Reply to Reviewers

We thank the reviewers for their detailed analysis and constructive inputs. A list of point-by-point replies to the reviewers' comments is detailed in the following.

Reviewer 1

A good account of very careful, detailed work on a technique which could have useful applications, with a good attempt to account for the inevitable difficulties of a real field test. Detailed comments (P=page, L=line):

1. **Reviewer**: *P2 L4: the term "lower spectrum" is not clear - or is it a typo?*
   Authors: We meant the lower frequencies (such as 1 per revolution, or 1P). The text was updated for improved clarity.

2. **Reviewer**: *P3: in L2 "does not need to be trained with data" but in L7 "is tuned" - what sort of tuning (and isn't that a simple form of training with data)?*
   Authors: The observer does not need to be trained with field data since it can be derived from the standard performance curves of the machine. Nevertheless, to compensate for possible sources of error, it can be fine-tuned with operational data. The text was updated for improved clarity.

3. **Reviewer**: *P4 L8: change "write" to "can be written as" or "are given by"*
   Authors: This has been changed.

4. **Reviewer**: *P4 Figure 1: top left figure (vertical shear) shows arrows originating from a non-vertical line. Does this represent rotor tilt? It should be explicitly stated somewhere that rotational symmetry depends on the coordinate system being tilted to align with the shaft axis. Presumably, after estimation you would need a final step to transform the wind components back to the 'normal' (untilted) reference frame.*
   Authors: As suggested, the text was rephrased to explain that the reference frame in Fig. 1 is a nacelle-attached one, considering the nacelle uptilt.

5. **Reviewer**: *P5 L21: "horizontal shear does not (except in waked conditions)" - probably not very much on average, I agree, but still maybe a bit sometimes, at least onshore due to orographic / vegetation effects - but anyway there can be significant, though short-lived, stochastic changes in horizontal (and vertical) shear across the rotor due to spatial turbulence effects.*
   Authors: Thank you, indeed the text was not very clear and possibly misleading, and it has now been modified to better explain this point.

6. **Reviewer**: *P6 L4: I think you should explain how Equation (8) is derived, and where Q comes from.*
   Authors: The text was changed to better explain the formulation; a new bibliographical reference on weighted least squares estimates was also added for completeness.

7. **Reviewer**: *P7 L5: "fairly robust to changes" - maybe "fairly robust to typical changes"? Presumably can't be true in the case of large changes (hopefully unlikely).*

Authors: The sentence was changed as suggested.

8. **Reviewer***: P7 L27: Using phase-shifted measurements from blade 1 & 3 to estimate the load on blade 2: Presumably this actually means time-shifted using rotor speed? Probably needs an equation here, and a some justification for the absence of a blade 2 measurement not affecting the results. Can you say why there wasn't a measurement on blade 2?*
   Authors: The measurement of the load components of blade 2 was unfortunately not available, simply because that blade was not equipped with load sensors based on a choice of the turbine owner and operator. To apply the Coleman transformation, the load on blade 2 is necessary and, as explained, was obtained by averaging the loads of blades 1 and 3, which is probably the only way this load can be reconstructed with the present setup. This approach implies the reasonable assumption that neighboring blades are experiencing similar loads at the same azimuthal position. The shift is due to the angular spacing of the blades, so it is best described in terms of angles as done here; clearly, since $\psi = \Omega t$, the map between time and angle depends on angular speed.
   We have rephrased this part of the text to better explain these aspects of the discussion and improve clarity.

9. **Reviewer**: *P9 L12: presumably the reference explains in more detail, but can you give a justification for using 2/3 R? Wouldn't it depend on the turbine aerodynamic details?*
   Authors: We have rephrased this part, explaining that this result is valid for a linear shear and a 90-deg-wide sector. The reference where this result was first derived is also included.

10. **Reviewer***: P10 equations 16 & 17: Consistency of notation: is VPL(z) the same as V(z)PL?*
    Authors: Yes, thank you for spotting this. Equation 16 was changed accordingly.

11. **Reviewer**: *P10 L10: why was a 50-degree sector chosen, and why is it not exactly centred on the direction separating mast and turbine?*
    Authors: The size of the sector was initially chosen to include as many points as possible while still maintaining a reasonable alignment. The sector was now changed to be exactly symmetric, which has led to a slight decrease of the number of data points.

12. **Reviewer**: *P10 L13: "two measurements" - presumably these are actually estimates rather than measurements?*
    Authors: The word "measurement" was replaced with "estimates".

13. **Reviewer**: *P10 L14: Since the shear is actually non-linear, and different parts of the blade contribute differently to loading, some sort of weighted mean shear gradient might be more appropriate than the slope between hub and blade tip?*
    Authors: The observer can be formulated to work with non-linear or linear shears. Here, the linear vertical shear was chosen in order to exploit the rotor symmetry; this has now been better explained in the text.
    A weighted shear gradient was already investigated in *"Bertelè, M., Bottasso, C.L., Cacciola, S., Daher Adegas, F. and Delport, S.:Wind inflow observation from load harmonics,Wind Energ. Sci.,2, 615–640, doi:10.5194/wes-2-615-2017, 2017"*, where span-wise weighting was used to account for the non-uniform power extraction characteristics of rotors. Nonetheless, this approach did not lead to any significant difference in the profile characterization.

14. **Reviewer**: *P10 L16: different slopes in Figure 4: Might this be due to non-linearity of shear, and/or the use of 2/3 R, or do you have some other explanation?*
Authors: We have provided possible explanations for this behavior, although a certain proof of the cause is difficult to achieve with the present dataset. We have modified this part of the text, which is hopefully clearer now.

15. **Reviewer**: *P11 L14: What filter characteristic, and how was it chosen? Are you filtering the wind vane signal, or the wind direction obtained by combining the wind vane signal with the nacelle position signal?*
Authors: The filter is a simple 1-min moving average, applied to the difference between the wind direction measured at the mast and the nacelle position. The text has been rephrased here for improved clarity.

16. **Reviewer**: *P12 L8/9: Are you effectively assuming zero upflow, as you can't measure it?*
Authors: No, since we are using the symmetry conditions for the coefficients, we do not need to assume any specific value for the upflow as it is not used for training.

17. **Reviewer**: *P13 L6: "scheduled as functions of the rotor-effective wind speed" - Not clear how you did this - was it by binning results in wind speed bins according to 10-minute average rotor-effective wind speed estimate and fitting model parameters for each wind speed bin?*
Authors: The text has been improved for clarity, providing more detailed information on the implementation.

18. **Reviewer**: *Conclusions: "Training with 10-min data improves the quality of the estimates" stated without providing evidence. Can this be substantiated a bit better?*
Authors: Thank you, this was indeed not documented in the previous version. We have now added a new figure (number 8 in the new version of the manuscript), and expanded the text in section 3.2 to discuss the effects of time averaging.

19. **Reviewer**: *The importance of veer is becoming more apparent especially for large turbines and stable conditions. How easily could the model be extended to provide an estimate of veer?*
Authors: The current model formulation would not allow for the estimation of veer. Indeed, we have verified that, to distinguish the effects of veer, one needs to include also the 2P harmonics. These harmonics, however, are strongly polluted by turbulence and exhibit a non-linear behavior. We are currently developing a different approach to deal with these problem with promising results, which we hope to report soon in a future paper. A short comment on veer has been added to the introduction.

20. **Reviewer**: *Some comment on how the model should be adjusted in case of a turbine which is using individual pitch control?*
Authors: We have investigated this issue in a simulated environment in "*Bertelè, M., Bottasso, C.L., Cacciola, S.: Simultaneous estimation of wind shears and misalignments from rotor loads: formulation for IPC-controlled wind turbines, J. Phys. Conf. Ser., 1037 032007, doi:10.1088/1742-6596/1037/3/032007, 2018*". We added a sentence to the text to redirect interested readers to this reference.

Reviewer 2

This paper presents an experimental test of a method for generating estimates of characteristic wind properties based on loads measured on the turbine blades. Overall, I have no major objections to the methodology used or the results presented—it is refreshing to see data from a previous campaign being recycled and used to produce new results. However, I have some more comments and suggestions that I feel could improve reader understanding, as follows:

1. **Reviewer**: *Please provide a description (in text) of shear and misalignment in Section 2.1. The equations are not directly intuitive, and Figure 1 does not actually demarcate the quantities kappa_v, kappa_h, chi, or phi. Please include units for these, where appropriate. Similarly, please provide a reference or further explanation for eqs. (3a) and (3b), since it is not immediately obvious to the reader why one involves both chi and phi and other does not.*
   Authors: The picture was updated to clearly indicate the parameters and their units, and the text was expanded to better explain the relevant terms and equations.

2. **Reviewer**: *I find Section 2.3.2 to be confusing to read. Can you be more precise about what the power law is adding? On page 9, line 16 you say that it is 'useful' to fit a power law, but don't explain why. Since using the power law seems to make the procedure of calculating vertical shear more complicated than horizontal shear, perhaps you could provide a diagram of the steps needed to calculate each state, or a concise list of steps.*
   Authors: Thank you, indeed this part was not very clear. The text has now been partially rewritten and expanded to better explain this point.

3. **Reviewer**: *In Section 3.2, is the SEWS being used to generate the reference value for horizontal shear, given the lack of met mast measurement? This should be clarified. If so, it would seem that the error metric for kappa_h is a difference between two competing methods as opposed to an error, which you allude to on page 16, lines 4–5, but isn't clearly stated. It seems a little inconsistent to provide results for horizontal shear but not upflow angle, since the met tower did not provide data on either.*
   Authors: Yes, the SEWS is used to generate a reference for the horizontal shear. This is the best that can be done with the present setup and dataset. This limitation of the study was already clearly stated and explained at the end of section 3.1 "Wind shears", and in section 3.2 "Wind observer performance". The same limitation has now been added also to the introduction and conclusions. Furthermore, we have stressed the incompleteness of the dataset multiple times, warning the reader that this prevents a full validation. We believe that we honestly and openly present what we have done, and that we have amply clarified the limits of the work.
   The reason horizontal shear is discussed whereas upflow is not is simply due to the fact that for the former we have at least the SEWS, while for the latter we have nothing. Additionally, we write: "the horizontal shear is based on the same sector-equivalent wind speeds that estimate the vertical shear with good accuracy, so that there is no reason to believe that Eq. (15) should not provide a similarly good-quality estimate." Therefore, with the caveats above, a comparison of the horizontal shear with the SEWS is not completely meritless.

