Report: Design of Wind Energy Systems

ForWind – Wind Energy Systems

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Content

Introduction

Wind turbines can be used to produce energy in a substantial manner. Thus the design process of these turbines should lead to energy production in a safe and economical feasible way. The following report deals with the designing of a wind turbine, beginning at the general side conditions, the rotor design, the investigation of the turbine performance and followed by the turbine dynamics and evaluation of the gain and in the end a load analysis is done.

Design of a wind turbine

CIP 1 Selection of main parameters

Table 1 shows the side specific conditions and the limitations for the design process of the wind turbine.

Table 1: General parameters for the design of the wind turbine

Design wind regime [-]	Rayleigh
Target wind regime [-]	Medium
Weibull A-factor (local) [m/s]	8
Weibull k-factor (local) [-]	1,85
Rated electrical power [kW]	2500
Number of blades [-]	3
Cut-in wind speed [m/s]	3,5
Cut-out wind speed [m/s]	25
Max. tip speed [m/s]	77
Max. hub height – reference (*) [m]	100
Max. blade length - reference (*) [m]	55
Blade root length [m]	5
Transmission [-]	101

The choosen main parameters with respect to table 1 are shown in table 2.

Table 2: Main parameters of the designed turbine

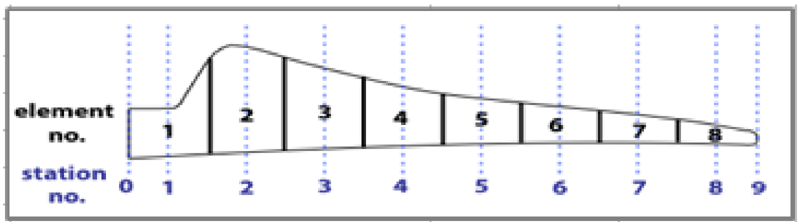
Calculate total conversion efficiency (Cp_ref, mech_eff, elec_eff) [-]	0,4705
Total wind power that needs to be extracted [kW]	5313,756
Rated wind speed [m/s]	10
Rotor radius [m]	53
Blade length (without hub) [m]	51,75
Rotor area (rounded radius) [m²]	8819,565
Specific rating (design) [W/m²]	283,461
λD Design tip speed ratio [-]	7,70

Rotor rated speed [rpm]	13,87
Blade element length (8 elements of equal length) [m]	6,469

The resulting power curve is shown in figure

The parameters that affect the results much are rotor diameter and rated power. The longer rotor diameter captures more power during partial operation and results in higher capacity factor. Selecting higher rated power will increase the power production during full load. This way we can reach higher rate of power and also higher energy yield but lower capacity factor.

Figure 1 shows the design values for the rotor blade.



Blade aerodynamics	Unit	Value
Lift coefficient – Profile 1	-	1.35
Lift coefficient – Profile 2	-	1.28
Lift coefficient – Profile 3 (cylinde	-	0
Drag coefficient – Profile 1	-	0.014
Drag coefficient – Profile 2	-	0.014
Drag coefficient – Profile 3 (cylinc	-	1
Angle of attack – Profile 1	deg	9.5
Angle of attack – Profile 2	deg	9
Angle of attack – Profile 3 (cylinc	deg	0

Figure 1: Upper part: Sketch of a rotor blade with elements, lower part: Lift coefficient, drag coefficient of parts of the rotor blade

For the blade design two profiles are used. Profile 1 (NACA 64-415) and profile 2 (NACA 64-421).

Figure 2 shows the lift to drag ratio and the lift coefficient at different angles of attack. Table 3 ahows the design values for two different methods.

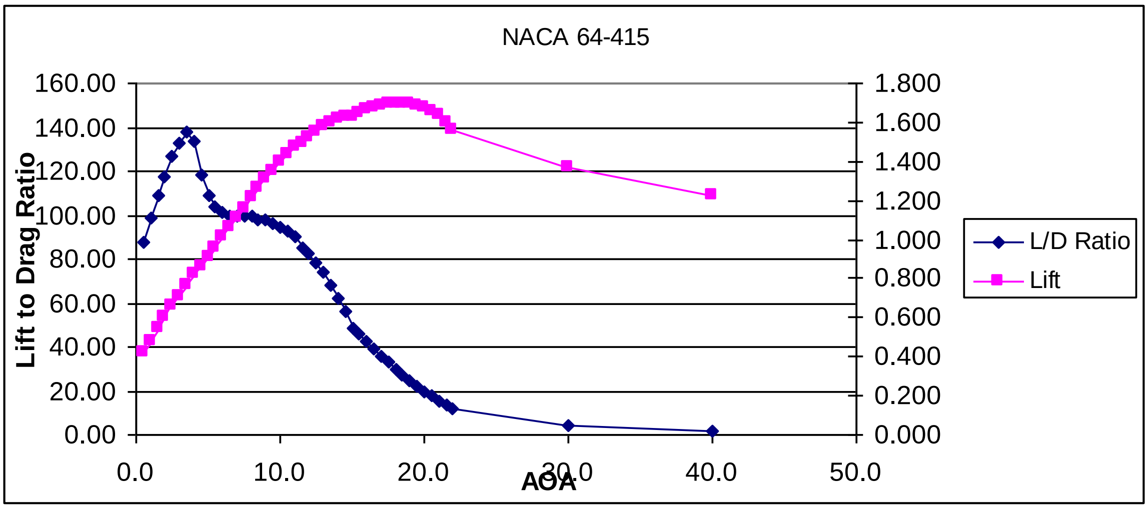


Figure 2: Lift to drag ratio of profile 1 (NACA 64-415)
X-axis angle of attack [°], Y-axes Lift to drag ratio (left side) [-], lift coefficient (right side) [-]

Table 3:Bllade design according to the 80 % method and the lift to drag method, profile used: NACA 64-415

	α	c_L	c_D	c_M
80% method:	9.500	1.352	0.014	0.077
lift to drag method:	3.500	0.769	0.006	0.087

Figure 3 shows the lift to drag ratio and the lift coefficient at different angles of attack. Table 4shows the design values for two different methods.

