Verification of simulated fatigue loads on wind turbines operating in wakes

Master Thesis

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\[(EIv'')'' = q - \rho A \ddot{v}\]
Verification of Simulated Fatigue Loads on Wind Turbines Operating in Wakes

Final Project
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Abstract

The Dynamic Wake Meandering (DWM) model is a new wake model designed to model both increased fatigue loading and decreased energy production of the wake affected turbines. The model has been adopted by the TOPFARM project geared towards developing new methods of designing wind farms and wind farm control considering both energy production and wind turbine fatigue loading. The DWM model implementation in the HAWC2 aeroelastic simulation has been verified with operational measurements although this new verification project was developed to compare simulated fatigue loads against actual measured fatigue loads for turbines operating in single wake conditions. The previous work done in [4] has shown that fatigue loads can increase with separation distance and this has been attributed to the meandering of the wake deficit as it translates downstream. This project aims to determine the simulated general trends of wind turbine component fatigue as a function of turbine separation distance, atmospheric boundary layer stability, inflow hub height wind speed, and ambient turbulence intensity. Fatigue load measurements from operational single wake cases are analyzed and compared to the general trends found from the model.

Structural loads measurements from three fully instrumented Vestas wind turbines are available from two large offshore wind farms, Horns Rev, Denmark and Egmond Aan Zee, Netherlands. In addition, the SCADA measurements and meteorological mast measurements are available from the wind farms as well. After a thorough assessment of the quality of the data, the measurements were filtered and queried to identify time periods of wake conditions on the instrumented turbines. Aeroelastic models in HAWC2 are made and the structural dynamics and the operational parameters are tested to ensure a close match to the measurements. Detailed queries into the large volume of data are post processed and the results are compared to the general trends found in the simulation results.

For free inflow conditions, the fatigue loading in the simulation and the measurements are in close agreement for two wind speed conditions, 6 m/sec and 8 m/sec. For single wake conditions observed in the Egmond Aan Zee and Horns Rev wind farms, the turbine tower base fatigue loading was found to decrease with separation distance between wake generating and the wake affected turbine. This is contrary to the results from the simulation when the meandering component is enabled. When the meandering component is disabled, the general trend in fatigue loading from the simulation is in close agreement with the measurements. The model was not tested in multiple wake situations, although detailed analysis of the measurements have shown that the peak fatigue loading occurs on the turbine at the end of the row. The simulation tends to over predict the wake affected turbine power deficit for low wind speeds and accurately predict the power deficit for the 12 m/sec case. The details of the methods used, key findings from the measurements and simulation, and the thorough discussions of these conclusions are the subjects of this paper.
Addendum

The simulated results presented in this paper are from the HAWC2 simulation, version 8.2. Recent calibration efforts have been completed successfully which will have an effect on the Dynamic Wake Meandering (DWM) model in the simulation. The wake deficit component of the DWM model has been calibrated more accurately with the actuator line simulation for multiple locations downstream of the wake generating rotor. The wake deficit is now not as severe as it was in version 8.2 and thus the wake deficit recovery behind the turbine occurs faster than it did in version 8.2. This improvement is shown in the recent work of Torben Juul Larsen in comparing the power deficit ratio (Paft/Pfore) at four different turbine separation distances from measurements and from the updated simulation.

The less severe simulated wake deficit will also decrease the tower base fore/aft fatigue loading and it is proposed that it this improvement create a better comparison to the measurements presented in this paper. In this paper, the fatigue loads comparison for the 12 m/sec inflow case, the simulated fatigue loads in the tower are approximately four times the measured loads for a separation distance of 11 rotor diameters. With the new version, this factor will be reduced although it is uncertain as to how much the simulated fatigue loads will be reduced.

Other features of the model that may contribute to the large difference between the measured and simulation fatigue loads include the following:

- Wind turbine controller controls rotor rotational speed to a lower rate than the operational turbine for wind speed range of 5 to 6 m/sec

- The operational turbine has a passive damping device that has small uniform impact on the tower base fatigue loads for all operational wind speeds and this is not included in the aerelastic model. This difference also exists between the simulated and operational turbines for the free inflow or non wake conditions.

- The operational turbine has a smart blade control system that alleviates blade loads during the blade rotation. This is not modeled in the simulation.

- The operational turbine tower/monopile structure has the same free length as the simulated tower structure although tower base is a fixed in translation and rotation boundary condition in the simulation. In operation, the monopile is secured by the seabed and is not considered a rigid connection as is assumed in the simulation.
1 Introduction

Wind energy is among the leading newly installed forms of energy production and is currently is the most common among the newly installed renewable energy sources. In 2008, wind energy was the second highest renewable energy production source behind hydroelectric and was the only significant source of power generation growth in the United States [28]. Also in the United States, 2% of the power generation capacity is now from wind energy and has surpassed power generation from oil-fired power plants [27]. Commercial scale wind turbines of 1.5 to 6.0MW are now being installed all over the world in a variety of climates and sites with varying topographies. These turbines are most commonly installed in wind farms, where a collection of these commercial scale turbines work together to create a wind farm power plant. The size of wind farm power plants can range from less than ten turbines or often up into hundreds of turbines. The wind farm setting introduces a new operating regime for wind turbines; wind turbines operating in the wakes of other turbines. The turbine layout within a wind farm is designed considering the dominant wind direction, land use restrictions, impacts to the environment, and the aesthetics of the wind farm. These design drivers often lead wind farm designers to place turbines in a grid pattern, with an overall orientation to take advantage of the dominant wind direction and maximize energy production. This design choice will produce the situation of turbines operating in single and multiple wake situations. Wind turbines extract energy from the wind and a result of this energy capture is a wake or wind speed deficit downwind of an operating turbine. It is in these wake conditions that turbines and turbine components are subjected to new load cases and turbine designers must account for these common load cases.

Currently, turbines are designed for wake operating conditions considering an increased turbulence intensity in the inflow conditions. The increase of inflow turbulence intensity represents the turbine influenced wind field behind an operating wind turbine. This increase of turbulence intensity and decrease in mean wind speed (caused by the power extraction of the up wind turbine) create a unique loading case that turbine designs must pass in order to be sold in the market. Higher variations in the mean wind speed, or higher turbulence intensities, will cause more dynamic loading on the wake affected turbine and can cause more fatigue damage to turbine components. The current International Electrotechnical Commission (IEC) standard for designing turbines includes the wake effects load case and is implemented in aeroelastic simulations by defining an effective turbulence for the inflow conditions. This approach however, does not take into account any of the large scale ambient turbulence structures that have been shown through experiment to translate the turbine wake structure as the wake structure translates downstream of the operating wind turbine.

A new model, the Dynamic Wake Meandering Model accounts for this lower frequency, large scale ambient turbulence. This large scale ambient turbulence translates the wake deficit in the vertical and lateral directions as it propagates downstream at a rate that matches the mean wind speed. The lateral and vertical translations can cause the wake deficit to interact with a downstream turbine such that the deficit is not centered on the wake affected rotor plane. This effect will cause an uneven loading on the rotor plane and increase the fatigue damage on key wind turbine components such as yaw motors and brakes, gearboxes, blades, and the tower. This effect has been shown to be true in recent aeroelastic simulation results [4] and further validation of these results with field measurements is required. The objective of this paper is to determine using measurements whether or not the meandering wake is creating increased fatigue loading in the key turbine components.

The Dynamic Wake Meandering Model (DWM) has been adopted by the TOPFARM (Next Generation Design Tool for Optimization of Wind Farm Topology and Operation) project as the wake model for performing sensitivity studies regarding the placement of wind turbines at a site considering both the structural loading environment on the turbines and the net power production of the turbines individually and as a wind farm. A key advantage of the DWM is the fact that both the power output of the turbines and loading conditions can be determined simultaneously in an aeroelastic simulation.

Work has been done to verify the meandering model with measurements using the experiment at
the Tjæreborg wind farm in Denmark [1]. A pitot tube was installed on the leading edge of one of the single wake effected turbines to accurately measure the inflow characteristics in the rotor plane. The objective was to determine if the wake affected turbine experienced any partial wake loading situations, that can be determined measuring the inflow angle of attack, thus the relative wind inflow velocity. Cases of low ambient turbulence or low wake meandering were used to identify partial wake situations, where only a percentage of the rotor with the pitot tube is within the wake deficit. Three cases were investigated, free inflow, 1/3 wake, and 2/3 wake and it was shown on a qualitative level that there was close correlation between the simulation and the measurements. Large numbers of measurements are needed to reduce any uncertainties, although the comparison showed both measurements and simulation produced the same trends for both the inflow flow field and the resultant blade flapwise root bending moment versus blade azimuthal position in the rotor plane.

In 2005, an additional experiment using a lidar system mounted on the nacelle and oriented downstream and calibrated to measure the wake flow field at different distances downstream was completed [3]. The objective of this experiment was to measure the wake deficit continuously behind a wind turbine to determine if the deficit translated in either the vertical or lateral directions. This meandering could be correlated with ambient turbulence measurements at the site to show the link between meandering and the ambient turbulence intensity. A close correlation was found between the wake path determined by the model and the actual wake path measured by the lidar system.

A more recent effort was performed by Torben Juul Larsen to compare the loading on wake effected turbines generating by the current IEC design standards and the new dynamic wake meandering model [4]. The objective of this analysis was to determine if any new and unique load cases exist that the current IEC design standard does not include. In this study, a systematic approach of varying the percentage of wake deficit on the wake effected rotor is used to show the impact on key turbine components when operating under different wake deficit percentages. In addition, two separation distances where used to determine if the turbine spacing had any influence on the loading seen by the downstream turbine. A key conclusion was reached that states that with large separation distances between turbines, there is more time for the wake to meander and thus there are more partial wake loading situations in the longer separation distance case. More partial wake situations indicate more dynamic loading on the turbine and thus higher fatigue loading than a turbine that operates in a steady wake as in the closely spaced case.

Further verification of the DWM model is required before the potentially new load cases are considered for inclusion in the IEC standard. The goal of this thesis project is to analyze the structural loads and SCADA measurement data from operating turbines from two offshore wind farms and compare the structural loading results with dynamic wake meandering model wind turbine loading results in HAWC2 aerodynamic simulations. The key objectives of this project are outlined below.

- At what time periods during the Egmond Aan Zee and Horns Rev structural loads measurement campaigns do the single wake conditions exist?
- Are there any methods to estimate fatigue loads on turbines without strain gauge systems by using other available measurements?
- Does the Dynamic Wake Meandering model accurately predict the measured fatigue loads for offshore turbines operating in single wakes?
- How does the fatigue loading in the blades and tower vary as a function of separation distance between wake generating turbine and wake affected turbine?
- What is the effect of the ambient large scale turbulence intensity on fatigue loads?
- How well does the Dynamic Wake Meandering model predict the wind speed deficit and mean power recovery as a function of separation distance for single wake conditions?
These questions are answered by analyzing the structural measurement data from two turbines from Egmond Aan Zee, Netherlands and one turbine from Horns Rev, Denmark, wind turbine ten minute statistics SCADA data from both wind farms, and ten minute statistics data from the met masts located at the wind farms. Chapters 2, 3, and 4 introduce the current wake models, the specifics of the dynamic wake model, and fatigue load determination in wind turbines respectively. In Chapter 5, the wind farms are introduced and the wind vanes and wind turbine yaw angles are calibrated. Chapter 6 covers the performance characteristics of the turbines and presents a unique method of estimating loads in non-instrumented turbines. In Chapter 7, the aeroelastic model is described and the model is compared to measurements; aeroelastic models of the V80 2.0MW and the V90 3.0MW are built in the HAWC2 aeroelastic code. Chapter 8 covers the analysis of the wind farm data to identify single wake cases as well as presents structural fatigue loading results from the measurements. Lastly in Chapter 9, the general trends from the aeroelastic simulations are compared to the measurements and the differences are discussed.
2 Wind Turbine Wake Models

The wake models currently used in the industry wide software packages are presented in this chapter. The performance against measurements for each model are also discussed and the need for an integrated wake model that both handles structural loads and turbine power production is shown.

2.1 Applications of Current Wake Models

Wind turbine wake models are an important aspect that must be included in the wind farm layout and wind resource software used to design and analyze the performance of wind farms. Wind turbines are no longer installed by themselves; wind turbines are grouped into large wind farms that act as clean and reliable power stations to the local electric grid. Thus, wind turbines are commonly operating in single and multiple wake deficits of other turbines during the operational lifetimes. Wind turbine wakes both introduce a wake deficit or reduction of wind speed downstream as well as an increase in the turbulence intensity which will cause an increase in fatigue loading of downwind turbines. A wake model has two objectives, 1.) produce the inflow wind speed conditions for energy production purposes, and 2.) produce the correct time scales of variations of the inflow wind speed for wind turbine structural loading purposes. Currently, these two features are handled separately in the design of a wind farm, each one with its own set of models to use. Currently, four different wake loss models are used in industry and one wake added turbulence model is used to design wind turbines for operation in wakes of other turbines. These models are discussed below.

2.1.1 Wind Farm Energy Production

The three main commercial wind farm design and wind resource assessment software packages (WindPRO [21], GH WindFarmer [20], and WASP [22]) all have engineering models of wind turbine wake losses implemented. There are four main wake models used in the industry for analysis of energy production from a wind farm. The N.O Jensen model, the Ainslie Eddy Viscosity model, the G.C Larsen model, and the Frandsen Semi-Linear model are all designed to model the wake deficit behind an operating turbine and produce the inflow wind speed over the downstream rotor at any specified distance. These models focus on determining the wake deficit width as well as the mean wind speed across the deficit. The models also account for the interaction of multiple wakes and create a composite wake deficit at the downstream turbine location. Given a specified site with given wind climate and wind rose, studies can be done using these models to determine the ideal layout that minimizes wake loss and maximizes energy production. A few details from each model are discussed below.

N.O Jensen Model The N.O Jensen model [23] has been adopted into the WASP and WindPRO software packages and primarily focuses on determining the mean constant wind speed of the deficit and wake deficit width. The deficit is assumed to be a flat top shape, with a constant wind speed across the wake deficit creating the bowl of the hat and the mean ambient wind speed creating the rim of the hat. The deficit is primarily driven by the thrust coefficient of the turbine. The higher the thrust coefficient, the more severe the initial wake loss. A high thrust coefficient indicates a high drag of the turbine on the free stream wind, thus the maximum amount of energy is extracted out of the wind at wind speeds where the thrust coefficient is maximum. The wake deficit decay is modeled using a decay factor, k and two values (k=0.075, k=0.05) are recommended for onshore and offshore respectively. This term is designed to specify the rate of wake deficit recovery back to ambient mean wind speed and the two values for on and offshore represent the on average faster recovery of wake deficits onshore than offshore.

Ainslie Eddy Viscosity Model The Ainslie model is a two-dimensional axi-symmetric model that is applied at the end of the near field of the wake region. The model solves the momentum and continuity equations with an eddy-viscosity closure [13]. This model focuses on the wake deficit from
this boundary and into the farfield where wake interaction with other turbines can occur. An empirical model for the near field wake deficit is used as the initial conditions to this model. This model has also been designed to handle the slower recovery of wakes in the offshore environment by reducing the initial wake deficit width as the input wake deficit. The initial wake deficit is Gaussian in shape and is a function of the ambient turbulence and the rotor thrust coefficient.

**G.C Larsen Model** The G.C Larsen wake model is known as a semi-analytical model based on asymptotic expressions from Prandtl's rotational symmetric boundary layer equations. The initial wake deficit in the near wake region can also be modeled as a bi-modal deficit shape [15].

**Frandsen Semi-Linear Model** Both the nearfield and the farfield wake deficits are modeled in this model with empirical expressions for wake deficit width and wake deficit wind speed. Again, the wake deficit is assumed to be a top hat in shape and the Mosaic tile method is used to combine multiple wakes to create one wake deficit. The wake deficit is defined as a function of the wake generating rotor thrust with increasing deficit with increasing thrust. The wake deficit area is determined by a power law expansion and takes into account extra wake expansion when the wake passes a nearby rotor. The tile method takes these two wake parameters for each separate wake at the downstream rotor and merges them into one wake. The relative difference between the deficits are summed for all combinations of wakes to generate a composite wake deficit over the wake affected rotor area [24]. The wake expansion parameter, α is used to model the wake expansion and recovery as the deficit translates downstream. This parameter, α is a function of the thrust coefficient and the ambient turbulence although it has been shown that the large variation in this parameter required to match measurements indicates that the wake expansion may not be modeled properly [14].

2.1.2 Wake Model Performance

Each of the above mentioned wake models has advantages and disadvantages and it is important to understand these to identify a need for a new wake model like the Dynamic Wake Meandering model. The N.O Jensen wake model in WASP has been shown to match Horns Rev offshore wind farm measurements more closely than the GH WindFarmer Eddy Viscosity model [26]. In this paper, the G.C Larsen and the Eddy Viscosity models both tend to underpredict the power deficit and thus over predict the power production for turbines deep in a wake situation. However, a recent presentation by Lars Landberg of Garrad Hassan [25] illustrates the new internal boundary layer model of the WindFarmer Eddy Viscosity model and the noticeable improvement in predicting power output from turbines deep in a wake situation. With the improvement, the Eddy Viscosity has a better agreement with measurements for turbines deep in a wind farm although slightly underpredicts the power deficit for the first few rows of turbines. Before this improvement was added, the Eddy Viscosity model in a non perfect wake alignment case tended to under estimate deficit at further distances and have a close agreement at close distances. The WindFarmer model is capable of running thousands of scenarios in a timely manner due to the empirical components of the model that complement the CFD calculation of the velocity deficit. The WASP package is limited in the wind directional sectors of 30 degrees, thus studies are restricted to this resolution. The WindFarmer package has links to the Garrad Hassan Bladed package where the inflow conditions can be simulated within GHBladed to estimate loads.

2.1.3 Wind Turbine Structural Loads

The second component of a wake model is the model for increased wake turbulence and wake deficit movement that will affect the loading on the downwind turbines. Currently, turbines are classified for the different IEC wind climate classes and to pass certification in each class, the turbine must pass a design load case that tests the turbine operation in single or multiple wakes of other turbines. Currently, the design load case for increased loading in a wake condition is based on an effective turbulence intensity. Full details of this design load case are provided in Annex D, [16]. For turbine
separation distances less than 10 rotor diameters, the effective turbulence intensity is defined as a function of the number of neighboring turbines, the added wake turbulence which is a function of the rotor thrust coefficient, the material Wöhler curve slope, and the inflow wind speed. For distances greater than 10 rotor diameters, the ambient turbulence intensity is assumed to affect the loading on the wake affected turbine. The effective turbulence intensity drops as a function of turbine separation distance and there is no length scale associated with the turbulence intensity. In addition, there is no component of this design case that specifies a situation with a prolonged gradient in turbulence intensity across the rotor. This model is sufficient for fatigue load determination only and will not determine ultimate loads.
3 Dynamic Wake Meandering Model

In this chapter, the Dynamic Wake Meandering Model is presented and it is shown to meet the needs of an integrated power production and loads wake model identified in the previous chapter. The key components of this model are presented and how the model has been implemented in the HAWC2 aeroelastic simulation is discussed.

3.1 Background and Introduction to Dynamic Wake Meandering

Wind turbines in principle are designed to extract energy out of the wind through transforming aerodynamic loads acting over airfoils, to rotational energy, and finally to electrical energy through the generator. A by-product of the wind turbine presence in an air flow is a wake, which can be described as a flow with a decreased mean wind speed from the inflow wind speed and an increased turbulence intensity. According to the Blade Element Momentum method, the wake deficit is known at the rotor plane as well as at the beginning of the farfield region, or approximately three rotor diameters downstream. The BEM method provides the induction factors, a along the radius of the blade and given these induction factors and the inflow wind speed, \( U_0 \), the mean wind speed at each section of the blade at the rotor plane \( U = (1-a)U_0 \) and three rotor diameters downstream \( U = (1-2a)U_0 \) can be determined. It is the job of the previously mentioned wake models to determine the wake deficit and a turbulence intensity further downstream. Turbulence intensity is defined as the standard deviation of the wind speed over the mean wind speed and turbulence intensity can be a vector quantity. A turbulence intensity can be determined for the three orthogonal axes if an appropriate sensor is used. The exchange of energy from the wind to the rotating blades of a horizontal axis turbine is responsible for the reduction in mean wind speed and the increased turbulence intensity is a function of the blade root and tip vorticities. The wake structure and path as is translates downstream can have varying effects on downstream wind turbines.

The wake meandering effect on wind turbine wake deficits has been studied by Taylor et al [18] where he correlated the wake meandering with the variability in the mean wind direction. Ainslie [17] worked further on this correlation and proved with field measurements the effect of wake meandering on the averaged wake velocity deficit. Since the wake velocity deficit has a known shape and is also shown to change shape as a function of downstream distance from the wake producing rotor a time or spatial average of this deficit can be determined assuming movement of this deficit perpendicular to mean wind direction. In unstable atmospheric conditions, high turbulence intensities, wake deficit measurements showed a less dramatic wake deficit at a particular distance downstream. This finding was linked to the meandering of the wake, causing a smearing of the velocity troughs in the deficit to create a more uniform velocity deficit. This experiment illustrated that a wake deficit may not always intersect a downstream turbine such that the deficit center is aligned with the rotor axis. A thorough and more detailed model of this phenomenon was needed both to study this meandering effect as well as study any unique wind turbine structural loading scenarios that may be introduced by a meandering wake.

3.2 Dynamic Wake Meandering Components and Physics

The dynamic wake meandering model has been under development at Risoe National Laboratory for Sustainable Energy, in Roskilde Denmark. Model development, experimental verification of the model and elements of the model, and integration of the model with the in house wind turbine aeroelastic simulation, HAWC2 are among the research activities that been completed or are currently being worked on. The key attributes of a wake structure, 1.) the wake velocity deficit, 2.) the added wake turbulence, and 3.) the low frequency meandering wake translation are integrated to create the dynamic wake meandering model.
3.2.1 Wake Velocity Deficit

The velocity deficit is determined by first making a key assumption that the inflow wind field to the wake producing turbine is uniform. In other words, there is no vertical or horizontal shear component in the wind field, thus the wake velocity deficit will be rotationally symmetric. The key steps in determining the deficit size and shape as a function of downstream distance include calculating the induced velocity, or axial induction factor, determining the wake expansion in the near wake region (1-2 rotor diameters), and determining the attenuation (slow return back to mean inflow wind speed) of the deficit. The axial induction factor or induced velocity is the term that relates the inflow wind speed to the wind speed immediately behind the rotor. The blade element momentum method is a method wind turbine design engineers use to determine the axial induction factor of a particular wind turbine blade and aerodynamics design. The attenuation of the deficit back towards the unaffected wind field is a function of the ambient 'mixing' turbulence and the shear between the wake deficit and the free stream wind speed around the boundaries of the translating wake deficit.

3.2.2 Added Wake Turbulence

The primary sources of the added wake turbulence are the root and tip vortices from the spinning rotor. These structures eventually break down and form high frequency turbulence intensity structures that contribute to the increased wake turbulence, or added wake turbulence. This high frequency, small spatial scale turbulence can also be generated by the wake shear, or difference in mean wind speed and turbulence between the wake and the free stream along the boundaries. The added wake turbulence will have a higher turbulence intensity than the surrounding or ambient turbulence and have a length scale on the order of 1.5 rotor diameters [5]. The added wake turbulence is calculated for each wake deficit that is calculated and these two structures travel together according to the large scale, lower frequency ambient turbulence discussed below.

3.2.3 Low Frequency, Large Scale Meander Turbulence

The most crucial aspect of the dynamic wake meandering model is determining the meander turbulence, or the large scale turbulence structures that act to translate the wake deficit and added wake turbulence as the wake propagates down stream. As stated by Gunner C.Larsen et al [2] "we consider wake meandering as being the primary result of large scale air movements, where the downstream evolution of the wake deficit position can be modeled, by considering the wake deficit as being a passive tracer transported in a large scale turbulence field". A low pass filter is introduced in the ambient turbulence field that allows turbulence structures with a spatial scale of approximately two times the wake deficit diameter to drive the meandering of the wake deficit and added turbulence. Since the wake deficit diameter expands as it propagates downstream, the highest meander drive frequency is used by assuming the wake deficit diameter to be diameter just downstream of the rotor. Frequencies lower than this frequency will be included in the turbulence boxes used to drive the wake in the vertical and lateral directions.

