University Oldenburg

ForWind - Wind Energy Systems

Design of Wind Energy Sytems

Supervisor:
Martin Kühn
Juan Jose Trujillo Quintero
Luis Enrique Vera Tudela Carreno

Author:
Jan Kämper
Florian Börgel

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Contents

1 CIP 1: Selection of main parameters and rotor design

In CIP 1 we were asked to estimate the main parameters of our wind turbine model. In addition we also calculated the airfoil aerodynamics properties and defined the geometry of our blade. The following table shows the side specific conditions and the limitations for the design process of the wind turbine.

Name	unit	value
Airfoil profile set number	-	4
Design wind regime	-	Rayleigh
Target wind regime	-	High
Weibull A-factor (local)	m/s	9
Weibull k-factor (local)	-	2
Rated electrical power	kW	3500
Number of blades	-	3
Cut-in wind speed	m/s	3.5
Cut-out wind speed	m/s	25
Max. tip speed	m/s	82
Max. hub height – reference (*)	m	100
Max. blade length - reference (*)	m	60
Blade root length	m	5
Transmission	-	90

Table 1: Design parameters

1.1 Total conversion efficiency

The total conversion efficiency is used to calculate the amount of energy which can be extracted from the wind flow. Therefore it contains all loses due to mechanical and electrical conversions as the corresponding c_p reference value. The c_p variable describes the maximum amount of energy which can be theoretical extracted from the wind. Taking all these losses into account we have the following equation for the total conversion efficiency:

$$\text{total conversion efficiency} = c_p * \nu_{el} * nu_{mech} = 0.4705 \tag{1}$$

1.2 Wind Power for nominal electrical power

The rated electrical power of the wind turbine is 3.500 kW. With the total conversion efficiency we computed in the last section we are now able to estimate how much wind power is needed to obtain nominal electrical power.

$$\text{total wind power} = \frac{\text{nominal power}}{\text{total conversion efficency}} = \frac{3500kW}{0.4705} = 7439.26kW \quad (2)$$

1.3 Rated wind speed

At rated wind speed the turbine is able to extract nominal wind speed. The following equation is used to calculate the power output of the wind turbine. It should be noted that resulting value had to be rounded up.

$$P_{rated} = 0.5 \cdot c_{total} \cdot \rho \cdot \pi \cdot R^2 \cdot V_{rated}^3 \quad (3)$$

where:
P_{rated} = rated electrical power
c_{total} = total conversion efficiency
ρ = density
R = reference max. blade length
V_{rated} = rated wind speed
This equation can be solved for V_{rated}:

$$V_{rated} = \sqrt[3]{\frac{2 \cdot P_{rated}}{\rho \cdot c_{total} \cdot R^2 \cdot \pi}} = 11m/s \quad (4)$$

1.4 Rotor radius

To calculate the rotor radius we used equation (3). Instead of solving for V_{rated} we solved for the blade radius.

$$R = \sqrt{\frac{2 \cdot P_{rated}}{c_{total} \cdot \rho \cdot \pi \cdot V_{rated}^3}} = 54m \quad (5)$$

With a hub diameter of 2.5 meters we end up with a blade length of 52.75 m.

1.5 Rotor area and specific rating

The rotor area is simply the area which is covered by the rotating blades. That leaves us with:

$$A_{area} = \pi * R^2 = 9161m^2 \quad (6)$$

Next we were asked to calculate the specific rating which is defined as:

$$rating = \frac{\text{electrical power}}{area} \quad (7)$$

We receive 382.06 W/m^2 as specific rating.

1.6 Rotor rated speed & design tip speed ratio

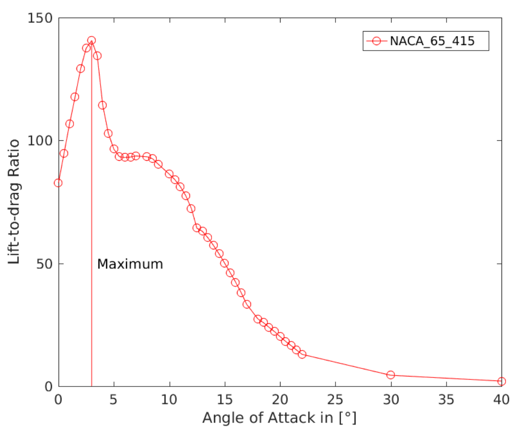
The design tip speed ratio is the ratio between maximum tip speed and rated wind speed of the turbine. The maximum tip speed for the wind turbine is $82m/s$ and the calculated rated wind speed is $11m/s$. That leads to a design tip speed ratio λ_d of **7.45**.
Next the we calculated the rotor rated speed. The rotor rated speed in rotations per minute (rpm) is given by:

$$n = \frac{60s/min \cdot \text{ max. tip speed}}{2 \cdot \pi \cdot R} = 14.5rpm \tag{8}$$

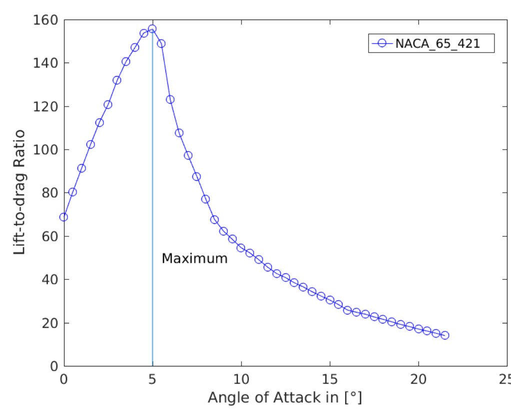
1.7 Annual Energy Production

1.8 Main aerodynamic properties

In order to estimate the design lift coefficient, the angle of attack and the drag coefficient we were given an excel sheet with the rotor design profile data for NACA-64-415 and NACA-64-421. Each sheet consists of 4 columns: angle of attack, lift coefficient, drag coefficient and thrust coefficient. According to the lecture, the optimal lift coefficient is defined as the maximum of the lift-to-drag ratio. Figure 1 shows the lift-to-drag ratio for different angles of attack (AOA).



(a) Lift-to-drag ratio for NACA 65-415



(b) Lift-to-drag ratio for NACA 65-421

Figure 1: Lift-to-drag ratio for different angle of attacks

The figures show that the highest lift-to-drag ratio occurs at low angles of attack. We identified the maximum at 3.0° for NACA 65-415 and 5.0°. For higher angles of attack the lift-to-drag ratio shrinks. However in practice there is another method to calculate the optimal design lift coefficient. In the further design we defined the design lift coefficient according to the following equation.

$$c_{l_{design}} = max(cl(max[\frac{c_l}{c_d}], 0.8 \cdot c_{l_{max}}) \tag{9}$$

The results are summarized in the following table:

NACA 65-415	α	c_l	c_d	c_m
80% method	10	1.345	0.016	0.071
lift-to-drag method	3.0	0.710	0.005	0.088
NACA 65-421	α	c_l	c_d	c_m
80% method	11	1.255	0.026	0.055
lift-to-drag method	5.0	0.952	0.006	0.092

Table 2: Main aerodynamic parameters

As the 80% method results in a higher lift coefficients for both profiles we selected the corresponding parameters according to the 80% method.