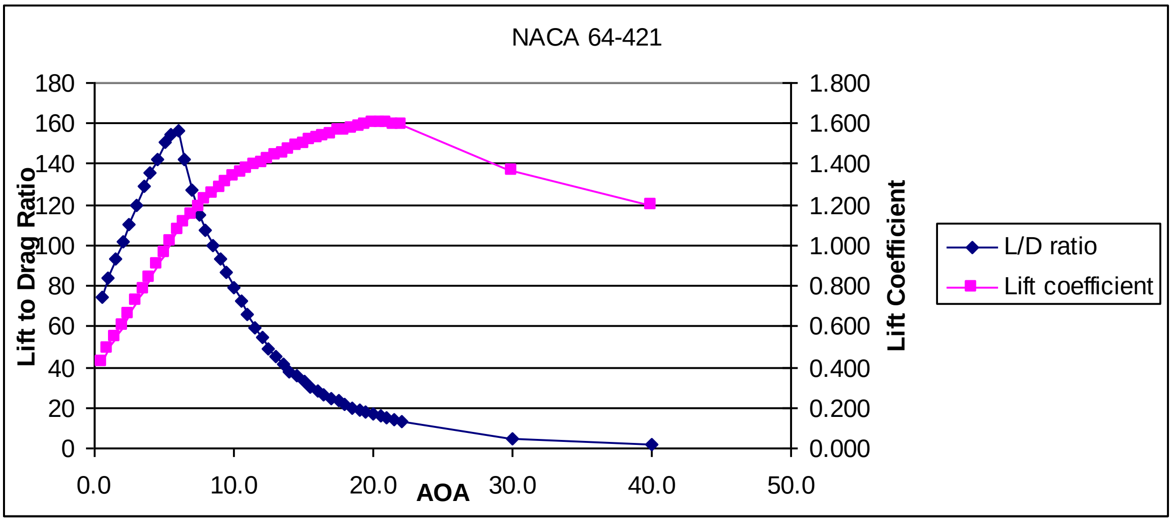


Figure 3 Lift to drag ratio of profile 1 (NACA 64-421)

X-axis angle of attack [°], Y-axes Lift to drag ratio (left side) [-], lift coefficient (right side) [-]

Table 4: Blade design according to the 80 % method and the lift to drag method, profile used: NACA 64-421

	α	C_L	C_D	C_M
80% method:	9.00	1.28	0.014	0.07
lift to drag method:	6.00	1.07	0.007	0.09

For both profiles maximum lift to drag ratio occurs in an AOA of lower value than that of for maximum lift coefficient. As the 80% of the maximum drag coefficient is higher that that where maximum L/D ratio happens then in both cases we selected the AOA on the basis of 80% of the maximum lift coefficient.

CIP 2 Advanced BEM theory

The rotor blade is generally designed to according to Betz and Schmitz theory. Table 5 summarizes the results.

Table 5 Blade design according to Betz and Schmitz theory

Station number			1	2	3	4	5	6	7	8
Distance (from rotor center) [m]			4,48	10,95	17,42	23,89	30,36	36,83	43,30	49,77
Distance (from blade root) [m]			3,23	9,70	16,17	22,64	29,11	35,58	42,05	48,52
Betz theory	Profile 1	Chord length [m]		5,50	3,63	2,69	2,13	1,76	1,50	1,31
		Twist angle [°]		13,23	5,26	1,37	-0,91	-2,40	-3,45	-4,23
	Profile 2	Chord length [m]		5,80	3,83	2,83	2,24	1,86	1,58	1,38
		Twist angle [°]		13,73	5,76	1,87	-0,41	-1,90	-2,95	-3,73
	Check	Power per element [kW]		191,76	277,88	368,15	460,42	553,73	647,66	741,96
Schmitz theory	Profile 1	Chord length [m]		4,70	3,38	2,59	2,08	1,73	1,48	1,30
		Twist angle [°]		11,93	4,87	1,22	-0,98	-2,44	-3,48	-4,25
	Profile 2	Chord length [m]		4,96	3,57	2,73	2,19	1,83	1,56	1,37
		Twist angle [°]		12,43	5,37	1,72	-0,48	-1,94	-2,98	-3,75

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 6 gives more detail about the design rotor blade.

Table 6: Design rotor blade

Station number	1	2	3	4	5	6	7	8
Used profile	Cylinder	NACA 64-421	NACA 64-421	NACA 64-421	NACA 64-421	NACA 64-415	NACA 64-415	NACA 64-415
Distance (from blade root) [m]	3,23	9,70	16,17	22,64	29,11	35,58	42,05	48,52
Chord length [m]	4,96	3,57	2,73	2,19	1,73	1,48	1,30	4,96
Twist angle [°]	12,43	5,37	1,71	-0,48	-2,44	-3,48	-4,25	12,43

Figure 4 shows the tip-loss factor at different blade stations. It can be seen that only at the last two stations this factor is significant and additionally that the tip los factor is lower at higher wind speeds.

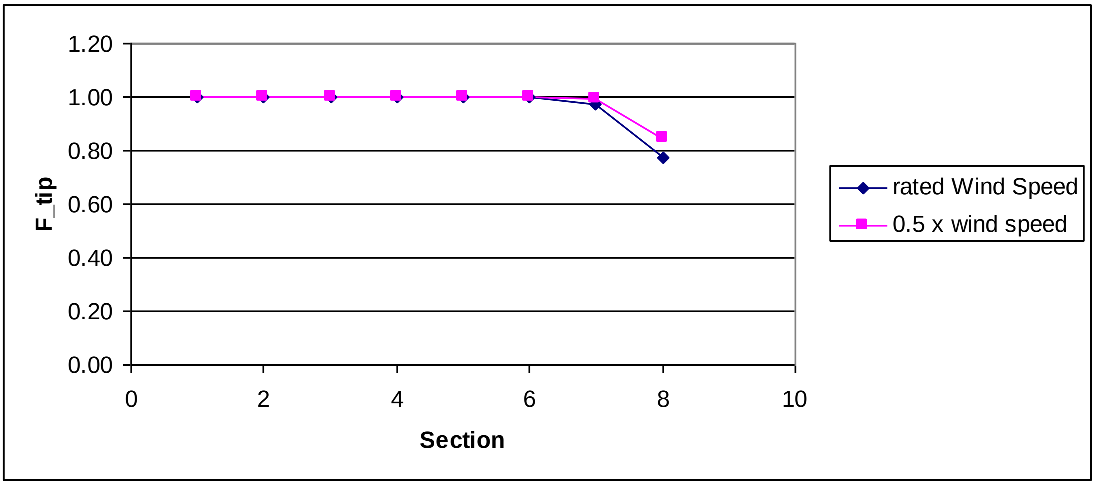


Figure 4: Tip-loss factor versus blade element location

Figure 5 and figure 6 show a 3D correction at different blade stations and angle of attack.66

