Micrositing using Rotor Equivalent Wind Speed – One Step Forward or Aside?

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ENGLISH

Abstract
Wind shear variation has been recognized as one of the main drivers for power curve uncertainties. The rotor equivalent wind speed (REWS) concept has been developed to address this issue and will be included in the upcoming release of the IEC 61400-12-1 standard. While this concept can be expected to reduce uncertainties related to power curve measurements, the consequences for the uncertainty of subsequent energy yield assessments and micrositing studies are less clear.
Our analysis shows that the differences between energy yields obtained using the classical approach (hub height wind speed and hub height power curve) and energy yields obtained using the equivalent wind speed approach show a clear dependency on wind shear, and even more important, on the wind shear frequency distribution. The magnitude of these differences reinforces the demand for considering wind shear for energy yield assessments.
On the other hand, this also raises the necessity to accurately determine the wind shear at the site. This requires at least two high-quality measurement heights, preferably close to hub height and with reasonable distance to each other. Experience shows that this is often not easily achieved. In such cases the wind profile often can only be estimated by models with considerable model errors and without reasonable information about the frequency distribution. While the additional uncertainty from using REWS instead of hub height wind speed is small, the additional measurement uncertainty cannot be neglected. Therefore, the advantage of having a less uncertain power curve is at least partly offset in the overall energy yield result.

Introduction

Currently, typical energy yield assessments (EYA) in wind farm micrositing focus on hub height wind speed, but ignore wind speed variations across the rotor area. While these effects may have been negligible in the past, they can hardly be ignored for rotor diameters of 100m and more. Consequently, the upcoming revision of the IEC 61400-12-1 [1] introduces the Rotor Equivalent Wind Speed (REWS) to account for vertical wind shear during the measurement of the power curve. This is expected to reduce the data scatter and hence reduce the uncertainty of power curve measurements (e.g. [2], [5], and references therein). Power curves as a function of REWS instead of hub height wind speed are therefore likely to be issued

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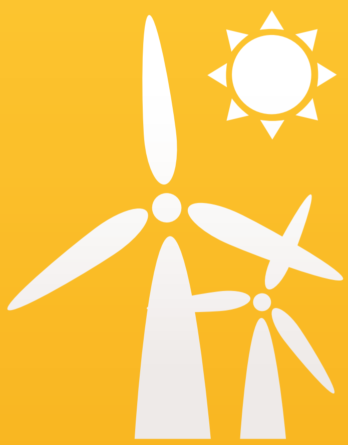

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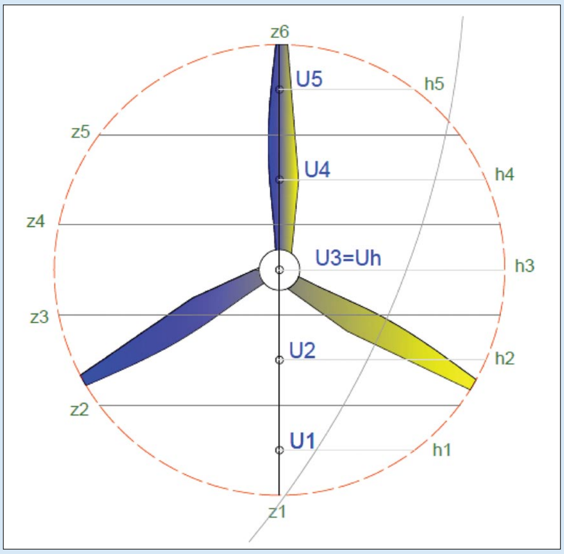

Fig. 1: Rotor area divided into five segments A_i to determine U_{REWS}

Tab. 1: AEP differences compared to the Current Method when using various methods to implement the REWS concept (Methods I and II, Static and Dynamic approach).