2 CIP 2: Advanced BEM

In the first part of CIP 2 we designed the blade of the wind turbine. In the lecture we discussed two theories which are used to design the blade geometry. Betz and Schmitz theory both have different approaches to calculate the chord length and the twist angle. For the following steps it is import to keep in mind that the given blade consists of 10 blade elements, which are shown in the following figure.

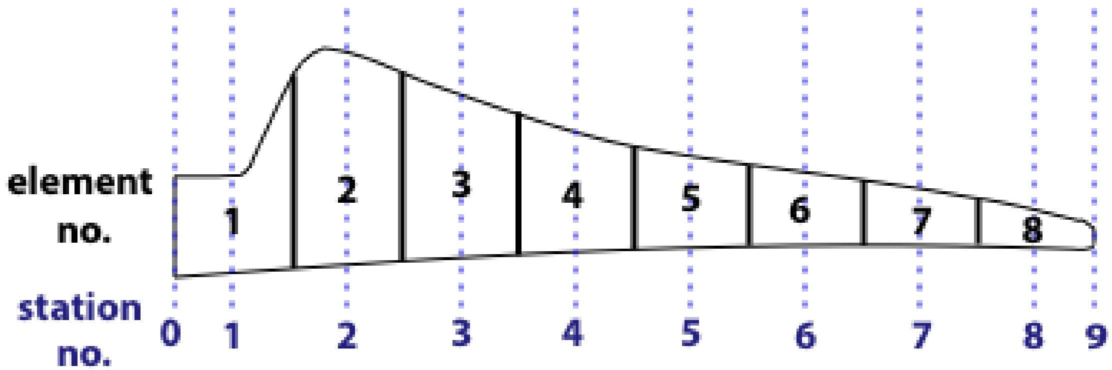


Figure 2: Blade Elements

2.1 Design your blade according to Betz theory

Betz theory estimates that the maximum of power that can be extracted from the wind is:

$$P_{betz} = \frac{16}{27} * P_{wind} \tag{10}$$

To understand why there is a certain limit, consider that if all energy coming from the wind movement through the turbine the speed afterwards would drop to zero and no new wind could get in. The principle of Betz's law is derived from the principles of conservation of mass and momentum of the air stream following through and idealized 'actuator disk' (see figure

If we want to design the blade geometry according to this law, the power from the blade element theory has to equal P_{Betz}. This leads to the following equations which have been used for the further calculation.

Planform:

$$t(r) = 2\pi R \frac{1}{N} \frac{1}{\lambda_a \sqrt{(\lambda_a \frac{r}{R})^2 + \frac{4}{9}}} \tag{11}$$

Twist angle:

$$\alpha(r) = \arctan(\frac{2}{3}\frac{R}{r\lambda_a}) \tag{12}$$

$$\alpha_{twist} = \alpha(r) - \alpha_a \tag{13}$$

Using the parameters from CIP 1, we calculated the chord length and the twist angle for each blade segment. And overview is shown in table 3.

Station number	1	2	3	4	5	6	7	8	9
Dist.(rotor center) m	4.547	11.141	17.734	24.328	30.922	37.516	44.109	50.703	54.000
Dist.(blade root) m	3.297	9.891	16.484	23.078	29.672	36.266	42.859	49.453	52.750
NACA 65-415									
Chord length m	10.963	5.989	3.957	2.932	2.324	1.923	1.639	1.428	1.342
Twist angle deg	36.725	13.436	5.233	1.228	-1.123	-2.665	-3.752	-4.559	-4.890
NACA 65-421									
Chord length m	11.749	6.418	4.240	3.142	2.490	2.061	1.757	1.531	1.438
Twist angle deg	35.725	12.436	4.233	0.228	-2.123	-3.665	-4.752	-5.559	-5.890

Table 3: Blade design according to Betz theory

2.2 Design according to Schmitz

The blade design according to Schmitz uses the following equations:
Planform:

$$t(r) = \frac{16\pi r}{Nc_l}\sin^2(\frac{1}{3}\alpha_1) \tag{14}$$

Twist angle:

$$\alpha(r) = \frac{2}{3}\alpha_1 \tag{15}$$

$$\alpha_{twist} = \alpha(r) - \alpha_a \tag{16}$$

where

$$\alpha_1 = \arctan(\frac{R}{\lambda_a r b}) \tag{17}$$

Using the same approach of the previous section we end up with the following results, shown in table 4.

Station number	1	2	3	4	5	6	7	8	9
Dist.(rotor center) m	4.547	11.141	17.734	24.328	30.922	37.516	44.109	50.703	54.000
Dist.(blade root) m	3.297	9.891	16.484	23.078	29.672	36.266	42.859	49.453	52.750
NACA 65-415									
Chord length m	6.184	5.063	3.671	2.812	2.262	1.887	1.616	1.412	1.328
Twist angle deg	28.589	12.022	4.812	1.054	-1.210	-2.714	-3.783	-4.579	-4.906
NACA 65-421									
Chord length m	6.628	5.426	3.934	3.013	2.424	2.022	1.732	1.514	1.424
Twist angle deg	27.589	11.022	3.812	0.0548	-2.210	-3.714	-4.783	-5.579	-5.906

Table 4: Blade design according to Schmitz theory

The final blade is designed according to Schmitz theory by a combination of profile 1 and profile 2. The first station has got a cylindrical shape. For stations 2-5 the thinner profile is used, for stations 6-8 the thicker profile is used.Table 5 gives more detail about the design rotor blade.

Station number	1 Cylinder	2 65-421	3 65-421	4 65-421	5 65-421	6 65-415	7 65-415	8 65-415	9 65-415
Blade m	3.297	9.891	16.484	23.078	29.672	36.266	42.859	49.453	52.750
Chord length m	6,628	5,426	3,935	3,014	2,425	1,887	1,617	1,413	1,329
Twist angle deg	27,590	11,022	3,813	0,055	-2,211	-2,715	-3,783	-4,580	-4,907

Table 5: Final blade design according to Schmitz

3 CIP 3: Performance Curves

3.1 Introduction

In this section we analysed the designed turbine under different pitch angles and tip-speed ratios. The design process of a wind turbine differs from turbine to turbine. In order to compare wind turbines non dimensional coefficients are used. These do not depend on factors like size or wind conditions. The most common coefficient is the power coefficient c_p. Further we used the torque coefficient c_q and the thrust coefficient c_t. These coefficient are defined as:

$$c_p = \frac{P}{0.5 * \rho A v^3} \qquad c_t = \frac{T}{0.5 \rho A v^2} \qquad c_q = \frac{Q}{0.5 \rho A v^2 * R}$$

where:
c_p = Power coefficient
c_t = Thrust coefficient
c_q = Torque coefficient
p = Power
ρ = Density
A = Area
v = Windspeed
R = Rotorradius