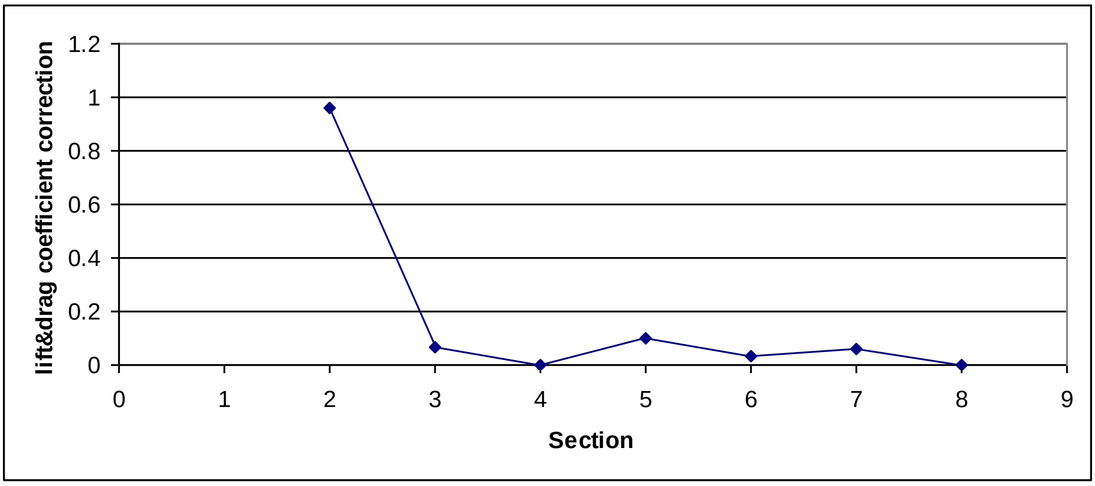


Figure 5: Lift and drag coefficient correction at different blade sections

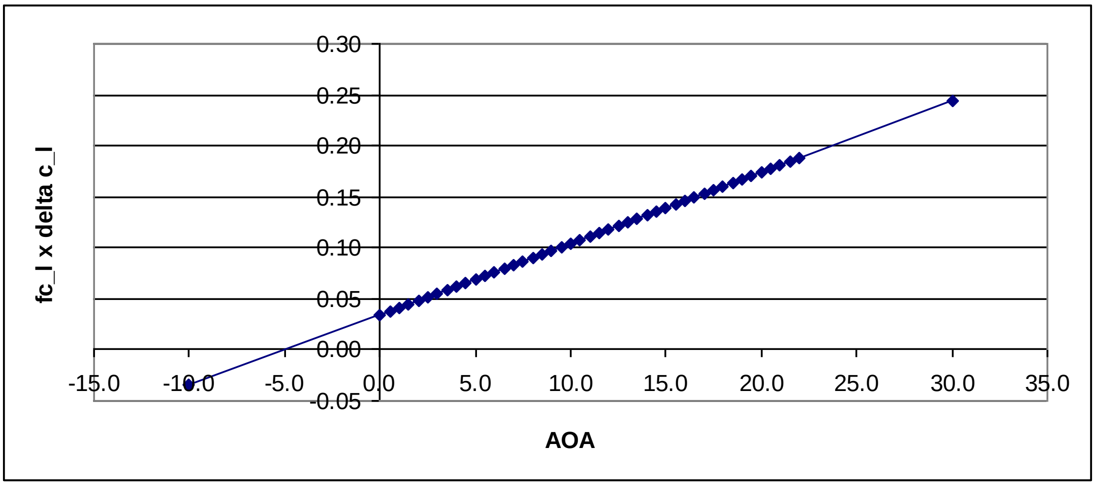


Figure 6: 3D correction in dependency of angle of attack (AOA)

CIP 3 Performance curves

In this section the performance of the designed turbine is shown under different pitch angles.

To describe the behavior of wind turbine different dimensionless performance coefficients can be used. The following part will consider the power coefficient (c_P), the torque coefficient (c_M) and the thrust coefficient (c_S). The following equations show, how these coefficient are calculated.

$$c_P = \frac{P}{\frac{\rho}{2} * A_{swap} * {v_{wind}}^3}$$

$$c_S = \frac{S}{\frac{\rho}{2} * A_{swap} * v_{wind}{}^2}$$

$$c_M = \frac{\tau}{\frac{\rho}{2} * A_{swap} * v_{wind}{}^2 * R_{rotor}}$$

The power, thrust and torque of the wind turbine is calculated with a program called WT_Pert. This program is based on the blade element momentum theory (BEM). It takes into account an algorithm for tangential induction factor, the Prandtl tip- and hup-loss algorithm and it also corrects for tilt and yaw. WT_Perf calculates the power coefficient, the thrust and the torque in dependency of the tip speed ratio for the determination of the performance curves. It is also possible to calculate these curves at different pitch angles. Figure 7 shows the results of the power coefficient. Figure 8 depicts the results of the thrust coefficient. Figure 9 shows the results for the torque coefficient at respectively a tip speed ratio from one to 20 and pitch angeles of : 0°, 5°, 10°, 15°, 20° and 30°. The curves are calculated at rated rotor speed (13.7 rpm)

Figure 7 shows the c_P-λ curve. The maximum at every single pitch angle appears at different tip speed ratios. The higher the pitch angle is the lower is the tip speed ratio at which the maximum is evident in general. At a pitch angle of 5 ° the maximum c_P is 0.58. This is very close to the theoretical limit of 0.592. The highest power coefficient of a 0 ° pitch angle is 0.54.

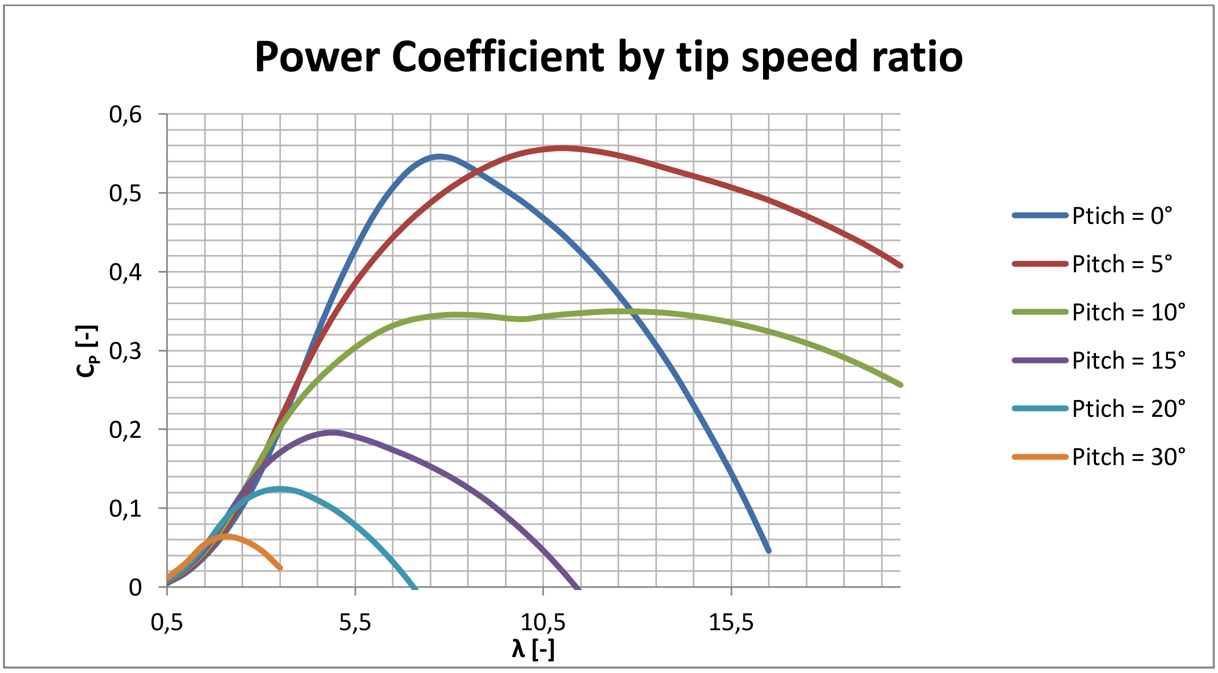


Figure 7 Power Coefficient by Tip-Speed-Ratio at different pitch angles

Figure 8 gives information about the behavior of the thrust coefficient. At low pitch angles and high tip speed ratios the thrust coefficient reaches high values. Because thrust is generally directly applied to the tower this has a considerable influence to the structural design of the tower. At high pitch angles the thrust coefficient is equal to zero at increased tip speed ratios. This way the loading on the tower structure can be reduces.