	Site-1	Site-2	Site-3
Average α	0.191	0.314	0.185
$AEP_{S,I}$ - AEP_C	-1.10%	-0.30%	-1.20%
$AEP_{S,II}$ - AEP_C	-1.30%	-0.36%	-1.30%
$AEP_{D,II}$ - AEP_C	+1.2%	+2.5%	+1.3%

more frequently in the future. When power curves are issued with respect to REWS rather than hub height, the wind measurement at prospective wind farm sites need to take this into account in order to be compatible. This paper addresses implications of implementing the REWS concept for EYA at wind farm sites. Two methods to accomplish this are presented, depending on whether REWS is used for the wind speed time series or for the power curve. Furthermore, for each method, the wind shear can be introduced as a time averaged value, or as time dependent. The results and implications are discussed. We also address the uncertainties introduced by incorporating wind shear into the EYA calculation.

Measuring Wind Shear

In order to implement the REWS concept for EYA at the wind farm site, the wind shear needs to be determined. Ideally, wind shear is derived from simultaneous high-quality wind speed measurements at two or more heights, so that a wind profile can be estimated for each measurement time step. To that end, met masts must have at least two (preferably more and reaching out above hub height) anemometers with sufficient vertical distance to each other (10m or more). Alternatively, remote sensing devices (Lidar, Sodar) can be used, which may have other limitations, e.g. in complex terrain or with respect to vertical resolution. If no wind profile data is available, it is still possible to model an average wind profile using the Wind Atlas method. This profile is based on the model representation of the wind farm site topography and roughness conditions in combination with assumptions of the vertical heat flux. Without loss of generality we assume in the following that wind shear is described by a power law and characterized by its exponent α.

The REWS Concept

For simplicity, turbulence and wind veer are neglected in the following, i.e. it is assumed that no horizontal variations of wind speed exist and that wind speed *U* only depends on height *h*. At any given height *h*, the kinetic energy flux *KE(h)* through a (small) area *A(h)* is a function of the third power of the wind speed *U(h)*,

$$KE(h) = \frac{1}{2}\rho\, U(h)^3\, A(h) \tag{1}$$

According to IEC 61400-12-1, the REWS is defined as the wind speed that corresponds to the kinetic energy flux through the rotor area[1]. The REWS is therefore essentially a cubic average of wind speed across the rotor area *A* while weighting each height with the horizontal width of the rotor. When the integral is replaced by a sum over finite horizontal rotor segments with area A_i, the REWS can be expressed as

$$U_{REWS} = \left(\sum_{i=1}^{n} U_i^{\,3}\,\frac{A_i}{A}\right)^{\frac{1}{3}} \tag{2}$$

Fig. 1 illustrates the principle for a rotor divided into 5 segments. For wind profiles described by a power law with exponent (α), equation (2) becomes:

[1] Of course, other methods exist to average the wind speed across the rotor [5], but these are less frequently used and are not likely to be mentioned in the IEC 61400-12-1 standard revision.