3.2 WT_Perf

To compute the nondimensional parameters a program called WT_Perf is used. WT_Perf uses blade-element momentum (BEM) theory to predict the performance of wind turbines. [1]. It also takes different correction algorithms into account, e.g. Prandtl's tip-loss and hub-loss model. WT_Perf can be used from the operating system's command prompt. In order to use WT_Perf we configured the input file by updating the 'Turbine Data' section and implementing the calculated blade geometry. WT_Perf also needs the aerodynamic data of the airfoils. We were able to used the provided data here. Last we defined the range of pitch angle and tip-speed ratio according to the tasks of CIP-3.
The following code-snippet gives an idea of the input file structure:

[1] WT_Perf_Users_guide.pdf

```
-----   Turbine Data   -----------------------------------------------------------
      3                NumBlade:                  Number of blades.
62.18                  RotorRad:                  Rotor radius.
   1.25                HubRad:                    Hub radius.
  -3.0                 PreCone:                   Precone angle, positive downwind.
   5.0                 Tilt:                      Shaft tilt.
   0.0                 Yaw:                       Yaw error.
   100                 HubHt:                     Hub height.
     8                 NumSeg:                    Number of blade segments.

  RElm    Twist   Chord  AFfile  PrntElem
  3.808  26.530   6.988    1     FALSE
 11.424   9.594   5.407    1     FALSE
 19.040   2.661   3.832    1     FALSE
 26.656  -0.866   2.906    1     FALSE
 34.272  -1.967   2.171    2     FALSE
 41.888  -3.354   1.806    2     FALSE
 49.504  -4.335   1.544    2     FALSE
 57.120  -5.066   1.348    2     FALSE
```

3.3 3.1,3.2

As already mentioned we configured the input file according to CIP-3. The generated output file contains values for the power coefficient c_p, thrust T and torque Q. For task 3.2 we wrote a small python-program which examines the data and plots the results for the three different nondimensional coefficient mentioned in the introduction of CIP-3: c_p, c_t and c_q. Since WT_Perf only writes the power coefficient we had to calculate c_t and c_q. Note that the coefficient are functions of $c_t(\lambda), c_q(\lambda)$. The following figures display the results for c_p, c_t and c_q with a tip-speed ratio λ from one to 20 and pitch angles of : 0,5,10,15,20 and 30 degree. The curves are calculated at rated rotor speed (12.59 rpm).

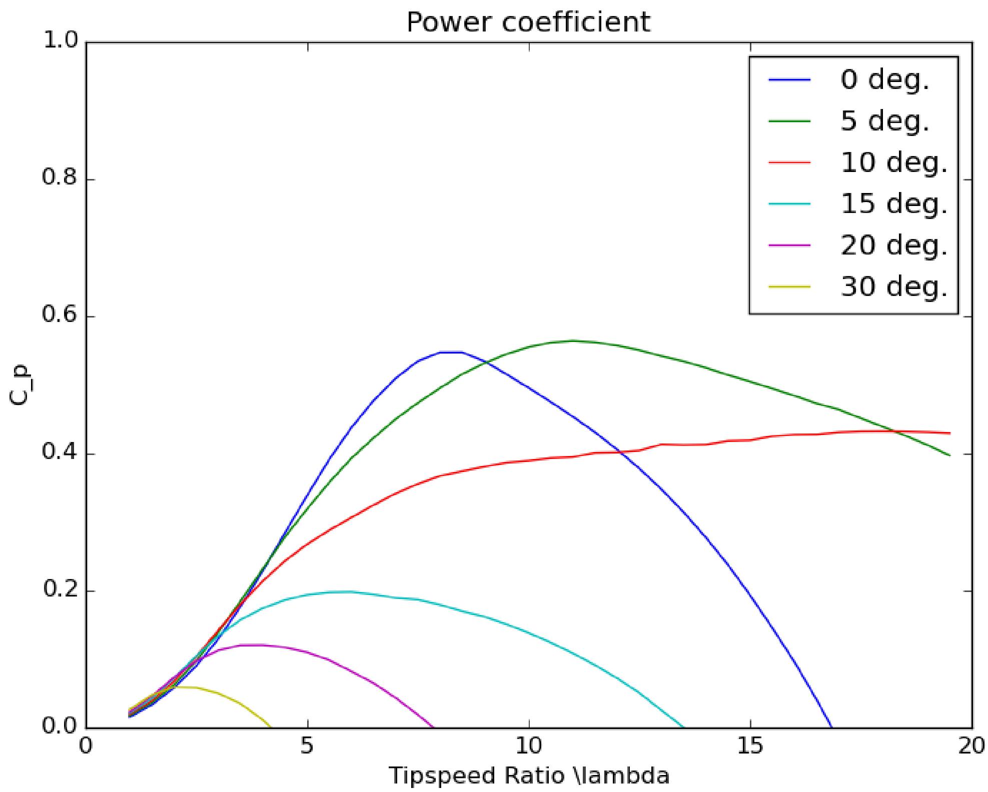


Figure 3: Power coefficient

The $c_p - \lambda$ curve shows different power coefficients at different tip-speeds and pitch-angles. Regarding the maximum for c_p at each curve we identify that they appear at different tip-speed ratios. At pitch angle $5°$ the maximum c_p is at 0.564 which is very close to the theoretical maximum of 0.592.

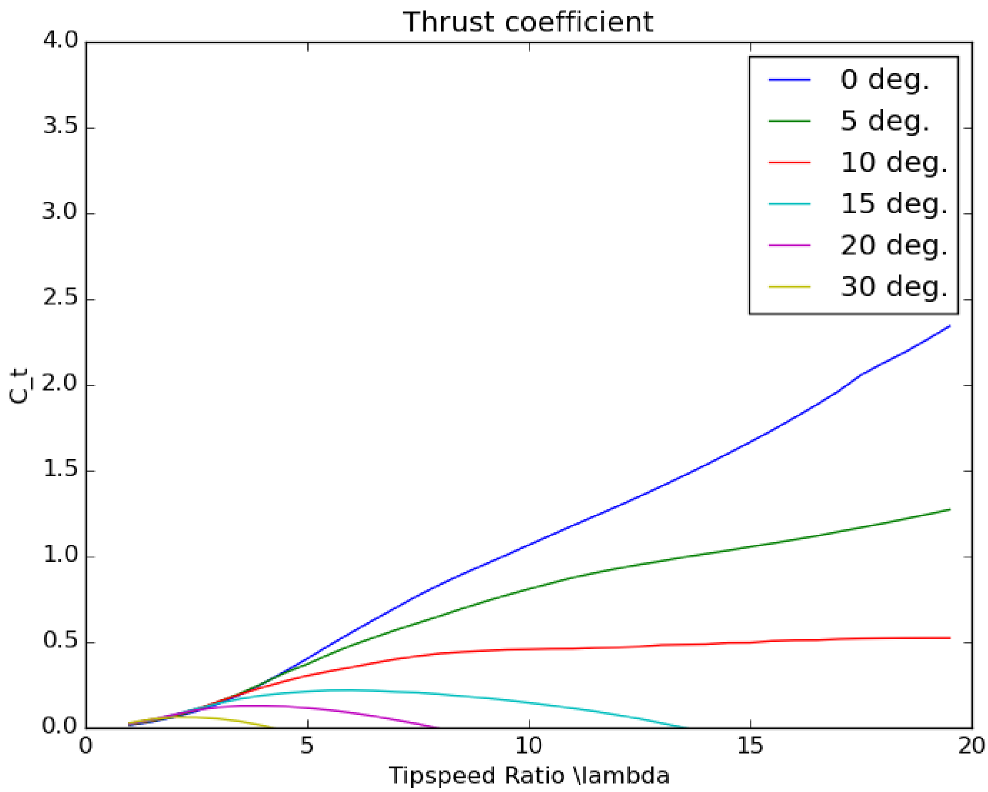


Figure 4: Thrust coefficient

Figure 4 shows the behaviour of the thrust coefficient. From 0° to 10° the thrust coefficient reaches high values. For higher pitch angles the resulting thrust coefficient is significantly lower and is equal to zero for higher tip speed ratios. The thrust is directly applied at the tower and can be decreased by increasing the pitch angle.