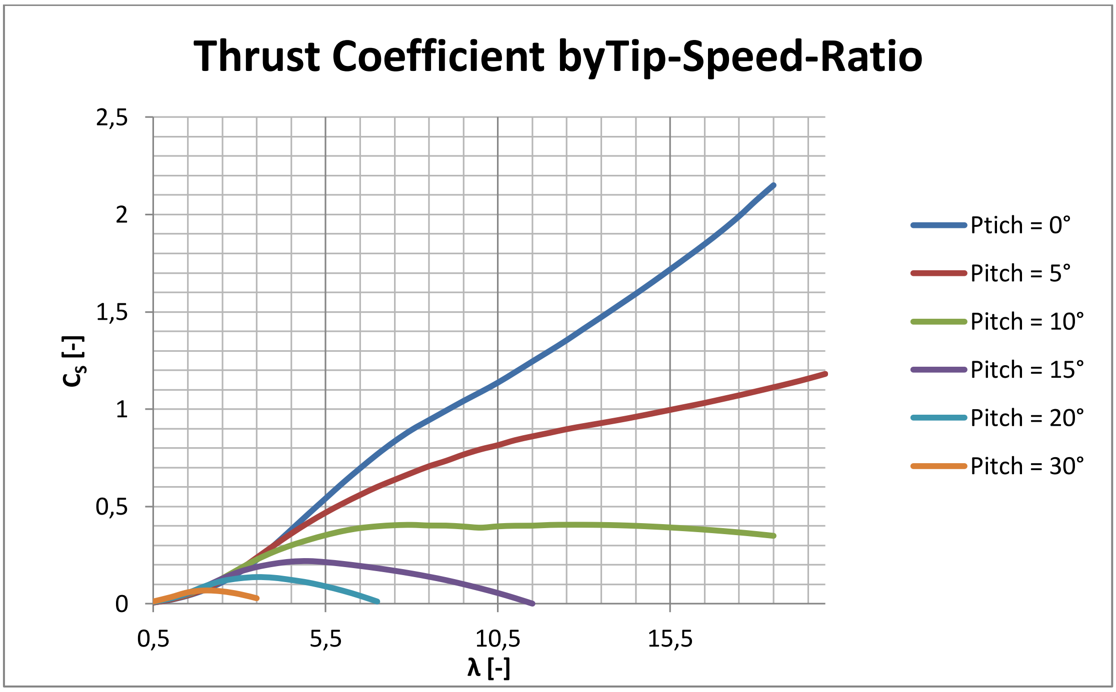


Figure 8: Thrust Coefficient by Tip-Speed-Ratio at different pitch angles

Figure 9 shows the behavior of the torque coefficient. Compared with the power coefficient curves the maximums of the torque coefficients are reached at lower tip speed ratios. The lowest maximum, at a pitch angle of 30 °, corresponds to a tip speed ratio of 1. The highest maximum is reached at a pitch angle of 0 ° and a tip speed ratio of 6.The C_M-λ curve can be used to perform torque assessment purposes when a rotor is connected to the gearbox.

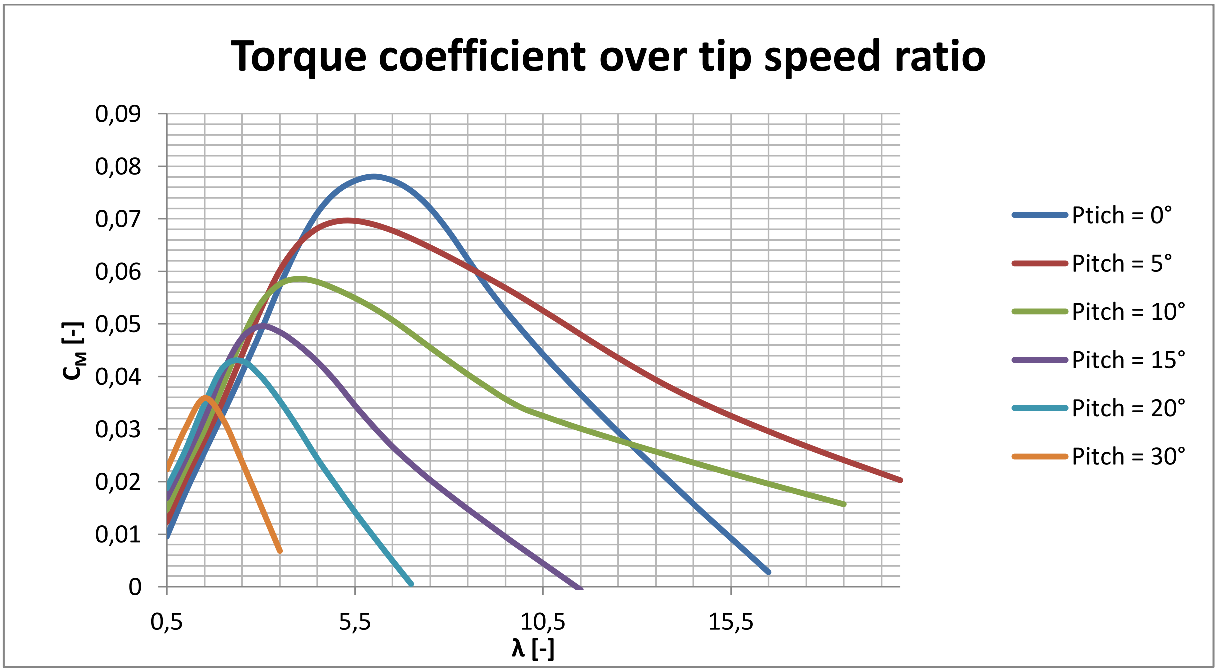


Figure 9 Torque Coefficient by Tip-Speed-Ratio at different pitch angles

Figure 10 shows a power curve from literature. The maximum c_P in the figure from the literature is ≈0.52 at zero degree pitch and design tip speed ratio. Figure 7 which shows the design turbine power curve indicates a maximum c_P at a tip speed ratio of around 11. This is above design tip speed ratio.

The curves at zero, twenty, thirty and forty degree have a similar shape at the designed turbine and the literature example. Figure 7 shows curves with a different proceeding for five and ten degree compared to figure 10. At a pitch angle of five and ten degree the designed turbine reaches high power coefficients at high tip speed ratios. According to figure 10 lower values for the maximum power coefficient would be assumed.