4. **Reviewer**: *Please provide better evidence for the third conclusion you draw in Section 4, regarding the improvement in the quality of training data when averaged (page 18, lines 13–14). This is an interesting result, but the only other mention of this that I found was a statement on page 15 (lines 13–14), which seem a bit brief to lead to a conclusive result.*

Authors: Thank you, this was indeed not explained in the previous version of the paper (see also a similar remark from Reviewer 1, question 18).

5. **Reviewer**: *Page 3, lines 20–25: Do you have a suggestion of how to get such an ideal measurement? I think that you're being a bit hard on yourselves, no measurement is perfect!*
   Authors: We have added a sentence to the introduction, indicating that a lidar scanning the inflow immediately in front of the rotor disk plane might be a possible –although still challenging– solution to this problem.

6. **Reviewer**: *Page 6, line 4: Equation 8 (the weighted least-squares solution) should have a bit more explanation. Is Q known? How did you measure/approximate it?*
   Authors: The text was modified to better explain this point, also in response to question 6 of Review 1.

7. **Reviewer**: *Page 5, line 20: Can you provide a reference for the statement that horizontal shear varies less than vertical shear?*
   Authors: This was misleading, and that sentence has been partly re-written, also in response to question 5 of Reviewer 1.

8. **Reviewer**: *Page 12, lines 1–2: Was that shift not done for the shear, also? Why shift the misalignment measurement but not the shear measurement?*
   Authors: Yes, all measurements derived from the mast, vertical shear included, were shifted in time. The text was modified for improved clarity.

We have taken the opportunity to make several small editorial changes to the text, in order to improve readability. A revised version of the manuscript is attached to the present reply, with the main changes highlighted in red (deletions) and blue (additions).

Best regards.
The authors

Wind inflow observation from load harmonics: initial steps towards a field validation

Marta Bertelè[1], Carlo L. Bottasso[1], and Johannes Schreiber[1]

[1]Wind Energy Institute, Technische Universität München, Garching bei München, D-85748 Germany

Correspondence to: C.L. Bottasso (carlo.bottasso@tum.de)

Abstract.

A previously published wind sensing method is applied to an experimental dataset obtained on a 3.5 MW turbine and a nearby hub-tall met-mast. The method uses blade load harmonics to estimate rotor-equivalent shears and wind directions at the rotor disk. A second independent method is used to extend the met-mast-measured shear above hub height to cover the entire rotor disk.

Although the experimental setup falls short of providing a real validation of the method, it still allows for a realistic practical demonstration of some of its main features. ~~The method appears to be robust to turbulent fluctuations and air density changes.~~ Results indicate a good quality of the estimated shear, both in terms of 1 and 10-min averages and of resolved time histories, and a reasonable accuracy in the estimation of the yaw misalignment.

1 Introduction

This paper presents a first attempt at the field validation of a wind sensing method based on load harmonics.

Wind sensing refers to the general concept of using the response of the turbine to estimate characteristics of the inflow, ~~which can be done~~ a task that can be accomplished in several different ways (Bottasso et al., 2010; Bottasso and Riboldi, 2014; Simley and Pao, 2016; Bottasso and Riboldi, 2015; Bertelè et al., 2017; Bottasso et al., 2018; Schreiber et al., 2020). Information on the inflow can support a variety of applications, including turbine and farm-level control, lifetime assessment and fatigue consumption estimation, power and wind forecasting, and others (Schreiber et al., 2020). In wind sensing, the rotor response is typically measured in the form of blade loads. If blade load sensors are already available, for example for load-mitigating control, wind sensing is ~~a way of augmenting the value of load sensors, by providing~~ just a software upgrade that provides an extra set of uses to ~~the data that they already collect~~data that is already collected for other purposes.

The method based on load harmonics was first proposed by Bottasso and Riboldi (2014), and then further elaborated and improved by Bottasso and Riboldi (2015); Cacciola et al. (2016a); Bertelè et al. (2017, 2018, 2019). In a nutshell, this method is based on the fact that some characteristics of the inflow (horizontal and vertical shear, lateral and vertical misalignment angles) generate a specific response of the rotor at the 1P (once per revolution) frequency. This is a very desirable feature, because:

- The 1P frequency is strongly dominated by these "deterministic" characteristics of the wind, and much less so by turbulent fluctuations (Bertelè et al., 2017);
- Low frequencies are easier to measure than higher frequencies, as they require slower sampling rates (typically around one second for capturing the 1P of a wind turbine);
- There should be limited variability in such low frequencies among different installations of a same wind turbine type;
- The lower ~~spectrum~~ frequencies of the response of a wind turbine should be reasonably well captured by existing simulation tools used for design and certification.

Higher frequencies may be polluted by turbulent eddies in the flow (Bertelè et al., 2017), although they may carry extra information that could possibly enable the observation of other characteristics of the wind, such as for example veer.

The load-harmonic method requires a training dataset consisting of measured rotor loads and corresponding measured wind characteristics. If the turbine implements individual pitch control, the dataset is extended to include blade pitch angles (Bertelè et al., 2018). The dataset can be based on experimental measurements, or be generated synthetically using a simulation model; these two approaches were respectively termed model-free and model-based in Bottasso and Riboldi (2014). Here we consider the former approach; indeed, a ~~model~~ simulation model with the necessary characteristics might not always be available, for example in cases when wind sensing is applied to a turbine without the support of the manufacturer. Even when a model is available, it might not have been fully validated, so that a purely data-driven approach has a significant appeal. Thanks to the rotational symmetry of the rotor (Bertelè et al., 2019), the measured wind conditions that are necessary for ~~training~~ the training phase can be limited to the vertical shear and the horizontal (or yaw) misalignment; based on these quantities, the effects caused by horizontal shear and vertical (upflow) misalignment can be reconstructed. After training, the method can estimate the four wind parameters online during turbine operation simply from measured rotor loads.

It is envisioned that, in a practical application of the model-free harmonic-based method, the training phase would be a one-off activity performed at a test site equipped with a met-mast or other wind measuring devices such as lidars or sodars (Carswell, 1983; Vogt and Thomas, 1995; Lang and McKeogh, 2011). Indeed, hub-tall met-masts are routinely used during certification (IEC, 2017), and could be employed for the additional purpose of training the observer. After training, the method could be used on other installations of that same turbine type at normal production sites without necessitating of met-masts or other devices.

~~Goal~~ The principal goal of this paper is to present the application of the load-harmonic estimator to field test data collected at a test site on a 3.5 MW wind turbine and a nearby met-mast (Schreiber et al., 2020; Bertelè and Bottasso, 2020). This experimental setup is a realistic representation of the scenario outlined above, where a hub-tall met-mast is located in close proximity of a wind turbine for certification purposes. From this point of view, the present dataset provides opportunities not only for a first —partial— field demonstration of the method, but also for addressing some important practical implementational aspects.

Specifically, the vertical shear requires special attention. In fact, a hub-tall met-mast with more than one anemometer can only measure the wind shear over the lower part of the rotor disk; on the other hand, the load-harmonic observer estimates a rotor-equivalent shear (i.e. a shear over the entire rotor disk area). For large modern rotors, half-rotor or full-rotor shears are not necessarily equal (Murphy et al., 2019; Schreiber et al., 2020). Therefore, a way is needed to extend the measurement of the inflow above the met-mast, possibly without resorting to extra wind-scanning equipment to reduce cost and complexity. This problem is solved here using yet another wind sensing method (Bottasso et al., 2018; Schreiber et al., 2016, 2020). This second approach uses blade loads to estimate the average local speed over sectors of the rotor disk; from these sector-equivalent wind speeds, one can then estimate shears, including a vertical shear defined over just the lower half of the rotor.

The sector-effective speed and load-harmonic observers have distinct characteristics, which make them somewhat complementary and applicable to different scenarios. In fact, the sector-effective observer does not need to be trained with data before it can be used, ~~which is particularly useful in the case considered here, but can~~ since it is derived from standard performance characteristics of the rotor (Schreiber et al., 2020). Although not indispensable, field data can optionally be employed to fine-tune the observer, as shown in Schreiber et al. (2020). The sector-effective approach, however, can only reconstruct shears and not wind directions~~(Schreiber et al., 2020). On the contrary, the~~. The load-harmonic observer, on the other hand, can reconstruct both shears and directions but needs to be trained from data, which is a potential complication. ~~A~~ Here, a three-step procedure is developed and demonstrated~~here~~, where the two observers are used in synergy combining some of their complementary features:

1. The lower-half-rotor shear measured by the sector-equivalent speed method is tuned and validated with respect to the met-mast reference;

2. The full-rotor shear is computed using the validated sector-equivalent speed method, extending the measurement of the inflow above the met-mast;

3. This rotor-equivalent shear is finally used for training the harmonic-based estimator.

Although the present setup allows for a first demonstration of this procedure, it also presents some limitations that hinder a real and complete validation of the method. First, the extension of the shear above the met-mast is performed through the same rotor loads that are also used by the harmonic-based estimator. Clearly, a completely independent measurement of the inflow up to the tip of the rotor would be preferable for validation purposes. Second, the present met-mast only includes a wind vane at hub height. This is a point-wise measurement, whereas the one provided by the observer —being obtained through the response of the rotor— is a rotor-effective quantity. Here again, it would be desirable to train and verify the method with an independently-derived rotor-equivalent quantity. Third, a met-mast cannot really provide a true and absolute ground truth, as it measures the flow away from the rotor disk (two and half diameters away, in the present case). When the wind is not directly aligned with turbine and mast, the wind shear and direction may be slightly different, on account of wind spatial variability, because of orographic and vegetation-induced effects. These differences are indeed visible to some extent in the present dataset. Even when wind, mast and turbine are aligned, the two measurements are not co-located and therefore not necessarily identical. Fourth, the met-mast does not provide measurements for two of the four observed quantities, namely horizontal shear and upflow, for which, consequently, no comparison nor conclusion can be made. Clearly, a more precise characterization of the effective inflow experienced by the rotor disk would be desirable for validation purposes. A lidar scanning the inflow immediately in front of the disk plane —to ensure co-location of the measurements— might be a possible solution.

Although the present study clearly falls short of a true validation of the harmonic-based formulation of wind sensing, it still provides for an interesting and —in the authors' opinion— very promising insight into some of its characteristics.

The paper is organized as follows. Section 2 describes the overall methodology, including a brief review of the harmonic-based estimator in §2.2 and a description of the test site and the measurement of the inflow characteristics in §2.3. The analysis of the wind observer performance is presented in Section 3, while Section 4 concludes the paper.

