Extension of the DWM model towards a static model for site-specific load simulations

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Abstract. The outlined analysis presents a method to extend the Dynamic Wake Meandering (DWM) model to allow a combination with load approximation methods, which are commonly used to estimate the loads during the planning process of a new wind farm layout. Determining a wind farm layout is a highly iterative process, where time-consuming calculations are avoided as much as possible. The DWM model is methodically designed such that it delivers an inhomogeneous wind field, which makes it useless for further application in load approximation tools that generally require a single value for the turbulence intensity. Furthermore, the DWM model is developed in a way that turbulent wind fields need to be generated to define the ambient turbulence as well as the meandering of the wind speed deficit itself. Likewise, this time-consuming process of calculating a turbulent wind field is in strong contrast with iterative wind farm layout optimization processes. Therefore, the developed extension of the model uses a probability density function to describe the meandering and requires no wind field simulations. The static DWM model is finally compared to the commonly used Frandsen turbulence model as well as to the original DWM model and produces less conservative fatigue loads than the Frandsen model.

1. Introduction
One key parameter in the design of a wind farm is the wake model, which is used to describe the interaction between the turbines in a wind farm. Such a model is not only important to calculate the energy yield of the wind farm, it is also highly relevant to determine the loads on each single turbine. For a wake-affected turbine the latter are often simulated based on the calculation of a so-called wake-induced or wake-added turbulence intensity (TI). One of the well-known models for predicting this wake-induced turbulence is the Frandsen model (see, e.g., [1]), where the total TI at the downstream turbine is calculated by a quadratic summation of the wake-added TI and the ambient TI. Subsequently, the loads on each single wind turbine are determined with a homogeneous wind field (calculated according to, e.g., [2]), which is scaled by the total TI. Previous measurement campaigns have shown that this method delivers conservative results for small turbine distances [3, 4]. Recently, the Dynamic Wake Meandering (DWM) model has been included in the new edition of the IEC guideline [5] to generate more accurate descriptions of the
actual physical behavior of the wake. This model assumes that the wake behaves as a passive tracer, i.e., the wake itself moves in vertical and horizontal direction [6]. The combination of this movement and the shape of the wind speed deficit lead to an increased TI at a fixed position downstream and thus strongly influences the loads on the downstream turbine. Based on the specific setup of the DWM model it delivers an inhomogeneous wind field, which can be directly connected to an aeroelastic load simulation software.

However, despite all advantages the model provides, it mostly remains unusable for the industry. This derives from the fact that planning a new wind farm layout is a highly iterative process, where time-consuming calculations, such as aeroelastic load simulations for a whole wind farm including all layout options, are usually ruled out. A common way to counteract this problem is to estimate the loads based on interpolations between already performed load simulations, which serve as grid points of a response surface [7]. This interpolation method usually only depends on a couple of site conditions (e.g., wind shear, TI, wind slope and air density). Unfortunately, such a load estimation method is not combinable with the DWM model, since it requires a single TI value for the whole wind field instead of an inhomogeneous wind field, as generated by the DWM model. The outlined analysis addresses this issue and presents a method to extend the DWM model to allow a combination with load interpolation methods. This will expand the model’s scope by improving its usability for site-specific load calculation processes. Accordingly, the description of the physical behavior of the wake will be improved compared with currently used models. The analysis focuses primarily on the loads of the downstream turbine and less on the calculation of power losses due to wakes. Furthermore, the extension is defined in a way that the computational costs of the calculation procedure are very low, thus allowing an application in wind farm layout optimization processes.

2. Methodology

The outlined method, denoted static DWM model, can be divided into three parts. The single parts of the model are summarized in Figure 1.

Figure 1: Overview of the components of the static DWM model. The calibration factor contains all small-scale turbulence.

