault occurs, metals are normally ground off the surface of the contacting surfaces. By monitoring the debris count in the oil flow, one can perform monitoring and fault detection of the drive train. RP 818 “Wind Turbine On-line Gearbox Debris Condition Monitoring” discusses this technique in detail.

4. Lubrication Oil Monitoring

Different from oil debris monitoring, lubrication oil condition monitoring monitors the oil health condition instead of the mechanical components. Oil analysis normally measures the cleanliness, water content, oxidation level, particle contamination, additive depletion, among many other key performance indicators. These indicators ensure the oil is operating at its optimal condition. Lubrication oil health is crucial to a wind turbine gearbox. RP 819 “Online Oil Condition Monitoring” covers this topic.

5. Grease Monitoring

Apart from the oil-lubricated components in the gearbox, components like generator bearings, pitch bearings, and main bearings are normally grease lubricated. One of the solutions to monitor the health of these components is by monitoring the grease condition. The detailed procedure to collect and analyze the grease sample from components along the wind turbine drive train can be found in RP 812 “Wind Turbine Main Bearing Grease Sampling Procedures” and RP 815 “Wind Turbine Grease Analysis Test Methods”.

6. Temperature Measurement

Temperature is one of earliest developed indicators of component health. Bearing manufacturers have long been aware of the relationship between bearing temperature and bearing life. Because of this relationship, temperature can be used to monitor bearing condition or other temperature sensitive components, such as generators. For further information please refer to RP 816 “Wind Turbine Temperature Measurement Procedures.”

7. Nacelle Process Parameters

Nacelle process parameter data is taken from process variables from the control system. Whether real-time or data stored in a plant historian, this data provides valuable insight into the holistic condition of the turbine. For further information please refer to RP 816 “Wind Turbine Nacelle Process Parameter Monitoring”.

8. Electric Current Analysis

The reliability and availability of wind turbine electrical and electronic components are critical to minimize life-cycle energy cost and benefit project financials. From up tower generators to substations, electrical current analysis can be widely used for the health indicator of mechanical or non-mechanical components. RP 831 "Condition Monitoring of Electrical and Electronic Components of Wind Turbines" discusses electrical current analysis in detail.

The above-mentioned condition monitoring technologies are merely a portion of what is available on the market today. Some of the other solutions have been mentioned in the rest of the recommended practice chapters. Systems tailored for the wind energy industry can ensure real-time health condition assessment coverage from the blades all the way to the non-drive end generator bearings. Most of the available systems take measurements periodically under certain operating conditions. For example, some of the measurements are only taken when the turbine is operating at a certain speed or at a certain section of the power curve. The frequency of measurement and the amount of data collected have to be balanced between necessity, the load on the data bus, and data storage cost, among others.

Different systems provide different health information regarding the turbine. There is no one technology that is more superior to the others. It is the responsibility of the owners and operators to evaluate the need of their wind farm and choose among all the available solutions.

While acknowledging the advantages of implementing condition monitoring technologies for the wind energy industry, the challenges should also be discussed. When it comes to slow-moving sections of the traditional planetary gearboxes, the early fault detection of the planetary section as well as the main bearing has always been a difficult task for many CMS suppliers. The issue is caused by slow rotating speed and poor vibration transmission path. Hence, it is important to carefully select hardware and algorithm combinations for these sections.

The properly deployed CMS can provide vital information on the wind farm site operating status. When fully integrated into the site maintenance logistics, maintenance actions can be coordinated across the farm and service calls can be better planned and optimized, all of which will increase the turbine uptime while reducing the maintenance cost, hence maximizing the profit margin of the entire operation. Moreover, with early detection of degraded components or drivetrains, less catastrophic failure will occur which increases the operational safety. Components are most likely to be operating at its optimal condition which directly leads to improved annual energy production.

Summary

The production cost is vital to the survival of wind energy as a viable future renewable energy source. Condition based maintenance plays a critical role in the significant reduction of operational cost. A, correctly and properly instrumented, wind turbine condition monitoring system can offer full operational situation awareness to the operator. With the help of the CMS, maintenance action can be performed only when it is necessary or convenient. Some of the cost-intensive down tower repairs can be avoided by detecting the fault in the early stage and a quick up tower servicing. Unplanned shutdowns can also be reduced to a minimum. The operator can also optimize the fleet-wide maintenance activities by consolidating services with the health information of all the similar degraded components at hand. Indeed there is an initial investment on the CMS, however, the return on investment is getting easier to justify due to the increased capability and reduced cost of modern condition monitoring technologies. Due to a wide range of available solutions in the market, it is crucial for the operator to select a system that is designed and tailored for the wind energy industry given its special needs.

Acknowledgement

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RP 811 Vibration Analysis for Wind Turbines

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Purpose and Scope

The scope of "Vibration Analysis for Wind Turbines" introduces wind energy professionals to vibration analysis methods used to detect and analyze machine component failures. This guide does not intend to make the reader an analysis expert. It merely informs the reader about common vibration analysis strategies and methods and lays the foundation for understanding vibration analysis concepts for the primary rotating components on the drive train of a wind turbine.

This recommended practice focuses specifically on the use of vibration analysis and encourages the consideration of additional condition monitoring technologies as part of a comprehensive pro-active maintenance strategy.

Introduction

The production cost of wind energy has decreased significantly, especially in recent years. According to the Department of Energy, that the cost of wind energy has decreased more than 90% since the early 1980's. And according to the American Wind Energy Association (AWEA), the cost of wind energy has dropped 66% just in the past 6 years. One major factor behind the wind energy production cost reduction is that the maintenance strategy of the industry is evolving from a schedule based maintenance to condition based maintenance or predictive maintenance.

Introduction
(continued)

Vibration analysis is one of the most commonly implemented condition based monitoring solutions in the wind energy industry. The fundamental theory of analyzing vibration data was established in the 1960s and vibration signal processing algorithms have been developing ever since. Back in the 1990s, time synchronous averaging algorithm was implemented which significantly increased the fault diagnostics capability on nonstationary machineries similar to a wind turbine drivetrain.

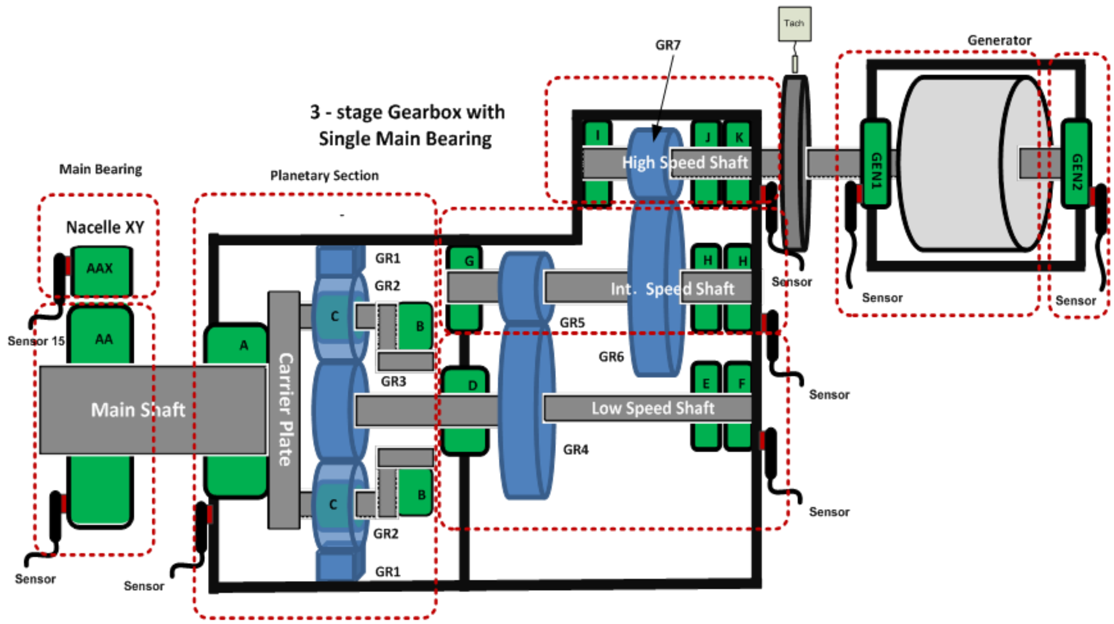
Due to the stochastic nature of the wind, the wind turbine drive train operational speed and load is always fluctuating. Traditional Fast Fourier Transform (FFT) based analysis techniques are not as effective when it comes to frequent speed variating components and is not capable of detecting non-periodical impacts in noisy environments such as gear fault signatures. The advantages of a well-instrumented vibration analysis, when compared with other practices, is the capability of early fault detection, fault localization in an online, real-time manner.

There are several key aspects of vibration analysis for wind turbines including:
- component coverage,
- sensor selection and configuration,
- sensor mounting,
- signal processing techniques,
- alarm setting or thresholding techniques,
- data interpretation, and
- severity assessment.

On top of these, there are several vibration standards commonly referenced by the industry. This article will discuss them in the following sections.

Component Coverage

Normal commercial condition monitoring systems have the capability of covering most of the drivetrain components. For bearings, we have the main bearing, carrier bearing, planetary bearing, low-speed shaft (LSS from now on) bearings, intermediate speed shaft (ISS from now on) bearings, high-speed shaft (HSS from now on) bearings, and generator bearings. For shafts, we have the main shaft, carrier shaft, planetary shaft, LSS, ISS, HSS, and generator shafts. For gears, we have the ring gear, planetary gear, intermediate pinion, intermediate gear, high-speed gear, and high-speed pinion. All the above-mentioned components are shown in the following figure. Also, normally one vibration sensor is assigned to monitoring an assembly.



Typical wind turbine drive train layout and sensor coverage.

Sensor Selection, Configuration, and Mounting

1. Sensor Selection

Vibration sensors are not the same. Accelerometers are the most commonly applied vibration sensor. However, they have different sensitivity, signal to noise ratio, spectrum range, frequency response, dynamic range, and so on. When combined with proper sensor configuration and algorithm, the sensor should be able to have enough sensitivity and resolution to monitor gear mesh and bearing fault peaks with a high signal to noise ratio. For a slow moving section of a wind turbine drivetrain, low spectrum range high sensitivity accelerometer should be applied. While in the high-speed section, spectrum range should be relatively high to cover the bearing fault frequency locations or the resonance band. A vibration condition monitoring sensor system precisely selected for wind applications can provide accurate diagnostics and be cost effective at the same time.

1. Sensor Selection
(continued)

Velocity sensors are also relatively common in the industry. Typically, velocity measurements are utilized to monitor low-frequency rotational faults (imbalance, alignment, etc.). Some practices also use velocity to help with bearing fault detection in later failure stages. As modern technology evolves, dynamic range is no longer a limit factor, accelerometer is getting more and more popular when compared with velocity transducers. Mathematically speaking, the best velocity transducer is an accelerometer and integrator. Velocity is good for broadband evaluations such as ISO 10816, but not necessary where you have frequency spectra since it just represents a change in the slope of the spectrum.

2. Sensor Configuration

The configuration of the sensor is also crucial and should be tailored to the section of the gearboxes one is monitoring. Normally, for an online retrofitted system, these are preset and can be changed by the condition monitoring system specialist. Each sensor is selected and configured based on the section it’s monitoring.

For a handheld system, these settings need to be constrained for the logger to function or to increase the fault detection capability. These configurations need to be changed based on which sections the sensor is collecting data from. The configurations should be logged precisely for the next time a technician performs testing, they should use the same setup to ensure reading consistency. Common sensor configurations are listed as follows:

1) Sampling time
2) Sampling duration
3) Spectrum resolution or number of spectral lines
4) Order tracking
5) Frequency range (fmax or low cutoff frequency)
6) Band pass filter selection
7) Tachometer setting
8) With or without averages, number of averages
9) Detection method (peak-to-peak, RMS, etc.)

2. Sensor Configuration
(continued)

For handheld systems in general, it is recommended that the acceleration measurement fmax should be higher than three times the focused gear mesh frequency and the acceleration enveloping fmax should be higher than five times the targeted bearing damage frequency. Data acquisition duration should be long enough to ensure at least 10 to 15 shaft rotations are acquired. Since the number of spectral lines together with the fmax setting determine the data acquisition duration, it may be difficult, in some cases, to satisfy both requirements with a single measurement (data acquisition duration and spectral line resolution).

Note: Signal averaging is not recommended for a variable speed machine. Not only will random noise be reduced, signals related to the speed, such as defect frequencies, will be affected.

3. Sensor Mounting

Ideally, the vibration should be measured for all three axis including vertical, horizontal, and radial. These measurements can be done if a handheld system is instrumented as long as the monitored locations are consistent from test to test. However, due to cost restraint, only one direction of vibration can be measured in online retrofitted commercial applications and typically it is the radial direction. The tachometer is normally mounted on the high-speed section of the drive train which is typically between the gearbox downwind side and the generator. The rotating speed of the other shafts of the gearbox can be obtained with given gear ratio.

The sensor mounting location can be different since the turbine and gearbox manufacturer are not always the same. The general guideline is the sensor should be mounted at or adjacent to the loading zone.

Signal Processing

Vibration analysis in simple terms is to detect machine abnormally based on change in vibration waveform in time domain or frequency domain. Statistics can be extracted from the waveform as condition indicators or descriptors. These condition indicators are designed to detect different fault modes of the monitored component.

However, in practice, a proper vibration analysis sequence is quite complicated which includes noise reduction, speed change compensation, fault mode detection algorithm, and fault feature extraction.

1. Noise Reduction and Speed Compensation

Speed compensation and noise cancellation are crucial for a robust and effective condition monitoring system. Noise cancellation is certainly quite straight forward. Complicated drive train like wind turbines consistently produces mechanical noises. An effective noise cancellation algorithm can ensure the fault signature gets isolated and greatly helps with fault isolation which greatly reduces the effort for uptowner inspection. Speed compensation is also quite critical when it comes to improving signal to noise ratio and improve reading consistency.