As far as the propagation rate of the wake deficit downstream from the wake producing turbine, Taylor's Hypothesis is assumed. Taylor's Hypothesis states that the propagation due to turbulence in the mean flow direction is small compared to the propagation caused by the mean flow itself, thus a turbulence field and wake deficit will propagate according to the mean flow speed. The wake is assumed to translate as a unit or slice at a velocity equal to the mean ambient free stream wind speed. The cut-off frequency associated with the low frequency large scale turbulence eddies that are responsible for the meandering is a function of the wake deficit width. Since this width changes as a function of downstream distance, the cut-off frequency should be variable with downstream distance. Figure 1 illustrates the vertical and horizontal wake meandering.
3.3 DWM Implementation in Wind Turbine Aeroelastic Simulation

The dynamic wake meandering model is implemented in the HAWC2 aeroelastic code and a number of parameters can be adjusted to analyze different wake conditions. The model requires three turbulence boxes, one for the meandering, one for the added wake turbulence, and one for the ambient turbulence. The structure and length scale of these boxes can be customized to match the site specific conditions. Weights are given for the turbulence components in the three orthogonal directions for each turbulence box. The rotational rate and the pitch angle of the wake source turbine are specified as well to provide the conditions to generate the initial wake deficit. Scaling parameters are included that model the affect of the velocity gradient within the deficit on the wake recovery and these have been tuned according to measurements and thus are not changed for the analysis presented in this paper. Another key parameter is the wake meandering turbulence intensity. This is a site specific parameter and should be matched a closely as possible to measurement conditions. The sensitivity of this parameter on wind turbine equivalent loads is discussed in this paper. The separation distance between the source turbine and the wake affected turbine is also adjustable and the wind turbine fatigue loads sensitivity to this parameter are also presented in this paper.

3.4 HAWC2 Modeling Assumptions

The assumptions made in the modeling of the wind turbine wake generation and transport are key to identify and a discussion of the impacts from each on the results is provided. The wake model in HAWC2 is an engineering model that has been validated against higher fidelity simulations and measurements. The hi-fidelity engineering model allows for faster run speeds and is a great set up for parametric analysis similar to what was presented above. The key model features can be determined by performing parametric studies across an array of possible input conditions. A list of the major assumptions made in the simulation is provided below.

- Uniform inflow with no shear component is used for generation of the wake deficit
- Wake deficit is assumed to be axisymmetric
- Ambient turbulence intensity does not vary with height
- Flow velocities outside of wake deficit assumed to be of the ambient inflow wind speed. In reality, the wind speed surrounding the wake will be accelerated slightly above the inflow ambient mean wind speed.
- Wake deficits assumed to translate down wind at rate corresponding to mean ambient wind conditions
- Scaling parameters of wake deficit and wake deficit gradient are fixed for all operating conditions of the turbine.
- In far wake regime, wake expansion is driven by wake deficit velocity shear and the ambient turbulence. Ambient turbulence in a wind farm may be increased relative to the inflow ambient turbulence.

![Power Law Wind Speed Profile](image)

**Figure 2: Power Law Wind Speed Profile**

A non-uniform wake deficit that can occur in operation due to the inflow wind shear across the wake generating rotor will not be axi-symmetric and thus there will be an additional wind shear component in the deficit from top to bottom. Figure 2 is included to show the difference in wind speed profiles for different power law exponents. This additional shear component may aid in the recovery of the wake as the deficit translates downstream. The deficit is also assumed to translate as a slice downstream with a mean velocity of the ambient mean wind speed. In operation, there will actually be a tunnel of higher wind speeds down the center of the deficit and slower wind speeds along the radius of the deficit associated with the aerodynamics of the rotor. There will be another shear component between this higher inner wind speed and the lower wind speeds in the outer radius which will cause an additional source of turbulent mixing that will help recover the wake deficit. Another key assumption is the uniform turbulence intensity for all heights. However, it has been shown that in both Horns Rev and Egmond Aan Zee wind farms, turbulence intensity is sensitive to heights for operational wind speeds. More turbulent mixing may occur due to the shear in turbulence intensity that would again help recover the deficit in operation. The simulation deficit may tend to take longer to recover because these additional mixing components are not included.

### 3.5 Applications

The dynamic wake meandering model is inherently a model that can be used to simultaneously study the effects of a meandering wake on downstream turbine structural loading and power production. The model maintains the required wake structures to accurately model the wake influence on the loading of the different turbine components. The model also maintains an accurate representation of the mean
wind speed flow field which will have an influence on the power production of the wake affected wind
turbine. The dynamic wake meandering model can be implemented in a wind farm design software and
analysis can be done considering turbine placement and the power production and structural loading
on the turbines. Wind farms are currently designed to maximize energy output, not considering the
wear and tear or fatigue on wake affected turbines. The wind turbine spacing is typically driven by
the manufacturers siting recommendations.

In addition and perhaps most importantly, the wake meandering phenomenon may be creating
load cases on turbines that are currently not considered in the IEC wind turbine design and testing
standards. Torben Juul Larsen wrote a paper [4] on the topic of how the fatigue loads change when
using the Dynamic Wake Model compared to the IEC wake load case. For instance, a prolonged period
of time with a partially wake affected rotor (caused by meandering of the deficit) may lead to uneven
loading and wear on the main shaft bearings, the yaw motors and brakes, as well as fluctuating tower
torsional loads. Smarter turbine control algorithms could also be developed to alleviate the loads on
a partially wake affected rotor. Blade pitch angle could be a function of rotor azimuth position if a
particular turbine is known to be operating in a partial wake situation. These partial wake situations
could be identified for each wind farm and smarter wind farm control could be implemented to al-
leviate loads on the wake affected turbines by deregulating the turbines or turning off completely the
wake affected turbine to prevent a high fatigue loading situation.
4 Fatigue Load Determination for Wind Turbines

The method of determining the fatigue life consumption of a particular wind turbine component using the measured time series of component loads is discussed. The equivalent load metric is used in this paper for comparing simulation results to measurements.

4.1 Introduction to Fatigue

Fatigue of a wind turbine component is defined as the consumption of reliable lifetime of the component due to operational loading cases throughout the lifetime of the turbine. Different materials lose their structural properties at different rates over their operational lifetime though the primary driver of material fatigue is the loading environment the material is subjected to. For instance at the root of a blade, the leading and trailing edge of the blade see a cyclical loading due to the position of the blade in the rotational plane of the rotor. The time series of the bending moment of the leading edge section at the root will look like a sine wave, tension or positive bending moments in one section of the rotational plane and compression or negative in a position 180 degrees from the positive location. This alternating or varying loading profile (in this case due to gravitational loading) will be the dominant source of fatigue loading for lead lag root position of the blade. Not all loading will be cyclical in nature, thus a method is required to essentially count the number of cycles that occur within different stress ranges.

4.2 Rainflow Counting Method

The rainflow algorithm is used to count full cycles and half cycles of a loading time series from any component of the turbine with structural measurement channel installed. The first step of the algorithm is to remove the noise that does not define a local minimum or local maximum. These small bumps and troughs in between the local extreme minimums and maximums in the time signal are assumed to not contribute to the overall fatigue loading of the component. The output of the rainflow algorithm is a histogram of the number of cycles and half cycles that occur in the different stress ranges within the given time series. A metric called an equivalent load is then calculated using this histogram and direct comparisons between different time series of measurements for the same component can be compared on the same level with this equivalent load metric.

4.3 Equivalent Loads

The equivalent load metric has a time scale associated with it and is used to represent the loading of a component that occurs over a given time series. Typically in the wind turbine industry, time series of 10 minutes are monitored and stored each 10 minutes on an instrumented wind turbine. Applying the rainflow algorithm to each 10 minute time series will yield the histogram of number of full and half cycles that occur with the different stress ranges in the series. This time series represents a certain loading profile with a varying cyclical frequency although this can be represented using a constant loading (equivalent load) that if applied at a 1 Hz frequency, would represent the same amount of loading. The equivalent load applied at 1 Hz produces the same fatigue damage as the original 10 minute time series. 1 Hz is most commonly used in the wind turbine industry, thus this will be used in the results presented in this paper. The equation used to determine the equivalent load as specified in [9] is shown below. $R_{eq}$ is the equivalent load, $R_i$ is the stress range of the $i^{th}$ class of the fatigue spectrum, $n_i$ is the number of cycles in the $i^{th}$ class of the fatigue spectrum, $n_{eq}$ is the equivalent number of cycles, and $m$ is the material specific S-N curve slope.

$$R_{eq} = \left[ \sum R_i^{m} \frac{n_i}{n_{eq}} \right]^{1/m}$$
The S-N curve is material specific and it presents the relationship between the stress range, S and the number of cycles that it would take to reach failure, N for different mean stress ranges. One key important fact of the equivalent load calculation is that it does not take into account the mean stress of a given loading time series. Typically, values for m for steel and fiberglass range between 3-5 and 8-12 respectively. If not mentioned, m=3 and m=10 for steel and fiberglass respectively in this paper.

4.4 Wind Turbine Component Equivalent Loads

The loads of key components of the wind turbine that are typically investigated are the blade root bending and torsion in both lead-lag and flap directions, main shaft bending and torsion, tower top torsion and fore/aft and side to side bending, and tower base torsion and fore/aft and side to side bending. Strain gauges are mounted at key locations on the different components and given the strain, material elastic modulus and other material properties, and the component geometry, bending and torsional moments can be calculated. It is these signals that are often used to determine the equivalent loads thus the units of equivalent loads are kNm. More details of the specific locations of the measurement sensors on the turbines used for this project are provided in the Appendix.
5 Wind Farm Data Setup and Analysis

The Egmond Aan Zee and Horns Rev wind farms are presented in this chapter. Also, identification of the time periods of wake and free stream conditions acting on the instrumented turbines is essential before measurements can be extracted from the large database and compared to simulation. Wind vanes and wind turbine yaw angle sensors are known to have time varying offsets and this chapter is included to present methods of determining these offsets and provide corrections such that the sensors can be used to assess wind direction.

5.1 Egmond Aan Zee Wind Farm, Netherlands

5.1.1 Wind Farm Description

The Egmond Aan Zee wind farm is the first large commercial scale offshore wind farm in the Netherlands with energy production starting in January 2007. The 108 MW wind farm was built in a collaborative effort from Nuon and Shell and consists of 36 Vestas 3.0 MW V90 wind turbines installed on monopile foundations. The wind farm is located between 10 and 18 km from the coastal town of Egmond Aan Zee in the Netherlands and is anticipated to produce enough annual energy to supply 100,000 typical households, or 1.5% of all Dutch households.

One meteorological mast is located at the site and is located in the free stream of the dominant wind direction for this site, a wind direction from the southwest. Figure 3 shows the wind resource statistics at hub height for the first six months of operation in 2007. The wind farm is oriented to take advantage of this dominant wind direction as shown in the following figure. The site for this period has a 70m mean wind speed of 9.4 m/sec from a wind direction bin 225 degrees to 255 degrees [19]. For the measurement between between June 2005 and July 2006, the yearly average 70m wind speed is 8.8 m/sec and the dominant wind direction is between 195 and 225 degrees [19].

![Wind Resource Statistics](image)

Figure 3: Hub Height Wind Resource 1/2007 to 6/2007

Figure 4 also outlines the turbines that will be considered in this project. Two wind turbines (WT), WT 7 and WT 8 are instrumented with additional structural measurement sensors compared to the other turbines. These two turbines are located in the southwest most row of turbines and
are closest to the met mast. Two other turbines, WT 21 and WT 29 have been identified as the wake producing turbines that will create the single wake conditions sought after for this project. The spacing and the orientation between each of the single wake cases are also provided in the figure. For instance, the distance spacing between WT 21 and WT 8 is 13 rotor diameters and these two turbines are aligned along the 15/195 deg orientation. The distance spacing between WT 21 and WT 7 is 18 rotor diameters and these two turbines are aligned along the 356/176 deg orientation. In the titles of the figures of the wind farms, D refers to the separation distance in rotor diameters, and deg refers to the wind direction for a perfect wake alignment. For example, there is a 18D separation between WT 7 and WT 21 and the wind direction for perfect wake alignment of WT 7 in the wake of WT 21 is 356 degrees. The black diamond markers indicate the two turbines with the full structural instrumentation sensor system, the green markers indicate the single wake producing turbines on the two instrumented turbines, and the blue crosses represent the other turbines in the wind farm. The met mast is identified with the red square marker. The coordinates are expressed in the standard UTM, Zone 31 European Datum 1950 (UTM31 ED50) coordinate system used in Europe that represents a true curved surface of the globe on a 2D piece of paper.

![Diagram of Egmond Aan Zee Offshore Wind Farm](image)

**Figure 4: Egmond Aan Zee Offshore Wind Farm**

The structural measurements are recorded at a 32 Hz rate and measurement strains and accelerations in key components of the turbine. A total of 47 extra channels for WT 7 and 54 channels for WT 8 are available for determination of loads in the different turbine components. The structural measurement data is available from 2/2007 through 12/2007 and 5/2008 through 9/2008. In addition to the high resolution structural measurement data, the 10 minute statistics SCADA data from all the turbines is available for period of 4/2007 through 12/2008. The typical SCADA measurements exist in the data set: power, rotor RPM, generator RPM, nacelle wind speed, and nacelle orientation. More details are provided in the Appendix. The third and final data set for this wind farm are the 10 minute statistics from all sensors on the met mast from 1/2007 through 12/2008. The met mast consists of three measurement levels, each level has three branches (south, northeast, and northwest), each branch with a Mierij Meteo KNMI Anemometer model 018 and Mierij Meteo KNMI wind vane model 524. The northwest branch at all three measurement heights has a Gill 3 Axis Ultrasonic Meteorological Anemometer.
Before the measurements from the wind farm can be used to identify unique wake and free inflow conditions, each of the sensors needs to be characterized such that any fixed or time varying offsets are known and can be corrected for prior to using the data. For instance, met mast wind vanes in the offshore environment can be difficult to install such that the zero point is aligned with North, thus there is often small misalignment errors associated with this mounting issue. Also, the yaw angles for the wind turbines at Egmond Aan Zee are defined as positive counter clockwise and all the wind directions from the met mast are defined using the standard zero North and positive clockwise. If the yaw angle sensors are to be used as filter sensors, the definition must be corrected. In addition, the yaw angle measurements have offsets as well and the zero point has been shown to change in time. This preliminary analysis is essential to ensure are the wind conditions are correct and the turbines are operating in a configuration that is expected.

5.1.2 Determination of the Meteorological Mast Wind Vane Installed Offsets

Method 1:
The installed offsets for the met mast wind vanes at all three measurements heights need to be determined to ensure there are no biases in the measured wind direction. The wind vane is ideally installed so that a zero reading occurs when the wind comes from due north, although this is not always the case as it is very difficult to install a wind vane to high accuracy while at sea and at measurement height. Each wind vane at each measurement height is tested to identify any fixed biases in wind direction measurement. The general definition of the offset, $\Theta$ for the met mast wind vanes is shown below.

$$\Theta = \Theta_{Measured} - \Theta_{Truth}$$

$$\Theta_{MM} = \Theta_{WindVane} - \Theta_{WindFarmGeometry}$$

The first approach to identifying these installed offsets involves knowing the geometry of the wind farm (turbine locations) and the principle that the variation in output power over the mean power is highest when a turbine is operating in the wake of another turbine. A metric of power turbulence intensity is plotted versus wind direction and it is expected that this power turbulence intensity is maximum for a perfect wake alignment. The increased turbulence intensity from the wake generating rotor will yield a higher variation on the output power from the wake affected turbine. To some extent, the variations in wind speed will be averaged out of the rotor area although it is proposed that this power turbulence intensity will be maximum for perfect wake alignment. Figure 5 shows the clear peak in power turbulence intensity of a turbine in the wake of another turbine. The first row of turbines (southwest most row) is aligned with the 135 to 315 degree orientation. If we plot the variation in the output power over the mean power for wind turbine 8 (closest to the met mast) versus the wind direction measured from a met mast wind vane for small wind direction bins of 1 deg, the peak in power variation orientation can be compared to the geometry of the wind farm. The query requirements for this method include and wind speed requirement of 5 to 10 m/sec as measured by a 116 m met mast anemometer, a wind direction requirement from the met mast sensor under study between 300 and 350 degrees, and a greater than zero power requirement on WT 8. This method works quite well for all wind vane sensors and the results, or fixed biases (difference between measured and true) of the measured wind direction by the wind vanes are shown in Table 1 below. More details are provided in the Appendix regarding the type and location of each sensor.

Figure 5 below an example of applying this first method to determine the wind vane installed offset. A smoothing filter is used to smooth the data and provide a more clear estimate of the true offset. The width of the window was started at +/- two data points although this filter width provided a smoothed result that followed the varying data too closely. Thus, the window size was increased to +/- three data points and this was shown to provide an accurate estimate for all sensors investigated. The figure shows the 1 degree offset from the wind farm geometry of 318 degrees found for
the WD 524/NE/21 wind vane. There are two sub peaks to the main peak and these are attributed to the slightly higher power turbulence intensity for partial wake affected rotor. These peaks will be symmetrical about the perfect wake alignment though thus the offset can still be estimated accurately.

![Power Variation Intensity for Wind Turbine 8](image)

**Figure 5:** Offset between measured wind (WD 524/NE/21) direction and wind farm geometry

**Method 2:**
A second approach can be used to determine the wind vane offsets as a check and to ensure no wall effects have created a measured wind direction bias in the first approach mentioned above. The turbines are essentially a roughness element in the air flow and as a wind front approaches a wind farm, the wind senses the wind farm and can change locally directions. Because the met mast is located downstream of a line of turbines and the wind direction is along the line of turbines, the turbines can actually introduce a change in wind direction along the boundary of the line of turbines, causing the wind vane to incorrectly measure the wind direction. This is an example of a wind turbine wall effect. Method two uses the wind farm geometry, free inflow conditions to the wind vanes, and the power deficit that is known to occur for turbines operating in the wakes of other turbines.
For instance, the wind direction can be collected from a wind vane sensor and the power can be extracted for wind turbine 21. Also ensuring wind turbine 8 to be operating and selecting mean wind speeds from the cup anemometer located next to the wind vane under investigation, the power of wind turbine 21 can be plotted versus 1 deg wind direction bins, as measured by the wind vane under study. Ideally we would like to use wind turbine 8 to test the N/W and S wind vanes and wind turbine 7 to test the N/E sensor. This is done to ensure the wind vane is not influenced by the wake of the met mast for the wind directions considered. Although, the large distance of 18D spacing between turbine 7 and 21 and few returned samples does not provide a clear picture of how the power drop is oriented relative to the wind farm geometry. The trough in the power at the wind direction the drop occurs at is compared to the geometry of the wind farm, 196 deg orientation (wind turbine 8). The query requirements for this approach include a met mast wind direction between 187 and 212 degrees, and WT 8 power requirement between 1000 and 2000 kW, and a WT 21 power requirement between 500 and 2000 kW. The slightly lower power requirement (500 kW) for WT 21 allows for the cases where a power deficit has occurred because of the operating WT 8 upwind. The offsets for each wind vane determined using this approach are shown below in Table 2 As an example, for wind vane WD 524/S/116 a true wind direction from 90 degrees will be measured by this wind vane as 92 degrees.

<table>
<thead>
<tr>
<th>Sensor Name</th>
<th>Height</th>
<th>Offset (deg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WD 524/NW/116</td>
<td>116</td>
<td>0</td>
</tr>
<tr>
<td>WD 524/NE/116</td>
<td>116</td>
<td>1</td>
</tr>
<tr>
<td>WD 524/S/116</td>
<td>116</td>
<td>2</td>
</tr>
<tr>
<td>WD 524/NW/70</td>
<td>70</td>
<td>-1</td>
</tr>
<tr>
<td>WD 524/NE/70</td>
<td>70</td>
<td>-4</td>
</tr>
<tr>
<td>WD 524/S/70</td>
<td>70</td>
<td>-3</td>
</tr>
<tr>
<td>WD 524/NW/21</td>
<td>21</td>
<td>-4</td>
</tr>
<tr>
<td>WD 524/NE/21</td>
<td>21</td>
<td>-2</td>
</tr>
<tr>
<td>WD 524/S/21</td>
<td>21</td>
<td>-1</td>
</tr>
</tbody>
</table>

Figure 6 below shows the wind vane offset for the WD 524/NW/70 sensor relative to the calculated wind turbines 8 and 21 geometry. Here, the trough in the mean power of wind turbine 21 is plotted versus wind direction bin. The similar smoothing filter as described in the first method is used to smooth the raw power data to extract the actual position of the trough in power. The offset is found by comparing the trough to the wind farm geometry between wind turbine 8 and wind turbine 21 of 196 degrees.

The measurement accuracy of the wind vane sensors is 1.4° [1] thus a few of the resultant offsets obtained using either of the two methods fall within this sensor measurement resolution. The total offset is a function of the mean installed offset and the fluctuations about this mean caused by the uncertainty of the sensor. Thus, the offsets are not fixed. For example, the offset for the WD 524/NW/21 sensor using the second method is −4° ±1.4°. The offsets calculated using the first method may be affected by wind farm wall effects, thus the offsets calculated using the second method are used to correct these wind vane measurements.

5.1.3 Determination of the Wind Turbine Installed Offsets

A similar installed offset may and will probably exist for each of the wind turbine yaw sensors. For the Egmond Aan Zee wind farm, the yaw measurement is defined as positive in the counter clockwise direction, yet the met mast definition for wind direction is the typical positive clockwise. For the wind turbines, zero degrees is north and 90 degrees is defined as west instead of the typical east. Both systems assume zero degrees starts at north although offsets have been found for the four turbines of interest at the Egmond Aan Zee wind farm. Throughout the paper, the displayed wind turbine yaw angle will be the corrected angle in the positive clockwise frame with 0 degrees north and 90 degrees
Figure 6: Offset between measured wind (WD 524/NW/70) direction and wind farm geometry

east. The definition of the wind turbine yaw angle offset is shown below. $\Theta_y$ refers to the wind turbine yaw angle and $\Theta_i$ refers to the corrected wind vane measurement or truth.

$$\Theta_{WT} = \Theta_y - \Theta_i$$

A met mast sensor with high availability is used and considered as truth since it is corrected based on the analysis discussed above. Since we are interested in a time history of any potential offsets of the WT yaw measurements, we need a reference sensor that is available for the entire time period we are interested in for the wind turbine yaw angle. The three 116 m wind direction sensors are checked for availability and it was found that the N/W and the S sensors have 74.5% and 76.5% availabilities respectively. Other met mast sensor availabilities are provided in Table 3 below. The other N/E sensor at 116 meters has a 62.5% availability for the time period and in addition, this wind vane will be in the shadow of the met mast for the wind directions of interest for this analysis. A higher variation of the wind direction for this sensor for these wind directions can be expected due to the increased turbulence in the shadow of the mast. The N/W wind vane is used as the reference sensor for determining the time varying offsets of the WT yaw angle measurements.

The technique used to determine these offsets includes extracting the wind turbine yaw angle, the corrected met mast wind direction measurements, and requiring the wind turbine to be operating. The wind direction requirement is placed on the met mast sensor and free inflow angles for the met mast sensor from 235 to 260 degrees are used. This wind direction window was chosen for two reasons, it is a free inflow wind direction bin and the wind is also unaffected by neighboring turbines (wall effect). The WD 524/NW/116 is used for comparison to each of the wind turbine yaw angle measurements. The met mast wind direction is plotted against the wind turbine yaw measurement and a relationship is determined between these two sensors. A least squares fit to the data is used to generate a best relationship between the two signals. The offset is adjusted until the slope is very near one and the intercept is zero. Since the met mast sensor is corrected and considered to be truth, the relationship to wind turbine yaw angle will correct the wind turbine yaw angle measurements into the standard
Table 3: Met Mast Sensor Availability

<table>
<thead>
<tr>
<th>Sensor Name</th>
<th>Height</th>
<th>Availability (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WD 524/NW/116</td>
<td>116</td>
<td>74.5</td>
</tr>
<tr>
<td>WD 524/NE/116</td>
<td>116</td>
<td>62.5</td>
</tr>
<tr>
<td>WD 524/S/116</td>
<td>116</td>
<td>76.5</td>
</tr>
<tr>
<td>WD 524/NW/70</td>
<td>70</td>
<td>65.2</td>
</tr>
<tr>
<td>WD 524/NE/70</td>
<td>70</td>
<td>58.6</td>
</tr>
<tr>
<td>WD 524/S/70</td>
<td>70</td>
<td>60.6</td>
</tr>
<tr>
<td>WD 524/NW/21</td>
<td>21</td>
<td>75.3</td>
</tr>
<tr>
<td>WD 524/NE/21</td>
<td>21</td>
<td>67.1</td>
</tr>
<tr>
<td>WD 524/S/21</td>
<td>21</td>
<td>73.6</td>
</tr>
</tbody>
</table>

wind direction frame. Wind turbines 7, 8, 12, 21, and 29 were analyzed and the process and results are discussed below.

The analysis is focused in the two instrumented turbines and the two potential wake producing turbines. Queries into the database can be corrected using the offsets found to ensure the cases returned are what the analyst was looking for. Wind turbine 7 was found to have a small offset of 4.4 degrees relative to the corrected wind direction measurements from the met mast. The offset of 4.4 degrees the wind turbine measuring a slightly larger wind direction than the true wind direction determined by the corrected met mast wind vane.