The first part (blue box) consists of the description of the meandering as well as the downstream expansion of the wind speed deficit. The description of the latter is fully adopted from the DWM model. In the second step (yellow box), the added TI induced by the meandering itself is determined and superimposed on the ambient TI (TI-Total). The last step (green box) is the calculation of a rotor-averaged TI (TI-Rotor), which afterwards serves directly as an input for the load simulation software, so that the damage equivalent load (DEL) can be calculated. In the following the different substeps are explained in more detail.
2.1. Wind speed deficit
In the DWM model, the downstream expansion of the wind speed deficit is calculated by the thin-shear layer equations. This approach was originally developed by Ainslie [8] and subsequently incorporated into the DWM model [9]. The thin-shear layer equations in their axisymmetric form, are expressed as follows:

\[ \frac{U}{\partial x} + V_r \frac{\partial U}{\partial r} = \frac{1}{r} \frac{\partial}{\partial r} \left( \nu_T \frac{\partial U}{\partial r} \right), \]

\[ \frac{1}{r} \frac{\partial}{\partial r} (r V_r) + \frac{\partial U}{\partial x} = 0, \]

where \( U \) is the wind speed in axial and \( V_r \) in radial direction (see also coordinate system in Figure 2). The boundary conditions for solving the thin-shear layer equations are based on the axial induction factor derived from the blade element momentum. The equations are solved by a finite-difference method combined with an eddy viscosity \( (\nu_T) \) closure approach. The model definition used here is further outlined in [10].

For the present analysis, the recalibrated eddy viscosity definition, also provided in [10], is adopted. Although the expansion of the wind speed deficit is solved numerically, the computational costs are very low, making it also applicable in an optimization process, as long as the axial induction factor has been calculated in advance for several different wind speeds and stored in a database or look-up table. Alternatively, it is possible to simply replace the wind speed deficit definition with an entirely analytical model (e.g., [11, 12]).

2.2. Meandering
The meandering in the DWM model is based on the assumption that the wake behaves as a passive tracer in the turbulent wind field. Consequently, the movement of the passive structure, i.e., the wake deficit, is driven by large turbulent scales [6, 9]. In the proposed extension of the model the meandering is described by a probability density function (PDF), which characterizes the probability of the position of the wind speed deficit in horizontal and vertical direction at a specific downstream position. The approach of using a PDF to describe the meandering is adopted from Keck [13]. The PDF is defined as a normal distribution with the standard deviation of the deflection in horizontal \( \sigma_y \) and vertical direction \( \sigma_z \), respectively. Thus, the probability of the horizontal and vertical position \( y_i \) and \( z_i \) of the wind speed deficit is defined as follows:

\[ PDF(y_i, z_i) = \frac{1}{2\pi\sigma_y\sigma_z} \exp \left[ -\frac{1}{2} \left( \frac{(y_i - \mu_y)^2}{\sigma_y^2} + \frac{(z_i - \mu_z)^2}{\sigma_z^2} \right) \right]. \]

This description of the meandering is in contrast with the original model definition, since due to this adjustment the meandering only depends on two parameters, \( \sigma_y \) and \( \sigma_z \), which can be calculated from the integral of the single-sided velocity spectrum of the component \( k \) of the ambient wind field. A Kaimal spectrum is used in this analysis, which can be defined as follows [5]:

\[ S_k(f) = \frac{4(L_k/U_0)\sigma_k^2}{(1 + 6fL_k/U_0)^3}, \]

where \( L_k \) is the velocity integral scale parameter, \( f \) the frequency, \( \sigma_k \) the velocity standard deviation, and \( U_0 \) the ambient wind speed. The index \( k \) refers to the considered velocity
component (longitudinal, lateral, or vertical). Integrating the single-sided velocity component spectrum up to the corner frequency $f_c$ delivers the standard deviation of the lower frequency part of the fluctuating wind speed, which is correlated to the meandering itself:

$$\sigma^2_{k,m} = \int_0^{f_c} S_k(f) df .$$  \hspace{1cm} (5)

The corner frequency defines the large-scale turbulence that is correlated to the meandering. It is specified by the ambient wind speed and the rotor radius as \[14\]:

$$f_c = \frac{U_0}{4R} .$$  \hspace{1cm} (6)

