Category: LIDAR

STATISTICAL LOAD ESTIMATION USING A NACELLE-BASED LIDAR SYSTEM

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Summary

The paper presents the results of statistical load analyses based on data measured at the 5MW AREVA Wind M5000 onshore prototype. Measurements with standard meteorological measurement devices are analysed and compared to measurements with a pulsed LIDAR system which is enhanced with a multi-purpose scanning device installed on the top of the nacelle of the turbine. Based on these measurements statistical summaries of relevant meteorological parameters have been used for normative procedures to calculate the mechanical loads which occur at the wind energy turbine. It could be verified that LIDAR systems can substitute standard measurement devices for a load estimation of wind energy turbines.

1 Introduction

An accurate estimation of mechanical loads of a wind energy turbine is one of the key elements in the certification process for wind energy turbines. Usually the necessary data for the calculation of mechanical loads according to [1] is collected with anemometers installed at a met mast in the vicinity of the turbine in a distance of 2-4 times the rotor diameter *D*. The main disadvantage of such devices is the lack of information about the entire incoming wind field. The purpose of this work is to investigate and develop strategies to improve the statistical load evaluations by not only regarding point measurements of meteorological parameters with standard measurement devices of the incoming wind but by introducing the whole incoming wind field into the analysis. This is important because of the inhomogeneous character of the wind field in front of a wind turbine.

Remote sensing techniques such as LIDAR offer such measurement possibilities of the wind conditions and are in addition cost and time-saving as it is not necessary to erect a met mast. This becomes even more important for offshore purposes. Such devices can be ground- or nacelle-based but need different preprocessing routines to get verified data sets.

This paper shows an approach to calculate the statistical data for the mean wind speed and turbulence intensity by means of data collected with a nacelle-based LIDAR system and a comparison of this data with standard measurements, as well as the exemplary calculation of load spectra and damage equivalent loads for selected components of wind energy turbines.

This work is carried out within work package B.3 of the joint research project "Development of LIDAR wind sensing for the German offshore test site". Figure 1 illustrates the described process of a load estimation using a nacelle based LIDAR device enhanced with a scanning interface.

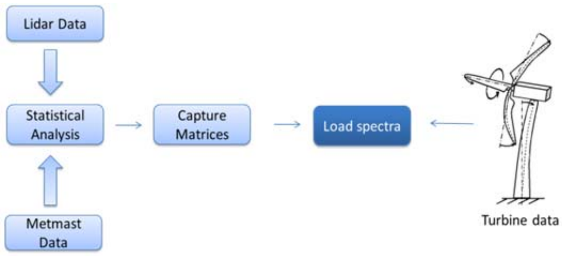

Figure 1: Outline of data processing

2 Data Analysis & Measurement Results

2.1 Experimental Setup

The experimental data analysed in this research has been collected with a pulsed LIDAR system equipped with a scanning device developed by the Endowed Chair of Wind Energy (SWE). The whole system is mounted on the nacelle of a 5MW wind energy turbine with a rotor diameter *D* of 116 m and a hub height of 102m. [2]
In the vicinity of the turbine in a distance of 290m, which is equal to 2.5*D*, measurements of the wind speed, wind direction, air temperature and air pressure are executed by means of standard measurement devices installed on a met mast at hub height.

2.2 Wind field analysis

The LIDAR scanning device allows the application of complex trajectories [3] and a following data processing of the wind field's grid points so that one gains an enhanced estimation of the incoming wind field. The measured data gives information about wind speed, wind shear, wind direction and turbulence intensity over the complete rotor area.

This paper is based on data collected with a so-called 7x7 grid which comprises a 0,75*D* x 0,75*D* square swept by the scanner beam in 1*D* distance to the wind energy turbine. A sketch of this trajectory can be seen in Figure 2. This distance has been chosen due to the fact that the deployed LIDAR system has some limitations of its carrier to noise ratio (CNR) for larger scanning distances. In addition the blocking effects of the wind turbine are affecting the inflow wind field only to a small degree in a distance of 1*D*. Additional information about other possible trajectories is given in [4].