2 Methods

2.1 Wind parametrization

The wind inflow is described by four parameters: the vertical linear shear κ_v, the horizontal linear shear κ_h, the vertical wind misalignment angle (or upflow) χ, and the horizontal (or yaw) misalignment angle ϕ. These quantities are illustrated in Fig. 1 . and are expressed in a hub-centered nacelle-attached reference frame, where x is parallel to the axis of rotation (and it is therefore inclined with respect to the ground because of uptilt), y is horizontal with respect to the ground and points left looking downstream, while z forms a right handed triad. It should be noticed that the vertical shear is customarily defined with respect to the horizontal, instead of the uptilt, direction; additionally, its profile is typically either logarithmic or expressed as a power law, instead of linear. As explained later, these choices are made here to exploit the rotational symmetry of the rotor (Bertelè et al., 2019). Clearly, the four parameters, once estimated, can be readily transformed into a horizontal frame, if necessary. Furthermore, abandoning the rotational symmetry, the observer can be formulated in terms of a vertical non-linear shear, as shown in Bertelè et al. (2017).

A linearly sheared wind speed W at the rotor disk is defined as

$$W(y,z) = V_h\left(1 + \frac{y}{R}\kappa_h + \frac{z}{R}\kappa_v\right), \tag{1}$$

where V_h is the hub-height speed, and R the rotor radius. With reference to Fig. 1, the wind velocity vector components u, v and w By projecting the wind vector along the x, y and z axes, respectively, of a hub-centered the three nacelle-attached frame write velocity components u, v and w are readily obtained as

$$u(y,z) = W(y,z)\sqrt{1-\tilde{v}^2-\tilde{w}^2}, \tag{2a}$$

$$v(y,z) = W(y,z)\tilde{v}, \tag{2b}$$

$$w(y,z) = W(y,z)\tilde{w}, \tag{2c}$$

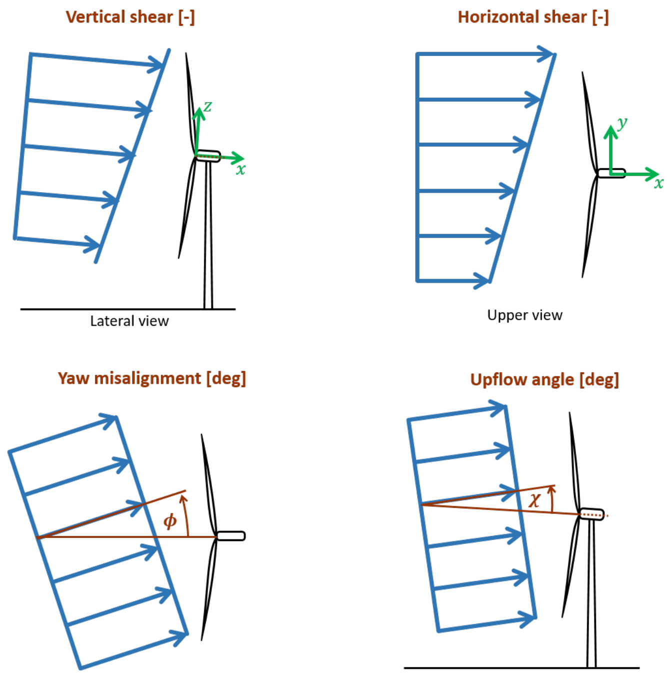

Figure 1. Definition of the four wind states used for parameterizing the wind field over the rotor disk.

where $\tilde{v}$ and $\tilde{w}$ are defined as

$$\tilde{v} = \frac{v(0,0)}{V_h} = \sin\phi\cos\chi, \tag{3a}$$

$$\tilde{w} = \frac{w(0,0)}{V_h} = \sin\chi. \tag{3b}$$

For notational simplicity, the four wind parameters are grouped together in the wind state vector $\boldsymbol{\theta} = \{\tilde{v},\ \kappa_v,\ \tilde{w}, \kappa_h\}^T$. Given $\boldsymbol{\theta}$, the misalignment angles can be readily computed by inverting Eqs. (3) to get $\chi = \arcsin\tilde{w}$ and $\phi = \arcsin\tilde{v}/\cos\chi$.

2.2 Wind observer formulation

The relationship between wind states and rotor loads is assumed in the form

$$\boldsymbol{m} = \boldsymbol{F}(V,\rho)\boldsymbol{\theta} + \boldsymbol{m}_0(V,\rho) = [\boldsymbol{F}(V,\rho)\ \boldsymbol{m}_0(V,\rho)]\begin{bmatrix}\boldsymbol{\theta}\\ 1\end{bmatrix} = \boldsymbol{T}\,\overline{\boldsymbol{\theta}}, \tag{4}$$

where $\boldsymbol{F}$ and $\boldsymbol{m}_0$ are model coefficients that depend on wind speed V and air density ρ. The dependency on wind speed is taken into account by discretizing the wind speed range in nodal values and linearly interpolating the model based on the current wind speed, while density is accounted for as explained in §2.2.1. The load vector $\boldsymbol{m}$ is defined as

$$\boldsymbol{m} = \{m_{1c}^{\mathrm{OP}},\ m_{1s}^{\mathrm{OP}},\ m_{1c}^{\mathrm{IP}},\ m_{1s}^{\mathrm{IP}}\}^T, \tag{5}$$

where m indicates the blade bending moment, subscripts $(\cdot)_{1\mathrm{s}}$ and $(\cdot)_{1\mathrm{c}}$ respectively indicate 1P sine and cosine harmonic amplitudes, while superscripts $(\cdot)^{\mathrm{OP}}$ and $(\cdot)^{\mathrm{IP}}$ indicate out- and in-plane load components, respectively. Harmonic components are obtained from measured blade loads using the Coleman transformation (Coleman and Feingold, 1958), followed by low pass filtering.

The ~~model~~ load-wind model (4) is static, which implies that both the wind states and the load harmonics are to be interpreted as time averaged quantities. Extensive tests were conducted to determine the most appropriate time averaging. Using field test data, results indicate that 10 minutes is typically a good choice, as shown more precisely later on.

The model coefficients $\boldsymbol{F}$ are not all independent, because of the rotational symmetry of the rotor (Bertelè et al., 2019). In a nutshell, the effects on loads caused by the horizontal shear are the same as the ones caused by the vertical shear after a rotation of $\pi/2$; the same holds true for the wind misalignment angles. This not only reduces the number of unknowns, but also eases the identification of the model, especially when using longer time averages. In fact, ~~whereas vertical shear changes naturally~~ while both vertical and horizontal shear undergo rapid changes due to spatial turbulence variability, it is easier to observe slower changes in vertical shear than in the horizontal one. In fact, vertical shear exhibits slow natural changes over a significant range~~(for example ,~~, for example because of diurnal fluctuations~~)~~. On the other hand, horizontal shear ~~does not (except~~ might exhibit slow scales because of orographic effects or in waked conditions~~)~~, which —depending on the turbine— might or might not happen very frequently or be particularly pronounced. Similarly, whereas yaw misalignment changes significantly in normal operation because of the inability of the yaw system to immediately and exactly track wind direction fluctuations, upflow changes little (except that for orographic wind-direction-dependent effects). Therefore, by exploiting the rotational symmetry, a complete model can be identified simply from variable vertical shear and horizontal misalignment, because the effects of the other two wind states are obtained by the symmetry of the coefficients.

The model coefficients $\boldsymbol{T}$ are identified by stacking side by side measured wind states $\boldsymbol{\theta}$ into a matrix $\boldsymbol{\Theta} = \left[\overline{\boldsymbol{\theta}}_1, \ldots, \overline{\boldsymbol{\theta}}_N\right]$, while the corresponding measured blade loads $\boldsymbol{m}$ are stacked into matrix $\boldsymbol{M} = [\boldsymbol{m}_1, \ldots, \boldsymbol{m}_N]$, obtaining

$$\boldsymbol{M} = \boldsymbol{T}\boldsymbol{\Theta}. \tag{6}$$

The model coefficients are then computed by least squares as

$$\boldsymbol{T} = \boldsymbol{M}\boldsymbol{\Theta}^T\left(\boldsymbol{\Theta}\boldsymbol{\Theta}^T\right)^{-1}. \tag{7}$$

Measured loads $\boldsymbol{m}_{\mathrm{M}}$ are defined as

$$\boldsymbol{m}_{\mathrm{M}} = \boldsymbol{m} + \boldsymbol{r}, \tag{8}$$

where $\boldsymbol{m}$ is given by Eq. (4) and $\boldsymbol{r}$ is the residual with covariance $\boldsymbol{Q} = \mathrm{E}[\boldsymbol{r}\boldsymbol{r}^T]$. Residuals are assumed to be zero-mean, and are due to measurement noise and unmodeled physics. Given the model coefficients, ~~the estimated wind states~~ a maximum likelihood (Strutz, 2016) estimate $\boldsymbol{\theta}_{\mathrm{E}}$ ~~are~~ of the wind states can be computed online from the measured loads ~~$\boldsymbol{m}_{\mathrm{M}}$ as~~

$$\boldsymbol{\theta}_{\mathrm{E}} = \left(\boldsymbol{F}^T\boldsymbol{Q}^{-1}\boldsymbol{F}\right)^{-1}\boldsymbol{F}^T\boldsymbol{Q}^{-1}(\boldsymbol{m}_{\mathrm{M}} - \boldsymbol{m}_0),$$

where $\boldsymbol{Q}$ is the co-variance weighting matrix. $\boldsymbol{m}_{\mathrm{M}}$ from Eqs. (4) and (8) as follows

$$\boldsymbol{\theta}_{\mathrm{E}} = \left(\boldsymbol{F}^T\boldsymbol{Q}^{-1}\boldsymbol{F}\right)^{-1}\boldsymbol{F}^T\boldsymbol{Q}^{-1}(\boldsymbol{m}_{\mathrm{M}} - \boldsymbol{m}_0). \tag{9}$$

2.2.1 Density correction

Aerodynamic loads can be written as

$$m_{\mathrm{A}} = qAC, \tag{10}$$

where $q = 1/2\rho V^2$ is the dynamic pressure, A the rotor disk area and C a non-dimensional coefficient. A correction for density can be simply obtained as

$$m_{\mathrm{A_{ref}}} = m_{\mathrm{A_i}} \frac{\rho_{\mathrm{ref}}}{\rho_i}, \tag{11}$$

where ρ_{ref} is a reference density, and ρ_i the density corresponding to measurement $m_{\mathrm{A_i}}$.