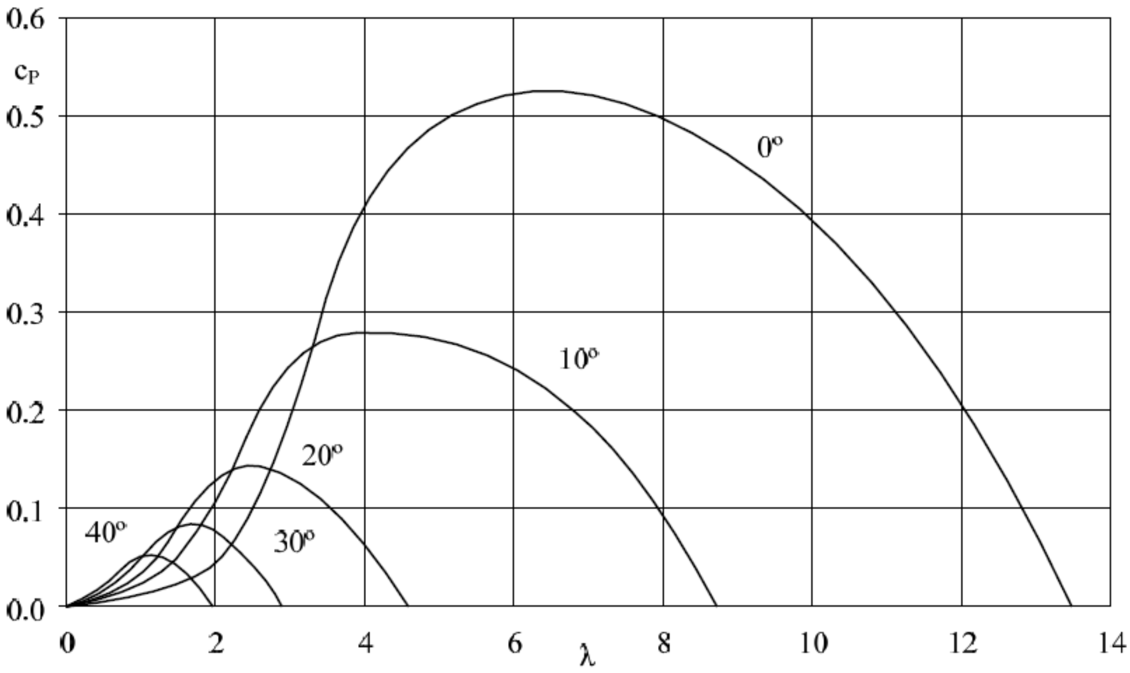


Figure 10 Power Coefficient over Tip-Speed-Ratio at different pitch angles from literature[1]. The design tip speed ratio is 7.

Figure 11 shows a thrust coefficient versus tip speed ratio curve from literature. The curves are similar to the designed turbine. At high pitch angles the curves reach zero at relatively low tip speed ratios. At a pitch angle of zero degree the thrust coefficient increases at high tip speed ratios. Both features are also evident at the designed turbine.

[1]Gasch, R. : Wind Power Plants – Fundamentals, Design, Construction and Operation, 1st Edition, Solarpraxis AG, Berlin, 2002

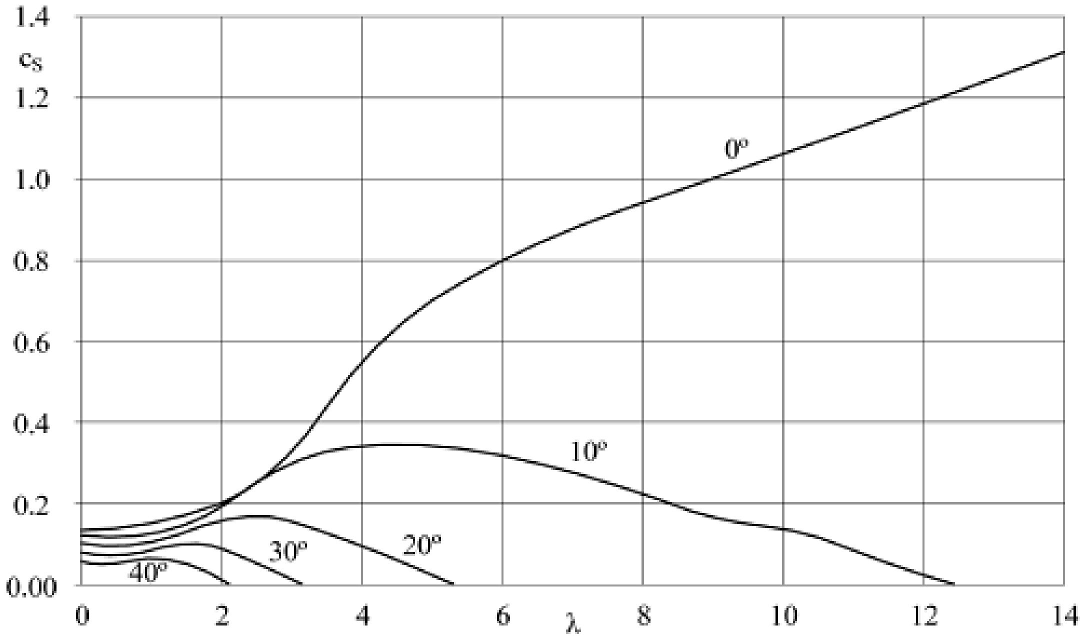


Figure 11: Thrust coefficient versus tip speed ratio at different pitch angles from literature[2].
Degree data are referred to the pitch angle, the design tip speed ratio is 7.

Figure 12 gives information about the torque coefficient at different pitch angles from literature. The differences between the designed turbine and the example from literature are similar to the differences at the power curves. At pitch angles of zero, twenty, thirty and forty degree the curves follow the same pattern and no curve intercept another curve. In figure 8 the five and ten degree pitch line intercept the zero degree pitch curve. According to Figure 12this is not expected.

[2] Gasch, R. : Wind Power Plants – Fundamentals, Design, Construction and Operation, 1st Edition, Solarpraxis AG, Berlin, 2002