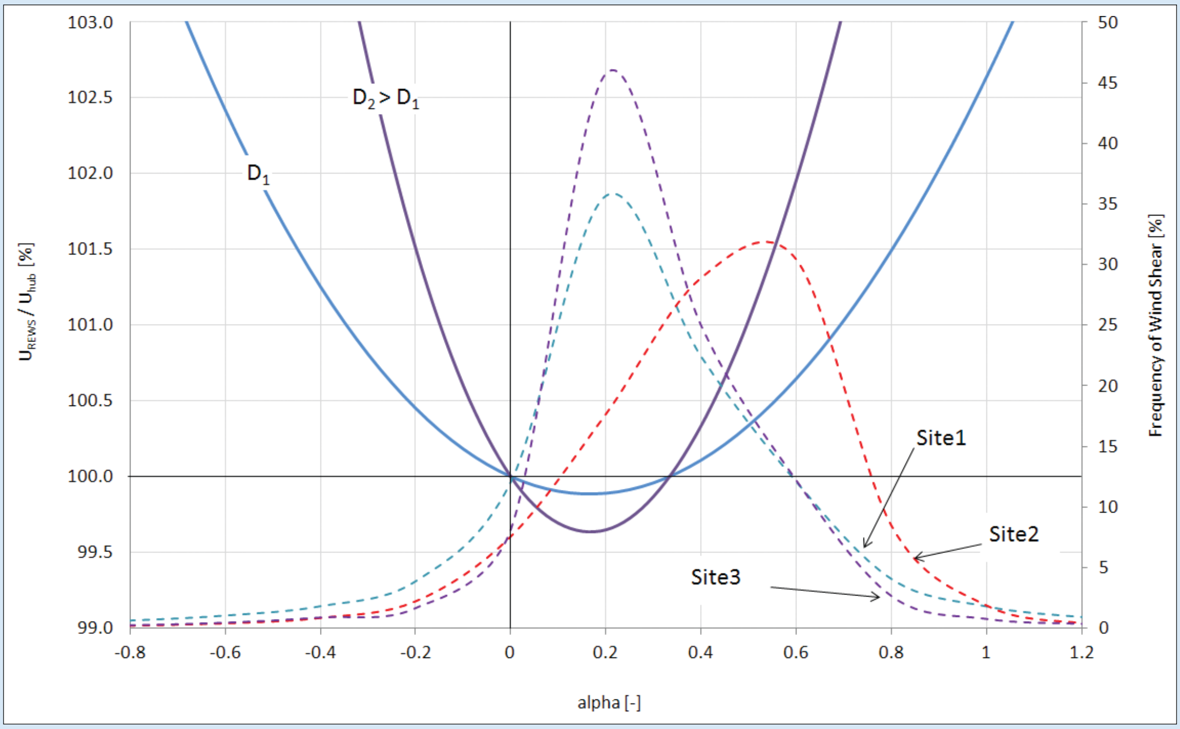

Fig. 2: Ratio U_{REWS}/U_{hub} (proportional to kinetic energy flux) for different turbine diameters. Also shown is the frequency distribution of α at three example sites (right ordinate).

$$\frac{U_{REWS}}{U_{hub}} = \frac{1}{H^{\alpha}} \left(\frac{1}{A} \sum_{i=1}^{n} h_i^{\,3\alpha} \; A_i \right)^{\frac{1}{3}} \tag{3}$$

For any given wind shear, the wind speeds across the vertical rotor diameter depend on the wind shear exponent (α). Therefore, both the kinetic energy flux and the U_{REWS}/U_{hub} ratio are also functions of α with a minimum at $\alpha \approx 0.163$, and $KE(\alpha=0) = KE(\alpha=0.337)$ (see Fig. 2). The exact value of the minimum depends on parameters like hub height and rotor diameter.

Approach

Currently, the standard method for EYA ('Current Method') considers only hub height wind speed and combines this with a power curve determined for hub height wind speed. Wind shear is ignored, both during the power curve measurement and when assessing the annual energy production (AEP). This implicitly assumes that the wind speed across the rotor plane is identical to hub height wind speed, equivalent to assuming a flat vertical profile ($\alpha = 0$). When a power curve is measured (or determined theoretically using a model) with respect to REWS according to IEC 61400-12-1, wind shear *is* considered during the measurement and used to convert the hub height wind speed into REWS as described in the REWS concept section. When using this power curve for EYA, the wind shear at the wind farm site also needs to be considered for the EYA. After measuring α at the wind farm site as described in the measuring wind shear section, this can be done in two equivalent ways that yield similar AEP results.

Method I uses eq. (3) to convert the REWS power curve into a hub height power curve by converting the REWS values in the power curve into hub height wind speeds for any site specific value of α. This resulting 'converted hub height power curve' can then be used along with the hub height wind speed data to calculate the AEP. Apparently, most approaches in the literature follow this approach (e.g. [2],[4]).

Method II, on the other hand, uses eq. (3) to convert each data point of the measured wind speed time series into a REWS time series for site specific α. This REWS time series is then combined with the REWS power curve to calculate AEP.

Which value of α is appropriate for the site? The simplest way would be to use average α from the Wind Atlas method or averaging the wind shear time series ('Static Approach'). A more sophisticated way would determine the wind shear for each point in time of the time series. This could then be used to calculate either the REWS either for the current value of hub height wind speed ('Dynamic Approach'). Alternatively, one could also determine the 'converted hub height power curve' for the current α, but this appears less convenient as a complete power curve would need to be calculated for each wind speed data point. In contrast to the Static Approach, the Dynamic Approach also takes into account the variation of α at the site.