Time Synchronous Averaging (TSA)

TSA is designed and developed to detect shaft and gear faults with non-stationary signals that operates at noisy environments which is ideal for wind applications. To successfully implement TSA, a tachometer reference signal is often necessary. The advantages of implementing TSA are noise reduction and speed compensation. Theoretically, noises or tunes that are not synchronous with the target shaft rotating frequency will be greatly reduced. The level of noise reduction correlates with the number of revolutions of the target shaft during the data collection timeframe. TSA can significantly enhance the shaft and gear mesh vibration signature signal to noise ratio while coping with speeding variation.

Time Synchronous Resampling (TSR)

TSR, like TSA, is used to compensate for speed variation. However, TSR does not average out the nonsynchronous vibration signals. This algorithm only resamples the vibration signal based on tachometer reference. The typical application of TSR is for bearing diagnostics. The implementation of TSR allows the system to sample for a longer period to increase the signal to noise ratio and spectrum resolution. This is especially useful when it comes to the slow speed end of the drivetrain since its rotation takes longer and normally involves quite a bit speed variation especially if one samples longer

2. Fault Mode Detection

Frequency Domain Analytics

Frequency domain analysis on rotating machineries allows the user to quickly identify potential fault on mechanical components, especially bearings. With each type of bearing fault triggering excitations at a different location of the spectrum (depends on the bearing kinematic) along with modulations on the fault frequency location peaks, frequency domain analysis is one the most commonly used diagnostics algorithms out there. It can also be used for shaft imbalance, misalignment analysis or generator related issues and so on. Fast Fourier Transform (FFT) is one of the most commonly used time to frequency domain conversion algorithm. Other similar algorithm is also explored by vibration analysts like power density spectrum, Welch's method, among others.

Time Doman Analytics

Time domain analysis is also one of the most commonly used technique for vibration analysis on stationary machineries. It is sometimes used for gear fault detection since non-periodical impact, like damaged gear tooth impact, will not show up in frequency spectrum but in time domain waveforms. Time domain analysis is also used for rough estimation of overall vibration level for simple systems. Time synchronous averaging is one of the most sophisticated time domain analytical methodologies.

Time-Frequency Domain Analytics

Time-frequency analysis is quite powerful when it comes to gear analysis. The basic idea is to convert the signal to frequency domain, filter the signals by only looking at a certain area of the spectrum or remove the undesirable frequency elements. Afterward, the signal is transformed back to time domain for assessment. This can be especially useful for gear analysis using narrowband, FM, and AM analysis along with others.

3. Fault Feature Extraction

After the signal goes through frequency, time or time-frequency analysis, a waveform will be extracted from the original signal. These waveforms need to be summarized by statistics so the user can easily assess the waveform by only looking at the key indicators extracted from the wave form.

3. Fault Feature Extraction
(continued)

These indicators are commonly called condition indicators or descriptors or as such. In simple term, these are basically statistics of the processed waveform or some sort. Commonly seen statistics are Root Mean Square (RMS), Mean, Median, Kurtosis, Peak to Peak (P2P), Crest factor (Peak over RMS), skewness, and so on and so forth.

Thresholding or Severity Assessment

Currently, there is no established and well-recognized standard for the wind turbine drive train vibration level assessment. Some references like ISO 10816 was not specifically developed for wind applications. Standards like VDI are specifically developed for wind application, but like ISO standards, they are focused on specific bands regardless of the operating condition or load of the turbine. The reason that these stand for vibration severity assessment is that the fundamental frequency of the gear meshing or bearing fault signatures is a function of shaft speed. Even if the band can successfully capture the bearing fault frequency at any opening speed, the drawbacks are inconsistent readings since the operational speed varies and the spectrum will be dominated by gear mesh frequency peaks. These standards also acknowledge that they are only good for general vibration level assessment. For modern CMS, the severity threshold should be set based on the condition indicators calculated by the systems and based on statistics.

While moving forward the statistics based threshold setting procedures, the threshold should be set based on the indicators' distributions. For example, if we set the alarm threshold to be mean plus three sigma, the false alarm rate of a normal distribution can be quite different than that of a Rayleigh or Weibull distribution. Most of the condition indicators, based on publications, are heavily tailed like Rayleigh. Hence, it is crucial to take into account the actual reading distribution when setting the alarm threshold statistically. Always assuming all the CI readings are normally distributed will sometimes lead to frequency false alarms which will lead to the user ignoring the alarms.

Threshold setting is a delicate balance between false alarm and miss detection. Different companies offer different solutions. However, it is recommended to check with the supplier with the thresholding methodology to make sure the alarm setting is effective and robust.

Summary

Vibration analysis techniques have been refined over the years. Vibration based diagnostics for wind applications has its challenges. The speed and load are always fluctuating because of stochastic wind speed and direction. On top of that, the front end of the turbine moves at a relatively slow speed. These issues have a great impact on the vibration based signal processing techniques which is quite different from stationary machines. And there have been a series of publications and algorithms developed to coup with these challenges. Further information can be found in the following references if the reader would like to investigate deeper into the algorithmic details or mathematical processing.

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RP 812 Wind Turbine Main Bearing Grease Sampling Procedures

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF
Principal Author: Rich Wurzbach, MRG
Contributing Author: Ryan Brewer, Poseidon Systems

Purpose and Scope

The scope of “Wind Turbine Main Bearing Grease Sampling Procedures” discusses the methods for taking uncontaminated and trendable grease samples from wind turbine main bearings. Samples that are taken properly can provide the user with accurate data for maintenance decision making.

The general procedure applies to wind turbine lubrication systems. There are several different wind turbine main bearing types. This paper will focus on two common main bearing types, those with drain purge plugs and those without. Following methods laid out in ASTM D7718-Standard Practice for Obtaining In-Service Samples of Lubricating Grease. These recommendations will give proper procedures for the handling of sampling devices and grease before and after samples have been taken to ensure that data obtained from grease analysis is accurate.

Introduction

Performing grease analysis from a specific sampling location is important in ensuring repeatability and accuracy. Unlike oil samples, which can more thoroughly mix and circulate through a gearbox or other location, greases are semi-solids and their flow behavior is quite different. Known as a “non-Newtonian” fluid, their movement and circulation in a bearing is dependent on the grease consistency, temperature, and force applied by nearby moving components, among other factors.

Introduction
(continued)

Published studies demonstrate that greases in wind turbine main bearings do indeed move and circulate, but only in an area very close to the moving parts of the bearing. Therefore it is critical that any sampling methods provide effective means to obtain grease close to these moving zones or otherwise ensure that grease samples are not compromised by contaminating or diluting influences as they travel away from these flow zones. The methods outlined in this recommended practice provide several approaches to achieve this goal.

Wind Turbine Main Bearing Grease Sampling Procedures

1. Main Bearing Grease Sampling Procedures (With Drain Access Plug)

NOTE: In this section, "grease sampler" refers to the "Passive Grease Sampling Device" described in ASTM D 7718, Section 8. The "T-Handle" describes a tool used to reach the grease sampler into the bearing and actuate the sampler at the proper point in the machine. This method ensures that the sample obtained is taken from the area of the bearing where grease circulates due to the action of the bearing.

1.1. Place a catch basin below the drain plug to catch any dripping grease.

1.2. Remove the drain plug, clean it, and set in a safe place for later re-insertion.

1.3. If necessary, remove the grease sampler from packaging used to keep it clean until ready for use. Ensure that the open end of the grease sampler is clear of any cap and that the internal piston is positioned to close off the sampling tube.

1.4. Attach the grease sampler piston handle to the T-handle tool by inserting the end of the handle into the internal rod.

Figure A

1.5. Insert the internal rod into the pusher tube with the grease sampler facing forward. (*See Figure A*)

1.6. Thread the base of the grease sampler into the female threads in the pusher tube and make adjustments to set the depth at which the sample will be taken. This should be made based on a measurement or print of the bearing and set such that the fully extended position of the sampler will be very close to, but not touching, the face of the bearing rolling elements.

Figure B

1.7. Position the pusher tube so that the internal piston is flush with the end of the grease sampler. (*See Figure B*)

1.8. Fully insert the grease sampler and T-handle into the drain hole until the positioning guides of the T-handle contact the bearing housing face, positively positioning the grease sampler at the desired set depth.

1.9. Slide the pusher tube forward, while holding the T-handle firmly against the housing face, to core a grease sample close to the bearing.

1.10. When the pusher rod has been slid completely forward, hold it in that position as the T-handle and grease sampler are withdrawn from the housing and access hole.

1.11. Using a clean rag, wipe the excess grease from the T-handle parts and the OUTSIDE of the grease sampler body, being careful not to contact the grease inside.

1.12. Release the internal rod so that it spins freely and unthread the grease sampler from the pusher tube.

1.13. If there is insufficient grease to sample using the T-handle, utilize a disposable spatula to gather grease from within the drain area and pack into the opened syringe. The syringe is opened by removing the plunger.

The grease selected in this manner should, wherever possible, be taken from the far end of the access hole. If necessary, drag out most of the grease in the hole and set aside to access the grease closest to the moving parts of the bearing.

Figure C

1.14. Additional grease can be put into the grease sampler by reinserting the plunger in the syringe and pushing grease into the grease sampler to achieve maximum fill. (*See Figure C*)

1.15. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

1.16. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

1.17. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

1.18. Affix a sample label on the shipping tube, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab. Ensure all samples are clearly identified and promptly submitted to the lab for analysis.

2. Main Bearing Grease Sampling Procedures (With Drain Access Plug Alternative Method

NOTE: This method follows guidance provided in ASTM D7718, Section 10.

2.1. Remove the drain plug and allow any grease near the plug to drain out.

2.2. Using a clean spatula or straw, remove all grease from the inside of the drain area, up to a point within about 1" of the moving parts of the bearing. Ensure that in this purging step a sufficient amount of grease remains to obtain the required sample amount.

2.3. Utilize a new, clean spatula or straw to gather grease from that area directly adjacent to the moving bearing parts and pack into an opened syringe. The syringe is opened by removing the plunger. In place of a syringe, a similarly suitable clean, closeable container can be used to gather the sample. If the analysis to be performed is a small-volume method as outlined in RP-814, it may be necessary to use the syringe to inject grease into the "Passive Grease Sampling Device" described in ASTM D7718. Instructions for properly filling that device are described in the previous section, steps 14-17.

2.4. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

2.5. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

3. Main Bearing Grease Sampling Procedures (Without Drain Access Plug)

NOTE: Some bearings do not have a drain access plug or this plug does not provide sufficient access to grease close to the bearing moving parts. In those cases, grease may need to be taken from the face of the bearing, where excess grease is purged in the natural course of the addition of new grease. Samples taken in this manner are much less protected from environmental contaminants, which can skew results. Effort is required to ensure the influence of these external contaminants are kept to a minimum and analysis of these samples should consider the potential influence of these factors when making evaluation and recommendations.

3.1. Obtain a disposable spatula or straw that will allow both movement and displacement of external contaminated grease and capturing of the protected underlying grease closer to the exit area. Opposing ends of this straw or spatula can be designated for these two purposes. A syringe or suitable container should be available to place the sampled grease and these sampling devices should be kept clean in protective packaging up to the time of sampling.

3.2. Using a clean rag, wipe the excess grease from the face of the bearing, being careful not to wipe away representative grease just exiting the bearing.

3.3. Select an accessible location on the face of the bearing, close to the bottom of the bearing roller travel, near the shield gap where excess grease exits the bearing. (*See Figure D*)

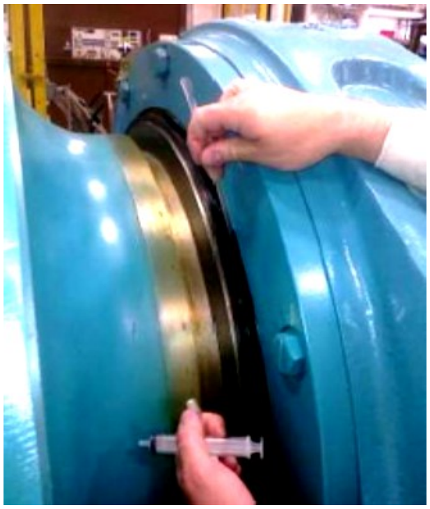

Figure D

3.4. Open the protective packaging and remove the disposable spatula/ straw and sample container. Using one end of the spatula/straw, wipe away the outermost grease in the area to be sampled, to remove ambient dirt and expose underlying recently purged grease.

3.5. Turn the spatula/straw around, utilize the other end to gather grease exiting the bearing face, and pack into the sampling container. If a syringe is used, it is opened by removing the plunger.

3.6. If the analysis to be performed is a small-volume method as outlined in RP-814, it may be necessary to use the syringe to inject grease into the "Passive Grease Sampling Device" described in ASTM D7718. Instructions for properly filling that device are described in the first section, steps 14-17.

3.7. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

3.8. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

Summary

Proper grease sampling methods are crucial for comparing samples from one turbine to another or for trending samples from the same turbine. If the proper methods are not employed, grease samples can be obtained that do not represent the condition of the bearing wear, contamination levels, or the physical properties of the grease actively involved in lubricating the bearing. Any analysis from such inadequate samples will be misleading and result in improper maintenance actions being taken. Properly obtained samples ensure that analysis results represent current bearing conditions and provide the basis for sound maintenance decisions to provide reliable main bearing operation.

RP 813 Wind Turbine Generator Bearing Grease Sampling Procedures

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF
Principal Author: Rich Wurzbach, MRG

Purpose and Scope

The scope of "Wind Turbine Generator Bearing Grease Sampling Procedures" discusses the methods for taking uncontaminated and trendable grease samples from wind generator bearings. Samples that are taken properly can provide the user with accurate data for maintenance decision making.