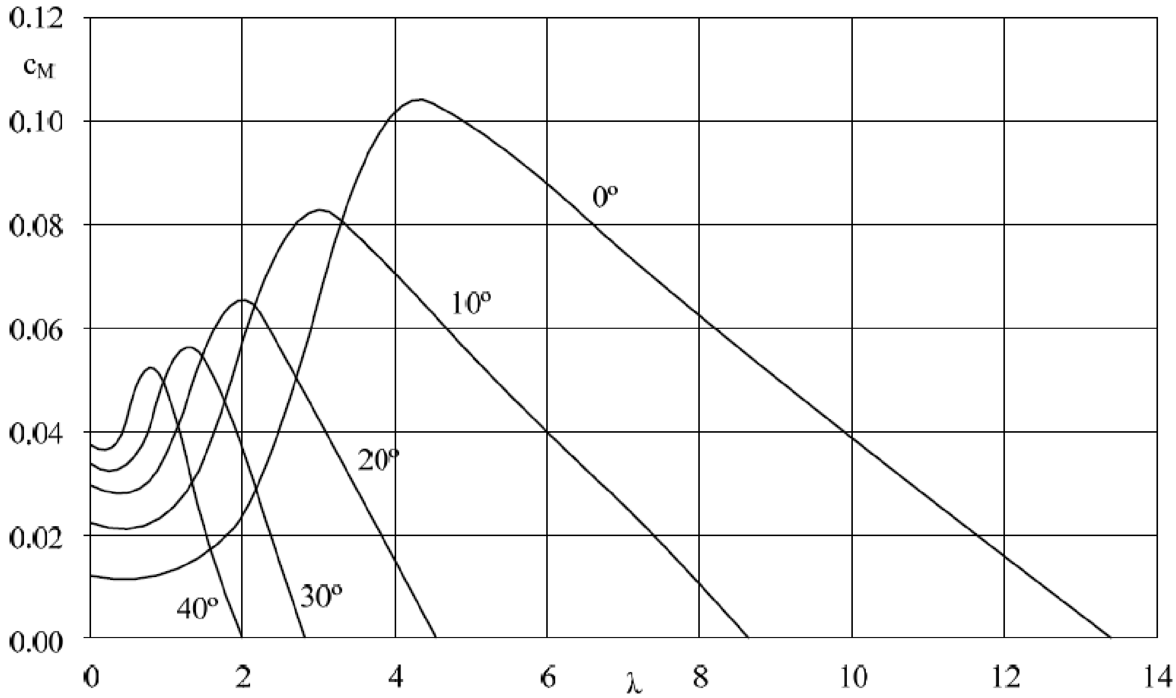


Figure 12: Torque coefficient versus tip speed ratio at different pitch angles from literature[3].
Degree data are referred to the pitch angle, the design tip speed ratio is 7.

Table 7 shows the operation conditions below rated wind speed at v=8 m/s ($v=v_{rated}$-2 m/s), at design tip speed ratio (λ = 7.70) and no pitch. The simulation is performed at a wind speed of 8 m/s and the rotational speed is set from 0 to 20 rpm with a delta rotational speed of 0.1 rpm. The tip speed ratio is calculated and the corresponding power coefficient, torque and thrust are chosen at the design tip speed ratio. The needed coefficients and the power are calculated afterwards. Also the mechanical and electrical efficiency is taken into account

Table 7 Turbine operation below rated wind speed

v [m/s]	Rotor speed [rpm]	c_P [-]	c_S [-]	c_τ [-]	P [kW]
8	11.1	0.546	0.860	0.071	1352

At a wind speed of 12 m/s the turbine theoretically can extract 3766 kW. Due to the fact that the rated power is lower than the power which can be extracted pitching is needed to reduce the power which is extracted from the wind. The power coefficient in this case is calculated as follows:

$$c_P = \frac{2500 * 1000\ W}{\frac{1.25\ kg}{m^3} * \pi * (53m)^2 * \left(12\frac{m}{s}\right)^3} = 0.263$$

[3] Gasch, R. : Wind Power Plants – Fundamentals, Design, Construction and Operation, 1st Edition, Solarpraxis AG, Berlin, 2002

This corresponds to a tip speed ratio of ≈ 4.5 (at a pitch angle of 10 °) which is read from figure 7.Another possibility to limit the power coefficient would be to keep the pitch at zero degree. Thus the tip speed ratio would increase to around 14.5.The resulting rotor speed for 10 ° pitching is calculated bbelow.

$$n = \frac{\lambda * v}{R} * \frac{60\ s}{2\pi * 1min} = \frac{4.5 * 12\ \frac{m}{s} * 60s}{53\ m * 2\pi * 1\ min} = 9.73\ rpm$$

Table 7 shows that below rated wind speed still a high power coefficient can be archived. The calculated power coefficient for a wind speed of 8 m/s is 0.55. If the wind speed is higher than rated wind speed the power coefficient drops significantly. The reason for this is that the generator capacity is limited. Thus not all kinetic energy of the wind can be converted into electrical energy by the generator. Pitching is needed to limit the power coefficient so that the adequate kinetic energy is extracted from the wind. If the no pitch is applied the turbine would reach very high revolutions can damage the generator.

In both cases (wind speed lower and higher than rated wind speed) the revolutions per minute are below the rated rotor speed.

The most efficient possibility to control a turbine is to have a variable speed turbine. As a result the turbine can operate at design tip speed ratio, resulting in a power coefficient as high as possible or necessary.

CIP 4 Wind Turbine Dynamics/ Tower Design

The following part deals about the design of the tower with respect the costs and the tower eigenfrequency.

For the tower design a safety margin of 10 %, with respect to the eigenfrequency is taken into account. The eigenfrequency is 10 % higher than the frequency due to the rated rotor speed. It is also assumed that the tower has a cylindrical shape with constant diameter.

The Eigenfrequency (f_0) is calculated by the following equations:

$$\omega_0 = \sqrt{\frac{k}{m_{modal}}} = f_o * 2\pi$$

$$m_{modal} = m_{towertop} + 0.25 * m_{towermass}$$

$$k = \frac{3E * I}{l^3}$$

$$I = \frac{\pi * D_{tower}{}^3 * t_{tower}}{8}$$

$$m_{tower} = \rho * \pi * D_{tower} * t_{tower} * H_{tower}$$

Table 8 summarizes the general design parameters and the results calculated with the formulars above. It shows the tower eigenfrequency of 0.254 Hz and the resulting wall thickness of the tower which is 42 mm.

Table 8 Values for the tower design and results

Hub height [m]	100
Nacell mass [t]	200
Rotor mass [t]	54
Tower diameter [m]	4.5
E-modulus [N/m²]	$2.11*10^{11}$
Steel density [kg/m³]	7850
Rotor rated speed [Hz]	0.231
10 % safety margin of rotor speed [Hz]	0.0231
Eigenfrequency [Hz]	0.254
Wall thickness [m]	0.042
Tower mass [t]	460.7

The design range of the designed tower is the classical soft-stiff design. The design results in a significant wave excitation. It also allows a variable speed turbine design because rotational frequencies lower than rated rotor speed will not result in resonances with the tower eigenfrequency.

Another widely used design approach is the soft-soft design. Here the eigenfrequency is placed within the resonance range of the rotor. But in this case some rotor frequencies have to be excluded of the operational range to no get resonances.

For the cost analysis a steel price of 500 €/t is assumed. The costs are calculated as follows:

$$Costs = m_{steel} * 500\ €/t$$

Figure 13 shows the tower costs as a function of wall thickness. The relationship between both is linear. So doubling the tower wall thickness would result in double costs for steel. For the chosen design wall thickness the tower costs are 230 000 €.