However, blade load sensors measure not only aerodynamic loads but also the effects of inertia and gravity, which do not depend on air density. Inertial loads for a rotor spinning at constant rotor speed do not generate rotating 1P harmonicsharmonic components, and hence do not appear in Eq. (4). On the other hand, gravitational terms generate 1P loads represented by the non-homogeneous term $\boldsymbol{m}_0$ in that same equation. According to Bertelè et al. (2017), this term can be written as

$$\boldsymbol{m}_0 = qA\boldsymbol{C} + \boldsymbol{g}. \tag{12}$$

The first term is a gravity-induced load due to the rotor deformation caused by aerodynamic loads; for example, if the blade bends under the push of thrust, the resulting deformation generates a non-null moment arm for gravity with respect to the blade root where the load sensor is located, resulting in a 1P load. This term is proportional to dynamic pressure and can be corrected for density. The second term $\boldsymbol{g}$ accounts for in-plane and out-of-plane gravity-induced loads, the latter being caused by blade precone, prebend and rotor uptilt. This term does not depend on density, and hence it should be eliminated by the equations before a density correction can be applied. To this end, the model coefficients of Eq. (4) were identified for a very low wind speed, just above cut-in. Here the effects caused by $qA\boldsymbol{C}$ are negligible, and hence $\boldsymbol{g} \approx \boldsymbol{m}_0$. Having first identified the gravity term $\boldsymbol{g}$ and then having eliminated it from model (4), each measured load was finally corrected for density using Eq. (11).

2.3 Wind parametrization in the field

Before wind states can be estimated at run time from measured loads using Eq. (9), the model coefficients must be identified through the simultaneous measurements of wind states and associated loads using Eq. (7). This section presents a practical method to perform this task, based on the use of a standard IEC-compliant (IEC, 2017) hub-tall met-mast. A similar procedure could be used to identify the observer for a specific wind turbine type. Having obtained the model coefficients, one should be able to use the same observer for other installations of that same wind turbine type. Although there is yet no direct demonstration of this assertion, it seems reasonable to assume that wind turbines of the same model will have a similar 1P response to shears and misalignment angles. Additionally, Bottasso and Riboldi (2015) showed that the method is fairly robust to ~~changes~~ the typical changes occurring in some of the wind turbine parameters ~~that may vary among~~ across different installations of a same wind turbine type, including changes in the stiffness of foundations, orographic effects, imbalance due to pitch misalignment, miscalibration of the load sensors and changes in airfoil lift and drag due to soiling/erosion.

2.3.1 Test site

Figure 2 shows a panoramic view of the test site (Bromm et al., 2018), which is located in Germany a few kilometers inland from the Baltic Sea and characterized by gentle hills, open fields and forests. Data was measured between October 19 and November 29, 2017 on a 3.5 MW eno114 turbine designed and produced by eno energy systems GmbH. The turbine (labelled WT1 in the figure) has a 92 m hub height and a rotor ~~radius~~ diameter of 114.9 m.

A met-mast is situated at about 2.5 diameters (D) from the turbine. Wind direction was measured at a height above ground of 89.3 m with a Thies GmbH wind vane, while wind speed measurements were obtained with three cup anemometers produced from the same company and located at 89.3 m, 91.5 m and at the lower tip of the rotor (about 34 m). All measurements obtained on the mast were shifted in time on account of the distance between turbine and met-mast, the time delay being computed from the average wind speed.

A second turbine (labelled WT2) is also present on site, and its wake affects the met-mast and WT1 for easterly and south-easterly winds. Similarly, the wake of WT1 affects the met-mast for northern wind directions. All these conditions were discarded from the training dataset, in addition to all other situations when WT1 was not in a normal power production state. A forest of 15-20 m tall trees is located 300 m east of WT1; as only wind directions $\Gamma \in [180, 340]$ deg were considered in this work, this high roughness area was never in the inflow direction. On the other hand, the town of Brusow is located about 1 km to the west of the site, and its effects on the inflow are unknown. A test campaign conducted at the same site in the period July-November of the previous year revealed an almost equal distribution of unstable, neutral and stable conditions, as measured by an eddy covariance station (Bromm et al., 2018).

Synchronized turbine and blade load data was sampled at 10 Hz on WT1. Blades 1 and 3 were equipped with strain gages, installed in close proximity of the blade roots and measuring both flapwise and edgewise bending components~~. The load on blade 2 was computed as the mean of~~ ; unfortunately, however, the same load sensors were not installed on blade 2. To reconstruct the missing load components, the measurements of blades 1 and 3 ~~,~~ were shifted by $\pm\pi/3$~~.~~ , averaged together and then attributed to blade 2. This approximation assumes that neighboring blades experience the same loads when they are at the same azimuthal position, which is reasonable because loads and wind states are time-averaged quantities linked by a steady load-wind model (cf. Eq. (4)).

In general, sensors deployed in the field cannot be assumed to be always exactly calibrated, and they may suffer from a variety of issues that affect the quality of the measurements that they provide. To address this problem, it is useful to devise simple and practical ways to correct the measurements, even when the root cause of the problem is unknown. Here, consistent mismatches between the long-term mean readings of the two blade load sensors were observed; this problem was eliminated by scaling the measurements as $\overline{m}_1(1+s) = \overline{m}_3(1-s)$, with $s = 0.0274$. Additionally, the azimuth signal was corrected to account for sensor bias and dynamic effects, as explained in Schreiber et al. (2020). The turbine on-board wind vane was not used here, because these sensors typically require a careful calibration to correct for nacelle and rotor effects. The yaw encoder signal was also corrected for an apparent inconsistency of its readings, as explained later in this section.

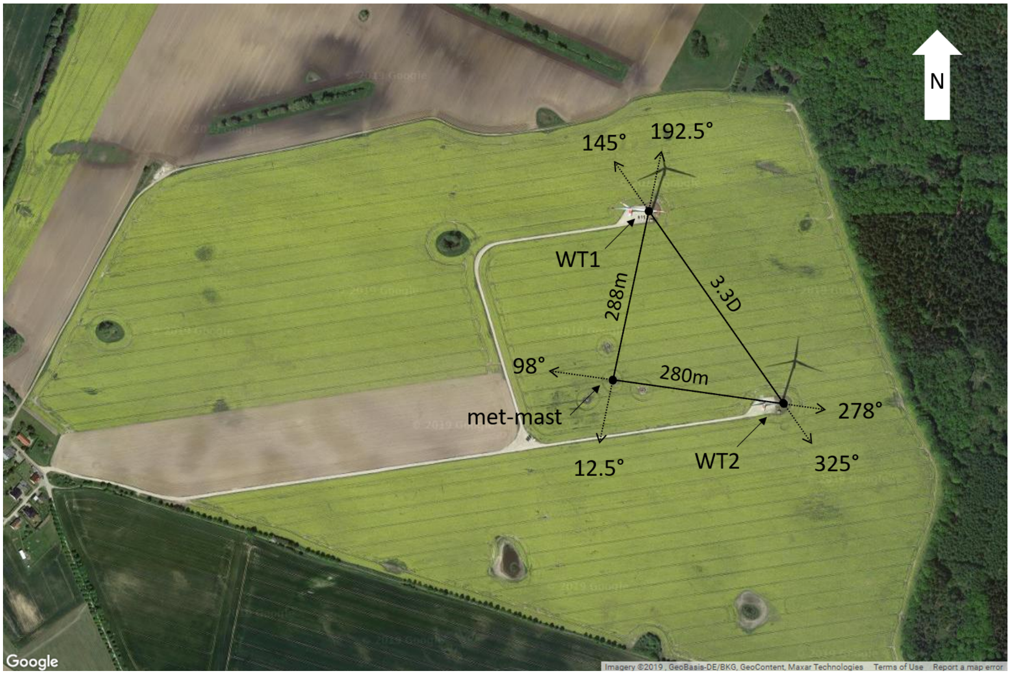

Figure 2. Satellite view of the test site, including waking directions and distances. WT1 indicates the turbine used for the present analysis (© Google Maps).

2.3.2 Wind shears

The met-mast present at the test site reaches only up to hub height; this is also the typical case of IEC-compliant met-masts used for certification (IEC, 2017). The three anemometers at 34, 89 and 92 m can be used to estimate the vertical shear over the lower half of the rotor, which however in general differs from the shear computed over the whole rotor height.

To address this issue, the sector-effective wind speed (SEWS) estimation method described in Schreiber et al. (2020) was employed. In a nutshell, the blades are used as local speed sensors that, scanning the rotor disk, provide average speeds over four rotor quadrants. By using the two lateral and the lower quadrants, the shear over the lower part of the rotor disk can be computed. This quantity is validated with respect to the shear measured by the met-mast, assumed as a ground truth. Then, having verified a good correlation between the measured and estimated shears over the lower part of the rotor, the average speeds SEWSs for all four quadrants are used to calculate the wind shear over the whole rotor disk. A brief overview of the SEWS estimator is reported next, and the interested reader is referred to Schreiber et al. (2020) for further details.

The rotor cone coefficient is defined as

$$C_m(\beta,\lambda,q,\psi_i) = \frac{m_i}{0.5\rho ARV^2}, \tag{13}$$

where β is the pitch angle, $\lambda = \Omega R/V$ the tip speed ratio and Ω the rotor speed, m_i the out-of-plane bending load of the ith blade and ψ_i its azimuthal position. The dependency of the coefficient on the azimuthal position of the blade is primarily dictated by the effects of gravity, which for an uptilted rotor generate an out-of-plane bending moment that needs to be taken into account. Accuracy can be improved by considering the deformation of the tower depending on operating condition (Bottasso et al., 2018), an effect that was neglected here for simplicity. Coefficient C_m was computed here with the aeroelastic from a complete aeroelastic model of the turbine, implemented with the code FAST (Jonkman and Jonkman, 2018). Inverting Eq. (13), a look-up table (LUT) is generated that returns the blade-effective wind speed V_i given measured blade pitch angle, rotor speed, azimuthal blade position, bending moment and density:

$$V_i = \mathrm{LUT}_{C_m}\left(\beta,\Omega,\psi,m_i,\frac{\rho}{\rho_{\mathrm{ref}}}\right). \tag{14}$$

This way each individual blade is turned into a local wind speed sensor, which scans the rotor disk. Since this local measurement is noisy, the rotor disk is divided into sectors of area A_S, and a sector-equivalent wind speed is computed as

$$V_\mathrm{S} = \int_{A_\mathrm{S}} V_i(\psi_i)\,\mathrm{d}A_\mathrm{S}. \tag{15}$$

Here the four sectors shown in Fig. 3 were used. This yields four measurements of the local speed at the rotor disk, located at $2/3\,R$ namely above, below and to the sides of the hub center(Bottasso et al., 2018). . Bottasso et al. (2018) showed that, for a linear shear and a 90-degree-wide sector, the SEWS corresponds to the inflow speed at a distance of approximately $2/3\,R$ from the hub center.