Wind turbine 8 was also analyzed and this turbine was found to have five different distinct offsets over the two year period. By plotting the difference between the WT yaw angle and the met mast versus each returned time stamp, we are able to get a time history of the offsets. The results can be binned into day or up to one week means, and a more smooth estimate of the offset results. It is assumed the offset remains is constant through periods where there is no data available. For example, within the time period 20/6/2007 → 13/7/2008, there is a large gap in data. This may be due to the lack of availability of either the turbine or the wind vane, or the wind direction does not fall within the window used with in this time period. It is more likely that the first explanation is the reason for lack of data. Table 4 shows the five different offsets for the yaw angle measurements after the correction of rotation direction has been applied. The offset marked with a (*) does not require a correction for the direction of rotation whereas the other time periods required this correction first. Other turbines were also found to have a similar problem with time dependent offsets so this smoothing of the difference approach was used to find these offsets. The time history of WT 8 yaw angle offset is shown below in Figures 7. Figure 8 illustrates the relationship between the WT yaw angle (rotation direction corrected) and the corrected wind vane.

To find the time periods where the offsets between the WT yaw angle and the corrected reference met mast sensor wind direction measurement change, the difference between these to signals is plotted versus the time stamp or runid. A running average of approximately 1 day is used to smooth the results to find an average offset for each run ID. This plot will identify the changes in the offset with time if any exist. The results of this analysis applied to the five turbines are provided in Table 4. Figure 9 shows an example of the time varying offset for WT 21. The colors indicate the time period between 2007 and 2008 and the red curve is a smoothing average of 144 samples (10 minute averages per day). Figure 10 shows the comparison between the WT 21 yaw angle and the reference met mast wind vane, 524/NW/116.

Wind turbine 21 was found to have a single offset of -61 degrees and this turbine as well is defined as positive yaw counter clockwise. Thus the negative of the wind turbine yaw angle is added to 360 degrees to correct the measurements to the standard wind direction definition frame. Wind turbine 29 was found to have a -56 degree offset and again this turbine has the yaw angle defined as positive...
counter clockwise. Wind turbine 12 is located at the end of the first row of turbines, northwest corner of the wind farm and this turbine offset was also analyzed because the yaw angle may be a nice indication of the disturbed wind direction. A constant offset in time of 60 degrees was found for wind turbine 12. As an example, a true wind direction from 270 degrees will be indicated by the yaw sensor on wind turbine 12 with a 330 degrees measurement.

5.1.4 Turbulence Intensity and Stability at Egmond Aan Zee

The turbulence intensity at the location of the met mast is determined by collecting all mean and standard deviations of the wind speeds from the three different sensor heights within wind directions of 180 deg and 270 deg. This inflow direction represents free inflow and the wind speeds at the mast should not be influenced by the wind farm to the north east of the met mast. The turbulence intensity is defined as the standard deviation of the wind speed over ten minutes over the ten minute average of the mean wind speed. The wind speeds are binned into 1 m/sec intervals and the mean turbulence intensity is determined and the results are plotted below in Figure 11.

A unique feature to this data for the lower heights is the peak in turbulence intensity at wind speeds between 15 to 20 m/sec. This is due to the increased wave height, thus surface roughness caused by the high winds. The turbulence intensity at the top anemometer of 116 m is however not affected by the increased wave heights. This will result in a gradient in turbulence intensity in the inflow conditions for wind speeds greater than 5 m/sec. The largest gradient will occur over the lower half of the rotor, between 70 and 21 m heights. It is also assumed the this turbulence intensity relationship is the same for all wind direction sectors and factors like water depth (between 16 to 21 m
### Table 4: Wind Turbine Yaw Offsets after Definition Correction

<table>
<thead>
<tr>
<th>Wind Turbine Name</th>
<th>Offset (deg)</th>
<th>Time Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>WT 7</td>
<td>4.4</td>
<td>1/1/2007 → 31/12/2008</td>
</tr>
<tr>
<td>WT 8</td>
<td>168</td>
<td>1/1/2007 → 19/6/2007</td>
</tr>
<tr>
<td>WT 8</td>
<td>170 (*)</td>
<td>20/6/2007 → 13/7/2008</td>
</tr>
<tr>
<td>WT 8</td>
<td>-10</td>
<td>14/7/2008 → 31/7/2008</td>
</tr>
<tr>
<td>WT 8</td>
<td>168</td>
<td>1/8/2008 → 27/9/2008</td>
</tr>
<tr>
<td>WT 8</td>
<td>164</td>
<td>28/9/2008 → 31/12/2008</td>
</tr>
<tr>
<td>WT 12</td>
<td>60</td>
<td>1/1/2007 → 31/12/2008</td>
</tr>
<tr>
<td>WT 21</td>
<td>-61</td>
<td>1/1/2007 → 21/12/2007</td>
</tr>
<tr>
<td>WT 21</td>
<td>38</td>
<td>22/12/2007 → 26/12/2007</td>
</tr>
<tr>
<td>WT 21</td>
<td>-61</td>
<td>27/12/2007 → 31/12/2008</td>
</tr>
<tr>
<td>WT 29</td>
<td>-56</td>
<td>1/1/2007 → 31/12/2008</td>
</tr>
</tbody>
</table>

Figure 11: Turbulence Intensity at Egmond Aan Zee Site (180 to 270 deg)
at the site location) [7], and fetch length do not affect this relationship for the two wind directions of primary interest, south westerly winds and winds from the north and north east.

The boundary layer stability is also important to consider in determining the environment that will affect the wake expansion, deficit recovery, and wake meandering. Typically for offshore sites, the stability is broken into three different stability classes, unstable, neutral, and stable and the Richardson Number, $R_i$ and the Monin Obukhov Length, $L$ are the metrics used to determine the stability. First, the Richardson Number is calculated according to the equation shown below. Given the Richardson Number and the height at which the Monin Obukhov Length is to be determined, the Monin Obukhov Length is calculated. Table 5 outlines the three stability classes the ranges of the Monin Obukhov Length. $g$ is the acceleration due to gravity, and $C_1$ is 10 and $C_2$ is 5 according to [10].

\[
R_i = \frac{\rho \frac{dT}{dz}}{\frac{dU}{dz}}
\]

\[
\frac{z}{L} = C_1 R_i \rightarrow R_i \geq 0
\]

\[
\frac{z}{L} = \frac{C_1 R_i}{1 - C_2 R_i} \rightarrow R_i \leq 0
\]

<table>
<thead>
<tr>
<th>Stability Class</th>
<th>Monin Obukhov Length, $L$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stable</td>
<td>$0 \leq L \leq 500$</td>
</tr>
<tr>
<td>Neutral</td>
<td>$</td>
</tr>
<tr>
<td>Unstable</td>
<td>$L \leq 0$</td>
</tr>
</tbody>
</table>

Typically, at low wind speeds, the boundary layer is unstable ($L \leq 0$) and the instability is driven by the temperature gradients between the sea and the air. Vertical and lateral translation of the wake can occur in these conditions in addition to increased mixing of the wake from the high ambient turbulence which can lead to a faster recovery of the wake deficit. The stability tends towards neutral ($L \geq 500$) and then towards stable ($0 \leq L \leq 500$) at the wind speeds increase. In other words, increased wind speeds correspond to larger vertical gradient in the wind speed thus will increase stability (a larger vertical gradient in wind speed will decrease the value of $L$). A few general trends for the offshore site are presented below and the stability classes will be discussed in more detail in the analysis of the wake cases for both offshore wind farms.

- **Low Wind Speeds ($\leq 7m/sec$)**
  - High Ambient Turbulence → Aids in faster wake deficit recovery
  - Unstable Atmosphere → More wake meandering
  - Increasing Thrust Coefficient → Stronger and more dramatic initial wake deficit
- **High Wind Speeds ($\geq 7m/sec$)**
  - Low Ambient Turbulence → Wake deficit will recover more slowly
  - Stable Atmosphere → Less vertical mixing, thus stronger, longer lasting deficit
  - Decreasing Thrust Coefficient → Weaker and less dramatic initial wake deficit

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The range of turbulence intensities at the site that fall within each of the three stability classes can be determined using the mean wind speed and standard deviation of the wind speed measurements from the three sensor heights on the met mast. Wind speed measurements from the south sensors in wind directions from 190 to 315 and within the 2007 and 2008 time period are considered to ensure the wind farm does not affect the turbulence intensity calculation. First, the wind speed measurements (10 minute mean and standard deviation) are binned according to the Monin Obukhov Length which is a function of the temperature and vorticity gradients (thus stability according to definition mentioned above). Turbulence intensities can be calculated for each stability class and each sensor height (116m, 70m, 21m). Figure 12 shows the range of the mean turbulence intensities for the three stability classes at the three sensor heights. Also seen in Figure 12 is the higher shear in turbulence intensity over the lower half of the rotor compared to the shear over the upper half of the rotor.

![OWEZ Turbulence Intensities for Different Heights and Stability Classes](image)

**Figure 12: Turbulence Intensity and Stability Class (South Sensors and Free Inflow Conditions)**

Using the above definition for classification of atmospheric stability, a percentage of time that the conditions are either stable, unstable, or neutral can be determined for the two year period measurements are available. Table 6 shows the percentages of the two year period that the atmosphere is either stable, unstable, or neutral. When analyzing the wake affects, the measurements are binned into either one of these three classes thus the affects of wake can be seen across the three different stability classes.

<table>
<thead>
<tr>
<th>Stability Class</th>
<th>Percentage of Measurement Period, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stable</td>
<td>26</td>
</tr>
<tr>
<td>Unstable</td>
<td>72</td>
</tr>
<tr>
<td>Neutral</td>
<td>2</td>
</tr>
</tbody>
</table>

**Table 6: OWEZ Atmospheric Stability Statistics**

Figure 13 below shows the relationship between the wind profile power law coefficient, $\alpha$ and the hub height mean wind speed for free inflow conditions as measured by the met mast. This relationship was determined by requiring a narrow wind direction between 230 and 240 degrees and wind speed
bins in 1 m/sec increments at the 70m height wind speed sensor. The narrow wind direction is centered on the dominant wind direction for the site, thus sufficient data is available at the operational wind speeds of interest. Given the measurements and the mean hub height wind speed, a wind speed profile can be fit to the data with a specific value of the coefficient, α. An iterative process is used to find the α that produces the best fit profile to the measured data for each hub height wind speed. The process started with large values of α (large shear) and decreased the values until the profile fit the measurements. The requirements at each measurement height (21m, 70m and 116m) was that the fit profile had to fit within ±5% of the mean value at each height. Because this is an ocean site, it is assumed that this relationship between α and hub height wind speed is the same for all wind direction sectors. Water depth, proximity to land, potential fetch length were considered although for the dominant wind directions at this site, these sources will not have a significant effect on the relationship.

\[ U(z) = U(z_{ref}) \left( \frac{z}{z_{ref}} \right)^{\alpha} \]

![Graph of Egmond Aan Zee, Wind Profile Power Law Coefficient](image)

Figure 13: Power Law Coefficient at Egmond Aan Zee

5.2 Horns Rev Offshore Wind Farm, Denmark

5.2.1 Wind Farm Description

Horns Rev Offshore wind farm is located approximately 14 to 20 km west off the west coast of Denmark in the North Sea. The 100 MW rated wind farm consists of 80 Vestas V80 2.0 MW wind turbines mounted on monopile foundations with hub height of 70 m. The wind farm is the first phase of an initiative started by the Danish government to produce a significant percentage of Denmark’s energy demand by non-polluting wind energy sources. The wind farm was then built by Eansam and Etra and was first operational with all turbines in December 2002. The wind farm is now co-owned and operated by DONG Energy (40%) and Vattenfall (60%). Figure 14 shows the orientation of the eighty turbines and the three meteorological masts at Horns Rev.

The wind farm is located on a shallow sand bar reef and oriented to take full advantage of the westerly and south westerly dominant winds. Met mast MM2 is considered in free flow conditions for
these dominant wind directions. Also illustrated in the figure above are the single wake producing turbines, WT 03, WT 04, and WT 05 that will produce a single wake on the instrumented wind turbine, WT 14. Three wind turbines spacings are available with this configuration of wind turbines. Between WT 03 and WT 14, the spacing is 10.4 rotor diameters; between WT 04 and WT 14, the spacing is 7 rotor diameters, and between WT 05 and WT 14, the spacing is 9.4 rotor diameters. SCADA and meteorological mast measurements are available from 14/8/2003 through 31/1/2005 and structural measurements from the main components of WT 14 are available from 24/8/2005 through 1/6/2007 (although with a few months missing in between). The components of interest include the tower base, mid section and and top section, blade root measurements, and main shaft measurements. More details on the measurement system and signal processing is found in the Appendix.

In addition to the structural measurements from WT 14, the 10 minute statistics SCADA data is available from all turbines for the same time period. The 10 minute statistics from the sensors from all three meteorological masts are also available for this project. One second time series data is also available for a few mast sensors and for a limited time period within the period mentioned above. Wind speed measurements are available at five different heights (62, 45, 30, 15m) and wind direction measurements are available at two different heights (43, 28m) on met mast MM2. Met masts MM6 and MM7 both have wind speed measurements available at six different heights (70, 60, 50, 40, 30, 20m) and wind direction measurements at two different heights (68, 28m). Met mast MM2 is located approximately 25 rotor diameters to the north from WT 1, met mast MM6 is approximately 26 rotor diameters from WT 95 in the eastern most column, and met mast MM7 is approximately 76 rotor diameters from WT 95.

5.2.2 Determination of the Meteorological Mast Wind Vane Installed Offsets

The MM2 meteorological mast has two wind direction sensors; one at 28 meters and the other at 43 meters and the installed offsets for the time period between 24/8/2005 and 31/12/2005 are required to ensure accurate database query construction. The offsets are determined by plotting the mean power
of WT 11 versus the wind direction measured by the met mast wind vane between wind directions 220 and 310 degrees. This wind direction window places WT 01 upwind of WT 11 and thus there should be a deficit in mean power of WT 11 along the wind farm geometry. Two turbine wake situations are included, WT 01 at a wind direction of 270 deg and WT 02, at a wind direction of 221 deg. The up stream turbine is required to have a power between 400 and 1100 kW to ensure a power deficit can be seen at WT 11. This power window represents wind speeds of approximately 6.5 m/sec to 9.5 m/sec according to the power curve from the V80 turbine.

Figure 15 below shows the power deficit for WT 11 at two locations, 250 and 300 degrees. This power deficit should occur at 221 and 270 degrees according to the wind farm geometry, thus DIR 43 SV wind vane on the MM2 met mast has a 30 degree installed offset for the time period of interest mentioned above.

![Wake Affected Normalized Mean Power of Wind Turbine 11](image)

Figure 15: Expected Minimum Locations (221 and 270 deg), Measured Locations (250 and 298 deg)

Figure 16 shows the power deficit for WT 11 at two locations, 250 and 300 degrees using the DIR 28 SV MM2 wind vane sensor. Again, there is a 30 degree installed offset for this sensor for the time period of interest. Table 7 summarizes the offsets for the two wind vane sensors installed on met mast MM2 for the 24/8/2005 to 31/12/2005 time period.

<table>
<thead>
<tr>
<th>Sensor Name</th>
<th>Offset (deg)</th>
<th>Time Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>DIR 28 SV</td>
<td>28.2</td>
<td>24/8/2005 → 31/12/2005</td>
</tr>
<tr>
<td>DIR 43 SV</td>
<td>30.6</td>
<td>24/8/2005 → 31/12/2005</td>
</tr>
</tbody>
</table>
Figure 16: Expected Minimum Locations (221 and 270 deg), Measured Locations (250 and 298 deg)

5.2.3 Determination of the Wind Turbine Installed Offsets

The installed offsets for the wind turbines of interest (WT 03, WT 04, WT 05, and WT 14) must be determined to ensure accuracy in the results of the database queries. These first three turbines are the single wake producing turbines on the instrumented turbine, WT 14. Again, the time period of 24/8/2005 to 31/12/2005 is considered as this is the time period in which SCADA data and structural measurement data from WT14 are available. During the preliminary analysis of the data, it was determined that the wind turbine yaw angle definition is consistent with the correct standard definition of wind direction measurements although the turbines yaw angles were found to have biases. The offsets are determined by determining the angle at which the minimum mean power occurs for a wake-affected turbine. For example, WT 13 mean power is plotted versus the wind direction measured by WT 03 yaw angle for wind turbine yaw angles between 220 and 310 degrees. In addition, the power of the wake producing turbine is required to be between 500 and 1000 kW. Using the known geometry of the wind farm and these two turbines, any offset will be evident between the trough in mean power and the expected trough location.

Figure 17 below shows the trough in mean power of WT 13 as a function of the nacelle position of WT 03. A 5 degree offset is shown for the yaw angle of WT 03. The mean power is plotted as a function of the nacelle position of WT 03. The query requirements for determining WT 04 yaw angle offsets are a power requirement of WT 04 between 500 and 1000 kW, and nacelle position of WT 04 between 220 and 310 degrees. A -10 degree offset is found for WT 04. The mean power is plotted as a function of the nacelle position of WT 04. A -13 degree offset is found for WT 05 by requiring the power to be between 500 and 1000 kW, and the nacelle position to be between 220 and 310 degrees. The mean power is plotted as a function of the nacelle position of WT 05.

The database query requirements for WT 14 include a power requirement on WT 04 between 500 and 1000 kW, and a wind direction measured by WT 14 yaw angle between 180 and 310 degrees. In this case, the nacelle position of WT 14 is extracted from the database and plotted versus the mean power of WT 14. Figure 18 shows the -1 degree offset found for this turbine. Table 8 summarizes the
offsets for the four wind turbine yaw angle sensors for the 24/8/2005 to 31/12/2005 time period. All wind turbine yaw offsets as a function of time are provided in the Appendix. In addition, MM6 and MM7 wind vane offsets over time are also included.

<table>
<thead>
<tr>
<th>Wind Turbine Name</th>
<th>Offset (deg)</th>
<th>Time Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>WT 03</td>
<td>5</td>
<td>24/8/2005 → 31/12/2005</td>
</tr>
<tr>
<td>WT 04</td>
<td>-10</td>
<td>24/8/2005 → 31/12/2005</td>
</tr>
<tr>
<td>WT 05</td>
<td>-13</td>
<td>24/8/2005 → 31/12/2005</td>
</tr>
<tr>
<td>WT 14</td>
<td>-1</td>
<td>24/8/2005 → 31/12/2005</td>
</tr>
</tbody>
</table>

5.2.4 Turbulence Intensity at MM2 Met Mast

The turbulence intensity as measured by the measurement sensors located on the MM2 meteorological mast is determined for free inflow wind direction conditions from the west and north west. The cup anemometers are not influenced by the mast or the wind farm for this wind direction sector, thus the turbulence intensity is purely a function of the ambient turbulence at the site. The turbulence intensity is shown as a function of wind speed, Figure 19 and has a similar relationship to the trends found at the Egmond Aan Zee site. The increasing turbulence intensity at higher wind speeds is most likely attributed to wave induced turbulent eddies that break up the steady wind speed profile at high wind speeds. Also evident is the gradient in turbulence intensity between the 15 and 45 measurement heights for wind speeds above 4 or 5 m/sec. Thus for all operating wind speeds of the turbine, there is a non-uniform turbulence intensity across the rotor plane of an operating turbine. This gradient may have a role in how the wake deficit breaks up as the wake deficit translates downstream. This non uniform turbulence intensity will also contribute to the generation of a non symmetric wake deficit just behind the wake generating rotor. There is a top mounted cup anemometer on the MM2 met
Figure 18: Expected Minimum at 221 and 270 deg, Measured at 219 and 268 deg

mast although for the time period of interest 8/2005 to 12/2005, there are no standard deviation measurements for the wind speed for this cup.
Figure 19: MM2 Met Mast Turbulence Intensity
6 Wind Turbine Performance Characteristics

The performance characteristics of the V90 3.0 MW and the V80 2.0 MW turbines are presented in this chapter. A method of estimating the mean blade pitch angle for the V90 given the measured power curve, rotor rotational speed, and a steady blade element momentum simulation is also discussed. Lastly, methods for estimating the mean fore/aft bending moment and the fore/aft fatigue loads of the tower using the standard SCADA measurements is presented.

6.1 Vestas V90 3.0 MW

6.1.1 Vestas V90 3.0 MW Power Curve

Estimates of the power curves for wind turbines 7 and 8 can be determined due to the relatively close proximity of the met mast (4.3D (WT8) and 6.0D (WT7)) to the turbines. The IEC specification states that the reference met mast should be located between 2 and 6 rotor diameters [6]. In addition, the met mast is located upwind of the two turbines for the dominant southwest wind direction, so there is sufficient amount of data to determine accurate power curves for the two turbines. An average of the two power curves is determined and the result is assumed to be the power curve for the other turbines in the wind farm that are of interest for this project. The inflow wind speed to these two turbines can be estimated by using the power measurement and interpolating within the power curve data. An accurate estimate of the inflow wind speed to these wake producing turbines is essential for setting up the inflow characteristics of the aeroelastic simulation.

Figure 20 below shows the data, mean, and standard deviations of the resultant power curve for WT 8. As expected, there are small variations in power for each wind speed bin investigated, thus mean value of each bin is used. Figure 21 below shows a very good agreement between the power curves of WT 7 and WT 8. It will be assumed that WT 21 and WT 29 have a power curve equal to the average of these two power curves. Under normal circumstances, all turbines at the wind farm should perform the same although due unexpected problems with turbines the power curves can be different from one turbine to the next. For example, if there was a stronger blade imbalance on one turbine compared to another, the control logic may try to accommodate this by pitching the blade thus affecting the power performance of the turbine.

![Figure 20: WT 8 Power Curve](image1)

![Figure 21: Power Curve Comparison](image2)

6.1.2 Vestas V90 3.0 MW Rotational Rate and Blade Pitch Angle Curves

The rotor rotational rate curve was determined by using the measurements from WT 8 for free inflow conditions and wind direction and hub height wind speed measured by the nearby met mast. Similarly
to the power curve estimation, the rotational rate as a function of wind speed can be found and it is assumed that all wind turbines will operate with this profile. Important to note is the maximum rotational rate of 15.6 RPMs instead of the 16.1 RPMs specified in V90 literature. Figure 22 shows the mean rotational rate as a function of hub height wind speed measured from the NW cup anemometer on the met mast.

![WT 8 Rotor RPM versus wind speed at hub height at met mast](image)

Figure 22: V90 3.0 MW Rotational Rate

The electrical and mechanical efficiency of the turbine was provided thus the net efficiency from the rotor to electrical output can be determined. This efficiency combined with electrical power curve, blade aerodynamics, and rotor rotational rate can be used in a blade element momentum model to find the correct blade pitch setting as a function of wind speed. A output power domain as a function of blade pitch angles and wind speed is created and thus given the power requirement at the rotor, the appropriate blade pitch angle is selected for each wind speed bin. Figure 23 below outlines the process used to find the mean blade pitch angle. It is assumed that the blade pitch angle remains constant over a rotation for a fixed wind speed, thus the small adjustments made to the pitch angle as function of rotor azimuth position are not included.

Two figures not included in public version show the V90 efficiency curves as a function of power and the resultant mean blade pitch angle as a function of wind speed. Ideally, I would be able to use the measured blade pitch angle although this channel for the majority of the period produced corrupt unusable measurements. The blade pitch angle is assumed to be correct since the output power from the BEM code times the efficiency matches the power curve determined from the measurements.

6.1.3 V90 3.0 MW Relationship Between Thrust and Power

The linear relationship between rotor aerodynamic thrust and the electrical output power for wind speeds less than 12 m/sec can be used to study the loading on non instrumented wind turbines. A relationship between thrust and tower base, mid section, and top section bending moments can be made using either instrumented wind turbine 7 or 8. Using the power measurements from non instrumented wind turbines, the relationship between power and thrust, and the relationship between thrust and bending moment, the tower fore/aft loads can be estimated on non instrumented turbines.
This method will open up may more wake conditions to study. For example, three more wake case separation distances are created by looking at a wind turbine in the second row of turbines. The tower mean bending moments can be studied in this case and the loading as a function of separation distance as well as atmospheric stability can be studied. Identified cases from the measurements can be compared to simulation results as well. The following steps were used to find the V90 rotor thrust to output power relationship for wind speeds below 12 m/sec.