After calculating the filtered standard deviation, the probability function of the meandering can be determined directly by

$$PDF(y_i, z_i) = \frac{1}{2\pi\sigma_{v,m}\sigma_{w,m}} \exp \left[-\frac{1}{2} \left(\frac{(y_i - \mu_y)U_0}{s} \frac{U_0}{\sigma_{v,m}} + \frac{(z_i - \mu_z)U_0}{s} \frac{U_0}{\sigma_{w,m}} \right)^2\right] \left(\frac{U_0}{s}\right)^2 .$$  \hspace{1cm} (7)

where $\mu_y$ and $\mu_z$ is the mean position of the wind speed deficit (e.g., $\mu_y = 0$ and $\mu_z = 0$ in full wake) and $s$ is the downstream distance.

The original model suggests a low-pass filtered turbulent wind field to describe the horizontal and vertical deflection of the wake. However, calculating a turbulent wind field requires considerable computational power. The aim of the here proposed model extension is to increase the usability of the DWM model in site-specific load calculations and wind farm layout optimization processes. Thus, the purely analytical PDF along with the Kaimal spectrum is more suitable and used instead. Regardless, it should be pointed out that this approach uses only a single-point spectrum and neglects any spatial coherence. Further analyses have shown that this simplification has only negligible influence on the overall results and, therefore, seems to be acceptable in this model approach. A comparison of the PDFs using either the Kaimal spectrum or the complete wind field is depicted in Figure 3. The horizontal meandering agrees very well, whereas there is a slight difference in the less dominant vertical meandering. However, since the turbine loads are mainly affected by the horizontal meandering, this deviation is acceptable.

2.3. Total TI

The next step is the calculation of the added TI induced by the meandering, which is based solely on the combination of the meandering PDF and the shape of the wind speed deficit. According to [13], the meandering TI can be calculated from the squared difference of the wind speed deficit in the meandering frame of reference (MFR) and the fixed frame of reference (FFR). This results in

$$TI_m(y_i, z_i) = \sqrt{\int\int (U(y_i - y_m, z_i - z_m)_{MFR} - U(y_i, z_i)_{FFR})^2 PDF(y_m, z_m) dy_m dz_m} .$$  \hspace{1cm} (8)
where \( U(y_i, z_i)_{MFR} \) is the mean wind speed in the MFR at the position \( y_i \) and \( z_i \). The wind speed deficit in the FFR \( U(y_i, z_i)_{FFR} \) can be calculated in a similar way and is consequently based on the convolution of the wind speed deficit in the MFR and the PDF of the vertical and horizontal deflection:

\[
U(y_i, z_i)_{FFR} = \int \int U(y_i - y_m, z_i - z_m)_{MFR} PDF(y_m, z_m) \, dy_m \, dz_m .
\]  

(9)

The calculated meandering turbulence intensity \( TI_m \) is subsequently added to the ambient turbulence intensity \( TI_0 \) in a quadratic summation as follows:

\[
TI(y_i, z_i)_{total} = \sqrt{(k_m \cdot TI_m(y_i, z_i))^2 + TI_0^2} .
\]  

(10)

This method is adopted from Keck \[13\], where it is applied to calculate power losses of wind farms. The calibration factor \( k_m \) for the meandering is added in this context and will be further explained in Section 3.

2.4. Rotor-averaged TI

The outcome of the previous step is the above-mentioned inhomogeneous wind field, which leads directly to the final step, the calculation of a load equivalent homogeneous TI. The purpose of this final step is to find a TI that correlates for all wake conditions with the turbulence-driven loads of the downstream turbine. Wake conditions could be that only one half of the rotor is in the wake (partial wake) or the full rotor is in the wake (full wake). A TI that is averaged over the whole rotor with respect to the Wöhler coefficient shows a good correlation with the turbulence-driven loads. It follows the approach of the effective TI introduced by Frandsen \[1\]. He identified a linear correlation between TI and DELs and introduced a weighted design TI over different wind directions, the effective TI, which should damage the structure equivalent to the sum of the damage contributions from all single wind directions. In consequence of this investigation and the fact that the here calculated rotor-averaged TI should be correlated to the DEL, the Wöhler coefficient is considered in the calculation as well. According to this, the rotor-averaged TI is defined as

\[
TI_{rotor} = \frac{1}{\pi R^2} \left( \int_0^{360^\circ} \int_0^{R} TI_{total}(r, \alpha) m \, r \, dr \, d\alpha \right)^{\frac{1}{m}},
\]  

(11)

where \( R \) is the rotor radius and \( m \) the Wöhler coefficient. Finally, the rotor-averaged TI can be used as an input for a response surface to calculate DELs.