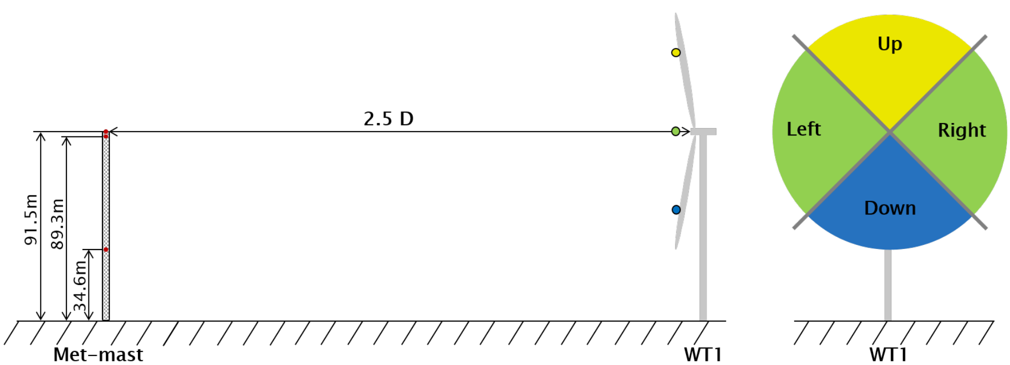

Figure 3. Definition of the four rotor sectors and their relative position with respect to the met-mast. Right: view looking downstream.

The rotor-effective horizontal linear shear can be computed inserting the sector-effective wind speeds SEWSs in Eq. (1) to get

$$\kappa_h = \frac{3}{2}\frac{V_{\mathrm{S,left}} - V_{\mathrm{S,right}}}{V_{\mathrm{S,left}} + V_{\mathrm{S,right}}}. \tag{16}$$

~~For a more coherent comparison of the linear vertical shears~~ The analysis of the vertical shears requires some care. In fact, the linear vertical shear estimated by the met-mast and by the sector-effective speeds ~~, it is useful to first fit a power law to the respective wind speed measurements, as they are obtained at different heightsabove ground.~~ are computed from measurements obtained at different heights above ground; as such, they are not directly comparable, because shear has typically a non-linear variability with height. To address this issue, a power law is first fitted to the measurements; once the power law parameters have been determined, linear shears are computed for mast and observer between the same two heights, resulting in comparable quantities.

More precisely, the calculation of the linear shears is conducted as follows. The power law profile is defined as

$$V_{\mathrm{PL}}(z)_{\mathrm{PL}} = V_{\mathrm{ref}} \left(\frac{z+H}{H} \right)^{\alpha}, \tag{17}$$

where H is the height of the hub, V_{ref} the wind speed at that point, and α the power law exponent. Given n measurements V_i at z_i, the parameters of the power law are computed by the following best fit:

$$(V_{\mathrm{ref}}, \alpha) = \arg \min_{V_{\mathrm{ref}}, \alpha} \sum_{i=1}^{n} \left(V_{\mathrm{PL}}(z_i) - V_i \right)^2 . \tag{18}$$

Notice that two measurements at two different heights are sufficient to estimate the power law, since it depends on only the two free parameters V_{ref} and α. Having solved the fitting problem (18), the linear shear κ_v between two generic heights z_A and z_B is computed as

$$\kappa_v = \frac{R\left(V_{\mathrm{PL}}(z_A) - V_{\mathrm{PL}}(z_B)\right)}{z_A V_{\mathrm{PL}}(z_B) - z_B V_{\mathrm{PL}}(z_A)} . \tag{19}$$

The left plot of Fig. 4 shows the correlation between 10-min averages of the vertical shears obtained by the met-mast and by the sector-effective wind speeds on the lower half of the rotor. Only wind directions between 170 and ~~220~~215 deg are considered, where the turbine and met-mast are aligned. The power law for the met-mast was obtained by using all three speed measurements, although the two at 89.3 and 91.5 m above ground are almost coincident. For the sector-effective estimator the power law was obtained by using the two ~~measurements~~ estimates $(V_{\mathrm{S,left}} + V_{\mathrm{S,right}})/2$ at $z = 0$, and $V_{\mathrm{S,down}}$ at $z = -2/3\,R$ (although this latter value is strictly valid only for linear shears). For both cases, the power law coefficients were first computed using Eq. (18), and then the lower-half-rotor linear shear was ~~computed~~ obtained from Eq. (19) using $z_A = 0$ and $z_B = -R$~~and the corresponding fitted power law~~. The figure shows that there is a good correlation between the two lower-half-rotor shears, resulting in a Pearson's coefficient of ~~0.906. However, the~~ 0.91.

The figure also shows that the linear fit (red dashed line) has a different slope than the ideal match (black solid line). ~~The~~ This could be due to a non-ideal power law profile, but also by a non-exact elimination of the effects of gravity, for example because of a different position of the load sensors in the model and reality or a slightly modified uptilt on account of tower deformation; unfortunately, not enough information on the present experimental setup was available to determine the cause of this discrepancy with certainty. However, the results presented later in Section 3 were pragmatically corrected to account for this error~~.~~: the slope deviation was evaluated from Fig. 4, and the estimates were modified accordingly to yield corrected results lying on the bisector.

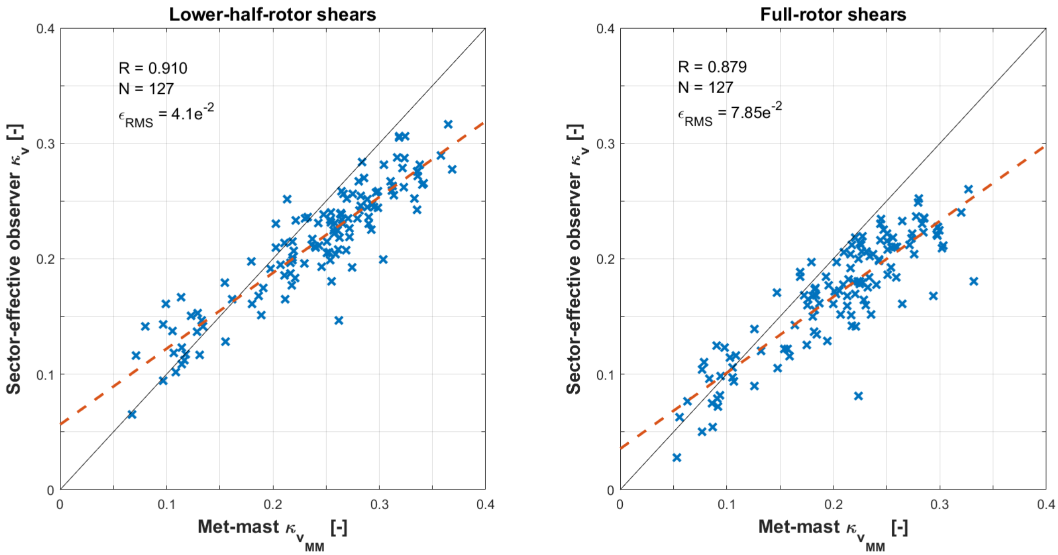

Figure 4. Correlation between 10-min averages of the vertical linear shears measured with the met-mast and the sector-effective observer. Left: lower-half rotor shears; right: full-rotor shears. Red dashed line: linear best fit; black dashed line: ideal match; R: Pearson's correlation coefficient; N: number of data points; ϵ_{RMS}: root mean square error.

For the same data points, the right plot of Fig. 4 shows the correlation between the vertical shears obtained by the met-mast and by the sector-effective estimator over the complete rotor. ~~Here again the~~ The power law for the met-mast was obtained by using all three speed measurements. For the sector-effective estimator the power law was obtained by using ~~the three measurements~~ Eq. (18) with the three estimates $V_{\mathrm{S,up}}$ at $z = 2/3\,R$, $(V_{\mathrm{S,left}} + V_{\mathrm{S,right}})/2$ at $z = 0$, and $V_{\mathrm{S,down}}$ at $z = -2/3\,R$, although here again the vertical coordinates are strictly valid only for a linear shear. For both cases, the full-rotor linear shear was computed from Eq. (19) using $z_A = R$ and $z_B = -R$~~and the corresponding power laws~~. It should be noted that, since the height of the top anemometer reaches only up to hub height, for the met-mast the calculation of the ~~full rotor~~ full-rotor shear implies a considerable extrapolation outside of the available measurements.

Comparison of the right and left plots of Fig. 4 shows that, in the full-rotor case, there is a lower correlation between the met-mast and the SEWS observer than in the lower-half rotor case. This indicates that the shear changes over the height of the rotor disk. In addition, as expected for a typical power law where the profile gradient increases with height, the lower-half-shear coefficient is typically higher than the full-rotor one.

Based on these results, it appears that the rotor-effective shear used for identifying the model of §2.2 would require a tall met-mast or other wind measurement devices such as lidars or sodars capable of scanning the inflow reaching the top of the rotor. Here —as such a tall mast was not available— an alternative approach was ~~used~~adopted: the sector-equivalent wind speed method was used to virtually extend the met-mast measurements to the required height. Based on the good correlation shown by the left plot of Fig. 4 for the lower-half-rotor shear, it was concluded that the two lateral and the lower sector-equivalent speeds are sufficiently accurate for the purpose of estimating shears. Since the top sector speed is based on exactly the same calculation procedure as the other ones, all four speeds were then used to estimate the full-rotor shear, which in turn was used adopted as reference for the identification of the model of §2.2.

Unfortunately a similar validation cannot be performed for the horizontal shear with the present met-mast, because of the lack of multiple lateral measurements. However, the horizontal shear is based on the same sector-equivalent wind speeds that estimate the vertical shear with good accuracy, so that there is no reason to believe that Eq. (16) should not provide a similarly good-quality estimate. Additionally, the horizontal shear based on the two lateral sector-effective wind speeds was shown in Schreiber et al. (2020) to track the movement of an impinging wake with remarkable accuracy.