The general procedure applies to wind turbine lubrication systems. There are several different manufacturers of generators and each may have a slightly different configuration, which could require slight modifications of this procedure. This paper will address one of the more commonly seen configurations in a wind turbine generator: a bearing bottom exit hole and a mating chute to direct purged grease to a catch tray. Following methods laid out in ASTM D7718-Standard Practice for Obtaining In-Service Samples of Lubricating Grease, these recommendations will give proper procedures for dealing with the chute and gathering grease samples and the use of sampling devices to ensure that data obtained from grease analysis is accurate.

Introduction

Performing grease analysis from a specific sampling location is important in ensuring repeatability and accuracy. Unlike oil samples, which can more thoroughly mix and circulate through a gearbox or other location, greases are semi-solids and their flow behavior is quite different. Known as a "non-Newtonian" fluid, their movement and circulation in a bearing is dependent on the grease consistency, temperature, and force applied by nearby moving components, among other factors.

Introduction
(continued)

Published studies demonstrate that greases in wind turbine bearings do indeed move and circulate, but only in an area very close to the moving parts of the bearing. Therefore it is critical that any sampling methods provide effective means to obtain grease close to these moving zones or otherwise ensure that grease samples are not compromised by contaminating or diluting influences as they travel away from these flow zones. The methods outlined in this recommended practice provide several approaches to achieve this goal.

1. Method 1: Generator Bearing Grease Sampling Procedures (Sampling From Bearing Drain Opening With Chute or Deflector)

NOTE: In this section, “grease sampler” refers to the ”Passive Grease Sampling Device” described in ASTM D 7718, Section 8. The “T-Handle” describes a tool used to reach the grease sampler into the drain chute or bearing exit slot. This method ensures that the sample obtained is taken from the grease which has most recently exited the bearing. This method references the style of drain chute shown in *Figure A*, common to certain Nordex units, with similar chute designs in other units. (*See Figure A*)

Figure A

1.1. Remove the purge container (if so equipped) from the generator bearing grease exit chute (*See red arrow, Figure A*) and place the container in a clean area.

1.2. Note the condition of the material in the container. If the grease is excessively runny, hard, discolored, or contains shiny or dark particulate, note this on the sampling label.

1.3. Determine if there is sufficient clearance for a T-handle tool or similar sampling tool to insert the tool with a grease sampler into the drain chute. If not, the chute must be removed to obtain the sample.

1.4. If necessary, remove the grease sampler from packaging used to keep it clean until ready for use. Ensure that the open end of the grease sampler is clear of any cap and that the internal piston is positioned to close off the sampling tube.

1.5. Attach the grease sampler piston handle to the T-handle tool by inserting the end of the handle into the internal rod. (*See Figure B*)

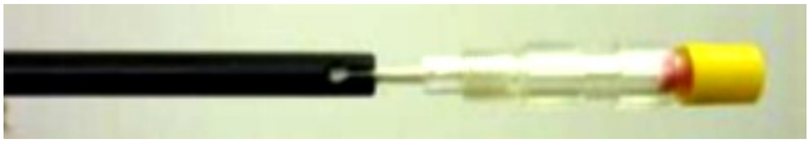

Figure B

1.6. Insert the internal rod into the pusher tube, with the grease sampler facing forward. (*See Figure C*)

Figure C

1.7. Thread the base of the grease sampler into the female threads in the pusher tube and make adjustments to set the depth at which the sample will be taken. Position the T-Handle so that the extended position of the open end of the grease sampler will be inside the bearing housing, adjacent to the area of travel of the bearing within the housing. This is often a few inches longer than the position that would be flush with the surface of the generator housing.

Figure D

1.8. Position the pusher tube so that the internal piston is flush with the end of the grease sampler. By looking up into the chute or bearing drain, verify that there is sufficient accumulation of grease that it presents a solid area of grease for coring. If there is not sufficient grease to permit the coring process described here, go to Method 2 to obtain this sample.

1.9. Insert the grease sampler and T-handle into the chute or bearing drain until the positioning guides of the T-handle contact the outside edge or the chute or drain hole in the generator housing.

1.10. Slide the pusher tube forward, while holding the T-handle firmly against the purge container lip, to core a grease sample close to the lower entry hole.

1.11. When the pusher rod has been slid completely forward, hold it in that position as the T-handle and grease sampler are withdrawn from the container.

1.12. Using a clean rag, wipe the excess grease from the T-handle parts and the OUTSIDE of the grease sampler body, being careful not to contact the grease inside.

1.13. Release the internal rod so that it spins freely and unthread the grease sampler from the pusher tube.

1.14. If there is insufficient grease to sample using the T-handle, refer to Method 2 to manually extract grease from the lower entry hole area.

1.15. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

1.16. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

1.17. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

1.18. Affix a sample label on the shipping tube, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab. Ensure all samples are clearly identified and promptly submitted to the lab for analysis.

2. Method 2: Generator Bearing Grease Sampling Procedures (Sampling From Bearing Drain With A Spatula/Straw)

NOTE: This method follows guidance provided in ASTM D7718, Section 10. This method assumes that the purge container opening is too small to allow the insertion of a grease sampler inside the container and the grease is to be manually extracted using a disposable spatula.

2.1. Using a clean, lint-free rag, wipe the outside of the grease purge container and surrounding area of the pitch bearing to avoid any of this external contamination from getting into the grease sample to be taken.

2.2. Remove the purge container (if so equipped) from the generator bearing grease exit chute (*See red arrow, Figure A*) and place the container in a clean area.

2.3. Inspect the exit chute or drain opening in the bearing and determine if there is sufficient grease accessible in this area for the required sample size.

2.4. Using a clean spatula or straw, remove grease from the inside of the drain area, up to a point within about 1” of the moving parts of the bearing, if possible. Ensure that in this purging step, a sufficient amount of grease remains to obtain the required sample amount.

2.5. Utilize a new, clean spatula or straw to gather grease from that area directly adjacent to the moving bearing parts and pack into an opened syringe. The syringe is opened by removing the plunger. In place of a syringe, a similarly suitable clean, closeable container can be used to gather the sample. If the analysis to be performed is a small-volume method as outlined in RP-814, it may be necessary to use the syringe to inject grease into the “Passive Grease Sampling Device” described in ASTM D7718.

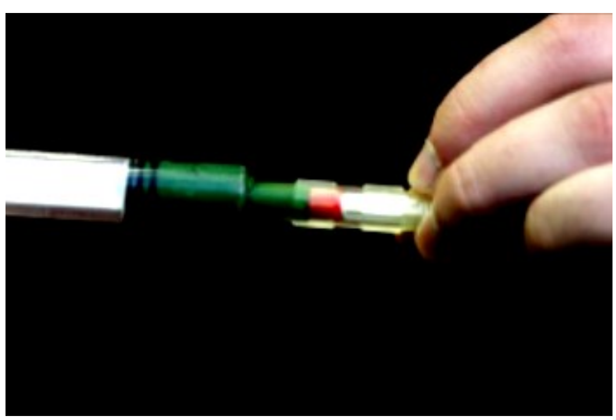

Figure E

2.6. Additional grease can be put into the grease sampler by reinserting the plunger in the syringe and pushing grease into the grease sampler to achieve maximum fill.

2.7. If there is insufficient grease in the drain path to fill the grease sampler, the remaining amount can be obtained from the chute, at the end closest to the bearing or from the purge container. The grease closest to the opening is the most recently purged grease and the most representative of the current condition of the bearing. If a sample is obtained from these alternate areas, note this on the sample label so the analyst can take this into consideration.

2.8. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

2.9. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

2.10. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

2.11. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler’s name, and any notes or observations for the lab.

2.12. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

Summary

Proper grease sampling methods are crucial for comparing samples from one turbine to another or for trending samples from the same turbine. If the proper methods are not employed, grease samples can be obtained that do not represent the condition of the bearing wear, contamination levels, or the physical properties of the grease actively involved in lubricating the bearing. Any analysis from such inadequate samples will be misleading and result in improper maintenance actions being taken. Properly obtained samples ensure that analysis results represent current bearing conditions and provide the basis for sound maintenance decisions to provide reliable generator operation.

RP 814 Wind Turbine Pitch Bearing Grease Sampling Procedures

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Gearbox - Kevin Dinwiddie, AMSOIL; Erik Smith, Moventas
CM - Bruce Hamilton, Navigant Consulting
Principal Author: Benjamin Karlson, Sandia National Laboratories

Purpose and Scope

The scope of "Wind Turbine Pitch Bearing Grease Sampling Procedures" discusses the methods for taking uncontaminated and trendable grease samples from wind turbine pitch (blade) bearings. Samples that are taken properly can provide the user with accurate data for maintenance decision making.

The general procedure applies to wind turbine lubrication systems. There are several different wind turbine pitch bearing styles and purge recovery systems. This paper will address two such pitch bearing purge recovery styles and can apply to both automatic and manual grease lubrication systems. Following methods laid out in ASTM D7718-Standard Practice for Obtaining In-Service Samples of Lubricating Grease, these recommendations will give proper procedures for the handling of purge recovery containers, sampling devices, and grease before and after samples have been taken to ensure that data obtained from grease analysis is accurate.

Introduction

Performing grease analysis from a specific sampling location is important in ensuring repeatability and accuracy. Unlike oil samples, which can more thoroughly mix and circulate through a gearbox or other location, greases are semi-solids and their flow behavior is quite different. Known as a "non-Newtonian" fluid, their movement and circulation in a bearing is dependent on the grease consistency, temperature, and force applied by nearby moving components, among other factors.

Introduction
(continued)

Published studies demonstrate that greases in wind turbine bearings do indeed move and circulate, but only in an area very close to the moving parts of the bearing. Therefore it is critical that any sampling methods provide effective means to obtain grease close to these moving zones or otherwise ensure that grease samples are not compromised by contaminating or diluting influences as they travel away from these flow zones. The methods outlined in this recommended practice provide several approaches to achieve this goal.

1. Method 1: Pitch Bearing Grease Sampling Procedures (Recovery From Purge Container With Removable Lid)

NOTE: In this section, “grease sampler” refers to the ”Passive Grease Sampling Device” described in ASTM D 7718, Section 8. The “T-Handle” describes a tool used to reach the grease sampler into purge container. This method ensures that the sample obtained is taken from the grease which has most recently exited the bearing. This Method 1 references the style of purge container shown in Figure A, common to certain Vestas units.

Figure A

1.1. Remove the purge container from the blade bearing and place the container on a level surface with the removable lid facing up.

1.2. Remove the lid and set aside.

1.3. Verify that there is sufficient accumulation of grease that it presents a solid glob adjacent to the lower entry hole, larger than the length of the grease sampler. If there is not sufficient grease to permit the coring process described here, go to Method 2 to obtain this sample.

1.4. If necessary, remove the grease sampler from packaging used to keep it clean until ready for use. Ensure that the open end of the grease sampler is clear of any cap and that the internal piston is positioned to close off the sampling tube.

1.5. Attach the grease sampler piston handle to the T-handle tool by inserting the end of the handle into the internal rod.

Figure B

1.6. Insert the internal rod into the pusher tube, with the grease sampler facing forward.

Figure C

1.7. Thread the base of the grease sampler into the female threads in the pusher tube and make adjustments to set the depth at which the sample will be taken. Position the T-Handle so that the extended position of the open end of the grease sampler will be slightly past the lower entry hole in the side of the container.

Figure D

1.8. Position the pusher tube so that the internal piston is flush with the end of the grease sampler.

1.9. Insert the grease sampler and T-handle into the top of the purge container, keeping close to the wall where the entry holes are located, until the positioning guides of the T-handle contact the top lip of the container, positioning the grease sampler at the lower entry hole.

1.10. Slide the pusher tube forward, while holding the T-handle firmly against the purge container lip, to core a grease sample close to the lower entry hole.

1.11. When the pusher rod has been slid completely forward, hold it in that position as the T-handle and grease sampler are withdrawn from the container.

1.12. Using a clean rag, wipe the excess grease from the T-handle parts and the OUTSIDE of the grease sampler body, being careful not to contact the grease inside.

1.13. Release the internal rod so that it spins freely, and unthread the grease sampler from the pusher tube.

1.14. If there is insufficient grease to sample using the T-handle, refer to Method 2 to manually extract grease from the lower entry hole area.

1.15. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

1.16. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

1.17. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

1.18. Affix a sample label on the shipping tube, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler’s name, and any notes or observations for the lab. Ensure all samples are clearly identified and promptly submitted to the lab for analysis.

2. **Method 2: Pitch Bearing Grease Sampling Procedures (Recovery From Purge Container Without A Lid)**

NOTE: This method follows guidance provided in ASTM D7718, Section 10. This method assumes that the purge container opening is too small to allow the insertion of a grease sampler inside the container and the grease is to be manually extracted using a disposable spatula.

2.1. Using a clean, lint-free rag, wipe the outside of the grease purge container and surrounding area of the pitch bearing to avoid any of this external contamination from getting into the grease sample to be taken.

2.2. Remove the purge container (see Figure E) from the pitch bearing and set on a level surface with the open end facing up. Other styles of purge container can also be used in this manner.

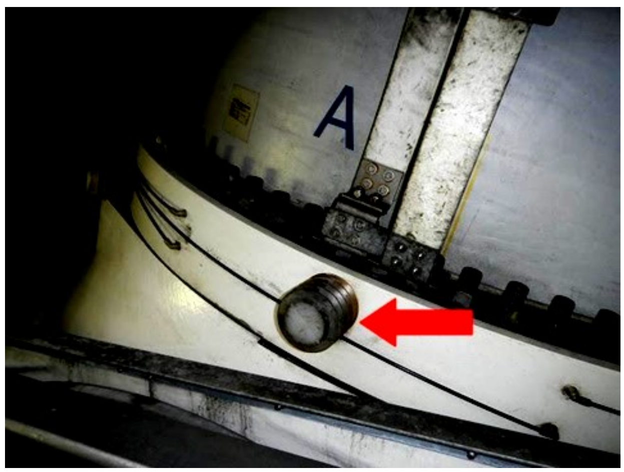

Figure E

2.3. Inspect the exit hole in the bearing and determine if there is sufficient grease accessible in this area for the required sample size.