3. Results

Figure 4(a) illustrates the wind speed deficit at hub height over the horizontal distance to the hub. The shown wind speeds correspond to a rotor diameter of 117 m, a downstream distance of 3.61D, an ambient wind speed of 8 m/s, and an ambient TI of 8 %. The original DWM model is compared to the PDF approach. It is apparent that both approaches match very well. The corresponding turbulence intensities at hub height are depicted in Figure 4(b). Besides the overall turbulence intensity of the original DWM model (solid blue curve), the total TI (dashed green curve), which is the combination of the meandering TI and the ambient TI of the original DWM model, as well as the PDF approach of the total TI (dashed dotted red curve) are illustrated. The comparison clarifies that the influence of the small-scaled TI, which is only considered in the overall TI of the original model version, is rather low. Furthermore, the PDF
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Figure 4: Wind speed deficit (a) and TI (b) at full wake conditions. The simulations are performed with an ambient wind speed of 8 m/s, an ambient TI of 8%, a rotor diameter of 117 m, and a downstream distance of 3.61D.

The approach also agrees very well with the combined TI from the original model. Based on the illustrated total TI, the rotor-averaged TI can be calculated. This delivers a rotor-averaged TI of 12.88% for the PDF approach, which agrees very well with the rotor-averaged TI derived from the original model of 12.90% (solid blue curve).

As mentioned before, the rotor-averaged TI shall correlate with the fatigue loads of the downstream turbine. The correlation between the rotor-averaged TI and the normalized DEL of the tower bottom fore-aft moment is displayed in Figure 5(a). Simulations based on the original DWM model for wind directions from $-30^\circ$ to $30^\circ$ are illustrated as crosses together with a linear regression between these points. The different inflow conditions are illustrated in Figure 2. The simulations are based on a turbine model with a turbine diameter of 117 m, and a hub height of 120 m. The simulations were carried out with the commercial load

Figure 5: Normalized tower bottom fore-aft DEL over the rotor-averaged TI (a) and over the wind direction (b). The DELs are calculated with a Wöhler coefficient of 4, an ambient wind speed of 8 m/s, an ambient TI of 8%, and a downstream distance of 3.61D.
simulation software alaska/Wind A validation of alaska/Wind can be found in [15]. The wake generating turbine and the wake-affected turbine are of the same type. The simulations were carried out at a downstream distance of $3.61D$ and are valid for an ambient wind speed of $8 \text{ m/s}$ and an ambient TI of $8\%$. Figure 5(a) proves a linear correlation between the rotor-averaged TI and the DEL of the tower bottom bending moment. Furthermore, it shows clearly that the slope of the regression line is different from unity and thus indicates that a calibration of the extended DWM model is necessary. Simulations reveal the highest slope of the regression at the tower bottom bending moment (see Figure 5(a), Figure 7(a), and Figure 8(a)). To achieve conservative results for all turbine components, the calibration of the model is based on the results of the tower bottom bending moment. It should be pointed out that it is only necessary to calibrate the TI related to the meandering itself, which leads to the previously mentioned calibration factor $k_m$, introduced in Equation (10). A suitable calibration factor is determined from simulations for different downstream distances. It is specified by a least-squares fit between the simulated static DWM model fatigue loads and the original model loads. This leads to the calibration factor depicted in Figure 6.

Simulations for different ambient turbulence intensities have proven that this factor is independent from the ambient TI.