2.3.3 Wind misalignment angles

The met-mast is equipped with a single wind vane measuring the wind direction Γ at hub height. Unfortunately, this means that only a point-wise measurement is available, instead of the rotor-equivalent one that would be ideally necessary for the training of the load-harmonic method of §2.2. This is a limit of the current setup and of the present attempt at validating the approach. Nonetheless, a pragmatic choice was made here to filter the wind vane signal with a moving average to remove the faster fluctuations, and to use this signal as a proxy for the rotor-effective horizontal wind direction. The misalignment angle between turbine and wind was obtained by subtracting the absolute yaw angle of the nacelle from the met-mast-measured wind direction. The result was shifted in time on account of the distance between turbine and met-mast, the time delay being computed from the average wind speedfiltered with a 1-min moving average to remove the faster fluctuations.

The top plot of Fig. 5 shows 10-min averages of the resulting met-mast yaw misalignment angle Φ_{MM}, plotted as a function of wind direction Γ. The clear trend visible in the plot is probably due to a miscalibration of the nacelle yaw encoder. Indeed, Bromm et al. (2018) also noticed a non-constant offset when comparing the turbine SCADA orientation with the one provided by a temporarily installed GPS system. This trend was removed using the first ten days of data, excluding waked directions, obtaining the bottom plot of Fig. 5.

As the current setup does not provide for measurements of the upflow, the rotational symmetry of the rotor was used to compute the relevant model coefficients.

2.3.4 Wind speed and density

Since the load-wind model expressed by Eq. (4) depends on the operating conditions, a rotor-effective wind speed was computed with the torque balance equation (Ma et al., 1995; Van der Hooft and Engelen, 2004; Soltani et al., 2013; Schreiber et al., 2020) and used as scheduling parameter of the wind observer. Figure 6 shows an excellent correlation for the 10-min averages of the computed rotor-effective wind speed and the met-mast hub-height speed. Density was obtained from the ideal gas law based on temperature, since no additional information was available, and was used to rescale the load measurements.

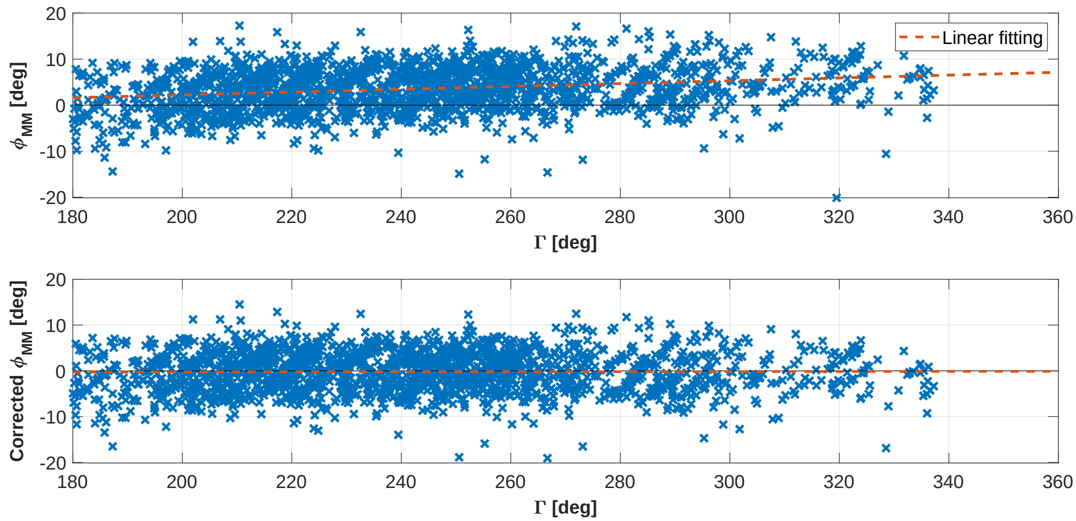

Figure 5. 10-min averages of met-mast horizontal wind misalignment angle ϕ_{MM} vs. wind direction at the met-mast Γ, before (top) and after (bottom) correction for yaw encoder error.

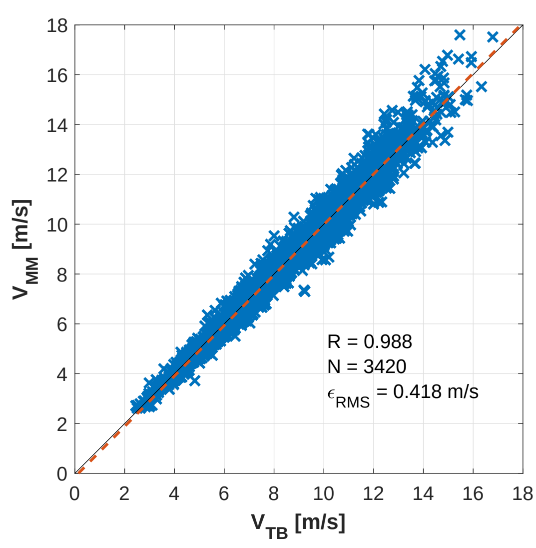

Figure 6. Correlation between 10-min averages of met-mast hub-height wind speed V_{MM} and rotor-effective wind speed V_{TB} estimated with the torque balance equation. Red dashed line: linear best fit; black dashed line: ideal match; R: Pearson's correlation coefficient; N: number of data points available; ϵ_{RMS}: root mean square error.

3 Results

3.1 Model identification

The observer coefficients were identified with Eq. (7) using the horizontal and vertical shears obtained from the sector-effective wind speeds, and the yaw misalignment angle computed from the met-mast wind vane and the nacelle yaw encoder, corrected according to Fig. 5. The upflow model coefficients were obtained from the rotational symmetry of the rotor behavior. Load measurements were corrected for density, the reference value being set to 1.238 kg/m^3.

The model coefficients were scheduled as functions of the rotor-effective wind speed computed from the torque balance equation~~, and load measurements were corrected for density.~~

~~The model was identified based on 10-min averages. The~~. The wind speed nodes of the linear parameter varying (LPV) model (4) were defined as ~~$V = [4,\ 5,\ 6.5,\ 8,\ 9,\ 10,\ 12,\ 13.5]$~~$V = [4, 5, 6.5, 8, 9, 10, 12, 13.5]$ m/s~~, while the reference density was set to 1.238 kg/m^3.~~. This means that model coefficients were computed at each of these wind speed nodes, while any speed within the range $[4,\ 13.5]$ m/s —i.e. not necessarily at the nodes— was used for identification, by linearly distributing its contributions to the two neighboring nodes. At run time, the coefficients were interpolated from the LPV based on the current wind speed.

Table 1 shows the range covered by each parameter within the training dataset.

About 15% of the available data was used for identification, leaving about 370 hours of measurements for validation. In the following, the performance of the harmonic observer is evaluated solely based on the validation dataset~~.~~, i.e. excluding all data points used for training.

Table 1. Minimum and maximum values of rotor effective wind speed, turbulence intensity (TI), density, yaw misalignment, vertical and horizontal shear within the training dataset.

	V [m/s]	TI [%]	ρ [kg/m^3]	ϕ_{MM} [deg]	κ_v [-]	κ_h [-]
min	3.89	1.15	1.221	−12.66	−0.045	−0.053
max	13.68	11.06	1.256	8.28	0.242	0.087

~~A similar identification was also performed using the same training set, but using instantaneous~~

3.2 Wind observer performance

Models were identified based on different time averages of the raw 10 Hz ~~measurements instead of~~ data. Here, the two cases of 1-min and 10-min averages are presented, because they correspond to the typical outputs of standard SCADA systems. In both cases, the raw data points were the same; this means that the 1-min model was identified on 10 times more load-state pairs than in the case of the 10-min model. ~~As this led to a small decrease in model performance, it was concluded that some time averaging may be beneficial as it probably alleviates the effects of possible outliers.~~

3.3 ~~Wind observer performance~~

~~Figure ?? gives an~~ An overview of the ~~model performance in terms of correlations between~~ performance of the two models is given by Fig. 7 (for the 10-min ~~averages of~~ case) and 8 (for the 1-min case). The figures report correlations between reference and observed parameters, using the validation sub-set for wind speeds above 8 m/s. For each parameter, one per subplot, the reference state is shown on the x axis, whereas the observed one on the y axis. ~~For~~

Comparison of the 10-min and 1-min cases shows that results are essentially identical for the shears. For the misalignment angle, results are very slightly better using the longer time window, notwithstanding the smaller number of load-state pairs used for identification. Probably this is because longer time averaging alleviates the effects of outliers. Based on these results, the rest of the paper only considers the 10-min case.

Considering the shears, Fig. 7 shows that the ~~shears, the~~ Pearson's correlation coefficients (R) is above 0.9, and the root mean square (RMS) error ϵ_{RMS} is of the order of 10^{-3}. The yaw misalignment angle is less accurate, possibly because the reference is point-wise whereas the estimate is rotor-effective. Indeed, investigations at the same site with a more complete setup including a lidar profiler reported significant veer at the inflow (Bromm et al., 2018). However, with a correlation coefficient of 0.85 and an ϵ_{RMS} of 1.9 deg, the matching is still good.

~~Correlation of 10-min averages between estimated parameters (y axis) and their reference quantities (x axis) for $V \geq 8$ m/s. From left to right: yaw misalignment angle, vertical linear shear, horizontal linear shear. Red dashed line: linear best fit; black dashed line: ideal match; R: Pearson's correlation coefficient; N: number of data points; ϵ_{RMS}: root mean square error.~~

It is very interesting to observe that, ~~although the model was~~ even a model trained only with 10-min averages, ~~it~~ is still able to provide for time-resolved estimates of the parameters. To illustrate this fact, Fig. 9 reports a 10 Hz time history of the vertical shears from the validation sub-set. The figure corresponds to about two days of operation, during which the wind direction (bottom plot) was $\Gamma \in [145, 260]$ deg. Turbine and met-mast are roughly aligned for $\Gamma \in [177.5, 215]$ deg; WT1 is in the wake of WT2 for approximatively $\Gamma \in [120, 170]$ deg, the two directions being indicated in the plot with two horizontal dashed lines. The top plot of the figure shows the lower-half-rotor shears measured at the met-mast and by the sector-equivalent speeds. Although some discrepancies are present, the figure shows that the sector-effective observer is capable of following the main changes in shear captured by the met-mast. The main discrepancies can be found between 2PM of October 21 and about 4AM of October 22, when WT1 is in the wake of WT2 or in its close proximity. However, one should not forget that the two estimates correspond to two locations spaced 2.5D apart, and that the exact ground truth at the rotor disk —where the observers operate— is unknown. The central plot of the same figure shows the rotor-equivalent shear estimated by Eq. (9) based on rotor harmonics and its reference quantity obtained by the sector-equivalent speeds. The two vertical shears are in excellent agreement, even with respect to relatively fast fluctuations.