- For wind directions between 190 and 270 as measured by the hub height wind vanes on the met mast, extract met mast hub height wind speed, tower base N/S mean bending moment, tower base E/W mean bending moment

- Calculate the fore/aft signal using the square root of the sum of the squares of the N/S and E/W signal and bin these measurements according to 1 m/sec wind speed intervals

- Using the known lever arm between rotor axis and strain gauge location, 53.15 m, calculate the thrust force creating the measured bending moment (Assume the thrust force is dominant force over the drag force from the flow around the tower)

- Merge the thrust versus hub height wind speed with the already determined mean power versus hub height wind speed curve to get thrust versus power for wind speeds below 12 m/sec

Figure 24 below shows the relationship between rotor thrust and output power for the V90 turbine. For wind speeds 15 m/sec and higher, the aeroelastic model was used to determine the thrust curve. Data was not available for these wind speeds in the free inflow wind directions considered for determining the rotor thrust. Figure 25 below shows the linear relationship between the rotor thrust and the electrical output power for the V90. The relationship is valid for wind speeds less than or equal to 12 m/sec. At wind speeds greater than 12 m/sec, the rotor thrust decreases with increasing wind speed. If all that was known was the bending moment, the inflow wind speed could not be determined; it would be one of two options.
Figure 24: V90 Normalized Thrust and Electrical Power

Figure 25: Rotor Thrust to Output Power, Wind Speed ≤ 12 m/sec
6.1.4 V90 3.0 MW Rotor Thrust and Tower Base Fore/Aft Bending Moment

A relationship between the aerodynamic rotor thrust and the tower base fore/aft bending moment has been determined to complete the transform from measured output power to tower base fore/aft bending moment. The bending moment is determined at a location 4.4 m above the bottom flange, which is the same location as the strain gauges in WT 7 and WT 8. Using the thrust power relationship above, the measured power from free inflow conditions can be converted to thrust. By extracting the mean NS and EW bending moment signals at the same time periods as the power, the mean fore/aft signal is determined by taking the square root of the sum of the squares. There is an approximate (10% to 15%) over approximation of the true fore/aft bending moment using this method although this method is used due to the lack of the original fore/aft time series data for all measurement time periods. The relationship in Figure 26 is valid for wind speeds at or less than 12 m/sec. This relationship combined with the above output power to thrust relationship opens up more wake cases since we can use the SCADA power measurements to estimate the mean fore/aft tower base bending moment. These relationships are applied and the results are discussed in a later section of this paper.

![Figure 26: Fore/Aft Tower Base Bending Moment 4.4 m from bottom flange, Wind Speed ≤ 12 m/sec](image)

6.1.5 V90 Output Power Variation and Tower Base Fore/Aft Equivalent Load

A strong correlation between ten minute average output power standard deviation and the tower base fore/aft equivalent loads has been observed for wind speeds below 12 m/sec. This is discussed in the equivalent load sensitivity section later in this paper. This transfer function opens up more turbine separation and wake scenarios where an estimate of the tower base equivalent loads can be calculated using the standard SCADA ten minute statistics of the wind turbine power. Separation distances include 7.1D, 11.1D, 13.3D, and 18.2D. The turbines used in these wake scenarios were chosen such that the met mast is in the ambient flow conditions and can be used to determine the inflow conditions for the wake generating turbine. The 7.1D case is between WT 12 and WT 11 in the northwest corner of the wind farm and the other three are between the first two southwest rows of the wind farm. More details about the wake cases are discussed in a later section of this paper. Figure 27 below shows...
the relationship between the power mean and standard deviation and the tower base equivalent load generated using measurements from WT 7. Each mean power level will have different amounts of fluctuations about this mean, thus the transfer function requires two inputs and returns an estimate of the tower base fore/aft 1 Hz equivalent load. The map is constructed by first plotting the equivalent load measurements as a function of mean power and power standard deviation. A linear least squares fit is used to create a linear relationship between the equivalent load and the standard deviation of the power. This is repeated for each mean power range and the surface is created by merging all the linear relationships.

A higher sensitivity to power fluctuations is seen for the lower wind speeds or lower output levels and this may be attributed to low wind speed control of the turbine. The rotor is operating in a variable speed mode and the thrust coefficient is also near maximum, thus the turbine is in a configuration of highest drag. A combination of slightly too high or too low rotor speeds coupled with a high drag coefficient may increase the variation of the fore/aft bending moment. All power measurements that do not fit the power curve ±10% at each wind speed bin are excluded from the dataset in generation of this transfer function map. This will ensure only periods of time when the turbine is operating over the entire ten minutes are included. Figure 28 shows a histogram of the equivalent loads used to generate the transfer function shown in Figure 27.

![Figure 27: Tower Base Fore/Aft Equivalent Load Variation with Power Statistics](image1)

![Figure 28: Histogram of Fore/Aft Equivalent Loads](image2)

Figure 27: Tower Base Fore/Aft Equivalent Load Variation with Power Statistics

Figure 28: Histogram of Fore/Aft Equivalent Loads

Figure 29 illustrates the standard deviation of each point on the equivalent load transfer function. This data provides an indication of the variation of the equivalent load value for a given mean and standard deviation power measurement from the SCADA system. The legend refers to the different power standard deviation bins in the plot of the transfer function surface. Figure 30 illustrates the close relationship between the true calculated fore/aft 1 Hz equivalent load and the estimated fore/aft equivalent load for WT 7 for the measurement period of June 2007. As shown, the estimation technique of the square root of the sum of the squares of the N/S and E/W signals produces higher values than the technique of first calculating the fore/aft time series, then calculating the fore/aft equivalent load. Due to time restrictions, the estimated values are used in the analysis and results presented in this paper. The correct fore/aft pseudo signals can be determined by using the corrected wind turbine yaw angle time series measurement and the measured N/S and E/W time series.

6.2 Vestas V80 2.0 MW

6.2.1 Vestas V80 2.0 MW Power and Mean Blade Pitch Angle Curves

The power curve for WT 14 was determined using free inflow wind conditions between the front column of turbines (WT 03, WT 04, and WT 05) to the west of turbine 14. The corrected nacelle wind
speed is used due to the lack of a met mast within the IEC specification for power curve determination. It is assumed that the nacelle wind speed is 90% of inflow wind speed. Mean blade pitch angle is also available in the SCADA information and the mean blade pitch angle versus inflow wind speed is also shown. Rotor rotational speed is not available in the SCADA information, although the rotor speed at rated power is 16.7 RPMs and variable speed at wind speeds lower than 13 m/sec. Figure 31 shows the raw power Figure 32 shows the average power. The mean blade pitch angle curves are not included in the public version of this paper. At wind speeds below 10 m/sec, the turbine operates with a variable rotor speed. The output power is more sensitive to the rotor rotational speed than the blade pitch setting for this low wind speeds. A negative mean blade pitch angle is used for wind speeds up to rated power. The slightly negative value for the blade pitch is the result of an optimization to minimize noise emissions and maximize power.
7 Aeroelastic Model Development and Analysis

In this chapter, the aeroelastic models of the V80 and V90 are described and compared to measurements. The performance parameters from measurements from the previous section are compared to simulated results. In addition, the controller used for both models is discussed.

7.1 Model Description and Assumptions

The Vestas V90 3.0MW and V80 2.0 MW turbine models are built for the aeroelastic simulation HAWC2 that will be used for comparison to measurements. HAWC2 was selected primarily due to previous working experience with the software, it is a proven software package developed and maintained by Risoe National Laboratory for Sustainable Energy, and most importantly the dynamic wake meandering model has been implemented. Currently, the simulation is limited to single wake situations although multiple wake analysis capability is currently being added. The development of the model was done in two steps. The first step was to define the structural components, verify component resonant frequencies and damping properties, and verify the power curve for steady state (constant RPM, fixed pitch, spec defined velocity profile and turbulence intensity) operation of the model. This step will ensure the blade geometry and airfoil properties are modeled correctly without influence from controller logic. The second step was to implement and tune the blade pitch and generator slip external controller.

The main bodies (components) used to define the turbine in HAWC2 are the tower, the main shaft (gearbox), and the three blades. The Vestas V90 does not have a slow speed main shaft, thus the connection between the end of the tower and the root of the blades is modeled with the gearbox specifications (length and mass). A diagram of the nacelle components and dimensions of the main components of the V90 are provided in the Appendix. Each of the main components is defined in the simulation using mass distributions and stiffness data. This information was provided for the steel tubular tower and for the blades. I was also provided general dimensions and mass data for the hub, nose cone, gearbox, generator, and nacelle so these components can be included in the main components of the model. For example, the mass of the nacelle without the gearbox is added to the last segment of the mass distribution definition of the tower. This is also done to consider the mass of the hub and nose cone at the end of the gearbox link between the end of the tower and the root of the blades. Accurate estimates of the mass distributions and dimensions will ensure accurate turbine response characteristics to fluctuations in wind speed or loading. In addition, at standstill, there will be a nonzero loading on the tower due to the cantilever of the rotor and gearbox from the tower vertical centerline. The reaction moment from the aerodynamic thrust will work to overcome this load during operation, although accurate estimates of the standstill loads will ensure more accurate readings of tower root bending moment during operation.

The V90 3.0MW turbine has a passive damping system located in the tower that is designed to damp out vibrations in the tower caused by dynamic inflow conditions or vibrations that may be induced by the control system. Independent analysis done by Vestas has shown a uniform reduction of approximately 8% of the tower base fore/aft equivalent load for all operational wind speeds for free inflow conditions. For a five rotor diameter spaced wake condition, the reduction effect is on the order of 5% for all operational wind speeds. This feature is not modeled in the HAWC2 model, thus the model will tend to overestimate the time required for oscillations to damp out.

Table 9 and Table 10 below show the comparison between the specified blade and tower frequencies, what was calculated in HAWC2, and independent FLEX method analysis. The V80 expected values for the component frequencies were not available so they are not included in the table. The only missing information for the blade structural definition is the composite Young's Modulus for the material. However, the stiffness data is provided as a function of this modulus, thus we can assume a value for E, run the eigenanalysis in HAWC2 and check the first three or four modes against the
expected values (from Vestas FLEX5 analysis). This can be repeated until the accurate estimate of the modulus produces a close match of the frequencies. As a secondary and independent verification, a frequency analysis was done for the blades using my eigenanalysis software (based on the FLEX method) that I developed for a project in a previous course. The method is fully documented in [8].

<table>
<thead>
<tr>
<th>Frequency</th>
<th>Expected Value (Hz)</th>
<th>FLEX Method (Hz)</th>
<th>HAWC2 (Hz)</th>
<th>HAWC2 Damping Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blade 1st Flap</td>
<td>1.019</td>
<td>1.016</td>
<td>1.015</td>
<td>0.33</td>
</tr>
<tr>
<td>Blade 2nd Flap</td>
<td>2.624</td>
<td>2.610</td>
<td>2.622</td>
<td>0.83</td>
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<tr>
<td>Blade 1st Edge</td>
<td>1.453</td>
<td>1.472</td>
<td>1.438</td>
<td>0.45</td>
</tr>
<tr>
<td>Tower Only 1st</td>
<td>0.443</td>
<td>N/A</td>
<td>0.487</td>
<td>0.63</td>
</tr>
<tr>
<td>Tower Only 2nd</td>
<td>4.483</td>
<td>N/A</td>
<td>4.350</td>
<td>2.77</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Frequency</th>
<th>Expected Value (Hz)</th>
<th>FLEX Method (Hz)</th>
<th>HAWC2 (Hz)</th>
<th>HAWC2 Damping Ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blade 1st Flap</td>
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<td>1.024</td>
<td>1.023</td>
<td>0.33</td>
</tr>
<tr>
<td>Blade 2nd Flap</td>
<td>N/A</td>
<td>2.535</td>
<td>2.543</td>
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<tr>
<td>Blade 1st Edge</td>
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<td>1.882</td>
<td>1.850</td>
<td>0.59</td>
</tr>
<tr>
<td>Tower Only 1st</td>
<td>N/A</td>
<td>N/A</td>
<td>TBD</td>
<td>0.40</td>
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<tr>
<td>Tower Only 2nd</td>
<td>N/A</td>
<td>N/A</td>
<td>TBD</td>
<td>3.0</td>
</tr>
</tbody>
</table>

### 7.2 V90 and V80 Controller Model

A controller for both aeroelastic model is required to ensure the turbine is operating in the simulation as it would in operation. A constant power, variable speed, and variable pitch controller was developed by Riso and this controller model was tuned for the V90 and V80 turbines. The rated power and rotor RPM at which the rated power is reached is set for each turbine in addition to the blade pitch angle versus wind speed profile. The controller utilizes a PID controller for generating the generator counter torques to apply to the rotor or main shaft and a PI controller for the blade pitch angle commands. Default controller gains were used and it has been shown that with these gains the controller performs very similar to observed operation. The external dll format controller interacts with the core HAWC2 simulation via action or control commands; a generator counter torque, and blade pitch angles. The controller is provided from HAWC2 core the output power, mean ambient wind speed, rotor rotational rate, and mean blade pitch angle.

The controller coupled with the wake model currently supports only positive blade pitch angle profiles specified in the configuration file. Without the wake model, the controller can control the blades to negative pitch angles. At low wind speeds, below wind speed at rated power the optimal mean blade pitch angles are below zero for the V90 and the V80 turbines. For the wake analysis, the controller controls the mean blade pitch angle to zero for these low wind speeds and controls the blades to larger positive values as the wind speed increases. The difference between the negative pitch angle and the zero pitch angle is significant enough to change the modeled thrust coefficient which is largest at low wind speeds (approx 7-8m/sec), and thus the tower bending moment. A negative blade pitch angle will increase relative velocity flow angle and thus increase the aerodynamic loading on the rotor, thus increase the thrust, and thus increase the tower and blade root bending moments.
The slight difference in bending moments at these low wind speeds is shown when the measured and simulated wake analysis is compared in a later section of this paper.

7.3 Calibration of V90 Model

In order to ensure the aeroelastic model is accurately modelling the operational turbine for non wake cases, a comparison is made between the aerodynamic power, the aerodynamic rotor thrust, the mean blade pitch angle, and the rotor rotational speed as a function of hub height mean wind speed. The measurement data was obtained from careful extraction and analysis of the two instrumented turbines in the Egmond Aan Zee wind farm, WT7 and WT8. The pitch measurement data was obtained according to the method presented in a previous section of this report.

The aeroelastic model is analyzed in free inflow conditions using steps in mean hub height wind speed with turbulence intensity of 8% and with step durations of 20 seconds. Each twenty seconds, the mean wind speed is incremented by 1 m/sec and held constant for the next 20 seconds. The mean of the signals used in the comparison is taken over the twenty seconds, although the first 10 seconds of the simulation are not included in the statistics to eliminate initialization transients. The transients during and after a step are included in all subsequent wind speed increments. The transients are included as a way to ensure the pitch angle responds to a value that is expected as indicated by the measurements. Figure 33 shows a very close agreement between the measured aerodynamic power curve and the simulated aerodynamic power curve. Figure 34 shows another close agreement between the measured thrust curve and the simulated aerodynamic thrust curve. Figure 35 in addition shows close agreement between measured and simulated turbine parameters for the rotor rotational speed as a function of hub height wind speed. The mean blade pitch angle comparison is not included in public version of the paper. A standard power law wind speed profile with exponent of 0.12 was used to simulate the inflow velocity profile.

![Figure 33: V90 Aerodynamic Power](image1)

![Figure 34: V90 Aerodynamic Thrust](image2)
Normalized V90 Rotor Speed

Hub Height Wind Speed (m/sec)

Normalized Rotor Speed (RPMs)

HAWC2

Meas.

Figure 35: V90 Rotor Speed
8 Wake Analysis Using Operational Measurements

Identification of the wake and free inflow scenarios for both Egmond Aan Zee and the Horns Rev wind farms is discussed. Also, the fatigue loading sensitivities to turbine separation estimated using the transfer function presented in the turbine performance chapter are presented. Further verification of the measurement data is discussed to ensure measurements included in comparison to simulation are accurate. A small study of fatigue load sensitivity to wind direction is included to compare single wake, multiple wake, and free inflow fatigue loads for the V90 and V80 turbines. Also, a study of the power deficit through a row of turbines for steady and unsteady atmospheric boundary layer stabilities is included to show the importance of atmospheric stability on power production and also structural loads.

8.1 Egmond Aan Zee

8.1.1 Assessment of Wind Directions to Include as Potential Wake Scenarios

The wake conditions will occur within a small range of wind directions, centered on the direct alignment that places the wake generating turbine directly upstream of the wake affected turbine. This window will obviously get smaller as the turbine spacing becomes larger and it is also assumed when determining the wind direction window limits that the two turbines of interest have the same yaw angle. For the ideal case, using the rotor diameter, the turbine spacing, and increasing values of yaw, the maximum yaw angle that will still produce a partial wake situation on the yawed downwind turbine can be determined. This case assumes no wake expansion. To further refine this case, wake expansion is included and it is expected that the allowable wind direction window should increase. Table 11 shows an example of how the wind direction limits change for different turbine spacing at a mean wind speed of 5.75 m/sec. The data for the wake expansion determination was obtained from [5]. The wake expansion is determined by a closed form equation that is a function of the wake expansion coefficient, $\alpha$, and the downstream distance. $\alpha$ has been determined by experiments and has been shown to change as a function of the rotor thrust coefficient, although in the current implementation it is considered a constant. An additional refinement to the determination of the limits would be to include the effects of wake meandering. This effect will be ambient turbulence, thus wind speed specific. This refinement will be handled on a case by case basis and discussed below in the wake case discussion. The first two model attributes should identify clean wake cases, such that we avoid wake interaction of neighboring wakes.

<table>
<thead>
<tr>
<th>Wind Turbine Spacing</th>
<th>W/O Wake Expansion</th>
<th>With Wake Expansion</th>
</tr>
</thead>
<tbody>
<tr>
<td>13D</td>
<td>±4.3</td>
<td>±7.5</td>
</tr>
<tr>
<td>18D</td>
<td>±3.1</td>
<td>±5.8</td>
</tr>
<tr>
<td>23D</td>
<td>±2.4</td>
<td>±4.8</td>
</tr>
</tbody>
</table>

Figure 36 illustrates the results from a similar analysis using the HAWC2 wake deficit widths instead of the closed form expression used in the method above. As expected, as the separation distance increases, the allowable yaw angles from perfect alignment that still produce a partial wake case on the downwind turbine decrease. A turbulence intensity of 8% was used to generate the wake deficits at five different distances and the wake width was interpolated for the in-between distances. Also shown is the small variation in allowable yaw angles for the three different wind speeds. As expected, the wake width for the low wind speed of 6 m/sec is smaller than the width of 8 and 12 m/sec and thus the allowable yaw angle from perfect alignment is smaller. Details of how the wake deficit is generated and transmitted downstream are discussed in the Dynamic Wake Meandering Model section of the paper.
8.1.2 Single Wake Cases

There are three single wake alignment cases in the Egmond Aan Zee wind farm that will align one of the instrumented turbines WT 7 or WT 8 in the wake of a single turbine. The wind direction, the wind turbines involved, and the spacing between the turbines are outlined in the Table 12. It is required to determine time periods of turbine operation in these wind inflow directions so the measurements on the instrumented turbines can be used. Different sensors at the wind farm can be used to determine inflow wind directions. For instance, the wind vanes on the met mast can be used to determine wind direction although for the cases listed, the mast is in the wake of the wind farm. Wind turbine yaw angles are an excellent source of wind direction and can be used to find time periods of the desired wind direction. Also important to consider in deciding what sensor to use as the filter requirement is the sensor availability. There may be cases of perfect wake alignment, yet the sensor used to measure the inflow wind direction is not operational, thus another sensor is needed. Other wind turbine yaw angles or the met mast wind vane sensors are thus used.

![Figure 36: Upwind Turbine Yaw Angle to Produce Partial Wake Conditions on Downwind Turbine](image1)

![Figure 37: Schematic for Determination of Yaw Angle](image2)

Table 12: Egmond Aan Zee Single Wake Cases

<table>
<thead>
<tr>
<th>Source Turbine</th>
<th>Wake Affected Turbine</th>
<th>Inflow Wind Direction</th>
<th>Turbine Spacing</th>
</tr>
</thead>
<tbody>
<tr>
<td>WT21</td>
<td>WT7</td>
<td>35°</td>
<td>18D</td>
</tr>
<tr>
<td>WT21</td>
<td>WT8</td>
<td>16°</td>
<td>13D</td>
</tr>
<tr>
<td>WT29</td>
<td>WT8</td>
<td>31°</td>
<td>23D</td>
</tr>
</tbody>
</table>

In order to ensure all possible time periods of single wake alignment cases were covered, the wind direction inflow sensors were used one by one to ensure no time periods were missed because lack of sensor availability. The number of 10 minute samples returned can then be plotted as a function of the measured wind direction. This histogram will provide an indication of the wake alignment periods as well as where most of the cases occur at or near the perfect alignment case. This process identifies single time periods of when the wind direction requirements are met. For instance, the wind direction may be shifting and only pass through the requirement bin for a single 10 minute period, thus manual inspection of the returned cases is needed to find sustained time periods of wake alignment. This process eliminates many of the returned cases although also identifies the few periods of sustained turbine operation in the wake alignment condition.

It is important to note here that the wind direction is the corrected wind direction according to the offsets presented in the earlier chapter. Figures 38 and 39 show an example of this histogram of returned wake cases for the two different met mast wind vane sensors for the wake case with wind...
direction of 16 degrees. Figure 38 illustrates the returned cases when the 524NW/21m wind vane is used and Figure 39 illustrates the different number of cases that are returned when used 524S/21m wind vane.

![Histogram of Wind Direction Measurements (21m, NW WD Sensor)](image1)

![Histogram of Wind Direction Measurements (21m, S WD Sensor)](image2)

Figure 38: Histogram of 10 Min. Periods of Near Wake  Figure 39: Histogram of 10 Min. Periods of Near Wake Cases

The next step was to look through the time periods within the perfect alignment periods and find time periods with more than one 10 minute sample to ensure the wake case is sustained in time. In addition to looking for sustained time periods, the bending moments on the tower and blade were scanned to ensure valid measurements were available during the periods of perfect wake alignment. It was found that for WT 8, the entire year of 2008 has bending moment measurements from all channels that are not comparable to 2007 measurements. 2007 measurements are of the correct magnitude and sign, whereas 2008 measurements are not scaled properly and thus are not used in this analysis.

No wake alignment cases were found for the WT 21 and WT 7 wake case using different inflow wind direction sensors. This wind direction of 357 degrees is not common to this site. The WT 29 to WT 8 wake case with inflow wind directions of 31 degrees was also analyzed and three time periods were found with wake alignment. Due to the extreme separation distances, only conditions where the wind direction was measured at 31 degrees are considered. The details of these three cases are listed in Table 13. The 524NW/116m wind vane was used as the wind direction filter for these three cases due to its high availability. The first case listed has a perfect wake alignment for two hours within the 21 hours, the rest of the time the wake is ±4 degrees or so.

<table>
<thead>
<tr>
<th>Start Time</th>
<th>End Time</th>
<th>Duration (hrs.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007/04/02 03:00</td>
<td>2007/04/03 00:30</td>
<td>21</td>
</tr>
<tr>
<td>2007/04/03 20:40</td>
<td>2007/04/03 21:40</td>
<td>1</td>
</tr>
<tr>
<td>2007/04/04 02:10</td>
<td>2007/04/04 08:30</td>
<td>6</td>
</tr>
</tbody>
</table>

Table 13: WT 29 to WT 8 Wake Cases (23D separation)

Given the time periods of wake alignment conditions, more detailed analysis can be conducted to ensure there is a wake condition by looking at the other sensors. The wake case of WT 21 to WT 8 found from the above process is further described in the following section. This case will be simulated and a comparison is made between the equivalent loads in the tower base and in the blades.

**Wake Case 1, WT 21 → WT 8: 2007/04/03 06:50 → 2007/04/03 08:30**

In order to verify that the wind direction is within the limits that will create a wake situation between WT 21 and WT 8, different wind direction sensors are analyzed for the time period of interest. Figure
40 below shows the time history of the 10 minute averages from five different wind direction sensors. WT 12 is used since it is located in a free stream position and should be a good indicator of the true wind direction for the 16 ±4.4 deg wind direction window of interest. As shown in a close up in Figure 41, the wind directions all indicate a mean that is within the window and the measurements seem to be correlated. For example, and increase in wind direction is measured by four of the five sensors at the RID of 13300. There is a period of approximately 2.0 hours from RID 13290 to 13300 of 10 minute measurements were WT 21 and WT 8 are within the wind direction requirement.

![Wind Direction Indicators for Wake Case (200704030810-->200704031520)](image1.png)

**Figure 40: Wind Direction (WT 21 to WT 8)**

<table>
<thead>
<tr>
<th>Wind Direction (deg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>20</td>
</tr>
<tr>
<td>10</td>
</tr>
<tr>
<td>0</td>
</tr>
<tr>
<td>-10</td>
</tr>
<tr>
<td>-20</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Wind Direction Indicators for Wake Case (200704030810--&gt;200704031520)</th>
</tr>
</thead>
<tbody>
<tr>
<td>wt 12</td>
</tr>
<tr>
<td>mm70NW</td>
</tr>
</tbody>
</table>

**Figure 41: Wake Case (WT 21 to WT 8)**

8.1.3 Free Inflow Cases

The free inflow cases for the Egmond Aan Zee instrumented turbines were found by using the upstream met mast wind vanes as wind direction filters. WT 7 and WT 8 have free inflow conditions for the dominant wind direction at the site, thus there are plenty of time periods with all different inflow wind speeds for the free inflow conditions. In addition, the met mast is located within 2-3 rotor diameters of both turbines thus can be used according to the IEC specification for determining the power curves of these two turbines.

8.1.4 Tower Base Bending Moment Verification

A way to verify the tower base bending moment measurements are configured as expected is to plot the mean tower bending moment as a function of wind turbine yaw angle for a range of wind speeds as measured by the nacelle anemometer of 5 to 7 m/sec. If the sensors are calibrated and located 90 degrees from one another as indicated by the N/S and E/W placement, the sinusoidal curve should be 90 degrees out of phase. Figure 42 and Figure 43 below show this correct relationship for both WT 7 and WT 8. The mean data is plotted as well as a smoothed running average curve with a bin width of 5 degrees.