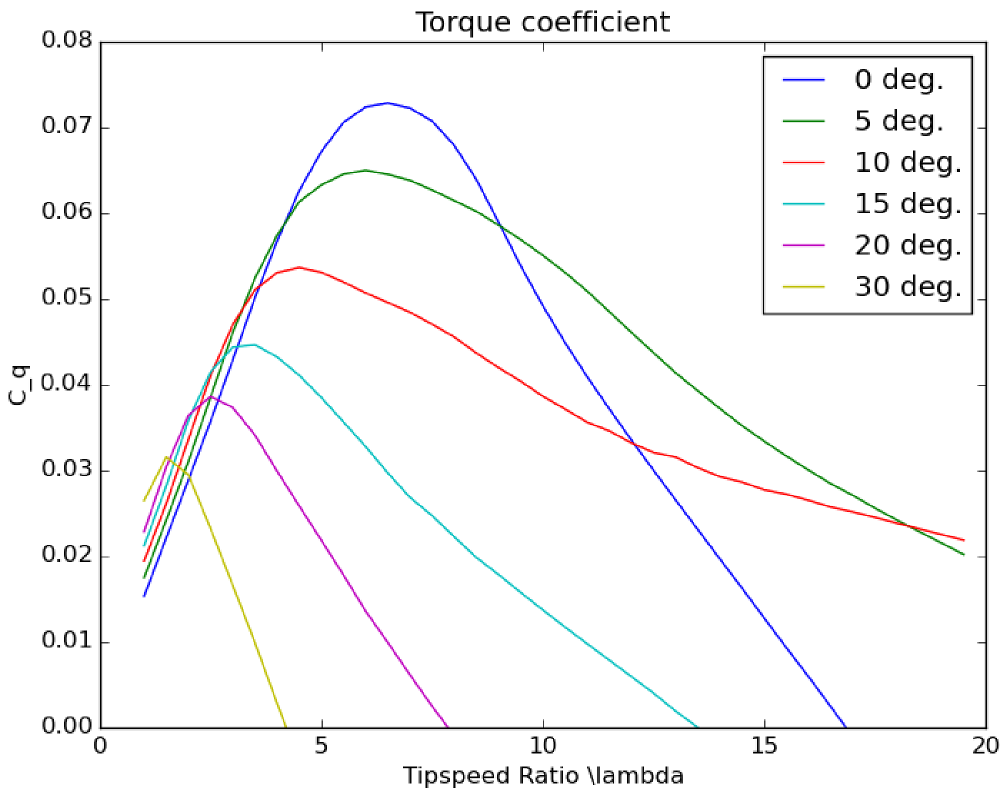


Figure 5: Torque coefficient

Figure 5 shows the torque coefficient for different pitch angles. Compared to the $c_p - \lambda$ the maxima are shifted to the left and decrease with increasing pitch angle.

3.4 3.4

In task 3.4 we were asked to calculate the resulting rotor speed for a rated wind speed of 8 m/s. For the calculation we used our design tip speed ratio:

$$\lambda = \frac{\Omega R}{v} \tag{18}$$

$$n = \frac{60\lambda v}{2\pi R} = 10.07 rpm \tag{19}$$

3.5 3.5, 3.6

Again we used WT_Perf to calculate the resulting operation conditions below rated wind speed. The input parameters are: v = 8 m/s, design top speed ratio λ = 8.2 and rotational speed n = 10.07 rpm. The results are shown in the following table:

v	rotor speed	c_p	c_t	c_q	P
m/s	rpm	-	-	-	kW
8	10.07	0.544	0.825	0.033	2054.846

Power aus WT_Perf

3.6 3.7,3.8

According to Betz, the wind turbine should be able to extract 7618 kW. However the rated power of the wind turbine is lower than the power which could be extracted. Therefore pitching is needed. The resulting c_p can be calculated as follows:

$$c_p = \frac{3500000}{0.5 \cdot 1.225 \cdot \pi \cdot 62.18^2 \cdot 12^3} = 0.272 \tag{20}$$

3.7 3.9

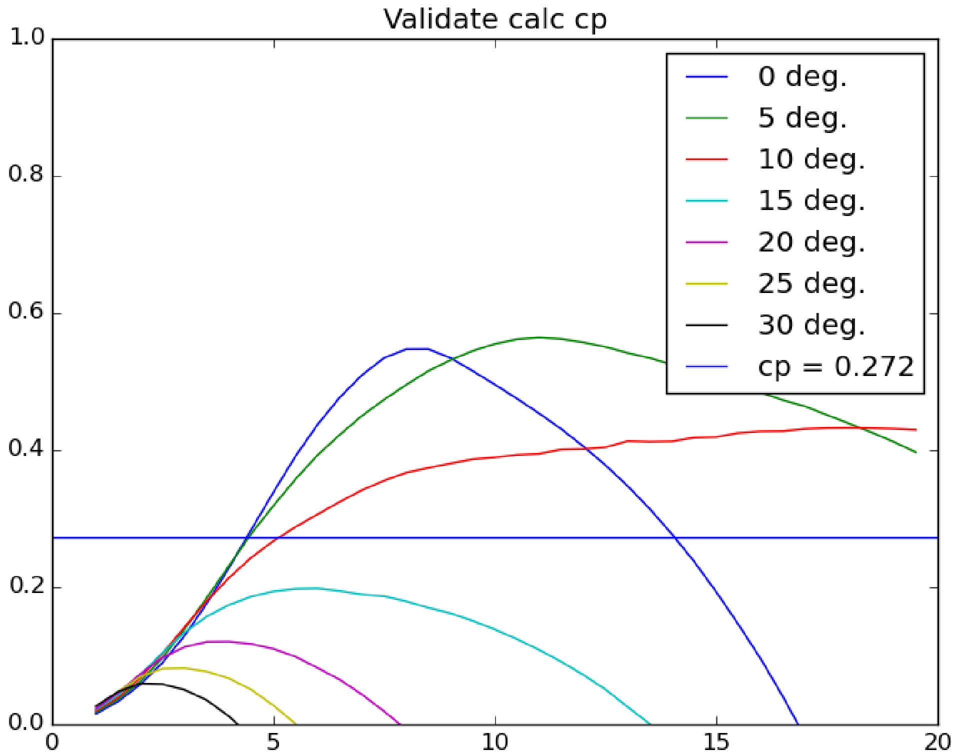


Figure 6: Validation of c_p
The resulting c_p corresponds to a tip speed ratio of 5 with a pitch angle of 10°