To provide for a more complete statistical characterization of the observer performance, the 10-min data points were binned for the various relevant parameters. For each bin, the mean absolute error (MAE) between the estimated θ_{E} and reference θ_{R} wind parameter was computed as $\epsilon = 1/N \sum_i^N |\boldsymbol{\theta}_{\mathrm{R}_i} - \boldsymbol{\theta}_{\mathrm{E}_i}|$.

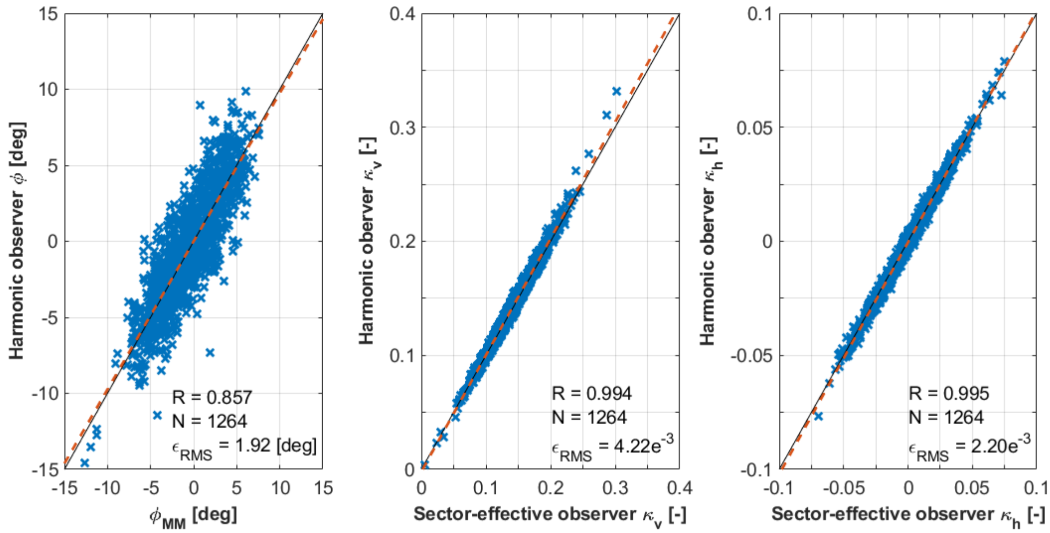

Figure 7. Correlation of 10-min averages between estimated parameters (y axis) and their reference quantities (x axis) for $V \geq 8$ m/s. From left to right: yaw misalignment angle, vertical linear shear, horizontal linear shear. Red dashed line: linear best fit; black dashed line: ideal match; R: Pearson's correlation coefficient; N: number of data points; ϵ_{RMS}: root mean square error.

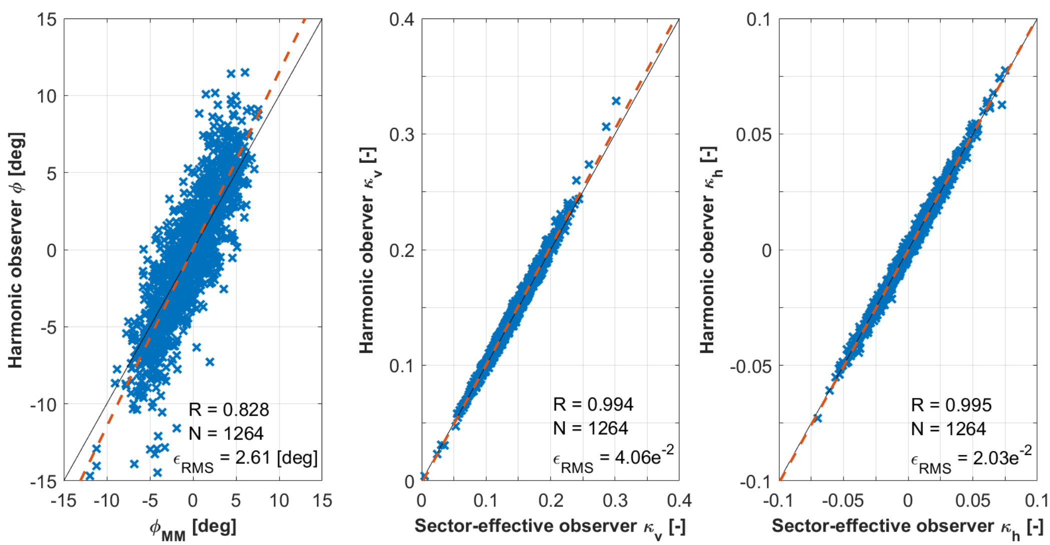

Figure 8. Correlation of 1-min averages between estimated parameters (y axis) and their reference quantities (x axis) for $V \geq 8$ m/s. From left to right: yaw misalignment angle, vertical linear shear, horizontal linear shear. Red dashed line: linear best fit; black dashed line: ideal match; R: Pearson's correlation coefficient; N: number of data points; ϵ_{RMS}: root mean square error.

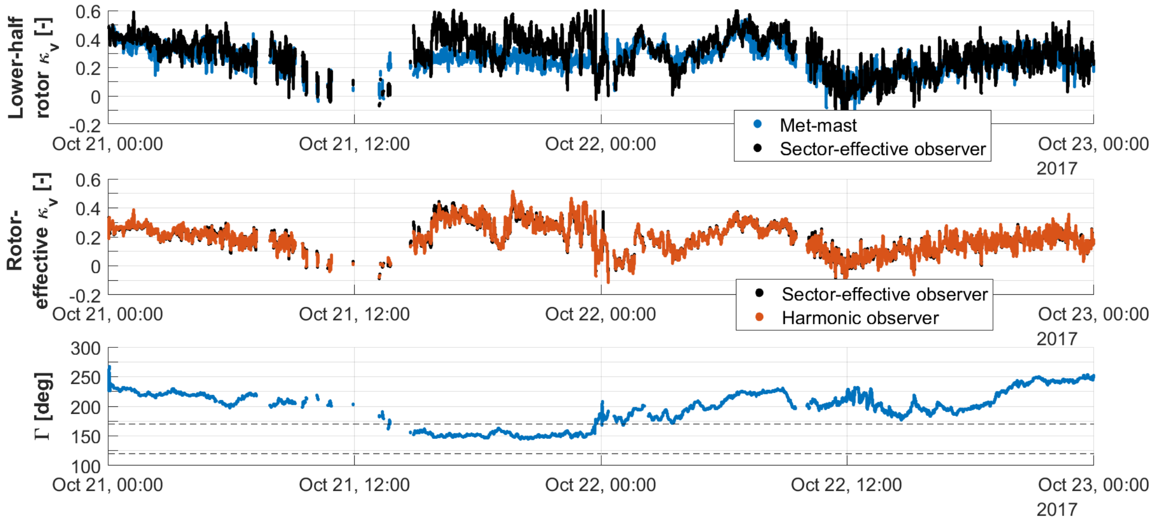

Figure 9. Time history of vertical shears at 10 Hz. From top to bottom: lower-half-rotor shear from the met-mast (blue) and the sector-effective observer (black); full-rotor-equivalent shear using Eq. (9) (red) and reference from the sector-effective observer (black); wind direction measured at the met-mast, with WT1 in the wake of WT2 between 120 and 170 deg (dashed horizontal lines).

Figure 10 shows the MAE ϵ for yaw misalignment (top left), vertical and horizontal shear (top and bottom right, respectively), plotted as functions of binned wind speed, for various binned turbulence intensity (TI) levels. The number of available hours of data is reported in the bottom left histogram of the figure, to help determine the statistical significance of the results. Looking at the yaw angle results, it appears that the maximum error is about 3 deg and that accuracy tends to increase for higher wind speeds. Moreover, TI appears to play only a small effect on the results. The error in the vertical shear includes the error between the met-mast and the sector-effective observer of §2.3.2. Even in this case the error is small, and effects of TI are present but relatively mild. The figure also reports the horizontal shear, whose error —although very small— might not be very indicative~~,~~ ~~as~~ : since no reference value was available from the met-mast for this quantity, only the error with respect the to sector-effective observer of §2.3.2 could be quantified.

Figure 11 reports the results for varying binned air density. The plots show that the density correction of §2.2.1 is not perfect, probably because of an only approximate identification of the gravity term in Eq. (12).

Finally, Fig. 12 reports the results for varying wind direction. Looking at the vertical shear, the best results are obtained for wind directions between 170 and 210 deg, when turbine and met-mast are aligned, whereas the error increases significantly for other wind directions. When turbine and met-mast are not aligned, the two can be subjected to slightly different inflows, on account of orographic and vegetation-induced effects. This indicates once again that, as noted earlier on, the information provided by the reference met-mast cannot be regarded as an absolute ground truth. The yaw misalignment angle seems to be

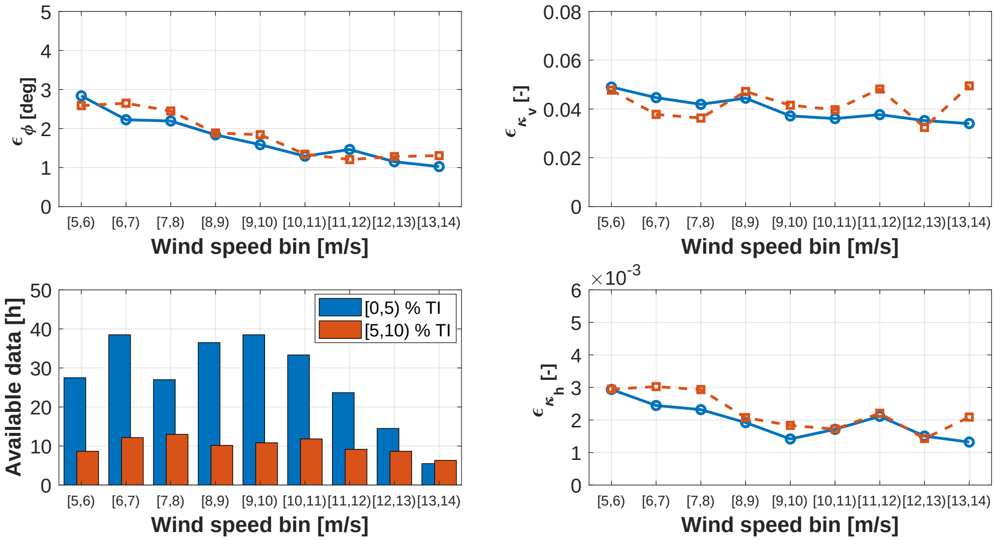

Figure 10. MAE ϵ vs. binned rotor-effective wind speed, for binned TI. Top left: yaw misalignment; top right: vertical shear; bottom right: horizontal shear; bottom left: hours of available data.