8.1.5 Tower Base Equivalent Loads Sensitivity to Wind Direction

The sensitivity of turbine base fore/aft bending moment equivalent loads to wind direction, thus inflow conditions (free, single and multiple wake) is an illustrative analysis into the affects of wakes on turbine loads. Wind directions measured by the NW 116m wind vane on the met mast and wind speeds measured by the loaded turbine nacelle anemometer are used to bin the equivalent load measurements. In addition, the wind turbines are required to be operating. Small 2 deg wind direction bins are used to calculate the raw mean equivalent load and a 4 deg bin is then used to smooth this raw data. The wind
speed range is between 5 and 8 m/sec to ensure enough data points are returned to generate the sensitivity relationship. There is a trade between opening up the wind speed and wind direction bins and thus sacrificing resolution or accuracy in the peaks and troughs and reducing the bins. A reduction in the wind speed bin will return fewer points to calculate statistics from although the peaks and troughs may be more cleanly defined when there is sufficient data. Figure 44 below shows the normalized sensitivity relationship. Each curve is normalized by the maximum value of that curve. The figure with the absolute values of the 1 Hz equivalent loads is not included in the public version of this paper.

The multiple single and wake situations are shown by the peaks in equivalent load and the free inflow condition between 170 degrees and 305 degrees is shown by the relatively lower valued constant equivalent load. The gap in the plots is associated with no measurements made for wind directions between 100 and 135 degrees and 355 to 15 degrees and this lack of data is consistent with the site wind rose presented earlier. Both wind turbines indicate side lobe peaks to the main peak which indicates that partial wake situations also produce high equivalent loads although the direct wake alignment seems to produce the peak tower base fore/aft equivalent loads.

Figure 45 illustrates the correlation between the 10 minute average power standard deviation and the 1 Hz fore/aft tower base bending moment equivalent load. WT 7 is used for this analysis due to the higher availability of this turbine for the time period considered. The curves are normalized by the maximum value of each curve. This strong correlation is observed for wind speeds up to approximately 12 m/sec and thus can be used to estimate the tower base equivalent loads on turbines without mechanical load measurement equipment. Using WT 7 and WT 8, a transfer function is developed that takes as inputs mean and standard deviation of the power (10 minute average) and returns the fore/aft tower base bending moment. This transfer function should be the most accurate and representative for wind speeds or power measurements with many cases. Wind speeds closer to 12 m/sec do not occur as frequently and thus there is fewer data available to generate a well defined transfer function. The lack of data is also evident by the gap in the curves at low values of wind direction as well as between 95 and 115 degrees.

8.1.6 Turbine Row Power Deficit

The performance of a row of turbines can be evaluated for different atmospheric stability classes to illustrate the power deficit as a function of position within the row of turbines. Figure 46 and Figure 47 below illustrate the raw data and the mean and standard deviation at each turbine location, for the stable and unstable cases respectively. Four rows of turbines are used to collect the power data set. Rows starting with WT 6, WT 7, WT 8, WT 9 are used and each row consists of four turbines equally spaced. In line in the plot illustrates the power and variation in power measured at each
Figure 44: Normalized Tower Base Equivalent Load Sensitivity

Figure 45: Correlation Between Power Std. and Fore/Aft Equivalent Load
turbine location along the row of turbines for one ten minute period. These plots illustrate how the output power is affected when the wind direction is aligned with the row of turbines and the power deficit sensitivity to atmospheric stability.

The inflow conditions are 7-9 m/sec hub height wind speed, wind direction as measured by the hub height wind vane on the mast of 228.7 ±2 degrees. It is assumed that for the inflow direction considered, there should not be a large difference in wind direction versus height. A power law profile is used to set wind speed requirements at the other measurement heights of 116m and 21m, with the power law exponent determined from the wind speed/exponent relationship presented earlier in the paper for Egmond Aan Zee. Because of the limited time periods of neutral conditions, there were no neutral conditions that met the tight inflow requirements stated above.

![Normalized Power Deficit Through Row of Turbines, Stable](image1)

![Normalized Power Deficit Through Row of Turbines, Unstable](image2)

Figure 46: Normalized Power Deficit ($U_0 = 7-9$ m/sec, 227 ±2 deg), Stable

Figure 47: Normalized Power Deficit ($U_0 = 7-9$ m/sec, 227 ±2 deg), Unstable

The lack of stability is shown to have a positive influence on the wake recovery and thus a smaller relative power drop from the lead turbine to the second turbine. More turbulent mixing is involved in the unstable case, thus the wake structure is broken up more so than in the stable or low turbulent mixing conditions. The second turbine power deficit changes from 70% of lead turbine for the stable case to 60% of the lead turbine for the stable conditions. This difference can be attributed to the turbulent mixing in the unstable case as well as more wake meandering in the unstable case. A set of very tight inflow conditions still yield significant scatter in the results. Other sources of scatter may include yaw misalignment problems or weather front passage events. For example, in the unstable wake case there is a period where the second turbine has a higher power than the first turbine which may be attributed to a gust situation. If available, it would be useful to plot the variation of each turbine yaw angle for the power deficit data presented. A low value of yaw misalignment standard deviation would eliminate this as a potential source for sending wakes on different downstream trajectories and provide proof of the meandering of the wake deficit.

8.1.7 Tower Base Equivalent Loads Sensitivity to Turbine Separation

The fatigue loads in wake affected turbines as a function of separation distance between the wake affected turbine and wake generating turbine is of particular interest since this information may help the wind farm designer properly locate turbines to reduce fatigue loads and maximize power output. The measurements from the Egmond Aan Zee wind farm are used in collaboration with the transfer functions (also generated from measurement data) presented in the turbine performance section of this paper. Because of the configuration of the instrumented turbines at Egmond Aan Zee, there are very few single wake cases that act on either WT 7 or WT 8, thus using the transfer functions provides for the ability to study tower loads on non instrumented (no strain gauges) turbines. These transfer functions provide the means to transfer the standard SCADA measurements available on all turbines.
to the mean and 1 Hz equivalent structural loads on the tower.

Four turbine separation distances are considered in this analysis, 7.1D, 11.1D, 13.3D, and 18.2D where D is 90m rotor diameter. Given the geometry of the wind farm and the dominant wind direction, these four cases produce the most data. The 7.1D case is between WT 12 and WT 11 at the north west most corner of the wind farm. This spacing is the closest spacing between turbines at this wind farm. The other three cases occur between the southwestern most row and the second row of turbines for different inflow wind directions. For these three cases, the wake generating turbine is either WT 5 or WT 3, so the wind direction and wind speed measured at the met mast is more or less what the turbine will see. A key requirement on the filter before using the measurements is the wind direction which will ensure the turbines are oriented in a direct alignment wake condition. A small binwidth of ±1 deg is used which will ensure a direct alignment between wake generating and wake affected turbine. Other key filtering requirements are stated below. Because of the lack of stable atmospheric cases available, only the unstable results are presented. Only 26% of the measurement time period is classified as stable.

- ±1 deg wind direction bin from perfect wake alignment on 116m NW wind vane
- Mean wind speed requirement met at 70m measurement height on met mast
- Mean turbulence intensity across three measurement heights ≤ 8%
- Unstable atmosphere, L ≤ 0
- Mean wind speed ≤ 12m/sec, thus bending moment and equivalent load transfer functions can be used

For each wind speed range and for each separation distance case, the mean tower base fore/aft bending moment, the mean fore/aft tower base 1 Hz equivalent load, the mean wake affected turbine power, and the mean power deficit is calculated. There are multiple cases for each wind speed bin and turbine separation case, thus the mean is presented for each category. Figure 48 illustrates the increasing tower base fore/aft bending moment as the turbine separation increases. This is due to the wind speed recovery at the further distances, thus producing a larger load on the turbine. Also shown here is the increasing mean bending moment with wind speed for each separation case. Figure 49 illustrates the relationship between separation distance and the tower base fore/aft 1 Hz equivalent load. For all wind speed bins, the 1 Hz equivalent load decreases as the separation distance increases. Small scale blade tip and root induced vortex structures are most likely the cause of the larger fatigue load at the smaller separation distances. As the separation distance increases, these structures break down and their affect on the fatigue load is reduced. At further separation distances, the wake meandering effect on fatigue loads may overtake the contribution to fatigue loads from the smaller scale root and tip vortices.

Also interesting to analyze is the power deficit between the wake generating and wake affected turbines. As expected, the power of the wake affected turbine approaches the power of the wake generating turbine as the separation distance increases. This is due to the recovery of the wake deficit (or recovery of mean wind speed towards ambient wind speed) that is driven by the turbulent mixing in the far field (greater than 3 rotor diameters) and the pressure recovery in the near field (less than 3 rotor diameters). For all wind speed ranges, the power deficit is reduced for increasing turbine separation distances. The power deficit for the higher wind speed bins is less than that of the lower wind speed bins due to the reduced thrust coefficient at the higher wind speeds. The initial wake deficit is less significant for the higher wind speed bins. These results from measurements will be compared to simulated results in detail in a later section of this paper.
8.1.8 Multiple Wake Equivalent Load Sensitivity

The power statistics to tower base fore/aft equivalent load transfer function is also applied to the multiple wake situations at Egmund Aan Zee to get an estimate of how the equivalent fatigue loads vary through a row of four turbines. The power mean and standard deviation are extracted for five different rows of turbines that are four turbines deep and row southwest to northwest. A strict wind direction requirement on the met mast 116m NW wind vane is set to 230 ±0.5deg and all turbines are required to be operating in each row. The transfer function was built using mean and standard deviation of power and measured fore/aft equivalent loads in single, multiple, and free inflow conditions from the instrumented turbines. It has been shown that there is a strong direct correlation between the power variation and the tower base fore/aft equivalent loads (Figure 47) thus we can assume this transfer function is valid for determining the trends of equivalent loads through a row of four turbines.

Figure 52 illustrates that there is an approximate increase in the normalized fore/aft 1 Hz equivalent load between the first and fourth turbine in the row of 20%. There is also a strong power deficit between the first and second turbines, which indicate a strong wind speed deficit from a high thrust coefficient. The atmospheric boundary layer is predominantly unstable for the measurement cases with a mean inflow turbulence intensity of 7%. Figure 53 shows a less significant power drop between the first and second turbines and also a 10% increase in the fatigue loads between the first and fourth turbine in the row. Another obvious difference between the lower wind speed case and the higher wind speed case is the trend of the equivalent loads. A large step occurs between the first and second turbine in the lower wind speed cases and then there is a steady linear increase to the last turbine. This initial large step is due to the strong wake deficit and the gradual linear trend is caused by a less...
significant wake deficit as well as more mixing of the deficit due to the increased turbulence intensity within the wind farm.

8.2 Horns Rev

At Horns Rev, the instrumented wind turbine, WT 14 is located on the western side of the wind farm in the second column from the west and in the fourth row from the north. The dominant wind direction for this site is from the west, thus there should be plenty of time periods one single wake alignment cases. The loads measurements data set that overlaps with the existing SCADA measurements for Horns Rev is available from 23/8/2005 through 31/8/2005. Thus, the wake cases and free inflow cases described below are from within this period.

8.2.1 Single Wake Cases

Three single wake cases exist for WT 14 and all involve a wake generating turbine from the first column of turbines. Table 14 below outlines the details of the three single wake cases considered for this project. Because the nearest met mast, M2 is nearly 25 rotor diameters (2km) from the northwest corner of the wind farm, the inflow wind direction is determined using the WT 14 yaw angle sensor. Each wake case is investigated independently, where in each query into the database the wind direction is specified by the WT 14 yaw angle sensor, and both the wake generating turbine and turbine 14 are required to be operating. A ±2 window is placed around each of the perfect aligned wind directions to allow for some variation in the yaw angles. This ±2 degree wind direction window is determined using the geometry of the park and the anticipated wake deficit width at the separation distance of the turbines.

<table>
<thead>
<tr>
<th>Source Turbine</th>
<th>Wake Affected Turbine</th>
<th>Inflow Wind Direction</th>
<th>Turbine Spacing</th>
</tr>
</thead>
<tbody>
<tr>
<td>WT3</td>
<td>WT14</td>
<td>312</td>
<td>10.4D</td>
</tr>
<tr>
<td>WT4</td>
<td>WT14</td>
<td>270</td>
<td>7D</td>
</tr>
<tr>
<td>WT5</td>
<td>WT14</td>
<td>221</td>
<td>9.4D</td>
</tr>
</tbody>
</table>

WT 3 → WT 14

Three time periods of 40 minutes or longer were found that met the filter requirements of WT 14 yaw alignment according to Table 15 ±2 degrees, and WT 3 and WT 14 are operating.
Table 15: WT 3 to WT 14 Wake Cases (10.4D separation)

<table>
<thead>
<tr>
<th>Start Time</th>
<th>End Time</th>
<th>Duration (hrs.)</th>
<th>Mean Wind Speed (m/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005/09/29 11:00</td>
<td>2005/09/29 13:10</td>
<td>2</td>
<td>11.5</td>
</tr>
<tr>
<td>2005/11/20 18:30</td>
<td>2005/11/20 19:10</td>
<td>0.8</td>
<td>10.1</td>
</tr>
<tr>
<td>2005/12/30 03:10</td>
<td>2005/12/30 03:50</td>
<td>0.7</td>
<td>9.2</td>
</tr>
</tbody>
</table>

WT 4 → WT 14
Three time periods of 40 minutes or longer were found that met the filter requirements of WT 14 yaw alignment according to Table 16 ±2 degrees, and WT 4 and WT 14 are operating.

Table 16: WT 4 to WT 14 Wake Cases (7D separation)

<table>
<thead>
<tr>
<th>Start Time</th>
<th>End Time</th>
<th>Duration (hrs.)</th>
<th>Mean Wind Speed (m/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005/12/23 16:40</td>
<td>2005/12/23 18:50</td>
<td>2</td>
<td>12.5</td>
</tr>
<tr>
<td>2005/12/22 23:20</td>
<td>2005/12/22 23:50</td>
<td>0.7</td>
<td>7.2</td>
</tr>
<tr>
<td>2005/10/01 21:20</td>
<td>2005/10/01 22:00</td>
<td>0.7</td>
<td>6.3</td>
</tr>
</tbody>
</table>

WT 5 → WT 14
Three time periods of 40 minutes or longer were found that met the filter requirements of WT 14 yaw alignment according to Table 17 ±2 degrees, and WT 5 and WT 14 are operating.

Table 17: WT 5 to WT 14 Wake Cases (9.4D separation)

<table>
<thead>
<tr>
<th>Start Time</th>
<th>End Time</th>
<th>Duration (hrs.)</th>
<th>Mean Wind Speed (m/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005/11/09 12:40</td>
<td>2005/11/09 13:10</td>
<td>0.7</td>
<td>10.7</td>
</tr>
<tr>
<td>2005/12/10 14:30</td>
<td>2005/12/10 15:30</td>
<td>1</td>
<td>13.6</td>
</tr>
</tbody>
</table>

8.2.2 Free Inflow Cases
The free inflow time periods for WT 14 are determined by requiring the WT 14 yaw angle to aligned along either 291 deg or 245.5 degrees. These inflow wind directions ±5 degrees will create non wake affected inflow conditions for the turbine, thus data collected from within these wind directions can be used for determining the turbine power curve as well as the equivalent loads for free inflow conditions. The power curve for this turbine is determined by using the nacelle wind speed, since there is no met mast available. 10% of the nacelle wind speed is added to the nacelle wind speed to correct to inflow wind speed and the power curve is plotted against this wind speed. The 1 Hz equivalent loads from the wake cases are compared against the 1 Hz equivalent loads from from the time periods where the turbine is operating in these wakeless wind direction windows.

8.2.3 Tower Base Bending Moment Verification
Figure 54 shows the N/S and E/W mean bending moment signals as a function of the nacelle position for a nacelle measured wind speed range of 5 to 7 m/sec. The nacelle position is corrected for any offsets and expected is a peak in the N/S signal at 0 degrees and 180 degrees and a peak at 90 degrees and 270 degrees for the E/W signal. The signals are approximately 90 degrees out of phase although both seem to be shifted relative to where the peaks should be. Also noted in the results is the non physical magnitudes of the mean bending moments. This data was provided from the large

62
data repository provided by the co-owner and operator of the wind farm. Relative analysis can still be conducted although any absolute results from this data are not discussed in this paper. Comparative analysis is done between free and wake conditions and different turbine separation distances during the wake conditions.

![Tower Base N/S and E/W Mean Bending Moment (5–7 m/sec)](image)

**Figure 54: Tower Base NS and EW Bending Moment Signals**

### 8.2.4 Tower Base Fore/Aft Equivalent Loads Sensitivity to Wind Direction

A comparative analysis between multiple and single wake cases as well as free inflow for WT 14 by plotting the normalized fore/aft 1 Hz equivalent load versus the wind direction for wind speed ranges between 6-8 m/sec. Since the magnitude of the loads are incorrect, the results are normalized and the different wake and free inflow conditions can be compared relatively. Figure 55 shows the equivalent load at the tower base as a function of the nacelle position with a nacelle measured wind speed requirement of 6-8 m /sec. Highlighted on the figure are the eight single or multiple wake situations for WT 14 at Horns Rev. When comparing the three westerly single wake cases, the results indicate the larger spaced case (from 312 and 221 deg) produces the smaller equivalent load and the shortest distance case (from 273) produces the second highest equivalent load. This will be shown to be consistent with results found in the Egmond Aan Zee results presented later.

Figure 56 illustrates the blade root flapwise 1 Hz equivalent load for two blades, Blade B and Blade C. The wind speed requirement is the same, as this range is a frequent wind speed for the site in addition to a high rotor thrust coefficient at these wind speeds. Evident in the results are the peaks associated with the wake cases as well as the small side lobes of the main peaks that correspond to partial wake loading situations. The equivalent load is a peak at wind directions where WT 14 is perfectly aligned with the turbine upwind. The surrounding turbine availability in this time period is high so cases included in results with non operating nearby turbines are minimal.
Figure 55: Fore/Aft 1 Hz Equivalent Load Sensitivity

Figure 56: Normalized Blade Root Flap 1 Hz Equivalent Load Sensitivity
8.3 Measurement Uncertainty Considerations

According to the IEC 61400-13, First Edition specification, measurement uncertainties are categorized into two types, type A and type B. Type A uncertainties are determined by analyzing a series of repeatable measurements. The standard uncertainty of the mean value of the results is determined by dividing the standard deviation of the measurements that made the mean by the square root of the number of observations. Type B uncertainties can not be determined by analyzing repeatable measurements although an estimate of the uncertainty is made using the general knowledge of the quantity being measured. A example of a type A uncertainty is estimating the mean wind speed at a 70m position on a met mast. An uncertainty estimate can be made by taking the standard deviation of the measured values for one period, and the same can be done for a slightly longer period that includes this first period. The larger the number of properly made measurements, the lower the statistical uncertainty. A type B uncertainty may be for example an incorrectly calibrated sensor or component in the measurement chain.

To determine for example the uncertainty associated with binning tower base N/S equivalent fatigue loads in 1 m/sec wind speed intervals, three components of uncertainty exist; the sensor calibration uncertainty, the signal or measurement quantity uncertainty, and the measured wind speed uncertainty. The sensor calibration uncertainty can be addressed by viewing the mean bending moments in the N/S signal as a function of nacelle mounted wind speed and looking for changes in slope of the curve. A change in slope may be indicative of a change in the gain or offset in the sensor used to measured the strain that was used to calculate the bending moment. The raw measurements for WT 7 and WT 8 from Egmond Aan Zee are provided in the Appendix for reference. All non verified or non physical measurements were eliminated from the dataset used in determining the loading trends presented in this paper.

The signal uncertainty is assessed by plotting the standard deviation of the measurements used to determine the mean loads in the results. Where possible, the standard uncertainty of the measurements is included in the paper. For example, in the transfer function of measured power to fore/aft tower equivalent loads, the uncertainty for each point on the map is presented. A large source of the uncertainty may be attributed to using the met mast wind speed instead of the nacelle mounted wind speed or the power and robust power curve from the either WT 7 or WT 8. However, the met mast wind speed is only used for conditions where the sensor is in free stream and not affected by either the met mast structure itself or the wind farm. The met mast is located within 6D from the two instrumented turbines and is larger than the IEC 61400-12 specification for wind turbine power curve testing. Therefore, there is an uncertainty associated with the spatial difference between the loaded turbine and the measured wind speed. The impact of this uncertainty is binning equivalent loads in a slightly lower or slightly higher wind speed bin and thus the results are not significantly affected. It is proposed that the dominant source of uncertainty in this project is the type A standard uncertainty of the measured quantity.
9 Comparison of Operational Measurements with Aeroelastic Model

In this final section, the key results from analysis of the measurements are compared to the general trends found from the HAWC2 aeroelastic simulations. The simulated wake deficit shape and the wake meandering statistics are included to illustrate how these change with distance downstream. Both free inflow and wake conditions are compared and most of the comparison work is focused on the V90 wind turbine due to the issues with the V80 structural measurements. V80 results are only included in the frequency spectra analysis section later in this section.

9.1 Free Inflow Conditions

The mean bending moments in the tower base, the blade flap direction, and the blade edge direction have been determined using the measurements from free inflow conditions at different hub height mean wind speeds. For a given wind direction window and for different mean wind speeds measured by an undisturbed anemometer on the nearby met mast at hub height, the magnitude of the mean bending moment at the tower base (4.4 m from the bottom mast) can be found using the N/S and E/W bending moment sensors and measured wind direction. Measurements from WT 7 are used for this comparison due to the higher availability of the measurement system for this turbine (see Appendix for WT 7 and WT 8 bending moment data versus time). Each point on the plot represents the mean value of the ten minute average bending moment measurements for a wind speed bin with a mean value as indicated on the plot. The mean bending moments for the three sensors can also be generated using the aeroelastic model. A steady state analysis was done using the aeroelastic model, where the rotor is kept at a constant rotational rate for each wind speed, the hub height mean wind speed is set to match the measurements, the power law wind shear profile with $\alpha = 0.12$ was used for the inflow conditions. The mean bending moments are taken from a time period where the simulation has initialized and large fluctuations of loads have stabilized. Figure 57 and 58 shows the comparison between the aeroelastic model results and the measured mean bending moments for the tower base (4.4 m above bottom flange) and blade root (6.6m from root) respectively. There is close agreement between the measurements and the model, which indicates that the aerodynamics (thrust) is correct in the model. A close agreement between model and measurements in the free inflow conditions provides a solid foundation for comparison of the two in the single wake conditions.

![Normalized Tower Base Mean Load Comparison](image1)

![Normalized Blade Root Edge Mean Load Comparison](image2)

Figure 57: Mean Fore/Aft Tower Base Bending Moments

Figure 58: Mean Blade Root Bending Moments

In addition to comparing the mean loads between the measurements and the aeroelastic simulation for free inflow conditions, the 1 Hz equivalent loads of the tower base fore/aft bending moment, the tower top tension bending moment, and the blade root flap wise bending moment can be compared as a validation of the model. Measurements are extracted from the database from WT 7 and WT 8 for free inflow conditions with winds from the southwest as measured by the 116 m NW wind vane.
on the met mast. The comparison is done for three different mean inflow wind speeds and for a turbulence intensity of 8%. The wind speed requirement is placed on the 70m NW cup anemometer for the three cases, (5-6m/sec), (8-9 m/sec), and (12-13 m/sec). The presented measured results correspond to periods of time where multiple sequential time periods met the wind speed and wind direction requirements and the values presented represent the mean equivalent loads. An equivalent load is determined for each ten minute period, then the mean is taken of all equivalent loads. For the simulation, a turbulence intensity of 8%, wind profile shear values of 0.08, 0.10, and 0.12 were used for the three mean wind speeds of 5.5, 8.5, and 12.5 m/sec respectively. Thirty minute simulations were run with one turbulence box and the equivalent loads are determined by using the later 1700 seconds of the simulated time series to eliminate any start-up affects in the calculation of the equivalent load.

Figures 59 and 60 illustrate the a close agreement between the measured tower base equivalent loads and the simulated equivalent load for the wind speed bins of 8-9 m/sec and 12-13 m/sec respectively. However, the blade root flapwise 1 Hz equivalent load for the higher wind speed cases is not in agreement with measurements. This is most likely attributed to the large wind shear at these wind speed levels and the simulated constant blade pitch angle assumed over all azimuthal positions. In reality, the blade can be pitched as a function of azimuth position to maximize energy and also to alleviate the unbalanced blade loads and nacelle yaw or tilt moments.