3.8 3.10

$$n = \frac{60\lambda v}{2\pi R} = 9.21$$

4 CIP 4: Tower design

In this part of the Design project a modal analysis for tower design will be carried out and evaluated with respect to economical factors. For this purpose the following parameters are relevant:

$$\begin{aligned}
\Omega_{rated} &= 14.5rpm \text{ (rotor rated speed)} \\
D &= 5m \text{ (tower diameter)} \\
E &= 211000000000\frac{N}{m^2} \text{ (elastic modulus)} \\
l &= 100m \text{ (hub height)} \\
m_{top} &= 323000kg \text{ (nacelle and rotor mass)} \\
\rho &= 7850\frac{kg}{m^3} \text{ (material density)}
\end{aligned}$$

4.1 Eigenfrequency

For tower design resonances of excitation frequencies from the rotating blades must be taken into account. The Eigenfrequency of the tower can thus be obtained by adding a 10% safety margin to the rotor rated speed which represents the maximum stationary rotor speed:

$$f_0 = \Omega_{rated} \cdot 1.1 = \frac{14.5}{60}Hz \cdot 1.1 = 0.2658Hz$$

4.2 Desiugn range

The design range of our turbine is a classical soft-stiff design which results in large wave excitation but allows variable speed turbine design since resonances with tower eigenfrequencies at frequencies lower than rated rotor speed are avoided. There are a few other common design approaches one of which is the soft-soft design where the eigenfrequency lies within the resonance range of the rotor. In this case certain rotor frequencies have to be excluded in order to avoid resonances.

4.3 Wall thickness

The wall thickness t can be computed from the following equations:

$$f_0 \cdot 2\pi = \sqrt{\frac{k}{m_{top} + 0.25 m_{tower}}} \tag{21}$$

$$k = \frac{3E\pi D^3 t}{l^3 8} \tag{22}$$

$$m_{tower} = \rho \pi D t l \tag{23}$$

By substituting Equations (22) and (23) into (21) we obtain the following equality which can be fed into Matlab in order to solve for the only unknown t:

$$0 = \sqrt{\frac{3E\pi D^3 t}{l^3 8 \cdot (m_{top} + 0.25\rho\pi D t l)}} - f_0 \cdot 2\pi$$

Extract from Matlab code used to solve for variable t:

```
t=1;
func = @(t) sqrt(3*E*pi*D^3*t/(l^3*8*(mTop+0.25*rho*pi*D+t*l)))-f0*2*pi;
t = fsolve(func,t);
```

The resulting value for the wall thickness is $t = 0.0318m$. The tower mass is then $m_{tower} = 391730kg = 391.73t$. The material cost for this tower would thus be of 195870 €, assuming a price of 500 €/t. Obviously a thicker tower wall leads to a higher price overall (linear increase). As depicted in Figure 7 a thicker wall leads to a higher Eigenfrequency of the tower as well. However, in this case the relationship is not a linear one due to the exponent of 0.5 in the formula. Hence, a thicker wall results in a higher Eigenfrequency but the increase is only significant for wall thicknesses up to $0.1m$. Above that the cost increase does not justify the gain in Eigenfrequency because wall thickness and costs are proportional but the Eigenfrequency is under-proportional.

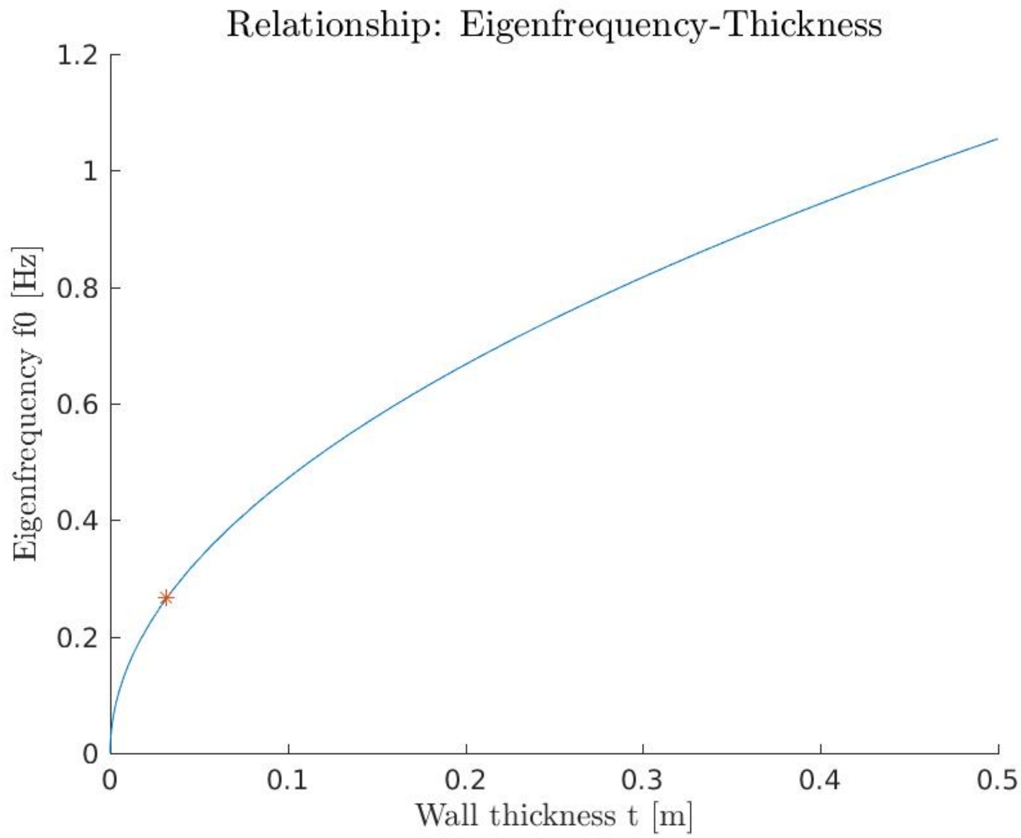


Figure 7: Effect of wall thickness on Eigenfrequency

4.4 Campbell diagram

The Campbell diagram is depicted in Figure 8. The red line shows the computed Eigenfrequency of the tower and the circles mark resonance cases for certain rotor speed values due to periodic excitations. For example the dashed blue line (1Ω) represents the 1P excitation (unbalance from the rotation), the second blue line (3Ω) represents the periodic excitation caused by a tower shadow of one of the three blades.

The operational range of the rotor with respect to tower Eigenfrequencies must thus be kept within certain limits. By designing the tower wall thickness with adding a 10% safety margin to the rotor rated speed we can are on the safe side and avoid 1P excitations (intersection point of the Ω line with the red line). It must further be excluded during operations that any of the other intersection points occur, e.g. 3Ω line with red line. Some rotational speed ranges must thus be excluded in operation in order to avoid any resonances.This analysis however only considers tower resonances. A complete evaluation must take into account more resonances as well, e.g. 1st blade edgewise and 1st blade flapwise eigenfrequencies.