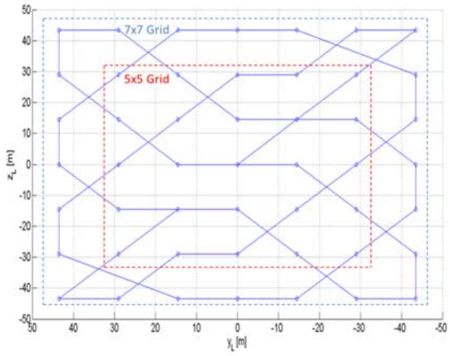

Figure 2: Illustration of the 7x7 grid trajectory

2.3 LIDAR data preprocessing

Because of temporal and spatial differences of each scanned grid point the data collected with the LIDAR device has to be preprocessed for a statistical analysis that applies to the current standards. A full documentation of the data conversion can be found in [4]. For this research two different data preprocessing methods have been used. The first method is a moving average algorithm which has been developed in [5]. The second method is a temporal and spatial interpolation method which is discussed in [3].

2.4 Data basis

The following analysis is based on four different wind speed measurements and computations. The wind speed $v_{metmast}$ applies to the data measured with the hub height anemometer, $v_{average}$ applies to LIDAR data generated with the moving average algorithm mentioned before, $v_{interpolated}$ defines data generated with the interpolation algorithm and $v_{interpolated\_50}$ applies to LIDAR data generated with the interpolation algorithm. In this case only the inner points (see Figure 2) are taken into account which could be considered as a reduction to a 5x5 grid. This was done due to the fact that the measurement of the outer grid points with the LIDAR beam implies a higher angle of attack between the beam and the moving air particles. This increases the incertitude of the measurement especially because those grid points comprise, due to the large differences of the wind field on the outer edges of the measured wind profile, the biggest deviation to the measurements on hub height. Other data preprocessing tools developed for the LIDAR data have also been applied to exclude false data sets [4].

A good impression of this wind profile deviation and of the benefit which can be gained by a scan of the complete wind field is shown in Figure 3, where a coloured plot displays the interpolated mean wind speed between the 7x7 grid points of the wind field for a 10-min time series. In this plot we can e.g. diagnose a deviation of $\sim 4\frac{m}{s}$ between wind speed velocities on the outer edges of the wind field.

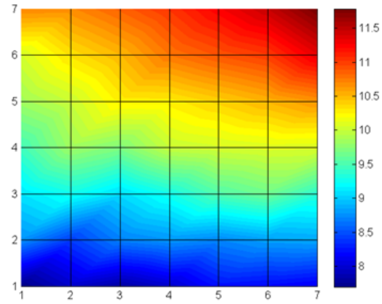

Figure 3: Illustration of the wind speed distribution of an interpolated wind field for a 10-min time series

To get a visual impact of the averaging methods which have been applied to the data, Figure 4 illustrates exemplarily a 10-min time series with all mentioned wind speeds displayed. It is obvious that large fluctuations of the wind field are already averaged to a certain degree by the probe volume and the preprocessing of the LIDAR data. Of course it has to be added that the LIDAR scans in this special case a wind field which has passed the met mast ~20s ago. A time shift has been neglected because only the 10min mean values are of relevance for the data evaluation and it will be shown that it is not important for such a statistical analysis.

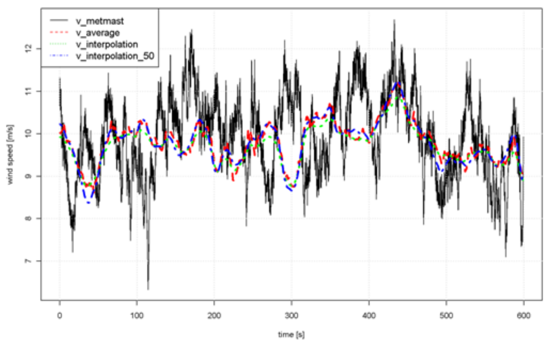

Figure 4: 10-min time series

For this study only data sets which apply to the definitions of Normal Operation Cases (NOP) defined in the IEC standards are taken into account. Other data sets have been filtered out. Due to the fact that other wind energy turbines and several tall structures in the vicinity of the turbine are limiting the valid measurement range only data sets from a small sector, where the wind direction is deviating at most 20° to the left and to the right of the met mast, have been considered for the research. Due to the small sector and after the filtering for valid time series only a small number of time series could be taken into account, i.e. the following analysis is based on 269 time series of 10 minutes which comprise approximately 10% of the whole data set.

3 Capture Matrices

The preprocessed LIDAR data and the measured data of a standard anemometer are classified according to their mean wind speed and turbulence intensity values for each 10-min time series into a capture matrix for normal power production. Figure 5 visualizes the mentioned matrices for the different wind speeds.