2.4. Using a clean spatula or straw, remove grease from the inside of the drain area, up to a point within about 1” of the moving parts of the bearing, if possible. Ensure that in this purging step, a sufficient amount of grease remains to obtain the required sample amount.

2.5. Utilize a new, clean spatula or straw to gather grease from that area directly adjacent to the moving bearing parts, and pack into an opened syringe. The syringe is opened by removing the plunger. In place of a syringe, a similarly suitable clean, closeable container can be used to gather the sample. If the analysis to be performed is a small-volume method as outlined in RP-814, it may be necessary to use the syringe to inject grease into the “Passive Grease Sampling Device” described in ASTM D7718.

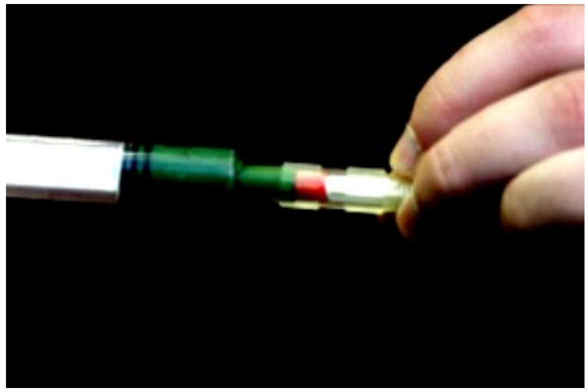

Figure F

2.6. Additional grease can be put into the grease sampler by reinserting the plunger in the syringe and pushing grease into the grease sampler to achieve maximum fill.

2.7. If there is insufficient grease in the drain path to fill the grease sampler, the remaining amount can be obtained from the area near the opening inside the purge container. The grease closest to the opening is the most recently purged grease and the most representative of the current condition of the bearing.

2.8. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

2.9. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

2.10. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

2.11. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

2.12. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

Summary

Proper grease sampling methods are crucial for comparing samples from one turbine to another or for trending samples from the same turbine. If the proper methods are not employed, grease samples can be obtained that do not represent the condition of the bearing wear, contamination levels, or the physical properties of the grease actively involved in lubricating the bearing. Any analysis from such inadequate samples will be misleading and result in improper maintenance actions being taken. Properly obtained samples ensure that analysis results represent current bearing conditions and provide the basis for sound maintenance decisions to provide reliable pitch bearing operation.

RP 815 Wind Turbine Grease Analysis Test Methods

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF
Principal Author: Rich Wurzbach, MRG
Contributing Author: Ryan Brewer, Poseidon Consulting

Purpose and Scope

The scope of “Wind Turbine Grease Analysis Test Methods” will focus on specific test methods which should be applied for accurate grease testing and analysis.

Introduction

Accurate grease analysis results are critical to the success of the diagnosis of wear rates, contamination levels, oxidation levels, and consistency of the grease. Inaccuracies can be due to improper test methods selected for the particular application, inadequate quality control of test methods, or poor sampling techniques. This practice is intended to assist in proper test selection specific to wind turbine grease samples, thus allowing for proper diagnosis and reasonable corrective action based on sound limits and warnings.

Test methods specific to wind turbine main bearing grease should provide accurate oil test results for which to base good maintenance decisions and reduce operating costs. Effectiveness of grease analysis test methods is directly and completely dependent on the accuracy of the samples obtained for this purpose. Consult AWEA guidance on grease sampling methods, developed in compliance with ASTM D7718, Standard Practice for Obtaining In-Service Samples of Lubricating Grease.

Wind Turbine Grease Analysis Test Methods

1. Procedures

Prior to sending grease samples to your laboratory, it is important to establish with your laboratory which tests are to be performed on the used in-service grease, the grease volume needed to run these tests, and the condemning limits that should be applied. Some methods exist that enable an in-service grease analysis basic test slate including measurement of wear, consistency, contamination, and oxidation with as little as 1 gram of grease. Some tests require greater quantities of grease. In all cases, the grease submitted for sampling must be representative of the condition of the grease actively lubricating the bearing and receiving wear particles by nature of proximity to the wearing surfaces.

2. Grease Analysis Methods

OEM's may require grease analysis more often during initial startup on new turbines. Grease analysis can be performed every 6-months or annually, depending on component age, history, or other factors. Samples can typically be taken while up tower performing other routine maintenance tasks. A typical test slate for grease analysis may include the following tests (these methods listed in this section are recommended for use with wind turbine grease):

1) Ferrous debris quantification.*****

2) Consistency testing (such as Cone penetration, Rheometry, or Die Extrusion Test*).

3) Infrared Spectroscopy (FT-IR).

4) Anti-Oxidant Additive quantification (such as Linear Sweep Voltammetry (ASTM D7527) or short-path FTIR).

5) Elemental Spectroscopy (such as RDE or ICP).

6) Visible Appearance (manually or Grease Colorimetry***)**.

7) Water PPM (D6304, Oven Method).

NOTE: These tests marked with asterisk (*****) are a pending ASTM Work Practice in review for ASTM standard in CS96 committee as of the writing of this procedure.

2.1. Ferrous Debris Quantification

This test determines the amount of ferromagnetic material present in the sample. Because the metallurgy of wind turbine drivetrain components are primarily ferrous, this test is effective at monitoring ferrous wear debris generation rate. Several methods exist that measure the change in voltage as it is dropped through an electromagnetic field. (The Hall Effect refers to the voltage induced in a conductor in the presence of magnetic flux.) One method must be selected an applied consistently, as there are differences in values produced by different ferrous debris monitoring technologies.

The values derived from such analyses are used as a general flagging mechanism for the lab to detect high wear levels. An action level should be developed based on the method used and statistical analysis or evaluation of historical values against observed conditions. When the sample has exceeded the action level, analytical ferrography is recommended to characterize the nature and severity of the wear. It should be noted that wear debris in grease is cumulative until flushed out by introduction of new grease and replenishment rate must be factored into the development of action criteria.

2.2. Consistency Test

The consistency of grease is a function of the base oil and thickener and their types and ratios. The consistency is important in ensuring that the grease will stay in place in the intended lubrication point and affects the ability of the grease matrix to supply liquid oil to maintain a lubricant film to separate surfaces in relative motion. After some time in service, the consistency can change due to variables such as grease mixing, aging, overheating, excessive working, or contamination. In new grease, consistency is measured by Cone Penetration and an NLGI number is assigned to the grease on a scale from 000 to 6. In-service greases usually cannot be tested per Cone Penetration method due to the large quantities required, so either a Rheometer or Die Extrusion methods are typically used.

In Die Extrusion, the consistency is determined by measuring the load required to force the grease through an orifice of know dimensions at varying speeds. The consistency of the grease is compared to the new baseline grease. Drastic increases or decreases in the consistency correspond to severe thickening or thinning of the grease, which could indicate abnormal operating conditions and/or compromise reliability.

2.2. Consistency Test
(continued)

For Rheometry, the grease is placed between opposing plates that are rotated and oscillated while measuring the resulting force, which is a function of the consistency and flow characteristics of the grease. Parameters measured include storage modulus (grease flow), oscillation stress (oil content and shear from thickener), and recoverable compliance (tendency to tunnel or channel in the bearing or gearbox).

In either test, results are compared to new, fresh grease, and criteria is developed to flag samples that deviate significantly in service from the new grease. Due to the geometry and loads in wind turbine main bearings, consistency reductions of as much as 40-50 percent may be considered typical for in-service greases and it is necessary to establish action criteria based on statistical analysis or comparative operating histories.

2.3. FT-IR Infrared Spectroscopy

Infrared (IR) Spectroscopy or Fourier Transform Infrared Spectroscopy (FTIR) have been used for many years to provide rapid, low cost, offline analyses of oil samples. The technology passes and infrared light source through a lubricant sample to an infrared detector. The light that passes through the oil is influence by the fluid properties as oil contaminants and additives absorb infrared radiation at varying frequencies. By comparing the frequency spectrum of new and used oil samples it is possible to determine the lubricant properties such as water, soot, oxidation, nitration, and glycol levels.

Through advances in electronics manufacturing techniques, IR technology is beginning to make its way into online sensing devices. Current technology does not have the refined measurement capabilities of laboratory devices. However, they do offer multi-parameter trending capabilities which can provide valuable, real-time insight into fluid condition.

FT-IR is used to fingerprint the molecular bonds in the grease. An IR beam is passed through a thin grease film, of known dimension, and the resulting absorbance spectrum is used to characterize the organic components of the grease. Alternatively, other sample introduction methods can be used, such as Attenuated Total Reflectance (ATR) or Photoacoustic Spectroscopy. By comparing the in-service sample to the baseline, oxidation, grease mixing, and organic contamination (including water) can be detected.

2.4. Linear Sweep Voltammetry

Linear Sweep Voltammetry, know commercially as “RULER”, measures the Remaining Useful Life of the anti-oxidant additive package. A voltage sweep is applied to the sample as the current is measured. The graph of current and time will contain peaks which correspond to different anti-oxidants and the concentration remaining in the sample is proportional to the area under the curve for these peaks. The results are reported as a percentage of the concentration found in the baseline grease.

2.5. Atomic Emission Spectroscopy

The quantification of metallic elements in grease can be accomplished by Rotating Disc Electrode (RDE), Inductively Coupled Plasma (ICP), or Xray Fluorescence (XRF). While atomic emission spectroscopy is routine for oil analysis, sample preparation is unique for greases. The grease must either be dissolved by a clean, filtered solvent and analyzed or use a uniform preparation method to introduce the solid grease to the analyzer. For ICP, the sample must be fully dissolved and the selection of the solvent system for each grease type is important to the effectiveness of the method. ASTM D7303 governs the ICP method. For the XRF and RDE methods, direct application (without dissolving sample) sample preparation methods are used in industry and standards are under development.

For the solvent methods, the grease is dissolved in reagent grade organic solvent and vaporized in the sample chamber. The atoms are excited with an electric arc and the light patterns emitted are compared with the known patterns of 19 different metals. The spectrometer detects most wear particles such Iron and Babbitt, as well certain additive elements that could indicate grease mixing. All results are recorded in parts per million (ppm). The limitation of this technology is the instrument is not sensitive to particles larger than about 6 microns because they do not vaporize in the AC arc.

2.6. Grease Colorimetry

Grease Colorimetry measures light absorbance in the visible light range (400 nm - 700 nm) under controlled repeatable conditions. The resulting spectrum has peaks which differentiate colors at a much higher sensitivity than the human eye. Because some grease products contain unique dyes, this method can be used to detect grease mixing when the true baseline is known.

2.6. Grease Colorimetry
(continued)

This method can validate observed appearance changes in greases, trend darkening due to aging or overheating, characterize dye formulations of new grease, and be used to approximate the concentration of certain particulate contaminants, such as coal dust, soot, or other solids accumulating in the grease. As an alternative method, subjective visual analysis of the grease and comparison to the appearance of new or typical used greases can be made.

2.7. Water PPM

The presence of moisture in lubricating greases lead to corrosion, wear, and an increase in debris load which contributes to bearing and gear fatigue. While FTIR can identify gross levels of water in greases, it is typically not accurate in assessing quantitative values.

A quantitative test is Karl Fischer titration by oven method, ASTM D6304. This test method detects the presence of water by thermal mass transfer of the grease to a dry gas, which is then titrated to determine parts per million of water in the grease. Action criteria can be determined from statistical analysis of a given population of similar wind turbine drivetrain components in a certain environmental application or comparative operating histories.

3. Interpreting Grease Analysis Results

1) Consult your specific laboratory for help with interpreting results and with understanding the lab reports.

2) Appropriate alarms, (min./max., percent change, deviation), will vary based on machine and population of sample data.

3) Any opportunity to evaluate and inspect a removed wind turbine drivetrain component should be made to correlate as-found conditions to the preceding grease analysis trends and expand the knowledge base for developing more precise and accurate action criteria.

Summary

A comprehensive, disciplined approach to grease sample collection, specific analysis methods, trend monitoring, and proper condemning limits can help identify grease, bearing, and gear issues. This enables wind farm operators to make cost-effective servicing and maintenance decisions and predict bearing and gear failures so that pre-emptive action can be taken. Overall, the objective supported by this recommended practice is to accumulate solid data in order to reduce guesswork and improve uptime and availability and ultimately to reduce O&M costs.

RP 816 Wind Turbine Temperature Measurement Procedures

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF
Principal Author: Eric Bechhoefer, NRG System

Purpose and Scope

The scope of "Wind Turbine Temperature Measurement Procedures" discusses the methods and procedures to facilitate temperature based condition monitoring. Temperature is available from most supervisory control and data acquisition systems (SCADA) and provides a low cost, late warning indicator for bearing, generators, and motor components in the turbine.

Introduction

Temperature is age old indicator of component health. Bearing manufacturers have long been aware of the relationship between bearing temperature and bearing life. Because of this relationship, temperature can be used to monitor bearing condition or other temperature sensitive components, such as motors and generators.

If temperature is a reliable method for component life prediction, why is its use not sited more often as an indicator of fault? While there are subtle changes in temperature due to wear, there are many other environmental factors that affect bearing temperatures, such as: load, speed, and ambient temperature.

The key to successfully use temperature is to remove the environmental factors so that differences in temperature between the same components on similar turbines reflect actual bearing faults or other components where temperature can signify failures.

Introduction
(continued)

Potential areas where temperature can be used for condition monitoring include, but is not limited to:

1. Main Bearing
2. Generator Bearings
3. Generator Windings
4. Gearbox Oil Sump
5. Gearbox Bearings
6. Yaw Motors
7. Pitch Motors
8. Slip Ring
9. Hydraulic Pumps

Temperature Condition Monitoring Procedures

In general, the temperature sensor must be attached in close proximity to the bearing/component under analysis.