The normalized DEL of the tower bottom bending moment over the simulated wind directions is illustrated in Figure 5(b), in which a wind direction of $0^\circ$ represents a full wake. It shows the simulation results based on the original DWM model, the developed static model as an extension of the original model, as well as the calibrated static DWM model with the introduced calibration factor $k_m$. The calibrated static version of the DWM model is in very good agreement with the original model over all wind directions. Additionally, two versions of the Frandsen turbulence model are displayed. The first considers a characteristic view angle, which leads to the rectangle shape of the turbulence distribution over the wind direction, while the second model version assumes a bell-shaped turbulence distribution [1]. Both versions lead to significantly higher loads, especially at full wake conditions.

Simulation results for the flapwise blade root bending moment are depicted in Figure 7. The flapwise moment shows a similarly good linear correlation between the rotor-averaged TI and the DEL (see Figure 7(a)). The comparison of the simulated DEL of the flapwise moment of the static DWM model and the Frandsen model to the original DWM model is depicted in Figure 7(b). The static model is in good agreement with the original DWM model but the discrepancies are higher than for the tower bottom bending moment. This predicates on the fact that the calibration factor is based on the tower bottom bending moment and afterwards applied on all other turbine components without recalibration. The Frandsen model overestimates the DEL again, especially at full wake situations, however, the overestimation for the blade root is less pronounced than for the tower bottom bending moment, which seems to be reasonable taking into account that the model is validated with this component [1].

A suboptimal correlation arises for the edgewise blade root bending moment (see Figure 8). The edgewise moment is mainly driven by the weight of the blades and has only a weak dependency on the turbulence, whereas the flapwise moment and the tower bottom fore-aft moment strongly correlate with the fluctuating wind. Therefore, the linear regression generates an appropriate linear correlation of the rotor-averaged TI with DELs of the turbulence dependent
loads, but not with weight-driven loads. Yet, even though there is no linear correlation, the static DWM model still predicts the edgewise fatigue loads superior to the Frandsen model. Its only disadvantage is the behavior at negative wind directions, where it is not possible to establish the decrease of the DEL. It should also be pointed out that the maximum increase of the edgewise moment in wake conditions is less than 6% (see maximum in Figure 8(b) at a wind direction of $8^\circ$), whereas the flapwise moment is more than doubled at partial wake conditions, so that altogether the static model seems to be an acceptable approach, even for the edgewise moment.

A comparison of the deviations of the static model and the Frandsen model to the original DWM model is summarized in Figure 9. The first row shows the deviation over different downstream distances, whereas the second row shows the deviation over different ambient turbulence intensities. In all cases, the deviations between accumulated DELs over all inflow conditions from $-30^\circ$ to $30^\circ$ are illustrated. The Frandsen model delivers significantly higher loads towards lower downstream distances, which is in agreement with the findings in [3].
deviations between the static model and the original DWM model are less pronounced in this region. The Frandsen model and the static model converge towards larger downstream distances as well as higher turbulence intensities, leading to slightly higher loads of the static DWM model at larger distances and higher turbulence intensities than the bell-shaped Frandsen model. For the tower bottom bending moment, there is a noticeable overprediction of the DEL at the two last distances. The reason for this is that at far distances the wind speed deficit has almost vanished and a suitable calibration is no longer possible. Furthermore, towards higher distances the static DWM model delivers higher loads than the Frandsen model. The deviation between the two static DWM models and the Frandsen model for varying ambient wind speeds is illustrated in the last row of Figure 9. The solid blue line displays the results of only one calibration factor for all wind speeds determined with the loads at the tower bottom bending moment at an ambient

![Figure 9: DEL deviations of the static DWM and the Frandsen model with respect to the original DWM model. The simulations were carried out with an ambient wind speed of 8 m/s and an ambient TI of 8% for varying downstream distances ((a) to (c)), for a fixed ambient wind speed of 8 m/s, but varying ambient TIs ((d) to (f)), and for a fixed ambient TI of 8%, but varying ambient wind speeds ((g)-(i)), both of the latter at a downstream distance of 3.61D](image-url)
Table 1: Accumulated DELs over all wind speeds weighted by a Rayleigh distribution with an average wind speed of 7.5 m/s.