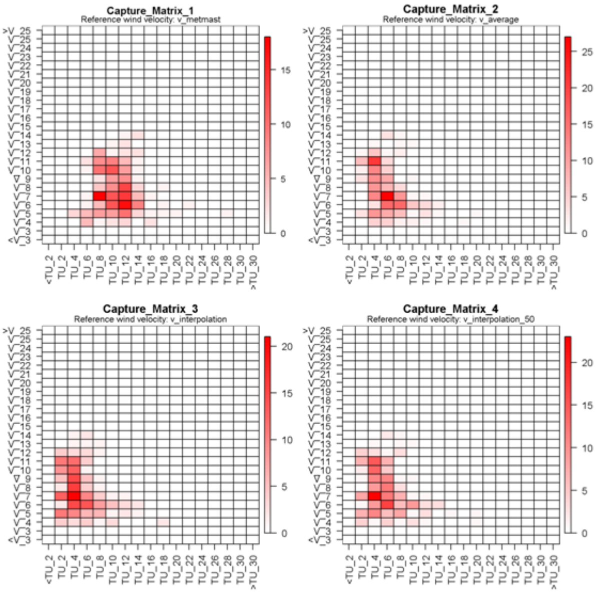

Figure 5: Display of the capture matrices

It is clearly visible that the matrices 2-4 that are based on LIDAR data differ from matrix 1 which is based on the anemometer data whereas there are only small differences noticeable between the LIDAR based matrices. If we sum the turbulence intensity and wind speed bins, it becomes obvious that the difference between the matrices results mainly from the turbulence intensity and not from the mean wind speed.

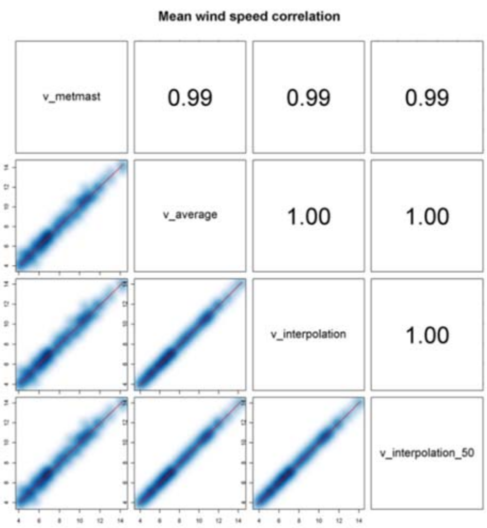

Figure 6: Comparison of wind speed, linear regression and correlation factors

If we do now plot the turbulence intensity and the mean wind speed as correlation diagrams, with a scatterplot in the lower corner and the appropriate coefficient of determination R^2 in the upper corner, for all possible comparisons (see Figure 6-7) we can state that the mean values of the wind speed differ only to a slight degree between the LIDAR and the anemometer measurements. But it can also be noticed that there are distinctive differences in turbulence intensity between both measurement methods.

The reason for this difference is on the one hand due to the spatial averaging effects of a pulsed LIDAR system which is discussed in [6]. On the other hand it is clear that an averaging and an interpolation of a whole wind field will result as a different standard deviation i.e. a lower turbulence level than for a single anemometer. This “averaging” also results in a lower temporal resolution of the data which reduces the standard deviation of the wind speed and thereby the resulting turbulence intensity.

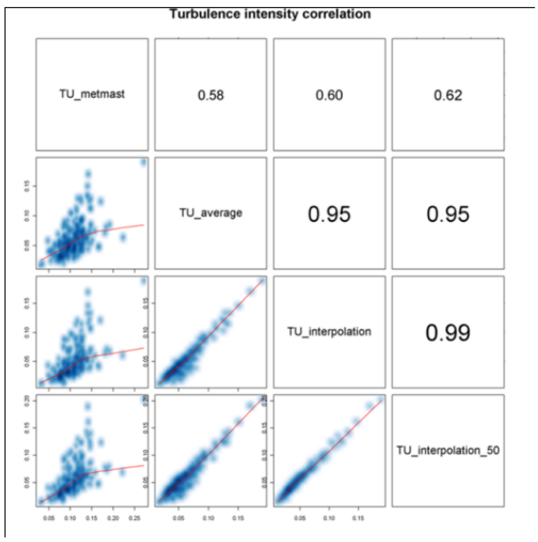

Figure 7: Comparison of turbulence intensity, linear regression and correlation factors

4 Fatigue analysis with LIDAR

Based on the above-specified capture matrices a fatigue evaluation of the wind energy turbine's components has been carried out for each wind speed. This paper focuses on the resulting fatigue of the edgewise and the flapwise root bending moment of a blade of the wind energy turbine.