1. Simple Trouble Shooting Rules For Bearings

No more than 82°C on the bearing housing. The bearing outer ring can be up to 11°C hotter than the housing. Note that lubricants are typically selected to run at lower temperatures and a temperature rise of 28°C may cause oil viscosity to drop by 50% or more.

2. Simple Trouble Shooting Rules For Electric Motors And Generators

The National Electrical Manufactures Association (NEMA) has defined temperature rise for electric motors and generators in MG 1-1998. This standard outlines the normal maximum temperature rise based on a maximum ambient temperature or 40°C, power/load, service factor rating, and insulation class. For example, for a 1.5 MW generators with service factor of 1.15 and insulation class B, the maximum allowable temperature rise would be 95°C. Thus, the machine should alert a warning condition when the winding temperature is greater than 135°C.

3. The Use Of SCADA For Temperature Condition Monitoring

SCADA systems can be used to alert for high temperature conditions on bearings, generators, and motors. As noted, successful temperature diagnostics requires reducing the effect of environmental factors.

3.1. Define a component temperature rise (CTR) which is the difference of the sensor temperature and ambient temperature.

3.2. Define a threshold for CTR. Since the operating temperature can be a function of load/power output, consider developing threshold bins by wind speed/power output to reduce variation. Additionally, threshold should be set for similar machine configuration (e.g. model, gearbox, and generator represent one type of machine configuration).

1) Use a minimum of 6 nominal machines, with a minimum of 21 acquisitions per machine, to generate test statistics (mean and standard deviation).

2) Assuming near Gaussian distributions, set the threshold for each power bin as MeanCTR + 3*Standard DeviationCTR, which will give an approximate probability of false of 1e-3.

3.3. Set Alarm Alerts for Hot Bearings at 82°C.

3.4. Set Generator/Motor Alerts based on NEMA MG 1-1998 as appropriate.

Summary

Temperature can be a powerful indicator of component health. That said, temperature of components is also affected by environmental factors such as ambient temperature, load, and speed. By reducing the effect of these environmental factors (monitoring temperature rise, binning by power), temperature can be used to diagnose component wear. For bearings, the absolute temperature should not exceed 82°C. For motors/generators NEMA MG 1-1998 should be consulted for absolute temperature limits.

RP 817 Wind Turbine Nacelle Process Parameter Monitoring

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF
Principal Author: Dan Doan, GE Energy

Purpose and Scope

The scope of “Wind Turbine Nacelle Process Parameter Monitoring” discusses the methods and procedures to facilitate nacelle process parameter modeling for condition based monitoring. The process parameters are available from the OEM controls system (SCADA) and provides an early warning indicator for degraded operation of bearings, gearboxes, blade controls, generators, motors, and control components in the turbine.

Introduction

There are many methods in which to monitor and utilize the supervisory control and data acquisition systems (SCADA) data collected around the processes within a wind turbine and wind plant. The issue is the high variability in the data and getting a sense of the data compared to the plant and historical operations. One proven method is using empirical nonparametric modeling of process parameters to complement traditional condition based maintenance techniques. The Process Parameters provide drivers and responses for modeling methodologies to detect “normalized” departures from historical behavior that could be early indicators of degraded conditions around the equipment in the Nacelle.

The industry description of this methodology is referred to as Advanced Pattern Recognition (APR) and has been used successfully in the Wind industry over all manufactures and designs of wind turbine generators. The understating of relationships between performance and mechanical systems has been known since the origins of Condition Base Maintenance. When a bearing temperature increases, the technician looks at trends in the data for the variable of concern: local ambient temperatures, oil supply temperatures, speed of the rotating system, load changes, cooling system operations, etc. These correlations were (and are) performed manually and by some simple data extractions and X, Y plots, or simply visual comparison of trends against the one in question.

Introduction
(continued)

This “validation” is performed in relationship to hard alarms, with little or no warning which placed the technician at disadvantage having to reacting to the equipment alarm conditions. By the end of the 1990’s computer hardware and software systems had advanced sufficiently in order to perform statistical modeling using standalone computer systems. The advanced pattern recognition algorithms were commercialized to take advantage of “online data mining” that is running advanced statistical models in real-time on process parameters.

The key to successfully using process parameters in Condition Based Maintenance is ensuring that there is known good historical reference data set to use for compression with current process parameters.

The APR methodologies are very robust and accurate in determining the behavior of an asset. They are very sensitive to changes in single instrument behavior that are clear indicators of degradation i.e. small deviation in bearing metal temperature (<10% of normal span of operation) while taking into many other environmental factors affecting the bearing temperature, such as: load, speed, and ambient temperature.

Statistical models are used to compare the same components, for similar assets, across a wind plant, detecting changes in the components behavior as compared to the other assets. This analysis, which can be automated, identifies the outliers and focuses resources where and when they are needed.

Areas where statistical models and APR can be used for condition monitoring include, but are not limited to:

Asset Components

1. Hub System
    a) Main Bearing
    b) Blades
2. Gearbox
    a) Bearings
    b) Oil Sump
    c) Gears
    d) Oil System
        i. Online Oil Particulates
        ii. Oil Cooler
3. Generator
    a) Bearings
    b) Windings
    c) Slip Rings
    d) Controls
    e) Cooling Systems

Introduction
(continued)

Asset Components Continued

4. Transformers
5. Converters
6. Yaw
    a) Controls
    b) Position
7. Wind
    a) Power
    b) Efficiency
    c) Direction
    d) Speed

The different assets include all physical measurements and calculations associated with these assets:

1. Pressures
2. Temperatures
3. Vibrations; including deterministic characteristic: Kurtosis, Crest Factor, Spike Energy, Stress Wave, etc.
4. Voltage
5. Current
6. Torque
7. Strain
8. Moment
9. Particle Count
10. Wind Direction
11. Wind Speed
12. Wind Deviation
13. Blade Tip Speed Ratio
14. Ambient Temperatures
15. Ambient Pressures
16. Power
17. Position
18. Set Points
19. Control Demand Signals
20. Etc… the more parameters around a component the better the detection of potential effects from degradation.

Fleet comparison of parameters for a component – localized models looking at all similar gearbox parameters, typically a correlation matrix verses statistical modeling.

Advance Pattern Recognition and Statistical Analysis Condition Monitoring Procedures

In general, the greater the number of parameters monitoring a process, the better the modeling. For most APR models there needs to be (at a minimum) three (3) drivers (independent parameters) - ambient temperature, rotor speed, power output and five (5) or more response (dependent parameters) bearing vibration, bearing temperatures, oil temperatures, etc. Typically the OEM installed sensors are enough to get started. A rule of thumb is: the more sensors around a process the better the detection of an abnormal behavior.

1. Where Advance Pattern Recognition (APR) Fits Into Condition Monitoring for Wind Turbines

APR is an “early” detection methodology for changes in equipment asset behavior using statistical techniques. They are typically early warning systems that gives time for the analyst to run fleet comparisons and analyze the behavior. With early detection there is some ambiguity in the actionability of the advisories that APR systems report.

These systems have low false reporting rates as compared to standard alarming systems since they use models based on each turbines unique historical behavior to determine when there has been a change that needs investigating.

APR systems increase the coverage for Failure Modes and Effects Analysis beyond traditional Predictive Maintenance Techniques. APR correlates all the behaviors which results in early notification in equipment degradation without having to deploy resources in the field. This helps optimize time base Predictive Maintenance and Preventive Maintenance work for up tower activities.

2. How Statistical Models fit into Condition Monitoring for Wind Turbines

Most wind plants have many “identical” turbines in a similar environment with the same operating profile. This enhances the ability to compare like assets across a large population. Statistical models are used to compare the behavior of each asset’s parameters on a wind turbine to the local populations of the wind plants similar wind turbines parameters. This allows for detection of an outlier on one turbine in comparison to the local population of wind turbines and classifies the severity of the change in behavior.

In addition, the power profile for one turbine is compared to the plant and degraded performance is classified compare to the overall plant performance which could identify control system degradation or equipment degradation that would be missed in monitoring a turbine in isolation.

3. The Use of SCADA for time series data trending and analysis

SCADA systems can be used to provide data for all the parameters measured within the nacelle. Successful diagnostics requires eliminating the effect of operational and environmental influences. This is accomplished by statistical/APR modeling and asset model comparisons across the wind plant.

3.1. Since statistical and APR models are based on empirical data, the range of operation of the parameters is used to set the actionability of a change in behavior.

3.2. Define a threshold for APR. Since the operating parameters can be a function of load/power output, engineering and technical understanding of the normal behavior of each asset is used to set the threshold criteria. Some of the APR and statistical products allow a service threshold to be set for similar machine configurations (e.g. motor, gearbox, and generator represent one type of machine configuration).

3.2.1. To build the thresholds, the user will use engineering judgment on how far from the normal range of operations that the modeled parameter can be for abnormal behavior. This can be done statistically or with engineering 1st principle knowledge of the wind turbines:

For example: a five (5) degree difference between actual value and the statistical normal behavior (modeled) for the metal bearing temperature of a high-speed bearing on the generator that is operating well below its OEM recommended temperature. Since the model takes into account all “known” behavior, this is an abnormal behavior that could be indicative of low oil level in the bearing cavity.

3.2.2 Suppliers of the different statistical and APR technologies have specific methodologies to determine the thresholds for each asset within a nacelle.

3.3. Alarm Alerts are determined by the model, thresholds, and persistence.

3.4. To date, there are no industry standards of setting advisory notifications.

Summary

SCADA statistical models and APR models are the best solution of process parameters modeling for determining component health. Since these methods remove the normal behavior and emphasizes the abnormal behavior across the process parameters associated with the assets within the nacelle (self-normalizing), these solutions focus attention to actual changes in behavior that is an early indicator of a possible failure mode.

Care should be taken that the modeled behavior does not allow a parameter to exceed the OEM, or best practices, thresholds that have been established to protect the equipment and for personal safety.

Statistical and APR theories have been around for approximately one hundred years. Since the late 1990's, the hardware and software in the industrial networks have evolved to a point where development and deploying of these solutions on real time data feeds is acceptable. They are used extensively in the power industries, oil and gas, and mining. In the power sector, they are deployed on many thousands of wind turbines throughout the world.

References

Shankar, R. (2006),Fleetwide Monitoring for Equipment Condition Assessment. EPRI, Final Report, March 2006 tinyurl.com/Fleetwide-Monitoring

RP 818 Wind Turbine On-Line Gearbox Debris Condition Monitoring

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

Committee Chairs: Gearbox - Kevin Dinwiddie, AMSOIL;
Erik Smith, Moventas, CM - Bruce Hamilton, Navigant Consulting
Principal Author: Andrew German, GasTOPS

Purpose and Scope

The scope of “Wind Turbine On-Line Gearbox Debris Condition Monitoring” discusses the use of oil debris monitoring to assess and monitor the health of a wind turbine gearbox as part of a comprehensive condition monitoring program.

Experience has shown that premature gearbox failures are a leading maintenance cost driver of a wind turbine operation. Premature gearbox failures reduce turbine availability, result in lost production and downtime, and can add significantly to project lifecycle cost of operation.

Oil debris monitoring used in conjunction with Prognostics and Health Management (PHM) techniques offers the potential of detecting early gearbox damage, tracking the severity of such damage, estimating the time to reach pre-defined damage limits, and providing key information for proactive maintenance decisions. Experience has shown that major damage modes in wind turbine gearboxes are typically bearing spall and gear teeth pitting, both of which release metallic debris particles into the oil lubrication system.[1, 2, & 3] Oil debris monitoring is well suited to provide an early indication and quantification of surface damage to bearings and gears of a wind turbine gearbox.

An oil debris sensor is used to detect and count metallic debris particles in the lube oil as it flows through the bore of the sensor. The amount of debris detected and the trend in particle counts can be used as an indication of component wear and damage. These sensors may employ inductive coils to detect debris resulting from early gearbox damage, and are capable of detecting both ferromagnetic and non-ferromagnetic metallic debris.

Introduction

The arrangement of a wind turbine gearbox typically consists of 3 stages of gearing - a high-speed stage, an intermediate stage, and a planetary stage. (*See Figure A*) The majority of the wind turbine gearbox problems that cause outages are due to bearing spall and/or gear pitting.[1, 2, & 3]

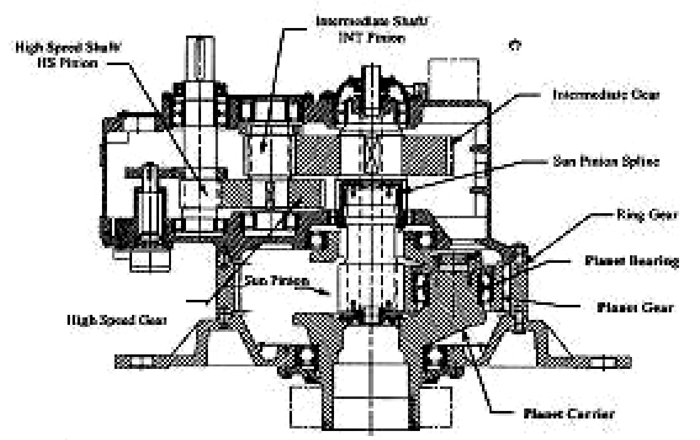

Figure A

Employing an oil debris sensor installed in the gearbox lube oil system provides the capability of detecting bearing and gear damage at an early stage and giving insight into the extent of the damage and its impact on the remaining life of the gearbox. Increasing particle counts have been successfully used as a notification to perform additional boroscope inspection of the gearbox to better localize and assess the progression of damage.

Inductive oil debris sensors can be installed in either a full-flow or partial-flow configuration. In the full-flow configuration 100% of the oil flow is passed through the sensor along with 100% of the debris particles. In a partial-flow configuration, the oil flow is divided and a portion of the flow is passed through the oil debris sensor while the rest is diverted. (*See Figure B*) In a partial-flow configuration, a number of factors can influence the amount of oil debris passing through the sensor. These factors include flow rate, sensor location, and sensor plumbing arrangement. It is recommended that some tests be performed to correlate the fraction of oil debris passing through the sensor as a function of oil flow rate for a given type of partial flow sensor configuration.