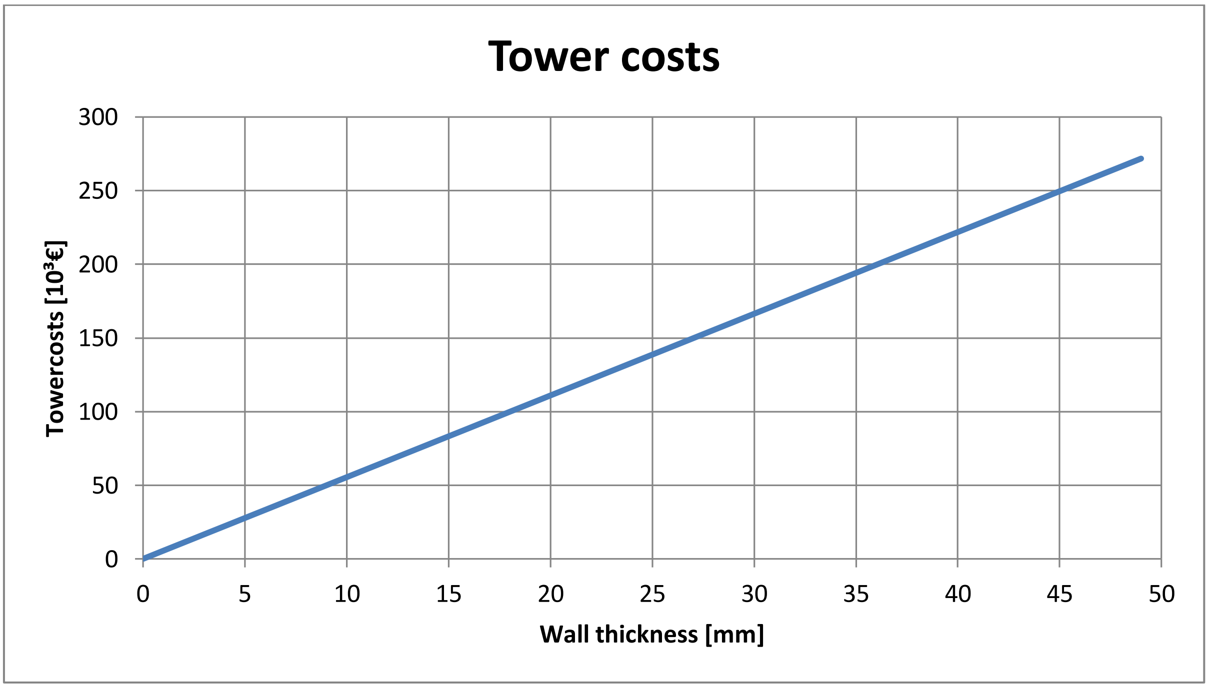


Figure 13 Tower costs as a function of the wall thickness

Figure 13 shows the dependency of the eigenfrequency over the wall thickness. In regions of higher wall thicknesses the gradient of this function is relatively low. Because the costs increase linear of a, as shown in Figure 13, a tower with a high eigenfrequency would be very expensive compared to a tower with a low eigenfrequency.

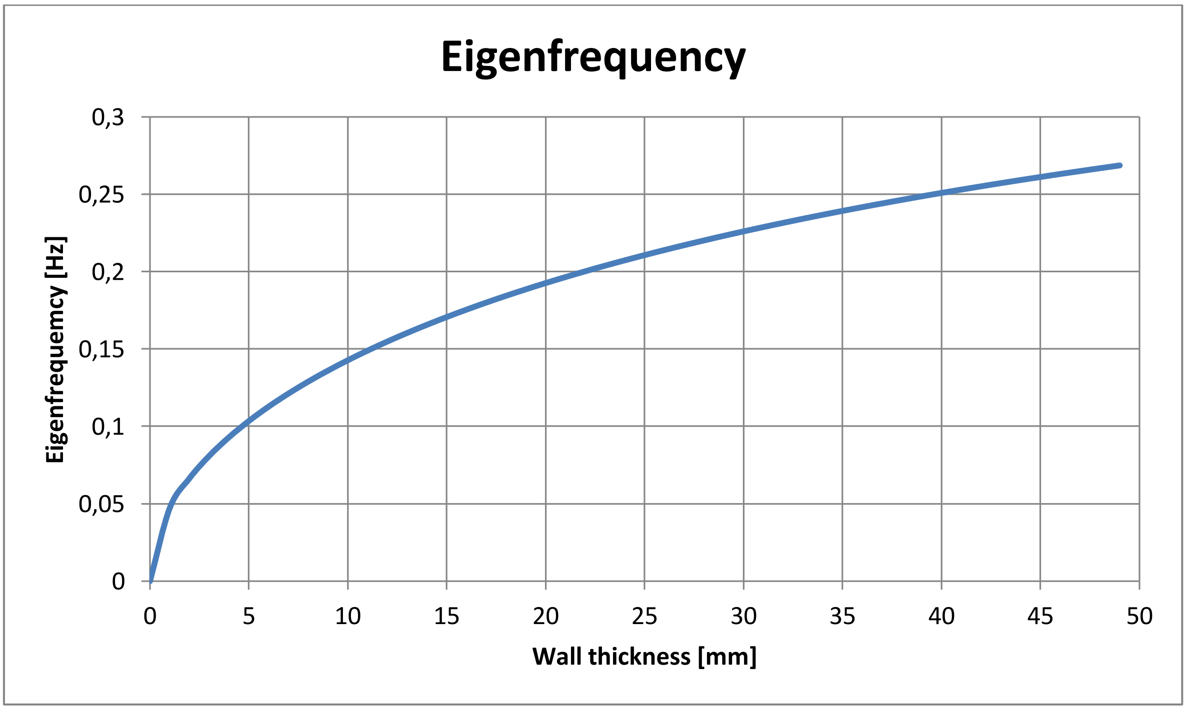


Figure 14 Eigenfrequency as a function wall thickness

Figure 15shows the Campell diagram of the designed turbine. The blue line refers to the rotor rated speed, the green line shows the calculated eigenfrequency of the tower and the red lines are referred to the periodic excitations. The 1P excitation is equal to the rotation frequency, the 3P excitation is equal to three times the rotation frequency, and so on. The 1P excitation range is caused by imbalances of the rotor. The 3P-excitation is caused by the rotation of the rotor. Every time one of the three blades is located in front of the tower the tower sees less stress. The reason for this it that the wind, which would usually hits the tower, is absorbed by the rotor blade. The whole procedure is repeated three times per revolution due to the three rotor blades. It can be seen in figure 15 that at rated rotor speed the tower eigenfrequency is higher than the 1P excitation. At higher rotational speeds the 1P line intercepts the tower eigenfrequency. In this case resonances can occur. But the wind turbine does not operate at this rotor speed range under standard conditions. Below the rated rotor speed the tower eigenfrequency crosses the 3P line at around 5.8 rpm. This means that at this point resonances are an issue. So the turbine should not operate at 5.5 to 6 rpm.

In this report only the tower eigenfrequency is analyzed. In reality different additional frequencies occur like the first flapwise blade bending frequency. For a save operation these frequencies have to be considered, too. But the most important frequency is the tower eigenfrequency because it hast the lowest frequency and due to this is has the highest amplitude.