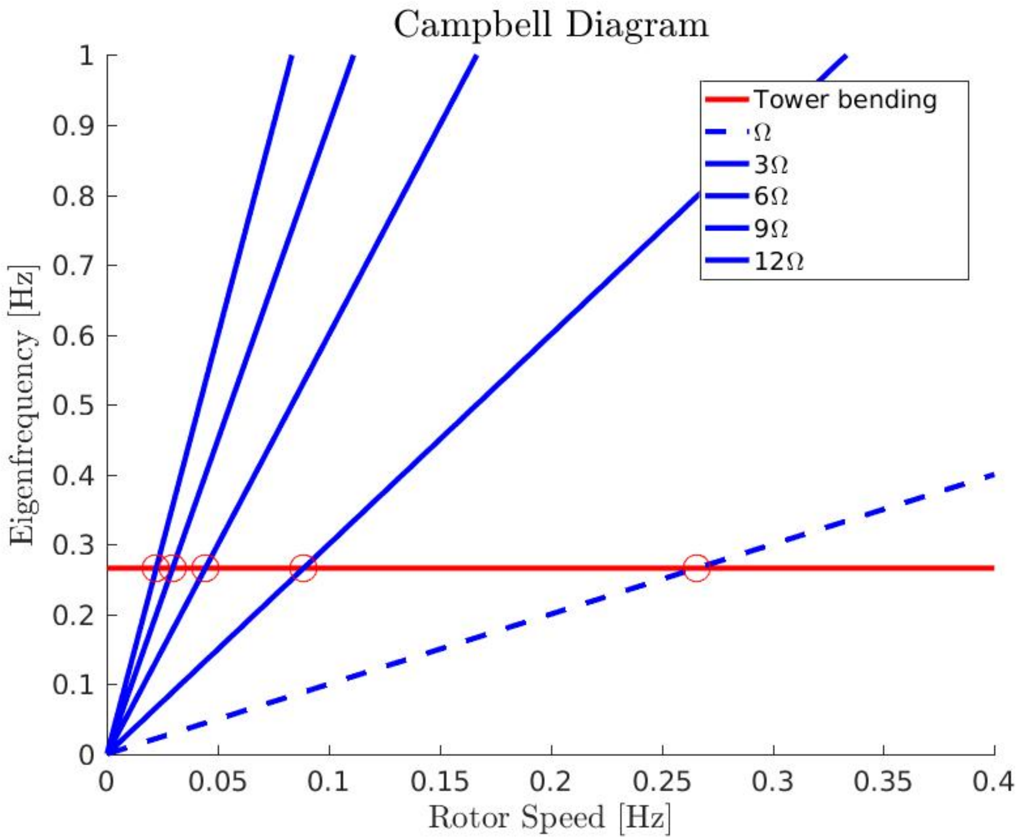


Figure 8: Campbell Diagram

5 CIP 5: Windfields and wake modelling

5.1 Wind speed distribution: Rayleigh

Assuming a wind class type I-B gives per definition a reference wind speed of $V_{ref} = 50m/s$ and a reference turbulence intensity of $I_{ref} = 0.14$. The Rayleigh distribution as a special case of Weibull where the shape parameter has a value of $k = 2$. The average wind speed can be derived from the reference wind speed as follows: $V_{ave} = V_{ref}/5 = 10m/s$. From this we can derive the scale parameter via $V_{ave} = \lambda \cdot \sqrt{\frac{\pi}{2}}$ resulting in $\lambda = 7.97m/s$. The corresponding wind speed distribution following a Weibull law with $\lambda = 7.97 m/s$ and $k = 2$ is depicted in Figure 9. Frequencies were multiplied with 8760 in order to represent the absolute number of hours per year. Three crucial windpeeds are highlighted in the diagram: Cut-In speed ($3.5 m/s$), Rated speed ($11 m/s$) and Cut-Out speed ($25 m/s$). These three limits define the operational conditions of the turbine: Between Cut-In and Rated speed the turbine is operating in partial load, between rated speed and Cut-Out the turbine is operating under full load. Beyond these limits the turbine is not operating.

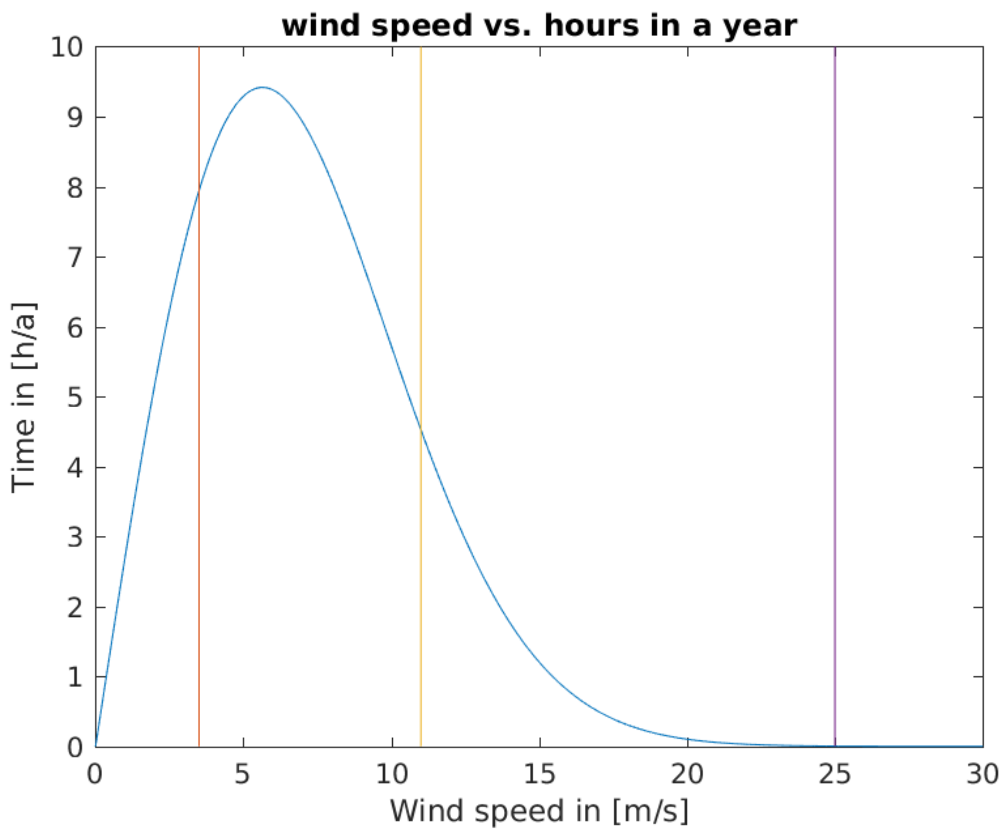


Figure 9: Wind speeds vs hours per year

5.2 Power curve and AEP

The power produced depending on the wind speed can be obtained from the following formula:

$$P(v) = 0.5 \cdot \rho \cdot \nu \cdot \pi \cdot R^2 \cdot v^3$$

Wind density is fixed at $\rho = 1.225$, the total conversion efficiency is given as $\nu = 0.4705$ and the rotor swept area is $\pi \cdot 54^2 m^2$. For wind speeds above rated wind speed the power output of the turbine will be constant. The corresponding power curve is depicted in Figure 10.