Either a full-flow or partial-flow configuration is suitable for wind turbine gearbox condition monitoring as both provide comparable data trends.

Introduction
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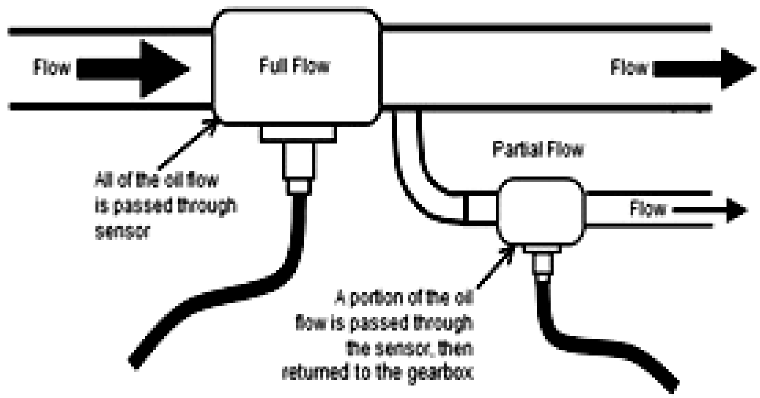

Figure B

Whether a full-flow or partial-flow configuration is used, the oil debris sensor is installed in the lube system at a point downstream of the gearbox oil return port and prior to the filtration system. Typically only a single sensor is used, and it can be installed in either a return line or a supply line as long as it is upstream of the filtration system.

On-Line Condition Monitoring (Debris Monitoring) Procedures

1. Site Survey and Installation Planning

1.1. Review the lube oil system to determine the most suitable location to install the debris monitoring sensor. The sensor must be located at a point downstream of the gearbox oil return port and prior to the filtration system and can be installed either before or after the pump.
(*See Figure C*)

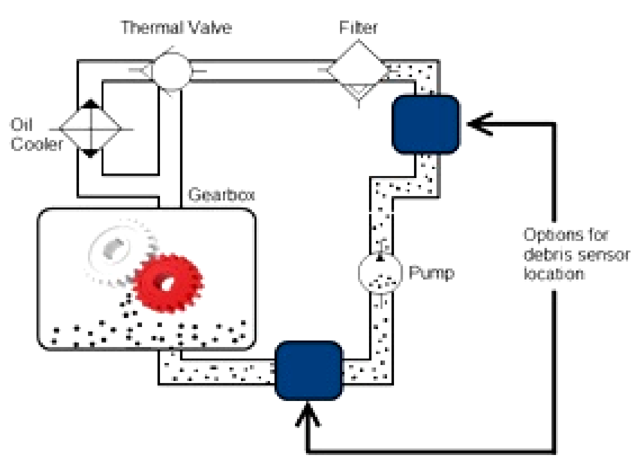

Figure C

1.2. If using a full-flow sensor, select a sensor bore that matches the lube oil line bore as closely as possible. This will ensure that the pressure drop across the sensor is minimized. If there is a difference between the oil debris sensor bore and the lube oil line bore, then a pressure drop analysis should be conducted prior to the sensor installation in order to confirm that the pressure drop across the sensor is acceptable.

If using a partial-flow sensor, select or install bypass flow stream that supports the sensor manufacturer's recommended flow rate. Bypass filtration systems and oil sampling ports are typical install points; consult with the sensor manufacturer for specific instructions. Ensure the bypass configuration maintains a suitable oil flow in the supply line to the gearbox lubrication points.

1.3. Ensure that there are no interferences and/or conflicts of space between the oil debris sensor and existing components.

1.4. Locate and mark the position where the sensor will be installed, as well as any bolts, brackets, and tubes that need to be replaced or repositioned.

1.5. Ensure that there is suitable power available for the oil debris sensor. Ensure that the power source has a switch or circuit breaker that can be turned off during sensor installation.

1.6. Ensure that all required tools and consumable materials are available and are on-site.

2. Sensor Electrical Installation

2.1. Connect the oil debris sensor to the SCADA or Control/Monitoring System (CMS) according to the instructions from the sensor manufacturer.

2.2. Ensure the switch or circuit breaker from the sensor power supply source is turned off.

2.3. Connect the oil debris sensor to the power supply according to the instructions from the sensor manufacturer.

2.4. Switch the power to the sensor on.

2.5. Perform a signal check by passing a metal particle through the sensor bore. Ensure that the sensor detects the particle and conveys this information to the SCADA / CMS. When available, perform a sensor self-test to verify functionality and communications; consult with the manufacturer for specific instructions.

3. Sensor Installation In Fluid Line

3.1. Ensure the switch or circuit breaker from the sensor power supply source is turned off.

3.2. Install the sensor in the lube oil line location that was marked during the site survey. Replace hoses, bolts, brackets, tubes, etc. as required.

3.3. Perform a leak-check for all installed lube system components including sensor, hoses, and fittings/adapters.

3.4. Perform a physical mounting integrity check to ensure that the sensor and all installed lube system components will remain secure without leaking, becoming damaged, or suffer degraded service life or performance.

4. Warning & Alarm Limit Configuration

Although all stages of gearing have experienced bearing problems, it is noteworthy that feedback from field experience suggests that high-speed shaft bearings and planet gear bearings are especially problematic. The former can be repaired in-situ whereas the latter requires gearbox replacement. This suggests that damaged high speed shaft bearings should be replaced early in the damage cycle while damaged planet gear bearings should be run to the damage limit that maximizes production and minimizes secondary damage in the gearbox. Hence, gearbox damage inspection limits will be set on the basis of bearing damage. These same limits will also provide valid inspection points for gearing, since surface fatigue phenomena for bearings and gears progress in a similar manner.

The recommended parameters for indicating severity of bearing damage are:

1) The total accumulated particle counts detected by the oil debris monitoring sensor.

2) An increasing rate of particle generation.

A correlation can be defined between the accumulated particles counts detected by the sensor and the spall size on a damaged rolling element bearing. Thus, the maximum severity of damage can be defined as an ALARM limit.

Summary

Condition monitoring is an effective technique for managing gearbox failures. Oil debris sensors, when installed within the gearbox lube system provide reliable information regarding the health of the gearbox. Sensor data can be interpreted easily as a condition indicator that provides an early warning of bearing spall and gear pitting damage and quantifies the severity and rate of damage progression towards failure.

Oil debris sensors are a proven technology and have been in operation since the early 1990s. There are now thousands of these devices operating in a wide variety of machinery applications accruing millions of operational hours.

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RP 819 Online Oil Condition Monitoring

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.
Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF
Principal Author: Ryan Brewer, Poseidon Systems

Purpose and Scope

The scope of “Online Oil Condition Monitoring” discusses the utilization of online oil condition monitoring to assess the health of a wind turbine gearbox lubricant.

Gearbox lubricants are designed to provide a protective layer between contact surfaces, thereby significantly reducing friction and wear. They also transfer heat, contaminants, and debris out of the gearbox. Due to the extreme conditions wind turbines operate under (temperature swings, high torque, frequent start/stops, humidity swings), gearbox lubricants are specially formulated with additives such as, oxidation inhibitors, corrosion inhibitors, extreme pressure protection, and anti-foam agents.

Maintaining a healthy lubricant is of critical importance to maximizing the operating life of a wind turbine gearbox. Over time and as a lubricant is exposed to debris or contamination, temperature swings, and extreme loads, its ability to provide the expected level of protection degrades. Ineffective or improper lubrication can lead to highly accelerated wear rates, development of corrosion, reduced efficiency, and ultimately functional failure.

In addition to traditional offline sampling and analysis, many online oil condition monitoring technologies exist which can provide users early warning of lubricant degradation. This recommended practice provides a summary of available technologies and their use for effective lubricant health monitoring.

Introduction

Traditionally, the condition of lubricating oils has been determined through periodic oil sampling and laboratory testing. The methods for collecting gearbox oil samples and recommended analyses are discussed in detail in RP 102 and 104. A full laboratory oil analysis of an oil sample provides a detailed report of a lubricant's physical properties, quantitative analysis of key contaminants, and an indication of its remaining useful life. However, with a limited number of oil samples from a given component and the significant time between sampling (typically 6 months or more), combined with variability in lab analysis techniques and contaminants which can rapidly fluctuate in concentration such as wear debris and water, offline analysis methods provide limited early warning of lubricant degradation.

Online oil condition sensors help to fill these information gaps and provide improved situational awareness when used with conventional offline methods. The real-time data provided by online sensing devices allows operators to identify and correct lubrication issues early, leading to improved long-term reliability and reduced lifecycle cost.

Online Oil Condition Monitoring

A multitude of online oil condition sensors are available from several different manufacturers. The sensing technologies used can be grouped into the following categories:

1) Impedance Spectroscopy

2) Conductivity Sensing

3) Infrared Spectroscopy

4) Moisture Sensing

5) Viscosity

The following sections describe the principles of operation of these devices and how they can be applied for wind turbine oil condition monitoring. Operators are encouraged to seek specific equipment recommendation and instructions from their selected device manufacturers.

1.1. Impedance Spectroscopy

Impedance Spectroscopy methods utilize a set of electrodes immersed in the lubricant to measure the fluid's impedance over a range of frequencies. Impedance measurements consist of a magnitude and phase angle and are frequency dependent. Contaminants, additives, and oxidation byproducts influence portions of the impedance spectrum. Properties such as anti-wear additive health, detergent/dispersant additive health, and dissolved/free water contamination can be detected and trended using impedance spectroscopy based devices.

Impedance based devices can provide the following fluid condition monitoring benefits:

Trend Analysis - Monitor impedance measurements to detect abnormal levels or patterns indicative of contamination or poor health.

Contamination and Remaining Useful Life Estimation - Some manufacturers provide data interpretation algorithms capable of providing remaining useful life estimates (estimate of time until oil properties reach unacceptable levels) and alarms for specific contaminations.

Additive Depletion Monitoring - Impedance-based devices are particularly sensitive to changes in additive levels in a lubricant. Some devices can even distinguish between surface protection additive loss and detergent/dispersant loss.

1.2. Conductivity

Conductivity-based devices operate on a similar measurement principle to impedance-based devices, using a set of electrodes immersed in the lubricant and measuring the electrical properties of the fluid between the electrodes. Conductivity measurements are performed at a fixed frequency and represent the inverse of the measured resistance at that frequency.

The measurement capabilities of a conductivity sensor are dependent upon the frequency at which conductivity is measured. They provide value in trending and alarming, but are limited in their capability by only measuring a single property of the fluid.

1.3. Infrared Spectroscopy

Infrared (IR) Spectroscopy or Fourier Transform Infrared Spectroscopy (FTIR) have been used for many years to provide rapid, low cost, offline analyses of oil samples. The technology passes an infrared light source through a lubricant sample to an infrared detector. The light passing through the oil is influenced by oil contaminants and additives which absorb infrared radiation at specific frequencies. By comparing the frequency spectrum of new and used oil samples, it is possible to determine the lubricant properties such as water, oxidation, glycol levels, and other breakdown products.

Through advances in electronics manufacturing techniques, IR technology is beginning to make its way into online sensing devices. Current technology does not have the refined measurement capabilities of laboratory devices; however, they do offer multi-parameter trending capabilities which can provide valuable, real-time insight into fluid condition.

1.4. Moisture Sensors

Water contamination has many detrimental effects on the performance of a lubricant, including accelerating oxidation, promoting corrosion, decreasing film strength, and increasing foaming. Water is also a difficult contaminant to control, particularly in gearbox applications which endure frequent temperature cycling, changes in atmospheric humidity, and do not experience high enough temperatures to evaporate water contamination. Online moisture sensors, often referred to as oil Relative Humidity (RH) or Water Activity sensors, can detect and trend water contamination in an oil lubrication system.

Nearly all online moisture sensors utilize a capacitive sensing element with a hydrophilic dielectric. As moisture is absorbed and desorbed by the lubricant and sensor, the measured capacitance value will change. These devices track moisture while it is present in its dissolved state and will not continue increasing as free water forms in a system.

Benefits of this technology to wind turbine gearbox lubricant monitoring include:

- Real-time tracking of dissolved water contamination during temperature and humidity swings that are missed by periodic offline analyses.
- Identifying turbines that have faulty desiccants.
- Identifying turbines that show potential for free water formation to prompt corrective actions.

1.5. Viscosity

Through monitoring the viscosity of the oil in a lubrication system, mechanical shear as well as contamination can be indicated. Reduced viscosity results in reduced film strength and increases the likelihood of excessive friction, wear, and heat generation. Elevated viscosity can result in reduced cold-start lubrication and oil filtration performance, and decreased efficiency due to increased fluid friction.

There are several types of online viscosity sensing techniques including rotational, vibrational, and displacement based sensors. Each method has its own advantages and disadvantages which should be discussed with the respective monitoring equipment manufacturers. Due to the very high temperature sensitivity of viscosity measurements and the temperature swings experienced by wind turbine oils, devices capable of providing a temperature compensated output or trending measurements from a specific operating temperature are recommended.

2. Installation Considerations

Proper installation of an online oil sensing device is critical to insuring reliable operation and expected sensor performance. The following sections detail the considerations required when selecting an installation location and plumbing the unit into the system. Always consult with the device manufacturer before installing a device.

2.1. Location Selection

The following considerations should be used to determine the optimal location for device:

- The device should be place in a section of the lubrication system with sufficient flow to insure a representative fluid sample is observed by the device.

- Insure the flow rate in the installation location does not exceed manufacturer recommendations.

- The device should not be placed at the bottom of a fluid reservoir or low point of a kidney loop as sludge and deposits may prevent accurate readings.