![Comparison of Free Inflow Conditions 1 Hz Equivalent Loads (8-9 m/sec)](image1)

![Comparison of Free Inflow Conditions 1 Hz Equivalent Loads (12-13 m/sec)](image2)

Figure 59: WT 7 and WT 8 Free Inflow Conditions, Figure 60: WT 7 and WT 8 Free Inflow Conditions, $T_i = 8\%$ (8-9 m/sec) $T_i = 8\%$ (12-13 m/sec)

Figure 61 shows the similar comparison although for the wind speed bin of 5-6 m/sec. There is a significant difference (30%) between the measured and simulated loads for the fore/aft tower base 1 Hz equivalent load although close agreement in the other two components. At the lower wind speeds, the equivalent load in the tower base may be more sensitive to the inflow turbulence intensity and also the shear in turbulence intensity which may explain why there is larger differences at the lower wind speed range. The model assumes no shear in turbulence intensity although measurements at the site have shown there is a significant difference in turbulence intensity as a function of height (between 21m and 70m) for wind speeds above 5 m/sec. Wind profile shear is minimal at 5 m/sec hub height wind speed, thus a constant blade pitch angle as a function of azimuthal position will not affect the simulated blade flapwise root 1 Hz equivalent load.

9.2 Simulated Wake Deficit Shape

The wake deficit profile and the corresponding overall physical extent or size is an important characteristic of the wake that must be considered when evaluating the turbine loading. The wake deficit is commonly displayed as a percentage of the wake wind speed, $U$ to the undisturbed free stream wind speed, $U_0$ versus the ratio of the radial position in the rotor, r to the rotor radius, R. As shown in Figure 62 the gradients of the 8 m/sec inflow wind speed deficit are larger for regions closer to the wake.
generating turbine and are reduced as the wake translates downstream. A large change in wind speed over small distances within the rotor plane can lead to unsteady aerodynamics and thus fluctuating loading on turbine components. This attribute combined with the meandering of the wake can lead to severe gradients in wind speed over the rotor plane, increasing the fatigue on turbine components. As shown in Figure 63, the 12 m/sec inflow wind speed deficit at center position of the rotor for the 4D separation is 0.70 of the free stream wind speed. This is slightly larger than the deficit associated with the same spacing and same location in the rotor plane for the 8 m/sec inflow wind speed case. This difference is due to the increased thrust coefficient at the 8 m/sec wind speed, thus the rotor is effectively slowing more of the incoming wind than in the 12 m/sec case, thus the deficit is more severe.

The deficit shape is driven by the pressure loss behind the rotor for the near wake region up to approximately 2-3 rotor diameters. Beyond this distance, the wake deficit shape is driven by the turbulence mixing of the ambient turbulence and the blade tip and root vorticities. In addition to the turbulent mixing, the deficit is also transformed as it moves downstream by the velocity shear within the wake itself and between the wake velocity and the ambient wind speed outside the wake region. An idea of the wake shape for varying distance downstream also provides the information needed for determining what inflow wind directions will produce wakes on downstream turbines for all the operational wind speeds. The wake deficit shapes were used in this project to determine when a downstream turbine would be influenced by a wake under no meandering conditions.

Figure 64 is included to illustrate the ambient turbulence effect on the wake deficit shape for two different downstream distances and for an inflow wind speed of 8 m/sec. Two ambient turbulence values are used, 7%, and 8% which represent the mean site turbulence intensities for the neutral and unstable atmospheric stabilities respectively. As shown, there is not a lot of difference between the two ambient turbulence cases for either downstream distance investigated. Added wake turbulence and ambient turbulence will contribute to the recovery of the deficit although the difference between 7% and 8% ambient turbulence intensity is not significant, thus the added wake turbulence is the primary driver of the wake deficit recovery.
9.3 Simulated Wake Deficit Center Meandering

In addition to the wake deficit shape and physical extent, the variability of the wake deficit center position, and thus the rest of the wake is also important to understand in relation to turbine wake affected loading. A convenient way to analyze the meandering phenomenon as a function of downstream distance and ambient turbulence is to plot the standard deviation of the wake deficit center horizontal and vertical positions. The simulated results presented are from unique ten minute simulations run for each turbine separation distance at each of the three turbulence intensity levels. The standard deviation of the wake position over each of the ten minute simulations is plotted. The turbulence box parameters are the same as for the simulation results presented in the next section. Figure 65 below illustrates that the horizontal position of the wake deficit has more variability as the it moves further downstream. In addition, large ambient turbulence intensities have larger variation in the deficit center location than do the small ambient turbulence intensities. Figure 66 shows the smaller standard deviation of the vertical position of the wake deficit center. Atmospheric turbulence is known to have more intensity in the horizontal direction than in the vertical direction which is considered in the turbulence box model in HAWC2.

For the closer separation distances with minimal meandering, the shape of the wake deficit combined with the minimal meandering may produce a loading environment that yields high fatigue loading on turbine components. However, a high fatigue loading situation may arise from the combination of a large amount of wake movement perpendicular to the downstream wake movement and a less severe (smaller velocity gradients) deficit. The discussion included below aims to address these questions.

9.4 HAWC2 Turbulence Box Specifications

Three turbulence boxes are required for each simulation run and the parameters are provided in Table 18. The meander turbulence box, the added wake turbulence box, and the ambient turbulent box are required for the wake model. The length scale term refers to the dominant length scale of the turbulence structure in the longitudinal direction. For the meander and ambient boxes, the length scale is recommended to be 33.6 according to IEC61400-1 ed3. The length scale for the added wake turbulence box is defined as one-tenth the rotor diameter of 90m. The $\alpha e^{2/3}$ term refers to a scaling of the standard deviation of the wind speeds in the center of the box to match the turbulence intensity specified in the $t_{int}$ parameter in the configuration file. This term is scaled internally and a value of 0.1 is set to match an example turbulence generator file. The $\gamma$, shear distortion parameter, term is set to the value recommended by the IEC specification and this is a factor to describe the degree of isotropy of turbulence. When this term is zero the turbulence in considered isotropic although when this number increases longitudinal and lateral variances increase and the vertical variance decreases.
Figure 64: Comparison of Wake Deficit for Different Ambient Turbulence Intensities

The seed is a random number to provide a random start point in the generation of the turbulence box. The High Frequency value is set to 1 as recommended by the HAWC2 manual. When the value is set to one, there is no spatial averaging of the grid velocity or in other words, the assumption that states that point velocities equal the average velocity in a grid cell.

<table>
<thead>
<tr>
<th>Turbulence Box</th>
<th>Length Scale</th>
<th>$\alpha \bar{c}^{2/3}$</th>
<th>$\gamma$</th>
<th>Seed Number</th>
<th>High Freq</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meander Box</td>
<td>33.6</td>
<td>0.1</td>
<td>3.9</td>
<td>11</td>
<td>1</td>
</tr>
<tr>
<td>Added Wake Turbulence Box</td>
<td>9.0</td>
<td>0.1</td>
<td>3.9</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Ambient Turbulence Box</td>
<td>33.6</td>
<td>0.1</td>
<td>3.9</td>
<td>21</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 18: Mann Turbulence Box Parameters

Table 19 below illustrates the dimensions of the three turbulence boxes. The dimensions for the three directions of each box are shown by the total number of grid points as well as the spacing in meters between each grid point. For example, the meander turbulence box is a total of 12288 meters and at 12 m/sec, the turbulence box with last for 1024 seconds. If the simulation is set to run for longer, the turbulence box is recycled. Most of the simulations were run for 600 seconds, thus these dimensions for the along wind dimension are adequate. Because the large scale turbulence is responsible for the wake meandering, the grid size in the lateral and vertical directions is the size of the rotor diameter. This large grid size acts as a filter, allowing only large scale turbulence structures to persist. The lateral and vertical dimensions for the added wake turbulence box is small to resolve different turbulence over the length of the rotor although the total size of the box in these directions is 10% bigger than the rotor diameter. The lateral and vertical box dimensions for the ambient turbulence box is the size of the rotor diameter and has a more coarse resolution than the added wake turbulence. The turbulence in this box is used in the generation of the initial wake deficit.
### Table 19: Mann Turbulence Box Dimensions

<table>
<thead>
<tr>
<th>Turbulence Box</th>
<th>$u - \text{dim.(Num.Pts, dist.between Pts.)}$</th>
<th>$v - \text{dim.}$</th>
<th>$w - \text{dim}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meander Box</td>
<td>16384, 0.75</td>
<td>32, 90</td>
<td>32, 90</td>
</tr>
<tr>
<td>Added Wake Turbulence Box</td>
<td>128, 1.7578</td>
<td>128, 0.78125</td>
<td>128, 0.78125</td>
</tr>
<tr>
<td>Ambient Turbulence Box</td>
<td>16384, 0.75</td>
<td>32, 2.875</td>
<td>32, 2.875</td>
</tr>
</tbody>
</table>

#### 9.5 Simulated Wind Turbine 1 Hz Equivalent Load Sensitivity to Turbine Separation

Wind turbine tower base fatigue loads have been shown in the Egmond Aan Zee wind farm measurements to vary as a function of wind turbine separation distance for the different measured ambient turbulence intensities at the site. The instrumented wind turbines, WT 7 and WT 8 are in a location such that not many time periods occur in the measurements with these turbines in a single wake case situation. Thus, the transfer function from power statistics to tower base fore/aft equivalent load obtained from these two instrumented turbines is used on the non-instrumented turbines that are in single wake cases and at different turbine spacings. Only turbine fore/aft 1 Hz equivalent load can be compared for the non instrumented turbines. An aeroelastic model of the V90 turbine has been made and used in the HAWC2 aeroelastic simulation to generate tower base, blade root flapwise, and tower top torsion 1 Hz equivalent load sensitivities to tower separation in single wake cases. Three wind speeds were investigated, 6 m/sec, 8 m/sec, and 12 m/sec and three turbulence intensities of 7%, 8%, and 9% to represent the three different mean turbulence intensities in the three different atmospheric stability classes. The wind shear is also set in the simulation to the appropriate value for each wind speed according to results in Figure 13.

The v90 HAWC2 configuration file in provided in the Appendix for reference. A small external application was built in C# programming language that was used to call HAWC2 repeatedly, each time changing the turbine separation distance and renaming the output files. The turbine separation distance was varied between two and twenty rotor diameters and the turbine hub height was fixed at 70m for each turbine separation case. In order to get a smooth estimate of the equivalent load sensitivities, three different meander, wake added, and ambient turbulence boxes were used and the mean equivalent load is shown for each turbulence intensity. The coherence and length scale properties of the turbulence boxes are the same although a unique seed was used to generate each box. As discussed earlier, three turbulence boxes are required for each HAWC2 simulation run and the turbulence is scaled with the ambient and wake meandering turbulence intensity parameters in the configuration file. The simulation results are presented for each wind speed case below.
### 9.5.1 Inflow Wind Speed: 6 m/sec

Figure 67 and Figure 68 show the tower base fore/aft and tower top torsion equivalent load as a function of turbine separation distance for three different ambient and wake meander turbulence intensities. The low wind speed case is considered due to the high rotor thrust coefficient which may cause severe initial wake deficits. Currently, wind shear is not taken into account in the generation of the wake deficit, thus an axi-symmetric wake deficit will be produced for three wind speed cases, although with different wake deficit shapes due do the different rotor rotational speed and the rotor thrust coefficient. It is shown that there is a peak in the tower base equivalent load at 10D, 12D, and 14D for the 7%, 8%, and 9% turbulence intensities. As expected, the higher the meander turbulence, the closer to the wake generating turbine the peak load moves. The deficit is able to move more in a shorter downstream distance for higher and higher meander turbulence intensities. This trend is also shown in the tower top torsion moment equivalent load with the peak locations at the same distance as the tower base fore/aft loads.

![Figure 67: Normalized Simulated Tower Base Equivalent Load](image1)

![Figure 68: Normalized Simulated Tower Top Torsion Equivalent Load](image2)

The blade root flapwise 1 Hz equivalent load is shown in Figure 69 and a similar trend of increasing load with turbine separation distance is seen for the three turbulence intensity cases. The loading decreases at further turbine separation distances which can be attributed to a less severe wake deficit meandering over a larger area. The 9% turbulence intensity case has a larger equivalent load than the other two turbulence cases for all turbine separation distances. As the turbulence intensity increases, the amount of lateral and vertical wake deficit movement increases, thus the fatigue loading will also increase due to the variation of wind speeds across the rotor plane. Unlike the tower base and the tower top torsion trends, the blade root equivalent load does not decrease significantly with distance after the local maximums. The deficit is still strong enough at the further distances to create a gradient in wind speeds across the rotor in addition to the shear. The deficit does not appear strong enough to keep the tower fatigue loads near the maxima however.
Figure 69: Normalized Simulated Blade Root Equivalent Load
9.5.2 Inflow Wind Speed: 8 m/sec

The peak loading locations of the tower base for 8 m/sec inflow wind speeds occurs at the same distances for each turbulence intensity case as the 6 m/sec inflow wind speed case. However, the magnitude of the equivalent load has increased for all turbine separation distances compared to the 6 m/sec wind speed case. At 8 m/sec, the load ranges or amplitudes counted in the rainflow algorithm are larger than the amplitudes counted in the 6 m/sec case, thus the equivalent load is higher.

Figure 70: Normalized Simulated Tower Base Equivalent Load

Figure 71: Normalized Simulated Tower Top Torsion Equivalent Load

Figure 72 illustrates the blade root flapwise fatigue loads as a function of turbine separation for the 8 m/sec inflow wind speed case. In this case, the fatigue loading after the local maximums remains relatively constant for distance further downstream. At 8 m/sec, the thrust coefficient is nearly the same as the thrust coefficient at 6 m/sec thus the loading trends should be similar to each other. Again, the magnitude of the blade root equivalent load for the 8 m/sec case is larger than the 6 m/sec case.
Figure 72: Normalized Simulated Blade Root Equivalent Load
9.5.3 Inflow Wind Speed: 12 m/sec

Figure 73 illustrates the tower base fore/aft 1 Hz equivalent load for the 12 m/sec inflow case for varying turbine separation distances. The magnitudes of the equivalent loads are larger than the 6 and 8 m/sec wind speed cases as expected and also important to note is the location of the peaks for each turbulence intensity. The peak locations are consistent with the peak locations from the other two lower wind speed cases, thus the peak location of the tower base equivalent load is insensitive to mean inflow wind speed. The key driver of the peak location is the wake deficit shape and the ambient low frequency, large scale turbulence structures. Figure 74 shows the tower top torsion equivalent load sensitivity to turbulence intensity and turbine separation.

Figure 73: Normalized Simulated Tower Base Equivalent Load

Figure 74: Normalized Simulated Tower Top Torsion Equivalent Load

Figure 75 shows the blade root flapwise 1 Hz equivalent load sensitivity with turbine separation and ambient turbulence intensity for the 12 m/sec inflow case. In this case, there is a significant reduction in equivalent load after the local maximums that is not seen in the other wind speed cases. The thrust coefficient of the rotor is significantly less at 12 m/sec than at 8 m/sec (almost 38% reduction) thus the deficit is not as severe and the wind speed gradients across the deficit are reduced. A less severe wake deficit that meanders across a rotor plane will have a smaller impact on the fatigue damage than a more severe wake deficit with the same meandering statistics.
Blade Root 1 Hz Equivalent Load, 12m/sec

Figure 75: Normalized Simulated Blade Root Equivalent Load
### 9.5.4 Comparison of Blade Root Flapwise Fatigue Loads

To illustrate the effect of wind speed on the fatigue loading trends for the blade flapwise and tower base fore/aft signals, the three wind speed cases are plotted together for an inflow turbulence intensity of 8%. For the tower, the peak load location remains at the same downstream distance (12D) although for the blade root, this peak location varies between 10D and 14D. Also shown in the blade plot is the steeper trend for the 8 m/sec case for distances below the peak fatigue loads. This is probably due to the more severe wake deficit associated with peak thrust coefficient at this wind speed. For the tower, the fatigue for all wind speeds is more or less the same for closely spaced turbines although for the blade, there is a significant difference between the three wind speeds. So for short distances or minimal wake meandering, the tower loads for three different wind speeds are approximately the same. Even though the deficits are different at the close locations, the fatigue load are similar. This provides evidence that the meandering component of the model is the key contributor to the increasing fatigue loads as the distance increases.

![Comparison of Simulated Normalized Blade Root Flapwise Fatigue Loads (T_i=8%)](image)

![Comparison of Normalized Simulated Tower Base Fatigue Loads (T_i=8%)](image)

**Figure 76**: Simulated Blade Root Flapwise Fatigue Loads  
**Figure 77**: Simulated Tower Base Fatigue Loads
9.6 Comparison of Simulated and Measured Tower Base Fore/Aft Equivalent Loads

The simulation results presented above produce clean trends of the wind turbine equivalent loads and the Egmond Aan Zee measurement results have been presented in the Operational Measurements section of the paper. In this section, the two are brought together and a comparison is made for three different mean wind speed cases, 6 m/sec, 8 m/sec, and 12 m/sec. First, the measurements and simulation will be compared with the meandering component of the simulated wake model enabled. Next, the same measured results are compared to simulated results without the meandering component (only wake added turbulence and wake deficit). Also, the results from the one dominant prolonged wake case identified for Egmond Aan Zee WT 8 are compared to a simulated case with similar wind conditions and turbine operating parameters.

9.6.1 Simulation with Wake Meandering

Figures 78, 79, and 80 present the comparison between the measurements results from Egmond Aan Zee and the simulation results. As shown, there is a significant difference between the two for all three wind speed cases. A similarity is the general trend of decreasing equivalent loads as a function of turbine separation distance after the local maximums. Only the tower base fore/aft equivalent loads are compared primarily due to the lack of wake cases acting on the actual instrumented wind turbines. A histogram of all the equivalent loads measured at WT 7 and WT 8 at Egmond Aan Zee was provided in an earlier section with the transfer function used to estimate the tower base fore/aft equivalent loads. There are very few instances of measured equivalent loads above the 3000 kNm level. It was shown that the model and the measurements were in agreement for the non wake cases for the tower base, blade root, and fore/aft equivalent loads for the three different wind speeds, although there is a significant difference between the model results and the measured results for in the single wake cases. To help identify the source of the difference, a small study was done where the meander turbulence was set to 0.001%. The remaining wake model components are the added wake turbulence and the wake deficit.

Figure 81 illustrates the variation in the equivalent loading trend for different meander turbulence box seeds used. The structure of the turbulence box has the same statistics and grid sizes although a different seed is chosen in the generation of the box. The mean inflow wind speed is 12 m/sec and the ambient and wake meander turbulence is 9% There is a 2D separation distance between two of the turbulence boxes and the third turbulence box. This is a significant difference although the turbine separation step size used in the parametric study is only two rotor diameters, thus the peak has moved one point. A finer separation distance parameterization will help determine the exact influence of the turbulence box on the peak location.
Figure 78: Comparison of Tower Base Equivalent Loads, 6m/sec, $T_i = 8\%$

Figure 79: Comparison of Tower Base Equivalent Loads, 8m/sec, $T_i = 8\%$
Figure 80: Comparison of Tower Base Equivalent Loads, 12m/sec, $T_i = 8\%$

Figure 81: Variation in Local Maximum with Different Turbulence Seeds, 12m/sec, $T_i = 9\%$
9.6.2 Simulation without Wake Meandering

When the wake meandering component of the aeroelastic model is disabled, there is a much closer agreement between the model and the measurements for the three different wind speed cases. The general trend of decreasing equivalent loads with increasing turbine separation distances is common to all three cases. The simulation is in close agreement or slightly over predicts the equivalent load for the 6 and 8 m/sec wind speed cases although under predicts the equivalent load for the 12 m/sec case. The measurement results represent mostly unstable atmospheric conditions, thus the wake deficit will recover more quickly than in stable conditions or in the simulation. At low wind speeds, the instability may be driven more by the temperature gradient than the wind speed gradient with height. For the 6 m/sec case, possible sources of why the simulated loads are higher than measured include, too severe a deficit, or too high of wake added turbulence.

Figure 82: Tower Base Equivalent Loads (No Sim. Meander), 6m/sec, $T_i = 8\%$

Figure 83 shows the comparison between the simulated tower base equivalent loads and the estimated loads from measurements for the 8 m/sec inflow wind speed case. Shown in the figure is the simulated mean and standard deviation of the fatigue loads for each turbine separation distance. Three sets of distinct (unique seeds and similar spatial dimensions) ambient and added wake turbulence boxes are used to generate the mean and standard deviation for each separation case. The same is shown in Figure 84 for the 12 m/sec inflow case.

Figure 84 shows the comparison between the simulated tower base equivalent loads and the estimated loads from measurements for the 12 m/sec inflow wind speed case. The measurement data presented in this comparison is identical to the measurement data presented in the Wake Analysis Using Operational Measurements section.

For the three wind speeds investigated, the general trend of the tower base fore/aft 1 Hz equivalent loads decreases with increasing turbine separation distance and this is common between the measurements and the simulated results without the meander component. Also in agreement are the magnitudes of the equivalent loads between the simulation and measurements. This indicates that
Comparison of Measured Tower Base 1 Hz Equivalent Loads to Simulated Loads (8m/sec)

Figure 83: Tower Base Equivalent Loads (No Sim. Meander), $8\text{m/sec}$, $T_i = 8\%$

Comparison of Measured Tower Base 1 Hz Equivalent Loads to Simulated Loads (12m/sec)

Figure 84: Tower Base Equivalent Loads (No Sim. Meander), $12\text{m/sec}$, $T_i = 8\%$
the deficit and the added wake turbulence are modeled more accurately than the meandering. The meandering component of the simulation is to severe and creates a loading environment on the turbine not experienced in measurements at the Egmond Aan Zee offshore wind farm.

9.7 Comparison of Simulated and Measured Wind Turbine Power Deficit

In addition to comparing the equivalent loads, a comparison between measurements and simulation for the power deficit for different turbine separation distances is conducted and the results are shown in Figure 85. The meandering component of the model is enabled for this comparison. There is very close agreement for the 12 m/sec wind speed case although the simulation tends to over predict the power deficit for the 6 and 8 m/sec cases. For the separation distances considered, the average standard deviation for the measured power deficit is 9% for all separation distances. This is consistent with the over prediction of the equivalent loads as well. The simulated power deficit may be too severe and cause two effects: 1.) stronger gradients across the rotor which increase the fatigue loads and 2.) lower mean wind speeds across the wake affected rotor thus reducing output power. As shown earlier, the ambient turbulence component in the model did not seem to have a significant effect on the recovery on the wake deficit. If this component was too conservative, the wake deficit may remain more severe than it should for ambient turbulence intensities in the 7% to 8% range. The simulated power deficit does more closely model the power deficit for the 18.2D case than the 7.1D case.

![Comparison of Measured Power Deficit to Simulated Deficit (Ti=8%)](image)

Figure 85: Wind Turbine Power Deficit (with Meandering), $T_i = 8$

9.8 Simulated Tower Base Fore/Aft Mean Bending Moment

To illustrate the effect of the meandering component of the model on the tower base fore/aft mean bending moment, the component is disabled in the model and the results are compared against a meandering case with meander turbulence intensity of 8%. The meandering creates periods of undisturbed inflow on the rotor, thus higher wind speeds, and thus higher thrust force and tower base bending moment for wind speeds up to 12 m/sec. When the meandering turbulence is set to a very
small value, 0.1% the deficit remains centered more or less over the downwind rotor so this rotor does not experience free stream wind speeds. This will keep the tower bending moment lower than the tower bending moment with the meandering enabled. Figure 86 illustrates these trends for the three different mean inflow wind speeds investigated (NM → no meandering, M → meandering). The overall increasing trend with separation distance is accounted for by the wake deficit recovery towards the ambient mean wind speed as the wake translates downstream.

![Figure 86: Simulated Tower Base Fore/Aft Mean Bending Moment $T_i = 8\%$](image)

9.9 Egmond Aan Zee Wake Case 1: WT 21 → WT 8

The single prolonged wake case found in the Egmond Aan Zee measurements is simulated using a set of configuration parameters set up to closely match the measurement period. An inflow mean wind speed of 12 m/sec with ambient turbulence of 7% is used in the simulation and two different meander turbulence boxes are used to determine the mean equivalent loads and power deficit for WT 8. The simulation was run for 30 minutes which is approximately the length of the perfect wake alignment period within the two hour wake scenario. For the measurements, the 1 Hz equivalent loads are determined from the original time series of the tower base, tower top, and blade root signals. The first 100 seconds is excluded from the simulation time series and the same algorithm is applied to these time series to obtain the simulated equivalent loads. A case without the meandering component, $T_{int} = 0.001\%$ is also provided for comparison.