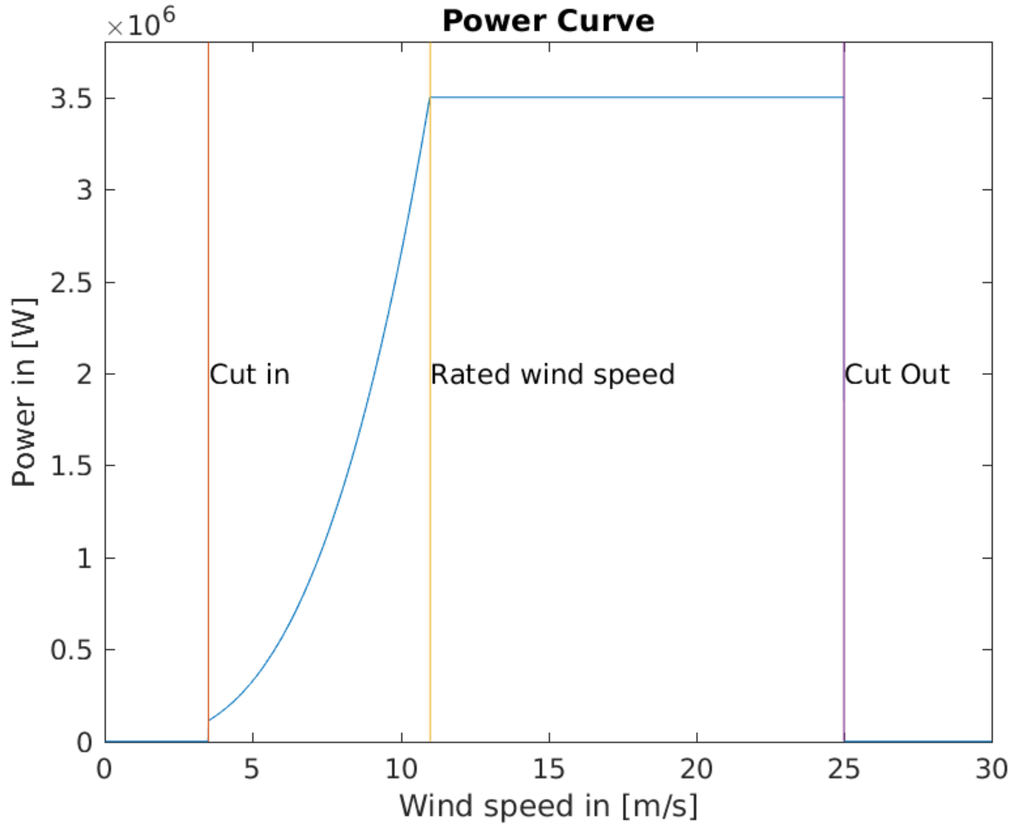


Figure 10: Power curve

Combining the wind speed distribution from Figure 9 and the power curve from Figure 10 enables computing the annual energy production. We multiply the number of hours for each wind speed with the power output at that specific speed and integrate this over all relevant wind speeds. The result corresponds to the area under the curve in Figure 11.

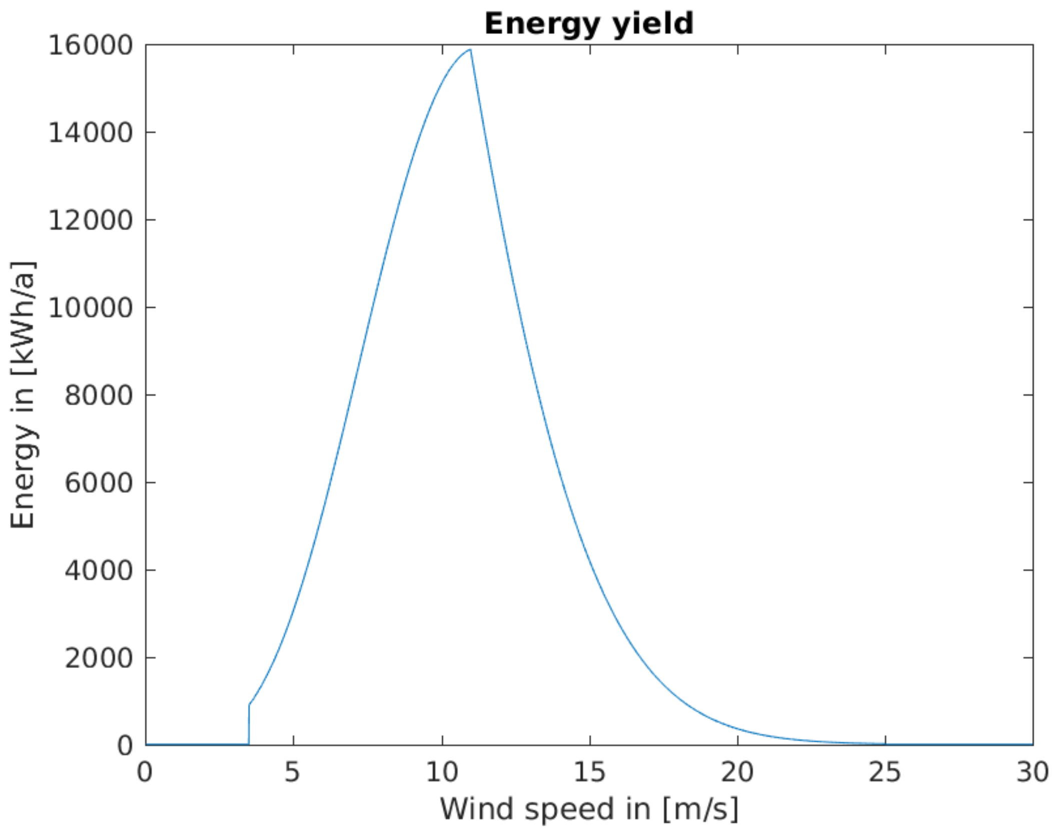


Figure 11: Energy yield for different wind speeds

Here, the total AEP is of about 11.099 GWh. For a 100% availability and a feed-in tariff of 0.08 €/kWh the revenue is thus of approximately 887930€. If we assume an availability of only 95% the corresponding revenue lies around 843530€which results in a loss of nearly 45000€in one year.

5.3 Turbulence intensity under free stream conditions

Applying the normal turbulence model we calculated the turbulence intensity for different wind speeds. The wind class type is I-B which defines a reference intensity of $I_{ref} = 0.14$. The result for the four given wind speeds is shown in Table 6.