2.1. Location Selection
(continued)

- For many online condition monitors, post filtration installation locations are preferred to prevent electrode shorting or damage to moving parts. Wear debris monitors should be installed pre-filter
- Insure the device's maximum ambient temperature will not be exceeded.
- Orient the device and/or design the device manifold in a manner that avoids entrapment of air bubbles or debris.

2.2. Plumbing

When installing the device into a system, consider the following:

1) If using a manifold, ensure it is free of machining chips and any burrs have been removed.

2) Lubricate any threads and/or o-rings prior to installation.

3) Tighten all fittings per the recommended torque specification.

4) After installation, engage the lubrication system and check for leaks.

Summary

Online condition monitoring enhances lubrication maintenance practices to help maintain healthy lubricant and ultimately extend gearbox life. Many online sensing devices are available which offer insight into a variety of oil condition parameters. The selection of an appropriate device depends on the monitoring objective, historical lubrication issues, site location, and the operator's budget. Regardless of the sensing method chosen, these technologies provide significant enhancement to a standalone offline sampling and analysis program by providing continuous data between the typical 6-month sampling intervals.

RP 821 Wind Turbine Blade Condition Monitoring

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

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Purpose and Scope

Blade condition monitoring systems may be capable of detecting and predicting failures and conditions that would otherwise be difficult to undetectable in megawatt class wind turbines (this is not accurate, almost all are detectable with visual inspection). Several technologies have been tried or adapted from other markets with varying ability to detect emerging failure modes. While a mature system is currently not yet commercially available, the scope of “Wind Turbine Blade Condition Monitoring” provides insight into the technologies and discuss common failure modes of wind turbine blades.

Condition monitoring of blades may be required in the future as wind turbines and blades increase in size or complexity, new insurance or lender requirements emphasize predictable reliability, and offshore wind turbines increase in number.

Introduction

There are six major failure modes that can be monitored by a blade condition monitoring system. To date, no commercially available system available is capable of detecting all major failure modes, although several approaches have been tested in the recent decade.

Historically, there have been many attempts at adapting technologies from other industries to this application with limited operational or commercial success. In order to gain market acceptance, any blade condition monitoring system must be able to detect (unknown failures, trend damage progression, and confirm) known failure modes, be easily installed in existing towers, be sufficiently robust to withstand operational and environmental conditions, and provide reliable cost-effective data on blade condition.

Wind Turbine Blade Condition Monitoring

1. Issues

- The first issue is if the technology or product detects the likely encountered failure modes.
- The second issue is if the system is a retrofit to existing towers.
- The third issue is if the system is cost effective.

There is a new patent which does show promise in addressing all three of these issues.

2. Failure Modes

Figure 2. A typical blade plan and region classification.

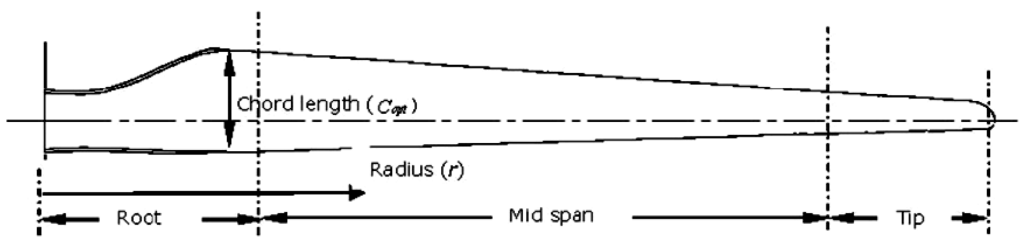

Figure A: A Typical Blade Plan and Region Classification.

2.1. Cracks

The ability to detect and provide early warning of cracks that typically occur at four common locations is critical feature of blade condition monitoring. These crack locations include the root, leading edge, trailing edge, and tip. (*See Figure A*) While there is some uncertainty as to where a crack might occur in these locations due to variables from one blade manufacturer to the next, these four locations are generally consistent.

2.2. Delamination

Delamination predominately occurs at the trailing edge location and is caused by separation of the layers of composites and laminations. Separation may be caused by poor structural design, resin-rich areas with inadequate reinforcing matrix, poor quality control in manufacturing, accumulated stress-fatigue damage, and other factors.

2.3. Icing

An accumulation of ice on the blade surface is not conducive to safe or reliable wind turbine operation. Performance is degraded and the extra loading of ice on blades creates uneven stresses which can be measured. A blade monitoring system should be able to measure this accumulation of ice on the blades and provide the operator with a warning if loads exceed an established action threshold (under operating conditions).

2.4. Imbalance (Either Aerodynamic or Static)

While blades are balanced from the factory within a tight tolerance, the operating environment and in-service wear or damage (e.g., leading edge erosion) may contribute to static imbalance in the field. In addition, aero dynamic imbalance may be result from variations in pitch index or sweep, improper placement of vortex generators or other aerodynamic aids, and variations in a blade’s aeroelastic behavior.

There may also be uneven loading issues caused by wind shear, pitch deviation, tip in/out, and yaw deviation. All of these conditions can be monitored and will return improved performance, reliability, and production. If not monitored correctly, these operational conditions may appear as imbalance, but a best practices blade condition monitor and a trained analyst should be able to discern between these differences. (This is actually a function of a legitimate analyst.)

2.5. Lightning Strikes

A blade condition monitoring system should be able to detect lightning strikes which contribute to one of the acknowledged failure modes. Since lightning is very common in certain geographical locations (like icing), best monitoring practices would dictate a system capable of detecting its occurrence.

3. Technology Approaches

While no single product or technology today can measure or detect all of the possible failure modes common in a wind turbine blade, many (only one actually) there are current efforts that show promise for future applications. Below are the different technologies that may be applied:

3.1. Fiber Optic

Fiber optic sensors provide fast high-resolution strain data from structures. They are light weight and would not affect performance. However, they are also difficult to install outside of initial blade manufacture, are expensive, and do not detect all failure modes. This is likely why fiber optic technology has had limited success and adoption in the wind industry, although it is quite common in the aerospace industry. Installation usually involves cutting a shallow slot into the perimeter of the blade where the fiber optic strand is then laid and epoxied in place.

3.2. Strain Gauges

Strain gauges are inexpensive, easy to install/retrofit to existing turbines, but have proven to be troublesome in the field having a lifetime as short as 6-9 months. Like fiber optic sensors, strain gages do not detect all blade failure modes, and their deployment has had limited success.

3.3. Acoustic

One wind turbine manufacturer has experimented with acoustic monitoring technology to detect blade cracks on a small number of towers. A focused microphone was placed on the top of the nacelle pointing forward towards the hub in an attempt to detect high-frequency acoustic signatures emitted by surface blade cracks. The detection capability of acoustic technology is limited to surface cracks, and it will not necessarily identify sub-surface delamination, or uneven stress loading. While easy to install/retrofit, and relatively cost effective, acoustic technology has not been successful in the wind industry for the same reasons as fiber optic.

3.4. Vibration Sensors

This approach has been used with the sensors mounted near the hub, not on the blades. There is good measurement ability in some failure modes such as icing, imbalance, and less than optimal operational conditions. Again, there is limited detection capability for all common failure modes, but ease of installation or retrofit and cost-effectiveness are good. As a secondary benefit, vibration sensors for blade monitoring are usually applied at the main shaft bearing which is also monitored. While main bearings are the least frequent failure (in most drive trains), they are expensive to repair. Main bearing monitoring is an added benefit of this technology.

3.5. Laser Reference

This method utilizes a laser and prism system which compares the spatial differences and changes between known reference points within a wind turbine blade. This is done by aiming the laser at the prism and then redirecting the laser to internal locations. This technology would provide an excellent system for quality control of blades to measure manufacturing deviations in substrates and composites. Once again, the inability to detect all common failure modes, complexity of retrofit, and system cost all contribute to a lack of widespread acceptance.

4. A Perfect System Summary

As a note to system designers and integrators, the perfect wind turbine blade condition monitoring system would have the following features:

- Be able to detect all 6 common failure modes.
- Have robust sensors.
- Provide blade and blade position identification.
- Provide sensor identification.
- Be cost-effective for either retrofit to existing turbines or installation at original manufacture.
- Use wireless and self-powered sensors to facilitate installation and data collection.

5. Analysis and Software

Like any good condition monitoring system, they are only as effective as the analyst who configures the alarms, monitors the data and performs the analysis. So even with a perfect blade CMS hardware, you still need a certified and experienced vibration analyst with familiarity in wind turbine blade defect analysis to set-up and monitor the CMS for results.

Software should be able to configure appropriate measurements, alarming and display of blade data in a familiar condition monitoring format consistent with industry standard vibration analysis practices and norms. This means industry standard measurements, units of measurements, labeling, measurement set-ups, alarming, charting and reporting.

With the blade CBM data streaming (off of the blades, tower, farm, and fleet), special considerations need to be made for appropriate data transportation, data storage and resulting data analysis with the aforementioned software and appropriate analyst.

Reference

Wind Turbine Blade Design by Peter J. Schubel* and Richard J. Crossley, 6 September 2012 Faculty of Engineering, Division of Materials, Mechanics and Structures, University of Nottingham, University Park, Nottingham NG7 2RD, UK, Tel.: +44-(0)-115-95-13979. www.mdpi.com/1996-1073/5/9/3425

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RP 831 Condition Monitoring of Electrical and Electronic Components of Wind Turbines

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.
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Purpose and Scope

The scope of “Condition Monitoring of Electrical and Electronic Components of Wind Turbines” discusses the condition monitoring techniques used for detecting emergent failures occurring in the electrical and electronic components of wind turbines. It will cover the condition monitoring of wind turbine generator, power electronics, transformer, and cables.

Introduction

Wind industry practice shows that for onshore wind turbines, 75% of faults cause 5% of downtime, and 25% of faults cause 95% of downtime. The majority of those 25% of faults are due to the failures of electrical and electronic components of wind turbines [1]. Considering the wet and corrosive environment of offshore sites and the difficulties of accessing offshore equipment, it is believed that above figure will be more undesirable offshore. Therefore, the reliability and availability of wind turbine electrical and electronic components are critical to minimize life-cycle energy cost and benefit project financials [2]. This highlights the importance of condition monitoring for electrical and electronic components of wind turbines either onshore or offshore. In the following sections, condition monitoring techniques for detecting emergent failures in wind turbine generators, power electronics, turbine and substation transformers, and cables will be discussed.

Condition Monitoring of Electrical and Electronic Components of Wind Turbines

1. Condition Monitoring Of Wind Turbine Generators

Since Doubly-Fed Induction Generators (DFIG) are the most common type in the wind turbine fleet, this section will focus on condition monitoring techniques for DFIG. The failure modes of permanent magnet generators, which are getting increasing market share, are different from those of DFIG, but still have many similarities.

The failure modes of DFIG include:

Mechanical - bearing failure; rotor mechanical integrity failure; stator mechanical integrity failure, cooling system failure.

Electrical - core insulation failure; rotor winding or insulation failure; stator winding or insulation failure; brush gear failure; slip ring failure; commutator failure; electrical trip.

The root causes of these failures are various, such as defective design or manufacture, poor installation, inadequate maintenance, heavy cyclic operation, severe ambient conditions, overload, over speed, low cycle fatigue, shock loading, high cycle fatigue, component failure, excessive temperature in windings, excessive temperature in bearings, steady or transient excessive dielectric stress, debris, dirt, corrosion and so on. Electrical current, flux, and power monitoring techniques have been well developed and are now successfully applied to the condition monitoring of wind turbine generators. Many characteristic frequencies have been identified from stator current signals for diagnosing those electrical failures occurring in the stator and rotor. The relevant information can be found from many openly published literatures.

1.1. Bearing

Since bearings account for over 40% of failures in generators, condition monitoring practice should concentrate on generator bearings. This can be achieved by onboard vibration monitoring and analysis, often in combination with temperature measurement. As the relevant techniques and monitoring procedures have already been introduced in AWEA O&M RP 811 and RP 815, they will not be repeated again in this section. Nonetheless, bearing faults may also be detectable from an analysis of generator electrical current and power signals. Bearings approaching failure contribute to changes to air-gap eccentricity, resulting in measureable effects on magnetic field.

1.2. Earth/Ground Fault Detection

While generator rotors, stators, and bearings are responsible for over 80% of failures of the generator (usually, stators exhibit more problems than rotors) [3], detection of other electrical faults in the generator cannot be ignored. For example, a single earth/ground leakage fault in a generator rotor winding is not serious in itself because the leakage current is relatively limited and cannot cause significant damage. But if multiple earth/ground leakage faults occur, higher current flows may eventually lead to the damage of winding, insulation and even the rotor forging. To early detect this type of fault, a rotor earth/ground fault detector is required, which applies a DC bias voltage to the rotor winding and monitors the current flowing to the rotor body via an alarm relay. Should an alarm occur, it is essential to shut down the generator for further investigation and to prevent additional damage.

1.3. Electrical Discharge Monitoring

Electrical discharge monitoring is another important technique that is often adopted in the condition monitoring practice of wind turbine generators. The discharge behavior of a generator is complex, but can be categorized in an ascending order of energy and potential damage as corona discharge, partial discharge, spark discharge, and arc discharge. Electrical discharge is an early indicator of many electrical faults occurring in the generator that are usually related to integrity and the residual life of insulation. Today, many commercial on-line discharge monitoring systems have been developed and are extensively used in the condition monitoring of wind turbine generators.

1.4. Other Practices

Besides the aforementioned techniques, some others are often adopted in practice as well for various condition monitoring purposes. For example, turn-to-turn faults in rotor or stator windings may lead to local overheating thereby increasing the temperature of the stator and rotor. Stator and rotor temperature is often measured as an indicator of overall condition.

In addition, the deteriorating performance of the brush gear in the generator can be detected by measuring brush or brush-holder temperature. A more advanced technique involves detecting the radio frequency energy generated by brush sparking, but this technique has not been commercially used in practice.