Results

As an example, we explored three sites with different characteristics of α. As displayed in Fig. 2 (right ordinate). Site 1 and site 3 are rather similar with average $\alpha \approx 0.2$, while site 2 has a relatively high average $\alpha = 0.31$. The wind shear probability distribution is also wider for site 2, leading to a considerably higher share of values with α > 0.337 for site 2 compared to the other sites. The differences in AEP when applying the static and dynamic approach for these sites compared to the AEP obtained by the Current Method (AEP_C) are shown in Tab. 1.

For method I, the static approach yields smaller $AEP_{S,I}$ compared to the Current Method. This corresponds to the kinetic energy flux in Fig. 2, which is close to its minimum for the average α at site 1 and site 3. Therefore, the differences to AEP_C are similar for these sites. For site 2 ($\alpha = 0.31$), however, the KE flux is similar to the KE flux of the Current Method ($\alpha = 0$). The reduction compared to AEPC is thus much smaller than for site 1 and site 3.

Method II using the static approach results in similar differences in $AEP_{S,II}$ compared to AEP_C as method I. The observed differences are due to using the (less exact) Weibull fit rather than the time series as basis of the AEP calculation. The reductions observed from both static methods are similar to those found by other authors using the static approach [4].

The dynamic approach yields greater AEP compared to the Current Method for all three sites. The difference is particularly high for site 2, but also considerable for site 1 and site 3, which again yield similar values. This result is due to those data for which α exceeds 0.337. For these high values of α, the KE flux is increasingly greater than the value obtained by the Current Method (i.e. at $\alpha = 0$). Due to the non-linear growth of KE for increasing α, even a limited amount of high wind shear values can balance the sum of reduced KE between $0 < \alpha < 0.337$, and lead to greater overall AEP compared to the Current Method.

It is therefore of great importance not to neglect the variation of α at the site by considering the dynamic approach or similar methods. Using only the average wind shear will, for most real-world sites with $\alpha < 0.337$, underestimate the actual energy yield and result in smaller AEP than when using the Current Method.

Uncertainty

One of the targets of introducing the REWS concept into the determination of power curves is to reduce the data scatter and thus the uncertainty of the power curve. This, however, can only reduce the uncertainty of the calculated AEP, when it is not outweighed by the additional uncertainty introduced by the wind shear determination.

The uncertainty of wind shear is caused by two factors: (a) the uncertainty of the additional wind shear measurements at the site, and (b) the uncertainty of fitting a profile to each set of wind speed measurements. The uncertainty of both factors can be estimated by usual error propagation methods and will typically result in a slightly higher uncertainty for the REWS than for the classical wind speed measurement at one single (hub) height.

How does the uncertainty of α affect the uncertainty of the REWS. Closer examination of eq. (3) shows that this is mainly dominated by the uncertainty of the hub height wind speed, U_{hub}, while the effect of the uncertainty of α on the uncertainty of REWS is about two orders of magnitude smaller. Therefore, the inclusion of wind shear in the wind speed measurement via the REWS does not significantly increase the wind speed uncertainty.

Conclusions

The non-linear wind shear dependency of the kinetic energy flux requires addressing the probability distribution of wind shear at wind farm sites when using the REWS concept in order to provide meaningful results. Considering only the average wind shear is likely to result in considerable underestimation of AEP for most wind farm locations.

Until now, wind shear distributions can only be derived from measurements. This means that future wind farm assessments will require enhanced measurement efforts at the site in order to provide not only one high quality hub height wind speed, but also to determine a wind shear time series at the same quality.

The additional uncertainty introduced by including wind shear in the energy yield assessment is relatively minor. Therefore, the reduced uncertainty that can be expected for power curves determined for REWS instead of hub height wind speed should also propagate into a reduced AEP uncertainty.

Turbulence has been ignored throughout this study, even though it is known that this also has an effect on the kinetic energy flux through the rotor. Unfortunately, the REWS concept has been found to be unsuitable to also account for turbulence [2]. Additional research is required to further address this issue and its implications for site assessments.

References

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