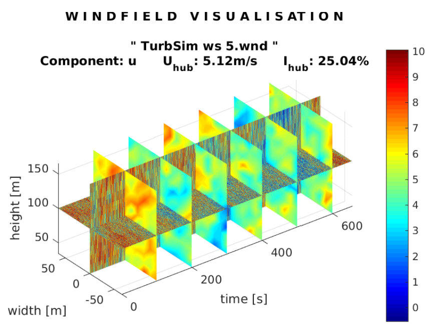
v	$5m/s$	$10m/s$	$15m/s$	$25m/s$
I	0.2618	0.1834	0.1573	0.1364
Operational condition	partial	partial	full	full

Table 6: Turbulence intensity according to NTM at different wind speeds

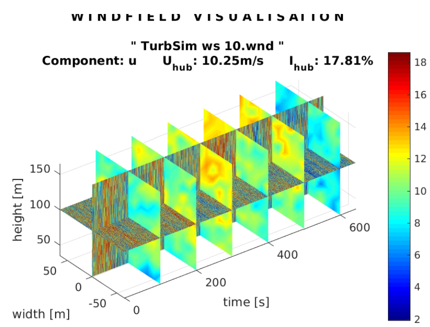
From Figure 11 in the previous section we have seen that the biggest portion of the AEP of the turbine is contributed by wind speeds around rated wind speed. At higher wind speeds less energy is produced because these wind speeds simply are much less frequent due to the distribution, especially speeds of 20m/s and higher are insignificant to the AEP. However, wind speeds around 5m/s or 15m/s do have an impact. Regarding the turbulence intensity shown above we can then conclude that there is no direct relation between turbulence and power output.

5.4 Wind fields with TurbSim

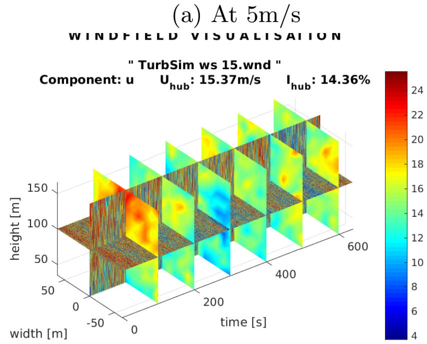
Using TurbSim we generated wind fields for the given conditions, see Figure 12.



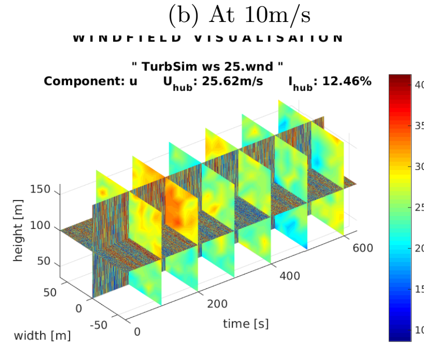
(a) At 5m/s



(b) At 10m/s



(c) At 15m/s



(d) At 25m/s

Figure 12: Wind fields by TurbSim

5.5 Wake modelling with Frandsen

We now use Frandsen's model in order to analyze wakes. Two different setups will be evaluated: One with distances between the turbines of 4 times the rotor diameter, and one with 8 times the rotor diameter. The result for the four given wind speeds is shown in Table 7. The results for the NTM model have been carried over in order to compare these to the wake results.

v	$5m/s$	$10m/s$	$15m/s$	$25m/s$
$\mathbf{4 \cdot d}$	0.2667	0.1867	0.1594	0.1370
$\mathbf{8 \cdot d}$	0.2621	0.1827	0.1562	0.1349
NTM	0.2618	0.1834	0.1573	0.1364

Table 7: Turbulence intensity according to NTM at different wind speeds

Clearly the turbulence intensity is lower for the case of larger distances ($8 \cdot d$) for all wind speeds. However, the difference between the free stream turbulence and the case of larger distances is only marginal. For a wind speed of 5 m/s the turbulence intensity is lower in the free turbulence model, but for all other wind speeds the Frandsen model leads to lower turbulences then the free stream model.

The complete dataset for all wind bins and all three cases is visualized in Figure 13. It is not easy to recognize, but by looking closely we find that the order $8 \cdot d$, NTM, $4 \cdot d$ from lowest to highest turbulences holds for all wind bins above 10 m/s.

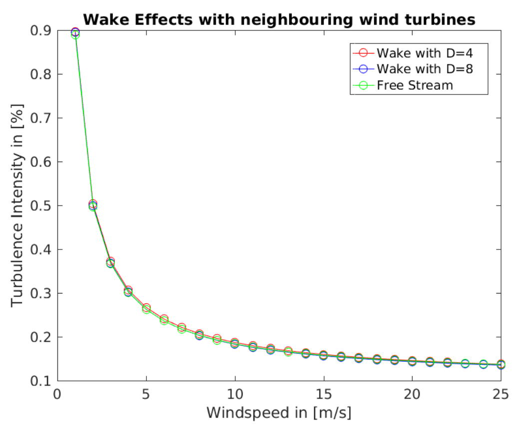
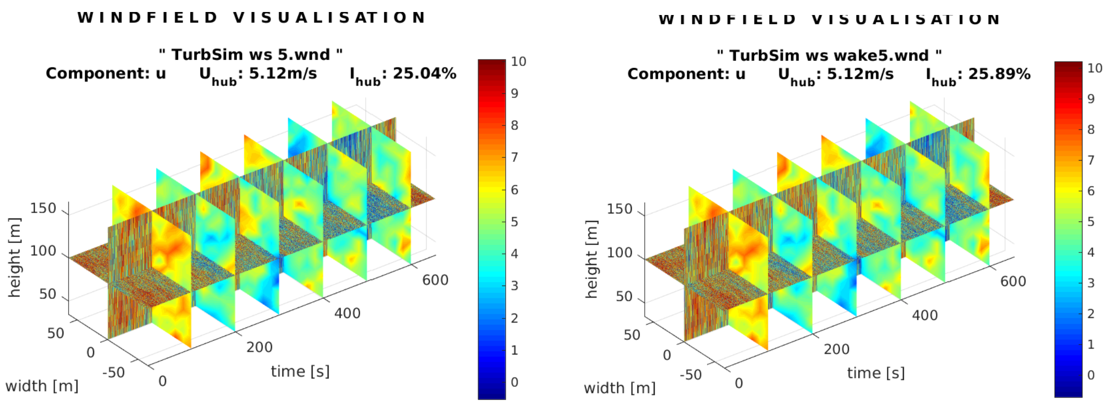


Figure 13: Turbulence intensity in different setups

We generated wind fields for wake conditions with both layouts as well since these will be used later. A comparison of the wind field under free stream conditions with the wind field under wake condition ($4 \cdot d$) for $v = 5m/s$ is shown in Figure 14. The two wind field do not diverge very much, but the computed turbulence intensity differs considerably (0.2504 vs 0.2544).



(a) Wind field for Free stream at 5m/s

(b) Wind field for Wakes with $4 \cdot d$ at 5m/s

Figure 14: Free stream vs Wake conditions

5.6 Possible faults

Failures can occur with respect to electrical components and the turbine control. These failures must be simulated in order to ensure structural integrity of the turbine. Possible faults are defect pitch or yaw actuators, which lead to the turbine being unable to reduce or increase forces and might cause a breakdown. Also it could be that sensors are defect and supply wrong data which would result in a fatal mis-behavior of the turbine. Likewise the drive train and gearbox might be affected by broken parts causing severe failure of the turbine if not handled correctly. The generator of a turbine can be subject to electromechanical problems, e.g. torque scaling fault, overheating, asymmetries etc.