Table 20 shows the results of the comparison for the mean 1 Hz equivalent loads and the mean power deficit at the downstream wind turbine. There is a significant difference between the measured and simulated fatigue loads when the simulation is done with a nonzero meandering turbulence intensity. When the meandering component from the simulation is removed, the comparison is much closer. Because of the large separation distance, 13D spacing, the results may be sensitive to the wind direction and because of the orientation of this particular wake case, the measured wind direction may be shifted relative to the free stream wind direction. Also, there may be a funnelling effect seen at WT 21 due to the line of turbines in a v-shape to the north east and to the north west.
9.10 V90 3.0MW Frequency Analysis

9.10.1 Tower Base Fore/Aft Frequency Spectra

A comparison of frequency response of the tower base fore/aft time series signal for different inflow mean wind speeds may yield incite into why there is a large difference between the measured and simulated fore/aft fatigue loads. Three free inflow mean wind speed ranges were analyzed in HAWC2 and three different periods in the measurements were found that matched the free inflow conditions of wind speed, wind direction, and mean turbulence intensity of 8%. The data used for the comparison of equivalent loads for free inflow conditions presented an earlier section of this chapter are used for the frequency spectra comparison. One long time series is created from the consecutive 10 minute periods and the fast fourier transform is used to determine the frequency content of the time series. For the simulation, the sample frequency is 50 Hz and for the measurements the sample frequency is 32 Hz. The respective Nyquist frequencies are 25 Hz and 16 Hz, thus only information below these frequencies will be considered. A close agreement between simulation and measurements in the tower system frequency response will eliminate the idea that maybe the model is too stiff or underdamped which both can lead to too high of equivalent load estimates.

Figure 87 shows the tower base fore/aft frequency response for an inflow wind speed range of 5-6 m/sec. There is a shift in first tower frequency, with the simulated version at a higher slightly higher frequency than measured. The simulated results also indicate a slight double peak at the first tower resonant frequency (0.38 and 0.45 Hz) and there is a faint indication of this same phenomenon in the measured signal although at lower frequencies (0.33 and 0.35 Hz). The measured tower first mode peak is at a lower frequency because tower is mounted in the seafloor and this is not considered a fixed base as assumed in the model. The model assumes a rigid connection at the mudline, so the modeled tower is also shorter than the operational tower. At these low wind speeds, the simulation controller controls the rotor rotational rate slightly lower than it should be, thus the 3P peak has moved down towards the tower resonant frequency for this wind speed range. The first narrow peak at approximately 0.2Hz is the 1P (once per revolution) loading that corresponds to the one blade passage of the tower. Multiples of this peak are also shown in the measurement frequency spectra.

Figures 88 and 89 show a better agreement between the simulated and measured tower base frequency response for both the first tower mode and the 3P frequency. The shift to higher frequencies for the simulated cases common to both wind speed classes may be attributed to the difference in the tower damping. The higher damped system will tend to have a lower resonant frequency and this is consistent with the slightly under damped model compared to the operational turbine. The close agreement between the simulated and measured tower base fore/aft frequency spectra cannot be a source of the difference between the fatigue loads for the wake conditions.
Figure 87: Tower Base Fore/Aft Frequency Spectra, (Free Inflow)

Figure 88: Tower Base Fore/Aft Frequency Spectra, (Free Inflow)

Figure 89: Tower Base Fore/Aft Frequency Spectra, (Free Inflow)
9.10.2 Frequency Analysis for Evidence of Wake Meandering

In addition to investigating the mean and 1 Hz equivalent loads, evidence of the wake meandering phenomenon may be available by analyzing the frequency content of a few key high resolution measurements from WT 7 or WT 8. The fast Fourier transform is an algorithm that transforms a time series of a particular sample rate into a frequency spectra. Peaks or large amounts of energy at various frequencies are found at or below one half (16 Hz) the sampling frequency of 32 Hz, or Nyquist frequency. Since the wake meandering occurs at very low frequencies and involves large scale movements of air, the sample rate of 32 Hz is sufficient to find low frequency content of the measured time series. According to [2], the cut-off frequency in Hz for the wake meandering is approximated by the following equation. The frequency is proportional to the mean wind speed, \( U \) and inversely proportional to two times the width of the wake deficit, \( D_w \).

\[
f_c = \frac{U}{2D_w}
\]

Consider an ambient wind speed of 12 m/sec and two separation distances, 4D and 20D. Using the wake deficit widths from above, the corresponding cut-off frequencies are 0.02 Hz and 0.03 Hz respectively. According this definition, frequencies at or below this cut-off frequency will be responsible for the meandering of the wake deficit.

The time series under consideration include the fore/aft tower base and top section bending moment, the output electrical power, and the tower top torsional bending moment. The time series data for the WT 21 and WT8 wake case mentioned previously. The turbine separation in this case is 13D and the inflow wind speed is approximately 12 m/sec mean over the time series used. In addition to looking at the wake case, I found a free inflow case with a similar mean inflow wind speed so that the frequency response of the relevant time series can be compared between wake affected and free inflow turbine operation. Figure 90 below shows the frequency spectra of the WT 8 tower fore/aft bending moment. The fore/aft signal is generating using the North/South and East/West bending moment signals prior to generating the frequency spectra.

![Figure 90: Fore/Aft Tower Base Frequency Response](image1)

![Figure 91: Low Frequency Content](image2)

There is also a low frequency broad peak at around the same frequency in the wake affected tower base fore/aft bending moment as shown in Figure 92.

The rotational speed of the rotor is shown as the first broad or flat top peak (1P) and the subsequent multiples (2P,3P, etc.) of this peak are also shown. Also shown is the turbine fore/aft natural frequency just to the right of the 1P peak. This sharp 1P peak seen in the tower is probably attributed to a blade imbalance such that everytime the blade passes the tower or another point in the rotation,
Figure 92: Low Frequency Content of Tower Base Fore/Aft Bending Moment

The loading is seen in the tower base. The peak only includes frequencies associated with the blade rotational speed for the measurement period considered, thus the sharp drop off on either side. Figure 91 is a zoom of the same plot focused on the low frequency content, below 1.5 Hz. It is evident that there is a peak near 0.12 Hz that occurs in the wake case and not in the free inflow case. This broad based peak may be an indication of the meandering deficit oscillating across the rotor, creating periods of higher free inflow conditions and periods of lower wake affected inflow conditions. This frequency may correspond to the frequency of oscillation between a mostly wake deficit covered rotor and a mostly free inflow covered rotor.

Figure 93: Tower Top Torsion Frequency Response

Figure 94: Low Frequency Content

The tower top torsion bending moment and the output electrical power are also analyzed to see if there is evidence of low frequency wake meandering. Figure 93 and 94 show the comparison of the frequency response for these two signals and both do not seem to have any dominant low frequency peaks as shown in the tower base and tower top fore/aft bending moments. The 1P peak is shown in the
ter top torsion frequency spectra which would also indicate a possible blade imbalance. The tower undergoes a torsional moment when one of the blades is perpendicular or near perpendicular to the tower. The output electrical power may have a low frequency filter acting on the source aerodynamic power that effectively smoothes out any low frequency variation that may occur in the aerodynamic power. The deficit not only moves in the lateral plane, it also translates in the vertical plane which in this case will not have an affect on the torsional bending moment.

As a way to verify whether or not the low frequency content of the measured fore/aft tower bending moment is due to wake meandering, the frequency spectra of the simulated wake deficit vertical and horizontal positions is analyzed. The simulation is set up such that the turbine spacing, the ambient turbulence intensity, the inflow wind shear, and the inflow ambient wind speed match the measured wake case. Figure 95 below shows the low frequency content of the vertical and horizontal wake deficit positions in a frame fixed to the base of the wake producing turbine, thus also in fixed frame relative to the wake affected turbine. There is a dominant low frequency peak of approximately 0.11 Hz in the horizontal time series signal although not evident in the vertical signal. This may be due to the fact that the turbulence scaling in the horizontal direction is 0.8 whereas in the vertical direction the scaling factor is 0.5. This analysis was done for three unique meandering turbulence boxes and all yield a similar peak at 0.11 Hz.

![Frequency Content of Simulated Wake Deficit Center Positions](image)

**Figure 95: Low Frequency Content of Wake Deficit Positions**

Evidence in the model that correlates with evidence found in the measurements indicate that this low frequency peak measured in the tower bending moment signals is an indication of wake meandering. Other mechanical loading sources of this low frequency peak may be ocean waves although I would expect the peak to show up in the free inflow frequency spectra as well. Further analysis with the Horns Rev data set is required to verify this peak is not unique to the turbine.

Another signal that may contain evidence of a meandering wake is the flapwise blade root bending moment. By comparing the free inflow conditions against known wake conditions at the 12-13 m/sec mean inflow wind speeds, any low frequency content in the wake case and not in the free inflow case will provide evidence of the wake presence. Figure 96 illustrates the significant difference in the energy
content at frequencies below the 1P frequency of the wake case compared to the free inflow case. The frequency of 0.1 Hz or a vibration with a period of 10 seconds may be attributed to a meandering component of the wake. A 10 second period may be too long for this vibration to be linked with tip or root vortices from the wake generating turbine. An interesting study may be to see if this peak moves as a function of turbine separation distance. Since the same peak is seen in the tower base fore/aft frequency spectra, the Horns Rev tower time series dataset can be used for this analysis utilizing the three different separation distances. Key to comparing the three wake cases is ensuring that the wake generating and wake affected turbines are operating with the same rotor rotational speed and that the same mean inflow conditions exist.

![Frequency Content of WT 8 Blade Root Flap Bending Moment](image)

**Figure 96: Flapwise Blade Root Frequency Spectra**

As a way to check the model resonant frequencies against measurements, the tower base fore/aft bending moment frequency spectra from three free inflow wind speed cases can be compared. A close agreement between the modeled and operational turbine in the tower base would indicate that the simulated results and not a result of too stiff or underdamped model. Figures 97, 98, and 99 show the comparison for the fore/aft mean bending moment signal for 6 m/sec, 8 m/sec, and 12 m/sec free inflow cases. The turbulence intensity is 8% for simulated and less than or equal to 8% for measured cases.

Shown in Figure 97 the simulated first resonant frequency of the turbine as measured at the tower base shows an indication of a double peak. There may be an aerodynamic damping effect at this wind speed that is causing the double peak resonance. Figure 98 shows a slightly better agreement between the first and second turbine resonant frequencies as measured at the tower base. And in Figure 99 the simulated frequency response more closely matches the measured response. Both the first tower mode and possible the first tower torsional mode are in close agreement. The simulation tends to overpredict both resonant frequencies by approximately ten percent. This shift is within the effect on the turbine first resonant frequency of the passive damping system on the V90.

Figure 100 shows a strong similarity in the measured fore/aft tower base bending moment and blade flapwise bending moment frequency spectra for the three different wake cases. There is no dominant peak at a frequency lower than the 1P frequency for any of the three wake cases. Also interesting
in these results is the damped 1P frequency in the free inflow case and only the wake situations show this 1P loading. This indicates that there is a low frequency component in the wake that may be contributing to the excitation of this mode. An imbalance in one of the blades can cause this type of loading although if this were the case, the 1P peak would appear in the free inflow case as well.
Figure 98: Fore/Aft Frequency Spectra Comparison, $T_i = 8\%$

Figure 99: Fore/Aft Frequency Spectra Comparison, $T_i = 8\%$

Figure 100: V80 Horns Rev, Tower Base Fore/Aft Frequency Spectra
10 Conclusion

General wind turbine fatigue loading results from the Dynamic Wake Meandering model implemented in the HAWC2 aeroelastic simulation have been compared to structural loads measurements from two turbines in the offshore operational wind farm, Egmont Aan Zee. First, the measurements from the meteorological mast were processed and a MySQL database was created. In addition, the 10 minute statistics SCADA data from the wind turbines was processed and stored in unique tables in the same MySQL database. Finally, the original 32 Hz structural measurement time series data was processed and stored in a unique table in the MySQL database. A database has been developed for the two years of operational data for this wind farm and a query and filter generation tool was needed to search the large volumes of data. For Horns Rev, the met mast measurements and the wind turbine SCADA information were already in a MySQL database. All that needed to be done was to process the WT 14 structural loads measurements, time synchronize them and store them in the loads table of the Horns Rev database. An application was built in C# that communicates with both MySQL databases and provides the ability to create custom queries and filter definitions for extracting the measurement data.

Prior to analyzing the measurements from the free inflow and wake conditions, a thorough analysis of the wind direction sensor offsets was completed to ensure the wind conditions were as expected. Also, the offsets associated with the wind turbine yaw angles were determined for the few key turbines used as filters in the analysis. Aeroelastic models of the V90 and V80 wind turbines were built for the HAWC2 simulation and checked against operational measurements. A close agreement between the models and the measurements was shown for both operational parameters like rotor speed, power, blade pitch angle, as well as for the resonant frequencies and damping properties. Due to the lack of nonphysical values for the V80 structural loads measurements, the majority of the analysis is focused on the V90 turbine.

Identification of the single wake cases for the two instrumented turbines at Egmont Aan Zee and the one turbine at Horns Rev was completed by analyzing wind direction and speed, measurements from local met masts or from the turbines themselves. Numerous wake cases were found for the Horns Rev wind turbine although only a handful of wake cases were found for the turbines at Egmont Aan Zee. At Egmont Aan Zee the turbines are oriented in a way that requires wind directions from the north and north east to produce wake conditions on these instrumented turbines. The single wake prolonged wake case at Egmont Aan Zee involved WT 21 and WT 8 during the time period of 3/4/2007 from 06:50 to 08:30 and the turbines were operating a near maximum power. The wind direction was measured by many sensors during this time and all indicated a prolonged wind direction with 15 to 16 degrees which is perfect wake alignment for these two turbines. The dominant wind direction for this site is from the southwest, thus there are very few periods in time the wind comes from these two needed directions. The turbines are predominantly in free inflow conditions. Thus a method was needed to be able to estimate the fatigue loads in turbines without strain gauge instrumentation. A transfer function from the typical 10 minute average SCADA power mean and standard deviation measurements to tower base fore/aft 1 Hz equivalent load was generated for the instrumented turbines. This transfer function map is then applied to other turbines in different single wake cases and thus estimations of the tower base fore/aft fatigue loads can be made. Another transfer function that takes power and outputs tower base fore/aft mean bending moment was generated using the two instrumented turbines. Again, this transfer function opens up many more wake cases where the tower mean bending moment can be estimated by using the standard ten minute average SCADA measurements.

HAWC2 aeroelastic simulations were conducted to find the sensitivity of the fatigue loads in the tower, and blades as a function of turbine separation distance and ambient turbulence intensity. It was found from the simulation results that the fatigue loads increase with distance to a local maximum, although decrease as the separation distance increases further. Another key conclusion from analysis of the tower base fatigue loads is the similarity of the fatigue loads for close separation distances over wide inflow wind speed conditions. There is minimal wake meandering at this point and the wake deficit shapes are different because the thrust coefficient of the rotor is different for the three wind
speeds. This indicates that the meandering component of the Dynamic Wake Meandering model is the key driver of the fatigue loading of downwind turbines. The separation distance of peak fatigue load is driven by the ambient turbulence intensity as was shown when the three different wind speed cases were compared. The peak location in tower fore/aft fatigue loads was at the same position for 6 m/sec, 8 m/sec, and 12 m/sec inflow conditions. This indicates that the meandering component of the model is responsible for the fatigue, not the added wake turbulence or the wake deficit shape.

For a given wind speed case, simulated fatigue loading in the tower base, tower top torsion, and blade root flapwise components varied with ambient or meander turbulence intensity. A small increase in turbulence intensity of only 1% moved the peak loading closer to the wake generating turbine. A higher meander turbulence intensity will move the wake more in a shorter distance than would a lower meander turbulence intensity. For the same meander turbulence intensity, the peak location did not change as a function of inflow wind speed. Only the magnitude of the loading increased when the wind speed increased.

Finally, the general fatigue loading trends found in the measurements at Egmond Aan Zee were compared to the simulated results. With the meandering component enabled, the simulated fatigue loads over predict estimated fatigue loads from measurements by almost a factor of four. This is predominantly true for the higher wind speeds and there is closer agreement between simulation and measurements for the 6 m/sec case. When the meandering component of the model is disabled, there is a significantly more close relationship between the measurements and the simulation for the three wind speeds analyzed. The meandering component of the model may be too severe for the low turbulence intensities of 7%, 8%, and 9% considered in the analysis. According to the single wake measurements and for the three wind speed cases analyzed, the fatigue loading in the tower base fore/aft direction decreases with increasing turbine separation distance. However, for multiple wake scenarios it was found that the peak fatigue occurs at the last turbine in the row considered. Rows of four turbines were analyzed at Egmond Aan Zee and it was shown that fatigue loading increases with the number of turbines upwind generating wakes. In addition, the largest step in fatigue loading occurs between the first and second turbines in the row. The fatigue loading then moderately increases to the maximum value at the forth or last turbine in the row.

The single wake effected turbine power deficit as a function of turbine separation distance was analyzed and a close agreement between measurements and simulation was found for the general trend of increasing power with increasing separation distance. The measurements predicted a faster recovery of the power deficit for the unstable conditions analyzed compared to the simulation. For the 6 and 8 m/sec cases the simulation predicts approximately 25% greater loss in power for the 7D and 11.1D spacings. The overprediction from the simulation may be attributed to too severe of a wake deficit at separation distances in the farfield. A too severe of deficit in the farfield may be attributed to a too weak of mixing between the deficit and the nearby freestream flow. The turbulent mixing in the farfield is the primary driver of the wake deficit recovery and this model may not account for the correct amount of mixing for the turbulence intensities of 7% to 8%. Lastly, the frequency spectras of the tower base fore/aft signal and the blade root flapwise signal were analyzed for free inflow and wake conditions. There is a significant amount of energy below 1 Hz in the wake cases that are not in the free inflow cases and it is proposed that this may be attributed to slight meandering of the wake or the energy associated with shed blade tip and root vortices in the wake. Because this energy is unique to the wake situation, loading induced from higher period (approximately 10 sec) ocean waves has been ruled out as the source of this broad band of energy in the wake case at frequencies less than 1 Hz.
11 Future Work

- Using the measurements, investigate fatigue loads on blades during partial wake loading for different wind speeds and turbine separation distances. Are these fatigue loads larger than the fatigue loads for a direct or full wake scenario?

- Using the simulation, determine when the dominant driver of fatigue loads transitions from the added wake turbulence for closer spacing to the wake meandering for larger spacing and higher ambient turbulence intensities.

- Investigate the effect of changing the spatial dimensions of the meander turbulence box. Increase the grid size to a size much larger than the rotor diameter, will meander frequency decrease? Decrease the grid size, and the meander frequency should increase. Compare the low frequency spectra of the wake deficit center horizontal and vertical positions for different meander box configurations.

- Use the wind farm geometry and power deficits as shown in the sensor quality chapter of this paper to estimate the amount of wake expansion and/or meandering. For a given inflow wind speed and assuming no wake expansion, there will be a wind direction such that the turbine in that was in the wake is no longer in the wake. The difference between the yaw orientation for this case and the yaw orientation when the power deficit ratio returns to unity is an estimate of the one half wake expansion of wake meandering. This can be repeated for different wind speed bins and thus different thrust coefficients to get an idea of the width of the wake at a specific distance downstream for a given inflow wind speed.

- Estimate the simulated tower fore/aft fatigue loads using the output power statistics (mean and std. dev.) and the found transfer function from measurements. This will eliminate the effect of the transfer function on the comparison between measured fatigue loads and simulation fatigue loads.
12 References

References


[16] IEC 61400-1 Ed. 3 Wind Turbines- Part 1: Design Requirements, Edited by IEC 2005-08


[27] Website: http://www.bp.com/sectiongenericarticle.do?categoryId = 9023790&contentId = 7044134

13 Appendices

13.1 Wind Farm Measurement Database Structure

The new Egmond Aan Zee measurement database was built in the format Kurt Hansen has developed for other wind farm measurement databases. For example, the Horns Rev database has been set up using the same listing of tables that are outlined and described below. For the Egmond Aan Zee measurements, pre processing routines where used to process the raw data and create large files that contain the information required by the table columns. The large file was the uploaded to the database in one MySQL call as this was shown to be the most efficient method.

The following tables (Channels, Runs, Powers, Directions, Speeds, Loads, Temps, Pressures) have been constructed for the Egmond Aan Zee measurement data. A query generation tool used to extract measurement data and specify different filters was built in C# and this tool will be described in the next appendix.

1.) Channels: Every sensor must have a unique channel identification number. This is also where the table name is specified which is where the data for the particular sensors is stored. All sensors, including met mast and wind turbine sensors are included in this list.

Recommended Table Format for Channels Table (Columns): ChannelId, Siteid, ChannelName, Units, SensorType, Height, Boom Direction, Start Time, End Time, TableName, Online

Column Descriptions:

- Siteid: Each mast has its own site id, all wind turbines will have one site id. Integer value
- SensorType: Sensors at wind farm can be broken up into different categories (Wind Speed, Wind Direction, Temperature, Pressure, Yaw Angle, Power, Rotor Rotational Rate)
- Height: Location of sensor above ground level or MSL
- Boom Direction: Orientation of the boom the sensor is located on using the standard 0 deg N, clockwise positive to 360 deg N convention.
- Start Time: First time stamp of the data series
- End Time: Last time stamp of the data series
- TableName: Name of the database table where the data for this sensor is stored
- Online: 0: Sensor is not available, no data for this sensor 1: Sensor is available and data exists for this sensor between the start time and end time stamps

2.) Runs: The runs table is a list of the time stamps available for the dataset. The run identification number is a unique integer that corresponds to a unique time during the data set. This table is simply a listing of all the run ids, and the time stamps affiliated with each run id.

Recommended Table Format for Runs Table (Columns): Run Id, Run Name, Year, Month, Day, Hour, Minute

Column Descriptions:

- Run Name: Year, Month, Day, Hour, Minute for example (200904272350)

3.) Powers: The powers table has all power measurements from all turbines in the dataset. A unique run id and channel id are included with each entry in this table to differentiate power measurements and time stamps. The 10 minute average power data is stored in this table.

Recommended Table Format for Powers Table (Columns): Run ID, Channel ID, Mean, Standard Deviation, Minimum, Maximum, Quality

Column Descriptions:
• Quality: 0: for invalid or corrupt measurement (this is to be decided upon user how to determine the quality of the power measurement. Possible method includes comparing the power measurement and nacelle wind speed measurement with the wind turbine power curve.) 1: valid measurement

4.) Directions: The directions table contains all the wind vane wind direction sensor measurements. The nacelle position (yaw angle) can also be stored in this table if the data is available in the data set. A unique run id and channel id are included for each entry in this table to differentiate directions measurements and time stamps.

Recommended Table Format for Directions Table (Columns): Run ID, Channel ID, Mean, Standard Deviation, Minimum, Maximum, Quality

Column Descriptions:
• Quality: 0: for invalid or corrupt measurement (this is to be decided upon user how to determine the quality of the direction measurement. Can possible compare measurements against a calibrated sensor or use the power deficit and wind farm geometry to verify each measurement,
1: valid measurement

5.) Speeds: The speeds table contains all wind speed measurements from the met masts and from the nacelle anemometers. The unique run id and channel id are included for each entry in this table.

Recommended Table Format for Speeds Table (Columns): Run ID, Channel ID, Mean, Standard Deviation, Turbulence Intensity (optional) Minimum, Maximum, Gust (optional), Quality

Column Descriptions:
• Turbulence Intensity: Can be a pseudo signal calculated by analyst before entering data into table. Standard deviation of the wind speed over the mean wind speed at the sensor height.
• Gust: Slope of the wind speed measurement within the ten minute period
• Quality: 0: for invalid or corrupt measurement (this is to be decided upon user how to determine the quality of the speeds measurement. 1: valid measurement

6.) Loads: The loads table contains all the structural loads measurements from the two instrumented turbines WT 7 and WT 8. The loads information is stored with the typical statistical values as well as the 1 Hz equivalent loads for different Wohler slope (m) values.

Recommended Table Format for Loads Table (Columns): Run ID, Channel ID, Mean, Standard Deviation, Minimum, Maximum, 1 Hz Equivalent load (m=1), etc.

Column Descriptions:
• 1 Hz Equivalent Load: 1 Hz equivalent load for original 10 minute 32 Hz time series data for a Wohler slope, m=1

7.) Temps: The temps table contains the temperature measurements from the three different temperature sensors on the met mast located at 116m, 70m, and 21m.

Recommended Table Format for Loads Table (Columns): Run ID, Channel ID, Mean, Standard Deviation, Minimum, Maximum

8.) Pressures: The pressures table contains the ambient pressure measurements from the met mast located at 116m.

Recommended Table Format for Loads Table (Columns): Run ID, Channel ID, Mean, Standard Deviation, Minimum, Maximum

13.2 Measurement Database Query Generation Tool

A tool that can generate queries into the large volumes of measurement data from Horns Rev and Egmond Aan Zee is required to analyze the measurements. If other wind farms measurement databases are set up in a similar format and structure as Horns Rev and Egmond Aan Zee, this tool can be used to extract and filter measurements from those wind farms. The tool is setup so that the user
can define custom filter requirements on any of the available sensors and extract data from either the same sensor or other sensors at times the requirements are met. For example, a wind speed profile and wind direction can be specified by requiring the met mast wind speed sensors to fit a particular power law profile and the wind direction requirement can be placed on all available sensors or a single sensor. The power and loads on WT 7 and WT 8 can be extracted when the wind speed and wind direction requirements are met and post processing of the extracted data can be done in Matlab or another post processing tool. The output of the query generation tool is the query definition used and more importantly the data in a comma separated format that can then be processed externally.