2. Condition Monitoring of The Power Electronics of Wind Turbines

Power electronics have been identified as the components that are most prone to fail, particularly in the wet, salty and corrosive environment experienced off-shore. However, condition monitoring techniques for power electronics have not been fully developed. The reasons are various, but the major ones include:

- The failures of power electronics develop quickly, not allowing sufficient time to implement condition monitoring.
- Power electronic systems have a compact structural design, not leaving enough space to install condition monitoring transducers.
- The power electronic components are relatively cheap in price and easy to replace, no need to monitor their health condition online if the system can be easily accessed.

However, power electronics have a wide range of failure modes, which can be caused by excessive temperature, excessive current and voltage, corrosion, thermal fatigue, ionizing radiation, mechanical shock, stress or impact, etc. A recent survey based on 200 power electronics products from 80 companies shows that failures in the converter are 30% due to capacitors, 26% due to PCBs, 21% due to semiconductors (e.g. Insulated Gate Bipolar Transistor - IGBT), and 13% due to poorly soldered connections[4]. Clearly, semiconductors and DC link capacitors are the most fragile components in wind turbine power electronics.

2.1. IGBTs

Temperature measurement is commonly used for monitoring the operation and health of wind turbine power electronic converters and inverters, but more advanced techniques are being researched today. The latest generation of IGBT products has been equipped with built-in thermocouples, so that variations in IGBT temperature can be readily tracked. However, measured temperature is reliant on many factors (such as ambient temperature and load), thus, diagnosis of an IGBT high temperature condition still requires further investigation.

2.2. Capacitors

Two kinds of capacitors are being used in the wind industry as DC link capacitors in power electronic converters - the aluminum electrolytic capacitor, and the metallized polypropylene film capacitor. The former is characterized by a high power density at a relatively low price, but is prone to fail in practical application. By contrast, the latter is more reliable and is able to withstand higher voltages and currents, with a tradeoff of comparatively lower power density. The condition of electrolytic capacitors can be approximated by trending three characteristic aging indicators - capacitance, equivalent series resistance, and the dissipation factor - and comparing the measured values of these parameters with recommended service thresholds. Although film capacitors are generally more reliable than electrolytic capacitors due to their self-healing capability, they are not free from failures. In contrast to the three aging indicators of an electrolytic capacitor, the film capacitor has only one ageing indicator - capacitance. Online condition monitoring of the capacitance of the film capacitor is exactly same as that used for monitoring the electrolytic capacitor. Since temperature is the main ageing accelerator of capacitors, temperature measurement is also applied to condition monitoring for capacitors, though the result derived from temperature monitoring could be less reliable.

3. Condition Monitoring of Wind Turbine and Substation Transformers

Wind turbine and substation transformers are critical to the operation of wind farms. Their safety and reliability is critical to profitable power generation, transmission, and distribution. As the transformers are subject to very high mechanical, electrical, and thermal stresses during operation, failures and aging issues often occur in their windings, bushings, tap changers, insulation, and auxiliary equipment. Although consistent failure rates for these components have not been established in surveys conducted by different organizations, winding, bushing, and insulation systems have been identified as the three most fragile components in transformers. Moreover, these components are responsible for over 50% of plant downtime [5].

3. Condition Monitoring of Wind Turbine and Substation Transformers (continued)

Bushing – Modern transformer bushings are generally designed with closely stepped capacitive stress control layers. The basic insulating systems of capacitive stress controlled high voltage bushings are classified as Resin-bonded paper bushing, Resin-impregnated paper bushing, and Oil-impregnated paper bushing. Despite the different types of bushings, bushing capacitance and dielectric dissipation factor are two key indicators of their operational condition. This is because both indicators are dependent on ageing, although they are also affected by the external environment (e.g., moisture, dirt, etc.). Dielectric dissipation factor is a function of bushing capacitance. An increase in bushing capacitance for all bushing types indicates partial breakdowns between the control layers. A short-circuit between two control layers could have little influence on the general health condition of a bushing. But the increasing number of defective control layers can result in a complete breakdown of the insulation. Storm conditions (lightning, high winds, etc.) and/or routine switching actions may cause a transient overvoltage condition that could damage the insulating layer of the bushing. Tracking and reporting of transient overvoltage conditions in transformers is recommended as an additional tool in the evaluation of transformer and bushing condition.

3.1. Other Practices

Besides monitoring bushing capacitance, dielectric dissipation factor and transient overvoltage, the following techniques are often useful for condition monitoring of wind turbine and substation transformers:

Dissolved Gas Analysis - High electrical and thermal stresses in the transformer will cause breakdown over time of insulating materials and release gases due to localized overheating, corona and arcing. Different concentrations of gases will appear depending on the intensities of energy dissipated by various faults and the analysis of dissolved gases is very helpful for the identification of the root causes of the faults.

Partial Discharge Monitoring - PD is also an important means for detecting the deterioration of the insulation system of a transformer. Once a defect has developed on the insulator, partial discharge pulses will be generated at its point of origin. Hence, the initiation and development of an insulation defect can be identified if partial discharge pulses are detectable.

3.1. Other Practices
(continued)

Temperature - Temperature measurement is used as an indicator of the operational and health/aging condition of transformer windings. Now, several approaches have been adopted for the measurement of transformer temperature. Among them, the most promising device is an optical fiber transmitter connected to a crystal sensor. The sensor converts an incoming light beam into an optical signal that can be correlated to sensor temperature. Currently, these devices have been tested, but are not widely in service.

Vibration Analysis - Vibration sensors magnetically attached to the sides and top of the transformer tank may help detect changes in the mechanical integrity of transformer windings (e.g., winding looseness) and the tap changer. But the practice has shown that vibration analysis of transformers is quite complicated due to the many vibration sources such as primary excitation, leakage flux, mechanical interaction, switching operations, etc.

Leakage Flux - This is a traditional method popularly used for detecting changes in winding geometry. It is known that any mechanical displacement of the windings can result in changes to the radial component of leakage flux. By using search coils that are installed in the transformer, these changes can be readily detected.

Analysis Of Current Signals - This is a very popular approach used in the condition monitoring practice of transformers. This method can be used to detect the undesirable conditions in single phase or three phase transformers. Usually, all three phases of current signals are used together for either comparison or comprehensive analysis (e.g., Park's vector pattern analysis) to detect the early malfunction of transformers.

Monitoring of Bushing Oil Pressure - For oil-filled bushings, it is possible to measure bushing oil pressure, thereby checking for possible oil leaks. Since changes to bushing oil pressure can also be affected by the thermal overload or partial discharges, it is recommended that careful onsite investigation be conducted once a significant drop in bushing oil pressure is observed.

4. Condition Monitoring of Electric Cables

Power cables used on wind farms represent a large capital investment. They are usually reliable, but are critical to the overall performance of the facility. Failures not only affect the power generation of individual wind turbines, but the production of the whole wind farm could be impacted. For this reason, monitoring and maintaining the condition of electric cables is of great significance to assure the profitable production of wind farms, particularly for those where cable installation and repair are difficult to carry out.

Different types of electric cables (e.g., paper/oil and extruded cables) are produced for different purposes. Cable systems used on wind farms are predominately insulated with solid dielectric insulation (e.g. plastic and rubber based materials). Electric cable systems can fail for a number of reasons [6]. The most common reason for failure on wind farms is poor installation technique. Low voltage cable systems, less than 1kV, commonly fail at the connectors due to overheating. One of the most effective tests for low voltage cable systems is the infrared assessment (see RP 601 and 602 Secondary Cables for more information). Medium and high voltage cable systems can fail due to overheating at the connection points but the predominant issue is insulation failure. Failure occurs when the local electric stress exceeds the insulation strength (e.g. a sharp metal protrusion in the insulation), a gas or air void is introduced where solid insulation should be (e.g. a lack of dielectric grease on a joint interface), or, as is most common, a more subtle mixture of the two cases. In either case partial discharge arises and begins erosion process. The erosion process only advances during voltage stresses which are sufficiently high enough to turn on the PD ionization process. Voltage transients, which are very common at wind farms, intermittently turn on PD sites and cause sporadic erosion. Manufacturer standards of modern solid dielectric components require the components to be PD free at stress levels well over the operating voltage, as they will not last long under continuous PD activity. Thus, IEEE, IEC and ICEA standards require and off-line 50/60Hz PD test with better than 5pC sensitivity to determine whether or not components are in or out of specification. Since this standardized test can only be performed off-line it is typically performed during construction and then periodically during plant shutdowns (see RP 601 and 602 MV Cable Systems for more information).

4. Condition Monitoring of Electric Cables
(continued)

Wind farm cable systems are presented with some extreme and unusual requirements. For example, the cable systems are typically designed for 100% loading; they can cycle from 100% to virtually zero load; they operate at more than two times the stress of typical medium voltage cable systems; and they often have relatively long cable runs
(longer than 1 mile). This combination of challenges is unusual for other types of power plants and utility distribution applications that use similar cable system components. These noted challenges are usually only seen in transmission class cable systems. For this reason, many owners have specified stringent commissioning test requirements, such as the off-line 50/60Hz PD test. In some cases owners have installed thermocouples to spot check cable systems. While it is possible to run an optical fiber in parallel with the cable system for distributed temperature sensing (DTS), it is not a common practice.

A more common practice is to minimize the number of underground joints and use above ground junction boxes. The junction boxes can be serviced using an infrared (IR) camera and the most common overheating point, the cable accessory, can be checked for overheating during high load conditions and prevent damage to the cable insulation. IR cameras and off-line 50/60Hz PD tests are complementary. There is virtually no IR signature associated with PD activity and there isn't any PD activity at overheating connection points until the insulation is slightly damaged. In addition, junction boxes are convenient points for fault indicators, sectionalization during failure locating and predictive off-line insulation testing.

An important issue in partial discharge testing is the level of test voltage. Using an excessive test voltage will initiate partial discharge pulses that would not exist at normal operating voltages, and may cause other damage that would not occur under normal operation. Therefore, it is recommended that system test voltage not be greater than 1.5 to 2 times the operation voltage.

Summary

Condition monitoring of electrical and power electronic components of wind turbines has long been overlooked in previous wind industry practice. It is now being recognized as equally important to the condition monitoring of wind turbine drive trains, particularly with the increasing deployment of the wind turbines offshore or in remote locations.

Summary
(continued)

In contrast to condition monitoring of wind turbine drive trains, condition monitoring of wind turbine electrical and power electronic components requires dedicated techniques or methods. While some methods come from traditional ideas (e.g., temperature measurement), they have been applied using more advanced technologies in order to meet special needs of wind facilities. This motivates the invention and development of even more innovative techniques in this young industry.

In this recommended practice section, a number of commercially available condition monitoring techniques for generator, power electronics, transformer and cables are briefly discussed in order to sketch an outline of the condition monitoring of the electrical and power electronics of wind turbines. However, the selection and practical application of these techniques is still reliant on the actual situations and physical requirements at site. Moreover, care should be taken in the application of some techniques (such as partial discharge testing) to assure they will not introduce negative effects or additional damage to the assets being monitored.

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RP 832 Lightning Protection System Condition Based Monitoring (CBM)

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.
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Purpose and Scope

The scope of "Lightning Protection System Condition Based Monitoring (CBM)" provides suggested methods for condition based monitoring of the lightning protection system. Specific methods of monitoring are not provided but the requirements for monitoring are described.

Introduction

The main purpose of the lightning protection system is to provide sufficient protection for the wind turbine to avoid damages in the event of a lightning strike. The lightning protection system can prevent or reduce damage that results in forced production outages and long-term degradation of components.

Lightning Protection System CBM

1. Monitoring Direct Attachment

1.1. Online Triggering CBM

As a minimum, it is recommended to monitor lightning strikes to the wind turbine by a simple trigger circuit that provides a digital signal in the event of a lightning strike. The trigger signal should be monitored by the controller of the wind turbine and this triggering may be correlated with other CBM signals/data so eventually incidents can be compared to the occurrence of lightning strike.

1.2. Parameter Measuring CBM

The online triggering CBM can be extended to also measure the typical relevant parameters of the lightning. By measuring such parameters, the chance of success in predicting and evaluating damage is further enhanced. These parameters are stored as values in the wind turbine data log and can be correlated with other events, trends or developments that might originate from the specific time of triggering.

Peak Current - This parameter is the easiest to measure. It will tell if there is risk of damage for connection components and risk of magnetic field coupling (i.e., damage to other parallel electrical components).

Energy - This parameter provides information of overheating risk of conduction materials.

Charge - The charge will indicate the wear erosion on lightning attachment points and on rotational transfer systems/bearings.

Current Rate-of-Change - The steepness of di/dt in a lightning strike will indicate whether there is risk of coupled transients or failing insulation.

1.3. Wave Shape Logging CBM

As a supplement to the online triggering and parameter logging the CBM can be extended to log the actual wave shapes of the lightning. The system logs and stores the curves. The curves can be used for further analysis of the lightning attachment.

1.4. Location Logging CBM

Each of the suggested systems can be expanded to either measure at several points or to do one detailed measurement. This will provide knowledge of where the lightning has attached and specific areas can be targeted for subsequent investigation or monitoring.

2. Monitoring Indirect Effects

2.1. Surge Protective Devices (SPD) Failure Monitoring

If the SPD system provides feedback, this feedback should be monitored. Furthermore, several systems use an upstream fuse that also needs to be monitored, if present. This monitoring may be done online, and any fault will require a service visit to the wind turbine to replace the defective component.

2.2. CBM of Surge Protective Devices

It is suggested that the operation of SPDs be monitored. By continuous monitoring and counting of transients, the SPD can be predictably maintained.

3. Inspecting the Lightning Protection System

On an annual basis, it is recommended that a full inspection is performed on all wear parts of the lightning protection system. The system should be inspected for excessive wear or defects. All adjustable systems should be inspected for correct adjustment and corrected if needed.

Reference

IEC 61400-24 webstore.iec.ch/publication/5437

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