| ΔDEL                      | Tower fore-aft [%] | Flapwise [%] | Edgewise [%] |
|---------------------------|--------------------|--------------|--------------|
| static cali. \(k_m(s)\)  | 13.24              | 18.82        | 2.58         |
| static cali. \(k_m(s, U_0)\) | -0.46              | 3.51         | 0.84         |
| Frandsen                  | 51.12              | 46.10        | 4.91         |
| Frandsen det.             | 35.55              | 36.08        | 3.39         |

wind speed of 8 m/s. The dashed blue line is based on different calibration factors for each wind speed bin, again established with the tower bottom bending moment. It is clearly shown that the calibration factor depends on the ambient wind speed, since a calibration factor per wind speed bin agrees considerably better with the original DWM model. In contrast, the static model with only one calibration factor delivers up to 40% higher loads than the original DWM model in some cases. One reason for the deviation at low wind speeds, i.e., 6 m/s and 7 m/s, is that the wake-affected turbine is operating close to the cut-in wind speed of 4 m/s. Thus, in the DWM model simulation, the turbine has been frequently turned off in the full wake region. The Frandsen model and the static model do not consider the wind speed deficit, which is why no turbine shutdown cases are included in the load simulations, resulting in large discrepancies at low wind speeds. At higher wind speeds, i.e., in the range of 9 m/s to 10 m/s, the deviation shows a clear peak in the flapwise as well as the tower bottom bending moment. Again, the presumed reason is the disregarded wind speed deficit. In this region, the turbine’s thrust possesses its maximum, whereas in the original DWM model the thrust is substantially lower due to the wind speed deficit. This explanation is encouraged by the fact that at higher wind speeds, where the turbine starts to pitch and the turbine’s thrust decreases, the static model version with a single calibration factor and the Frandsen model converge towards the original DWM model. The static DWM model with different calibration factors for each wind speed (dashed blue line) seems to be capable of eliminating this phenomenon by adjusting the rotor-averaged TI, even though, the real physical reason of the load decrease, the wind speed deficit, is not considered. To summarize the results for all simulated wind speeds, the accumulated DELs over all wind speeds weighted by a Rayleigh distribution with an average wind speed of 7.5 m/s are illustrated in Table 1. Nonetheless, even if only one calibration factor is used, the static DWM model still produces less conservative results than the Frandsen model in most of the ambient wind speed bins, thus, also the accumulated DEL over all wind speeds is less conservative for all load components. Compared to the original DWM model, the static DWM model delivers higher loads at almost all conditions. Only at wind speeds around 9 m/s and 10 m/s, the flapwise and edgewise moments results in significant lower loads than the original DWM model, when simulated with a wind speed dependent calibration factor. Finally, it should be mentioned that the tower bottom bending moment accords best with the original model, which predicates on the fact that the calibration factor is derived from this load component.

4. Conclusions and outlook
The analysis provides an extension of the DWM model towards a static model with a homogeneous TI over the whole wind field, enabling its application for load approximation methods, which are commonly used in site-specific load calculation processes. Furthermore, the computational costs of the developed model are very low, making it a valid alternative to the Frandsen model, when implemented in wind farm layout optimization processes. For this purposes, the utilization of a PDF to describe the meandering together with a single point
spectrum has been developed. Furthermore the identification of a rotor averaged turbulence intensity (TI-Rotor), which correlates with the turbulence depending loads as well as the determination of a calibration factor to scale the turbulence intensity related to the wake meandering are major contributions of this work. A comparison of the new static DWM model to the Frandsen model and the original DWM model has been carried out. Overall, a good agreement between the loads based on the calibrated static DWM model and the ones based on the original model is achieved. At low downstream distances, the Frandsen model predicts significantly higher loads than the DWM model. Especially in this region, the new static DWM model confirms to be an improvement to the commonly used Frandsen model. Furthermore, the analysis indicates that the calibration factor $k_m$ should be determined separately for each wind speed bin to achieve a significant advantage towards the Frandsen model over all wind speeds. However, an incorporation of a wind speed deficit into the static model description might also solve this limitation. This topic will be investigated in future studies.

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