### 13.3 HAWC2 V90 Configuration File

```plaintext
; v90controller htc
; configuration file for the vestas v90 machine with controller
;---------------------------------------------------------------------------------- begin simulation;
timestep 600.0;
solvertype 1 ; [newmark)
animation v90controlleranim.dat;
onoconvergence continue ;
logfile v90controllerlog.log ;
maxiterations 100;
begin newmark;
beta 0.27;
gamma 0.51;
deltat 0.02;
bdynamic 1.0;
end newmark;
end simulation;

;----------------------------------------------------------------------------------

begin newhtstructure;
;beamoutputfilename v90controllerbeam.txt ; inspect for large jumps between bodies
;bodyoutputfilename v90controllerbody.txt ;
;bodyeigenanalysisfilename v90controllereigen.dat ;

begin mainbody;
name tower ;
type timoshenko ;
nbodies 1 ;
nodedistribution c2def ;
damping 0.02 0.02 0.02 2.0E-3 2.0E-3 2.0E-3 ;
begin timoshenkoinput;
filename v90st;
set 3 1 ; set subset
end timoshenkoinput;
begin c2def;\nnsec 10 ;
sec 1 0.000 0.000 0.000 0.000 0.000 ;
sec 2 0.000 0.000 -0.500 0.000 ;
sec 3 0.000 0.000 -1.000 0.000 ;
sec 4 0.000 0.000 -1.999 0.000 ;
sec 5 0.000 0.000 -3.400 0.000 ;
sec 6 0.000 0.000 -17.90 0.000 ; location of tower base str gauge, actual tower starts at -13.5 thus 4.4 plus
sec 7 0.000 0.000 -61.50 0.000 ; location of tower torsion strain gauge
```

101
Figure 101: Query Generation and Data Extraction Tool

102
sec 8 0.000 0.000 -68.00 0.000 ; lower section of tower below -13.5 is included to make hub hght 70m
sec 9 0.000 0.000 -68.10 0.000 ; top flange location
sec 10 0.000 0.000 -70.00 0.000 ; hub height
end c2def;
end mainbody;

begin mainbody;
name shaft; no shaft in V90, using gearbox mass distr and assuming shaft of 1.3m radius, steel (same as tower
 type timoshenko;
nbodies 1 ;
nodedistribution c2def ;
damping 0.02 0.02 0.02 2.0E-3 2.0E-3 2.0E-3 ;
begin timoshenkoinput;
filename v90st ;
set 2 1 ;
end timoshenkoinput;
begin c2def;
nsec 8 ;
sec 1 0.000 0.000 0.000 0.000 ;
sec 2 0.000 0.000 0.500 0.000 ;
sec 3 0.000 0.000 1.000 0.000 ;
sec 4 0.000 0.000 1.500 0.000 ;
sec 5 0.000 0.000 2.000 0.000 ;
sec 6 0.000 0.000 2.500 0.000 ;
sec 7 0.000 0.000 3.000 0.000 ; nose cone and hub section
sec 8 0.000 0.000 3.100 0.000 ;
end c2def;
end mainbody;

begin mainbody;
name blade1 ;
type timoshenko ;
nbodies 1 ;
nodedistribution c2def ;
damping 1.0E-3 1.0E-3 1.0E-3 1.0E-3 1.0E-3 1.0E-3 ;
begin timoshenkoinput;
filename v90st ;
set 1 1; set subset
end timoshenkoinput;
begin c2def;
nsec 32 ;
sec 1 0.000 0.000 0 0.00;
sec 2 0.000 0.000 1 0.00;
sec 3 0.000 0.000 2 -27.00;
sec 4 0.000 0.000 2.6 -26.06; strain gauge location, blade root
sec 5 0.000 0.000 3.6 -24.50;
sec 6 0.000 0.000 4 -23.88;
sec 7 0.000 0.000 6 -22.97;
sec 8 0.000 0.000 8 -20.15;
sec 9 0.000 0.000 10 -17.50;
sec 10 0.000 0.000 12 -14.70;
sec 11 0.000 0.000 14 -12.22;
sec 12 0.000 0.000 16 -10.30;
sec 13 0.000 0.000 18 -8.78;
sec 14 0.000 0.000 20 -7.50;
sec 15 0.000 0.000 22 -6.35;
sec 16 0.000 0.000 24 -5.29;
sec 17 0.000 0.000 26 -4.33;
sec 18 0.000 0.000 28 -3.47;
sec 19 0.000 0.000 30 -2.70;
sec 20 0.000 0.000 32 -2.03;
sec 21 0.000 0.000 34 -1.45;
sec 22 0.000 0.000 36 -0.97;
sec 23 0.000 0.000 38 -0.59;
sec 24 0.000 0.000 40 -0.30;
sec 25 0.000 0.000 41 -0.20;
sec 26 0.000 0.000 42 -0.11;
sec 27 0.000 0.000 43 -0.06;
sec 28 0.000 0.000 43.5 -0.04;
sec 29 0.000 0.000 44 -0.01;
sec 30 0.000 0.000 44.5 -0.01;
sec 31 0.000 0.000 44.75 0.00;
sec 32 0.000 0.000 45.00 0.00;
end c2def;
end mainbody;
begin mainbody;
name blade2 ;
copymainbody blade1 ;
end mainbody;
begin mainbody;
name blade3 ;
copymainbody blade1 ;
end mainbody;
begin orientation;
begin base;
body tower;
inpos 0.0 0.0 0.0;
bodyeulerang 0.0 0.0 0.0;
end base;
begin relative;
body1 tower last;
body2 shaft 1;
body2eulerang 90.0 0.0 0.0;
body2eulerang 6.0 0.0 0.0;
body2mirotvecd 0.0 0.0 -1.0 1.2323; rotational rate at 5m/sec
end relative;
begin relative;
body1 shaft last;
body2 blade1 1;
```plaintext
body2 eulerang -90.0 0.0 0.0;
end relative;

begin relative;
body1 shaft last;
body2 blade 1;
body2 eulerang 0.0 0.0 120.0;
body2 eulerang -90.0 0.0 0.0;
end relative;

end orientation;

begin constraint;
begin fix0;
body tower;
end fix0;

begin bearing1; Free bearing
name shaftrot ;
body1 tower last;
body2 shaft 1;
bearingvector 2 0.0 0.0 -1.0; x=coo (0=global,1=body1,2=body2) vector in body2 coordinates where the free rotation is
end bearing1;

begin bearing2; forced bearing
name pitch1;
body1 shaft last;
body2 blade1 1;
bearingvector 2 0.0 0.0 -1.0; x=coo (0=global,1=body1,2=body2) vector in body2 coordinates where the free rotation
end bearing2;

begin bearing2; forced bearing
name pitch2;
body1 shaft last;
body2 blade2 1;
bearingvector 2 0.0 0.0 -1.0; x=coo (0=global,1=body1,2=body2) vector in body2 coordinates where the free rotation
end bearing2;

begin bearing2; forced bearing
name pitch3;
body1 shaft last;
body2 blade3 1;
bearingvector 2 0.0 0.0 -1.0; x=coo (0=global,1=body1,2=body2) vector in body2 coordinates where the free rotation
```
end bearing2;
end constraint;
end newhtostructure;

begin dll;
begin hawcdll;
filename basic3bact10n1.dll ;
dllsubroutine regulation ;
arraysizes 25 15 ;
begin output;
general constant 1 ; inputfile extension
general time ; 1
constraint bearing1 shaftrot 1 only 2; speed generator 2
constraint bearing2 pitch1 1 only 1; 3
constraint bearing2 pitch2 1 only 1; 4
constraint bearing2 pitch3 1 only 1; 5
wind freewind 1 0.0 0.0 -70.0 ; global coords at hub height
general constant 0.99 ; Kp pitch 9
general constant 0.30 ; Ki pitch 10
general constant 0.00 ; Kd pitch 11
general constant 5.294E+06 ; Kp torque 12
general constant 2.376E+06 ; Ki torque 13
general constant 0.0 ; Kd torque 14
general constant 1800 ; generator stop time
general constant 0.2 ; pitch stop delay
general constant 8 ; pitch stop velmax
general constant 0 ; stop type (not used)
general constant -1 ; cut-in time
general constant 10 ; max pitch velocity operation
end output;
end hawcdll;

begin dlls

begin dlls

begin dlls

begin dlls

begin dlls

begin dlls

begin dlls

begin dlls

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begin dlls
begin output;
general time ;
dll inpec 1 2;
dll inpec 1 3;
dll inpec 1 4;
constraint bearing2 pitch1 1 only 1;
constraint bearing2 pitch2 1 only 1;
constraint bearing2 pitch3 1 only 1;
end output;
begin actions;
constraint bearing2 angle pitch1;
constraint bearing2 angle pitch2;
constraint bearing2 angle pitch3;
end actions;
end hawcdll;
end dll:

begin wind :
density 1.25;
wsp 12.0;
horizontal input 1;
windfieldrotations 0.0 0.0 0.0;
centerpos 0.0 0.0 -70.00; hubheight
shearformat 3 0.12;
turbformat 1; 0: no turbulence, 1:mann, 2:flex
towershadowmethod 1;
tint 0.08; ambient turbulence intensity
;windrampabs 20.0 20.01 0.0 1.0;

begin wakes;
nsource 1; 0: no wake model used, 1: use wake model
sourcepos 0.0 -180 -70.0;
opdata 1.6330 0.000; rad/sec, pitch of wake source turbine
bleparameters 0.002 0.001 1; k1 k2 delete file
microturbfactors 0.60 0.25; wake deficit depth scaling, depth derivative scaling (defaults used)
tintmeander 0.08; meander box turbulence intensity
writefinaldeficits finally deficit;
begin mameanderturb;
createturbparameters 33.6 0.1 3.9 11 1; 42*0.8 for the length scale
filename meander86v1.bin;
filename meander86w1.bin;
boxdimx 16384 0.75; total length of turbulence box
boxdimw 32 90; 32 positions that wake center can translate to
boxdimn 32 90; 32 positions that wake center can translate to
stdscaling 1.0 0.8 0.5;
end mameanderturb;
begin mameanderturb;
createturbparameters 9.0 0.1 3.9 2 1; 1/10 rotor diameter for length scale
filename wake87u1.bin;
filename wake87v1.bin;
filename wake87w1.bin;
boxdimx 128 1.7578; 2.5D in length
boxdimw 128 0.78125; 100m, slightly larger than rotor diameter
boxdimw 128 0.78125; 100m, slightly larger than rotor diameter
stdscaling 1.0 1.0 1.0;
end manmxicroturb;
end wakes;

;---------------------------------------------------------------
begin manm;
createturbparameters 33.6 0.1 3.9 21 1; 42*0.8 for the length scale
filename u 90m8ms9u1.bin;
filename v 90m8ms9v1.bin;
filename w 90m8ms9w1.bin;
boxdimw 16384 0.75; total length of turbulence box
boxdimv 32 2.875; 90m, one rotor diameter
boxdimw 32 2.875; 90m, one rotor diameter
stdscaling 1.0 0.8 0.5;
end manm;

;---------------------------------------------------------------
begin towershadowpotential;
toweroffset 0.0;
nscc 2;
radius 0.0 2.10;
radius -68.10 1.15;
end towershadowpotential;
end wind;

;---------------------------------------------------------------
begin aero ;
nblades 3;
hubvec shaft -3; vector from hub (normal to rotor plane) directed from the normal pressure side of
the rotor towards the
link 1 mbdyc2def blade1;
link 2 mbdyc2def blade2;
link 3 mbdyc2def blade3;
aefilename hawcaev90;
pcefilename hawpecv90;
inductionmethod 1 ; 0=none, 1=normal
aerocalmethod 1 ; 0=w/o aerodynamics, 1=with aerodynamics
aerosections 31 ;
acsets 1 1 1;
tiplesmethod 1 ; 0=none, 1=normal
dyninstallmethod 2 ; 0=none, 1=stig ye method, 2=mhh method
end aero ;

;---------------------------------------------------------------
begin aerodrag;
begin aerodragelement;
mbdynamenu tower;
aerodragsections uniform 10;
nscc 2;
sec 0.0 0.6 2.10; tower top
sec 1.0 0.6 1.15; tower base
end aerodragelement;
end aerodrag;

;---------------------------------------------------------------
begin output;
dataformat hawcasci i;

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buffer 1;
general time;
wind freewind 1.0 0.0 0.0 -70.00; hub height wind speed
aero power;
aero thrust;
aero torque;
constraint bearing1 shaftrot 2;
constraint bearing2 pitch1 5;
constraint bearing2 pitch2 5;
constraint bearing2 pitch3 5;
mbdy momentvec tower 6 1 tower; tower str gauge location 4.4m above bot flange
mbdy momentvec tower 7 2 tower; tower torsion str gauge location 6.6m below top flange
mbdy momentvec blade1 4 1 blade1; Blade1 (root)
mbdy momentvec blade2 4 1 blade2; Blade2 (root)
mbdy momentvec blade3 4 1 blade3; Blade3 (root)
mbdy state pos blade1 31 1.0 blade1; blade tip position (blade coords)
mbdy state pos blade2 31 1.0 blade2;
mbdy state pos blade3 31 1.0 blade3;
windwake wakepos 1; wake deficit center location at location of downstream rotor
;
end output;
;
exit;

13.4 DONG ENERGY

A detailed analysis of the wind turbine yaw angle offsets and met mast offsets in time was conducted to clarify how the measurements relate to the true wind direction defined in the standard 0 deg North and positive clockwise frame. Knowing the time history of the wind direction offsets relative to truth opens up more sensors to use to determine the wind direction at the wind farm for any particular time period. A generalized method of comparing a sensor known to have a minimal offset or well known offset mounted on met mast M7 is compared against the yaw orientation for each turbine for all measurement periods. A time history of the difference between the truth signal and the wind turbine yaw angle is determined for all time. For many wind directions, there may be a different wind direction measured by the met mast than the wind direction indicated by the yaw angle of the turbine. These offsets represent the mean offsets at each point in time while the turbine is operating. Due to the large distance between the sensors, a time shift of one or two periods is also applied before the offset is calculated.

If a step in the offset is found, a more detailed analysis is done around this general time period of the step and the exact ten minute period is determined when the offset changed. An assumption made in this approach is that the engineer has a truth sensor to work from. It is proposed to find the truth sensor on a met mast near the wind farm by first finding its measurement offset relative to truth by using the known peak in turbulence intensity associated with flow through a met mast. Measuring the wind direction while plotting the turbulence intensity of a cup anemometer at the same height will yield an estimate of the location of the peak turbulence intensity and this can be compared to the known configuration of the met mast. There will be a wind direction that will produce a peak turbulence intensity measured by a cup anemometer for each met mast design. This wind direction is a function of the mast geometry, boom length, and cup height above the boom.

The tables below outline the time histories of the offsets for the wind direction sensors at Horns Rev for the the 2005 time period. Table 21 provides the wind turbine yaw offsets relative to truth and Table 23 provides the Met Mast wind vane offsets relative to truth. The offset is defined as
The raw measurements from WT 14 from the 08/2005 to 12/2005 time period are not provided in the public version of this paper. No clear scaling factor was found to convert these values into more physical values. Also, for example there are two calibration periods used for the blade edgewise bending moments. The labels on the y-axis are what was provided with the sensor file in the measurements dataset. The tower base signals are from the channels labeled (Mns5, Mew5) and the blade channels are (MxCl,MyCl).

13.5 Vestas

13.5.1 Vestas V90 3.0MW Specifications

![Technical specifications](image)

Figure 102: V90 Nacelle Components
<table>
<thead>
<tr>
<th>Wind Turbine Name</th>
<th>Start Date</th>
<th>End Date</th>
<th>Offset (deg)</th>
</tr>
</thead>
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Table 22: Horns Rev Wind Turbine Yaw Offset Time Histories (2005) (cont’d)

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<td>2005/12/31 23:50</td>
<td>-11.9</td>
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Table 23: Horns Rev Meteorological Mast Wind Vane Time Histories (2005)

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<tr>
<th>Wind Turbine Name</th>
<th>Met Mast</th>
<th>Start Date</th>
<th>End Date</th>
<th>Offset (deg)</th>
</tr>
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<tbody>
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<td>M2</td>
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<td>2005/04/20 10:30</td>
<td>3.4</td>
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<tr>
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<td>M2</td>
<td>2005/04/20 10:40</td>
<td>2005/12/31 23:50</td>
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<td>M2</td>
<td>2003/08/14 14:30</td>
<td>2005/04/20 10:30</td>
<td>6.4</td>
</tr>
<tr>
<td>DIR28SV</td>
<td>M2</td>
<td>2005/04/20 10:40</td>
<td>2005/12/31 23:50</td>
<td>28.2</td>
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<tr>
<td>M6d168</td>
<td>M6</td>
<td>2003/08/14 14:30</td>
<td>2005/12/31 23:50</td>
<td>-3.0</td>
</tr>
<tr>
<td>M6d28</td>
<td>M6</td>
<td>2003/08/14 14:30</td>
<td>2005/12/31 23:50</td>
<td>2.0</td>
</tr>
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<td>M7d168</td>
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<td>2005/12/31 23:50</td>
<td>-3.0</td>
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<td>M7d28</td>
<td>M7</td>
<td>2003/08/14 14:30</td>
<td>2005/12/31 23:50</td>
<td>1.5</td>
</tr>
</tbody>
</table>

7. Technical Specifications & Diagrams

7.1 Rotor
- Diameter: 90 m
- Swept area: 6362 m²
- Speed, nominal power: 16.1 RPM Speed, Dynamic operation range
- Rotor: 9.9 – 18.4 RPM
- Rotational direction: Clockwise (front view)
- Orientation: Upwind
- Tilt: 8°
- Blade coning: 4°
- Number of blades: 3
- Aerodynamic brakes: Full feathering

7.2 Hub
- Type: SG Cast Iron
- Material: GJS-400-18U-LT
- Weight: 8500 kg

7.3 Blades
- Principle: Airfoil shells bonded to supporting beam
- Material: Fibreglass reinforced epoxy and carbon fibres
- Blade connection: Steel root inserts
- Airfoils: RISO P + FFA-W3
- Length: 44 m
- Chord at blade root: 3.512 m
- Chord at blade tip: 0.384 m
- Twist (blade root/blade tip): 17.5°

7.4 Bearings
- Type: 4-point ball bearing

7.5 Sensors

7.5.1 Lightning Detector
- Appellation: Lightning detector
- Signal: Optical Analogue

7.5.2 Wind Sensor
- Appellation: Ultrasonic wind sensor, (2 units)
- Signal: RS485/optical

Figure 103: V90 Mechanical Specifications
7.5.3 **Smoke**
- Appellation: Smoke detector
- Signal: Digital 24 V

7.5.4 **Movements and Vibrations**
- Appellation: Accelerometer, tower
- Signal: RS485

7.6 **Generator**
- Rated power: Generator 60 Hz
- Type: 3.0 MW
- Asynchronous with wound rotor, slip rings and VCRS
- Voltage: 1000 VAC
- Frequency: 60 Hz
- No. of poles: 4
- Class of protection: IP54
- Rated speed: 1758
- Rated power factor, default at 1000 V: 1.0
- Power factor range at 1000 V: $0.98_{cap} - 0.96_{ind}$

---

### Figure 104: V90 Mechanical Specifications

#### 7.17 **Tower**
- Type: Conical tubular
- Material: S355
- Surface treatment: Painted
- Corrosion class, outside: C4 (ISO 12944-2)/offshore C5-M
- Corrosion class, inside: C3 (ISO 12944-2)/offshore C4
- Top diameter for all towers: 2.3 m
- Bottom diameter for all towers: 3.98 m
- Hub Height: 65 m
- 3-parted, modular tower: 80 m

The exact hub height listed includes 0.55 m distance from the foundation section to the ground level and 2.0 m distance from the tower top flange to the hub center.

#### 7.18 **Weight and Dimensions**

##### 7.18.1 **Nacelle**
- Including hub and nose cone:
  - Length: 13.25 m
  - Width: 3.6 m
  - Height: 4.05 m
  - Weight app.: 98000 kg +/- 3000 kg

- Without hub and nose cone:
  - Length: 9.05 m
  - Width: 3.6 m
  - Height: 4.05 m
  - Weight app.: 68000 kg +/- 2000 kg

---

Figure 105: V90 Mechanical Specifications
7.18.2 **Gearbox**
Length: 2100 mm  
Diameter: 2600 mm  
Weight max.: 23000 kg

7.18.3 **Generator**
Length max.: 2800 mm  
Diameter max.: 1100 mm  
Weight max.: 8500 kg

7.18.4 **Transformer**
Length: 2340 mm  
Width: 1090 mm  
Height: 2150 mm  
Weight max.: 8000 kg

7.18.5 **Rotor Blades**
Length: 44 m  
Weight: 6600 kg/pcs +/- 400 kg.

7.18.6 **Switch Gear, Feeder Function (Option)**

<table>
<thead>
<tr>
<th>Rated voltage [kV]</th>
<th>Width [mm]</th>
<th>Height [mm]</th>
<th>Depth [mm]</th>
<th>Weight [kg]</th>
</tr>
</thead>
<tbody>
<tr>
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<td>1400</td>
<td>850</td>
<td>135</td>
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<tr>
<td>36</td>
<td>420</td>
<td>1800</td>
<td>850</td>
<td>140</td>
</tr>
</tbody>
</table>

7.18.7 **Switch Gear, Circuit Breaker Function (Option)**

<table>
<thead>
<tr>
<th>Rated voltage [kV]</th>
<th>Width [mm]</th>
<th>Height [mm]</th>
<th>Depth [mm]</th>
<th>Weight [kg]</th>
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<td>36</td>
<td>600</td>
<td>1800</td>
<td>850</td>
<td>238</td>
</tr>
</tbody>
</table>

Figure 106: V90 Mechanical Specifications
13.5.2 Vestas V80 2.0MW Specifications

Figure 107: V80 2.0 MW Nacelle Components

13.6 Egmond Aan Zee Measurement System Description

13.6.1 OWEZ Meteorological Mast

More information about the sensor manufacturers and more specifics on the locations of the sensors can be found in [11]. The two images below outline the three measurement heights and the location of the sensors around the mast as well as the available measurements from the three measurement heights.

13.6.2 OWEZ WT 7 and WT 8 Structural Measurement Sensor Details

More details are available in [12] although the general location and description of the signals used in the analysis is provided here. The pseudo signals of tower base fore/aft bending moments were generated using the tower base NS and EW signals and the measured yaw angle of the turbine. Care was taken to ensure the yaw angle is defined in the standard wind direction frame. The yaw measurements for the OWEZ turbines was defined in a counterclockwise frame and the zero point is not always at north. The offsets presented earlier in this paper can be used to transfer the measured yaw angle to the standard wind direction frame and then the pseudo signals can be determined.
Table 24: WT 7 and WT 8 Structural Measurement Sensor Details

<table>
<thead>
<tr>
<th>Sensor Name</th>
<th>Wind Turbine</th>
<th>Location (m)</th>
<th>Units</th>
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<tbody>
<tr>
<td>Tower Base NS</td>
<td>WT 7</td>
<td>4.4 from bottom flange</td>
<td>kNm</td>
</tr>
<tr>
<td>Tower Base EW</td>
<td>WT 7</td>
<td>4.4 from bottom flange</td>
<td>kNm</td>
</tr>
<tr>
<td>Tower Top Torsion</td>
<td>WT 7</td>
<td>6.6 from top flange</td>
<td>kNm</td>
</tr>
<tr>
<td>Blade X Flap</td>
<td>WT 7</td>
<td>2.6 from root flange</td>
<td>kNm</td>
</tr>
<tr>
<td>Blade Y Flap</td>
<td>WT 7</td>
<td>2.6 from root flange</td>
<td>kNm</td>
</tr>
<tr>
<td>Blade Z Flap</td>
<td>WT 7</td>
<td>2.6 from root flange</td>
<td>kNm</td>
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<tr>
<td>Tower Base NS</td>
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<td>kNm</td>
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<td>kNm</td>
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<td>Blade X Flap</td>
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<td>2.6 from root flange</td>
<td>kNm</td>
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<td>Blade Y Flap</td>
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<td>Blade Z Flap</td>
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<td>kNm</td>
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Figure 109: OWEZ Meteorological Mast Schematic
<table>
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<tr>
<th>Position at drawing:</th>
<th>Location / Height (meters above MSL):</th>
<th>Instrument:</th>
<th>Instrument make and type:</th>
<th>Instrument code:</th>
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<tr>
<td>1</td>
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<td>Mierij Meteo 524</td>
<td>WD 524/S/21</td>
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<td>2</td>
<td>S/21</td>
<td>Cup anemometer</td>
<td>Mierij Meteo 018</td>
<td>WS 018/S/21</td>
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<tr>
<td>3</td>
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<td>Temperature/humidity</td>
<td>Vaisala Oyj HMP 233</td>
<td>RHTT 261/S/21</td>
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<td>Mierij Meteo 524</td>
<td>WD 524/NE/21</td>
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<td>WS 018/NE/21</td>
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Figure 110: OWEZ Meteorological Mast Channel Descriptions