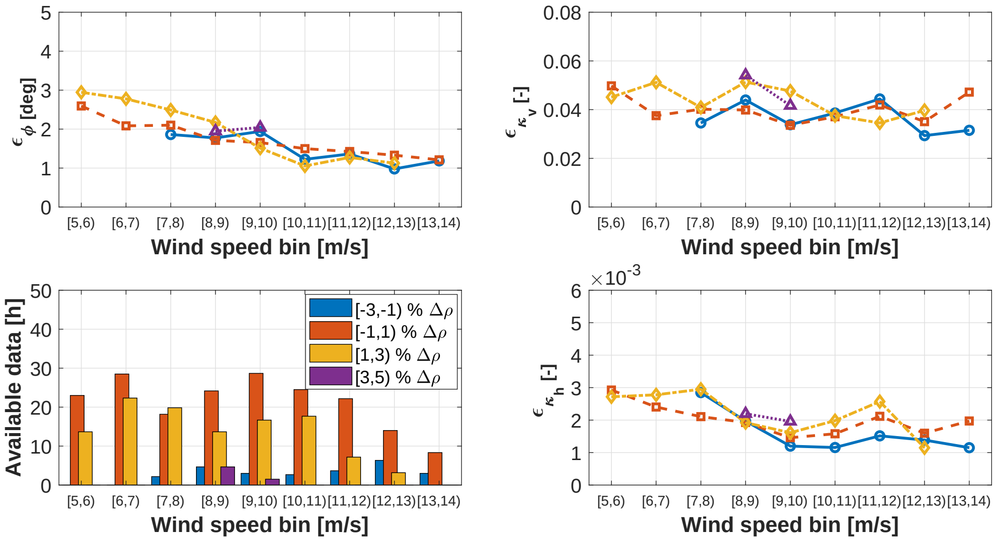

Figure 11. MAE ϵ vs. binned rotor-effective wind speed, for binned density change $\Delta\rho$ wrt. standard air. Top left: yaw misalignment; top right: vertical shear; bottom right: horizontal shear; bottom left: hours of available data.

less influenced by these local effects, which might induce stronger local changes in shear than in direction at this particular site.

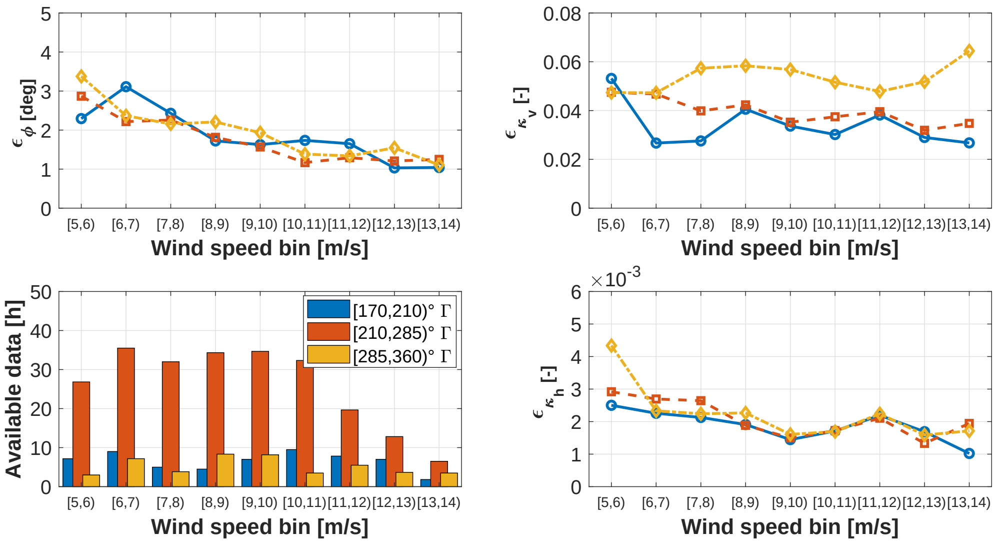

Figure 12. MAE ϵ vs. binned rotor-effective wind speed, for binned wind direction Γ. Top left: yaw misalignment; top right: vertical shear; bottom right: horizontal shear; bottom left: hours of available data.

4 Conclusions

This paper has presented the application of a previously published harmonic-based wind sensing method to an experimental dataset. The setup at the test site is not complete enough to provide for a true field validation of the method. However, it is representative of a practical scenario where, by using a hub-tall certification met-mast, the method is trained for a given turbine model, before being deployed on assets of that same type at other production sites. After having explained the methodology and described the test site, the paper has also formulated a new method to extend the shear measured by a hub-tall mast to the tip of the rotor, in order to compute a full-rotor shear.

Based on the results analyzed herein, and notwithstanding the limits of the present dataset, the following conclusions can be drawn:

- There is a good correlation between met-mast and estimated lower-half rotor shears;

- There is an excellent correlation between the full-rotor shear extended above the mast and the one estimated by harmonic loads;

– Training with 1-min or 10-min data improves the qualityof the estimates with respect to the case where a much larger set of higher-sampling-frequency data points are usedaverages produces shear estimates of a very similar quality, but there is a marginal improvement of the wind direction for the longer time window. This is probably due to the noisier nature of wind direction, which is measured here only at hub height.

– Notwithstanding a training based on 10-min averages, the quality of the correlation between estimates and references does not only apply to 10-min quantities, but it also extends to time-resolved 10 Hz signals. In this sense, the observer seems capable of following relatively fast changes in shear. This might be useful for certain application scenarios, as for example the tracking of horizontal shears induced by wake interactions.

– There is a non-negligible effect of wind-mast-turbine non-exact wind-mast-turbine alignment. In this sense, the actual quality of the correlation might be even better than what appears from the results shown here. This is in fact an intrinsic limit of field testing, where an exact ground truth is in general difficult if not impossible to obtain. Realistic simulations and wind tunnel studies as the ones reported in Bertelè et al. (2017, 2018, 2019) —where the ground truth is known— may help in this sense.

– Yaw misalignment is also estimated with reasonable quality, although the results here are less conclusive due to the fact that the met-mast reference is a point-wise measurement that might not fully represent rotor-effective conditions.

– There is only a modest effect of TI, which supports the hypothesis that 1P harmonics are mostly driven by “deterministic” wind characteristics and less affected by turbulent fluctuations.

– Notwithstanding the complicated effect of gravity on harmonic load components, its presence can be eliminated with enough accuracy to allow for a reasonably precise density correction.

The main limits of the present dataset are as follows: independent reference measurements for horizontal shear and upflow were completely missing, yaw misalignment was measured only at a point instead of over the rotor disk, and the vertical shear had to be extended over the hub by the use of another estimation method. Although the utmost care was put into the reconstruction of the full-rotor vertical shear, this operation still had to rely on the same blade load measurements used by the harmonic estimator, which is clearly a weakness. Other less substantial limitations are also present, for example caused by the missing load sensors on one of the blades.

A continuation of this work would greatly benefit from access to a more complete dataset, without the limits discussed above. Multiple, independent rotor-effective measurements of the inflow in very close proximity of the rotor disk would be necessary to establish an effective ground truth. This would allow for enable a better characterization of the accuracy of this method, and to study the effects induced by training with a standard hub-tall mast. A remaining open point is the demonstration that the method can indeed be trained on a turbine and, then, applied to another machine of that same model at another site; although this seems to be a very reasonable assumption, the evidence that this is indeed possible is lacking. Finally, it remains to be shown that the method does not need to be re-trained for an aging turbine. Here again, based also on the reassuring results already reported by Bottasso and Riboldi (2015), it is difficult to believe that 1P loads might change over time to the point of affecting the estimates, although a field proof of this assertion is clearly missing at this point in time.

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Nomenclature

A	Rotor area
C_m	Cone coefficient
H	Height of the hub above ground
m	Blade bending moment
$\boldsymbol{m}$	Vector of moment harmonics
N	Number of available data points
q	Dynamic pressure
R	Rotor radius or Pearson’s coefficient
$\boldsymbol{Q}$	Covariance matrix
V	Wind speed
V_h	Wind speed at hub height
$V_{\mathrm{PL}}(z)$	Power law wind speed profile
V_S	Sector-effective wind speed
V_{TB}	Torque-balance rotor-effective wind speed
$\tilde{v}$	Non-dimensional tangential ~~cross flow~~ cross-flow at hub height
$\tilde{w}$	Non-dimensional vertical ~~cross flow~~ cross-flow at hub height
x, y, z	Hub-centered nacelle-attached axes
β	Pitch angle
Γ	Wind direction
ϵ	Mean absolute error
$\boldsymbol{\theta}$	Wind state vector
κ_h	Horizontal shear
κ_v	Vertical shear
λ	Tip speed ratio
ρ	Air density

ϕ	Yaw misalignment angle
χ	Upflow angle
ψ	Azimuth angle
Ω	Rotor speed
$(\cdot)^T$	Transpose
$(\cdot)^{\mathrm{IP}}$	In-plane component
$(\cdot)^{\mathrm{OP}}$	Out-of-plane component
$(\cdot)_{\mathrm{1c}}$	1P cosine amplitude
$(\cdot)_{\mathrm{1s}}$	1P sine amplitude
$(\cdot)_{\mathrm{E}}$	Estimated quantity
$(\cdot)_{\mathrm{MM}}$	Met-mast measurement
$(\cdot)_{\mathrm{ref}}$	Reference quantity
$(\cdot)_{\mathrm{RMS}}$	Root mean square
1P	Once per revolution
MAE	Mean absolute error
Lidar	Light detection and ranging
LUT	Look-up table
RMS	Root mean square
SEWS	Sector-effective wind speed
Sodar	Sound detection and ranging
TI	Turbulence intensity
WT	Wind turbine

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