4.1 Loads estimation

As a first step a rainflow counting of the loads for each time series has been carried out according to [1]. In a second step these rainflow counts have been weighted with the wind field data of the four presented wind speeds and the Weibull distribution of the test site, with Weibull factors $A = 8.8$ and $k = 2.41$. The results are so-called Markov-Matrices for each time series that can be accumulated. The load spectra have been calculated based on these summation matrices.

If the different load spectra are plotted based on the four different wind speeds it can be noticed that all four load spectra (see Figure 8) for both bending moments coincide very well. This was expectable due to the fact that a weighting of the data based on a Weibull distribution as it is designated in the IEC standard only weights the data according to the mean wind speeds. The turbulence intensity is not taken into account.

Only for large oscillations small deviations are distinguishable in the load spectra display. This is because of the fact that these fractions of the spectra depend a lot on the wind speed and the resulting loads of the turbine close to rated speed which differ a bit between the two measuring methods. Low wind speeds and the differences between met mast anemometer and LIDAR in measuring them, do not affect the load spectra to a large degree.

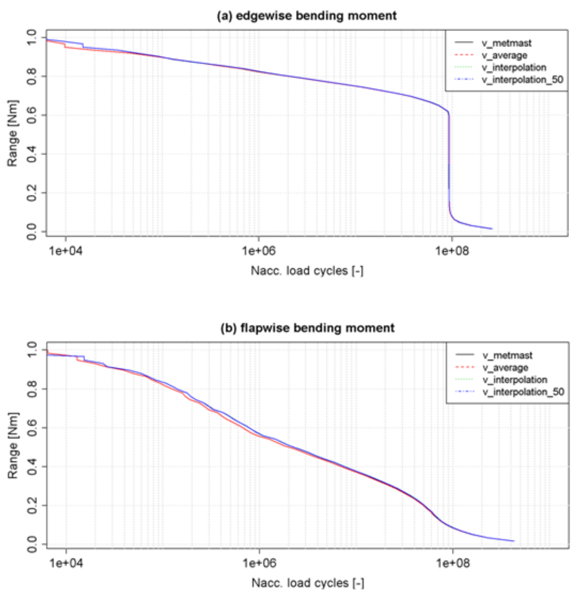

Figure 8: Comparison of load spectra (a) edgewise blade bending moment (b) flapwise blade bending moment

Another impression of the good agreement of the loads based on anemometer and LIDAR measurements can be gained if we regard the damage equivalent loads (DELs) which are presented in Table 1 for a Wöhler value of $m = 12$ and a reference number of cycles of $N = 10^6$.

	v_metmast	v_average	v_interp.	V_interp.50
Edgewise bending moment	1.000	1.0004	0.9987	0.9987
Flapwise bending moment	1.000	1.0059	1.0001	1.0001

Table 1: Comparison of DELs

We can state that the moving average algorithm estimates the wind speed and the resulting DELs better for the edgewise bending moment, whereas the interpolation algorithm gives better results for the flapwise bending moment. However both algorithms show a very good performance because of the maximum deviation of the damage equivalent loads of ~0.6%.

5 Conclusion and Outlook

It could be shown that a calculation of load spectra and damage equivalent loads based on measurements of the wind field by means of a nacelle-based LIDAR system is possible if certain computation methods of the wind field statistics are applied to the data. It is obvious that a current LIDAR system collects information about the wind differently as do standard anemometers. For this reason the standard deviation and so the turbulence intensity differs quite a lot between the two methods. Therefore the question arises whether e.g. the weighting of the statistical data of a rainflow count should also include the turbulence intensity if LIDAR devices are applied for measurements. But in contrast to standard methods it is possible to gain knowledge about the whole incoming wind field.

Further studies will investigate if other trajectories with less scanned points per trajectory are as well comparable to standard wind measuring procedures for a statistical analysis of mechanical loads. With respect to the different sectors of the wind field the load characteristics of the turbine resulting from these variable inflow conditions will be researched in upcoming studies. The influence of special inflow conditions such as variable wind profiles for different times of the day or season could be of high interest for the certification of design driving components of a wind energy turbine.

6 Acknowledgements

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