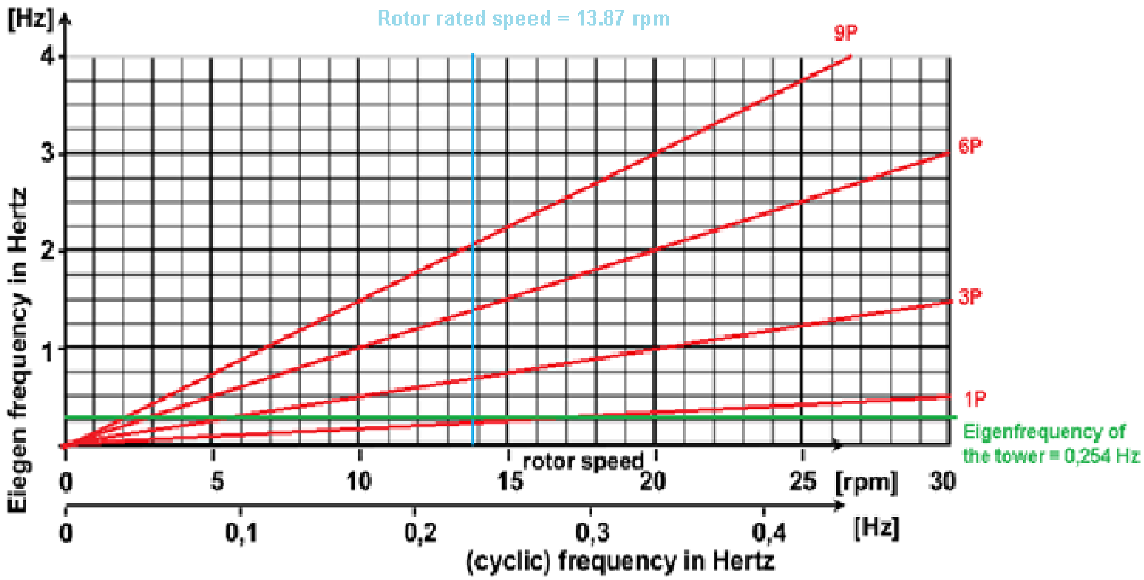


Figure 15 Campbell diagram of the designed turbine tower

CIP 5 Wind fields and Wake Modeling

Figure 16 shows the wind speed versus hours a year. It is shown that most of the time the turbine will operate between cut in speed ant rated speed, as indicated by a peak between at around 6 m/s.

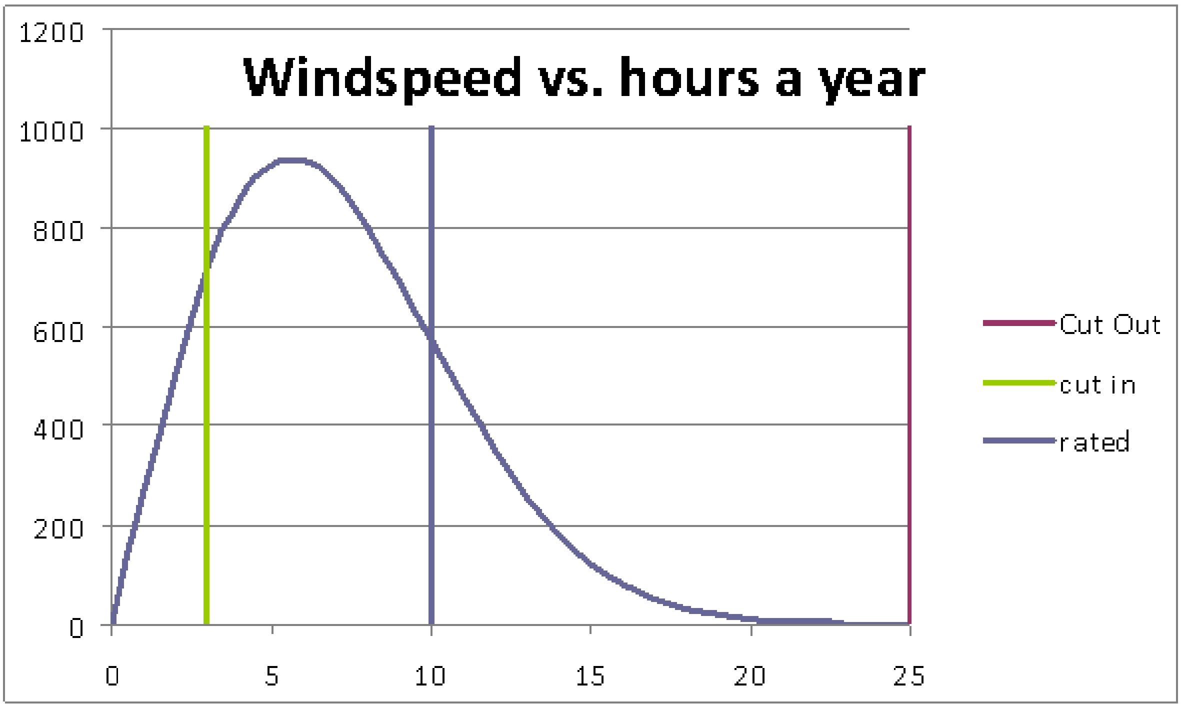


Figure 16: Wind speed vs. hours a year
X-axis: wind speed [m/s]; Y-axis: hours per year [h/a]

Figure 17 shows the power curve of the designed turbine. Also the cut in speed, the rated wind speed and the cut out speed is indicated.

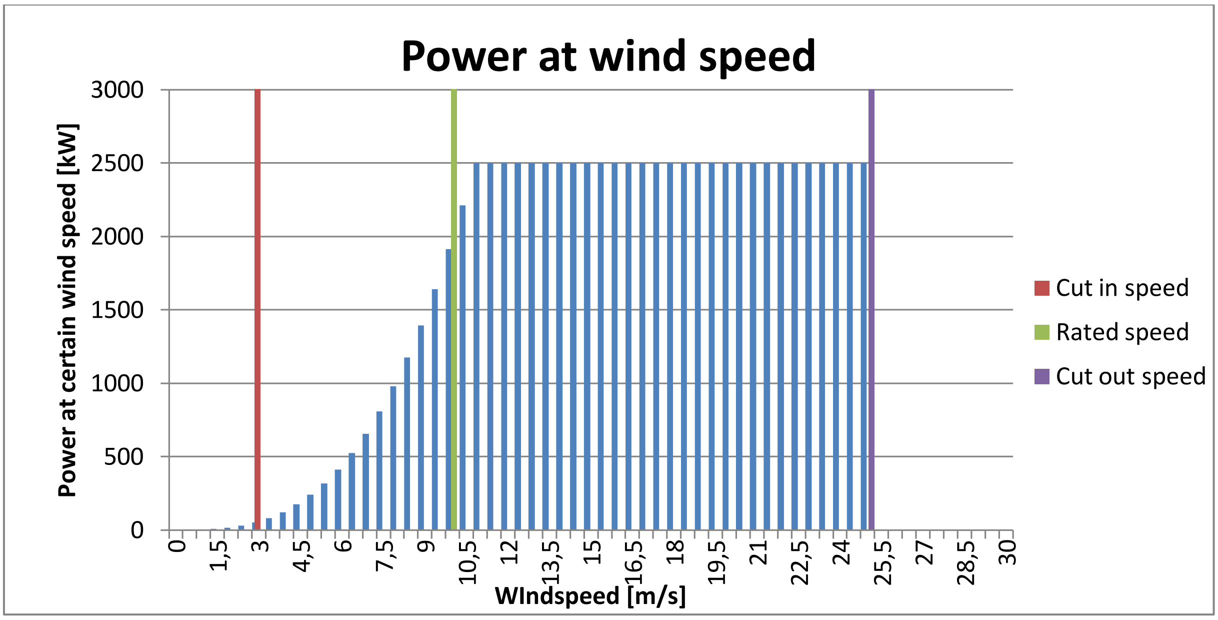


Figure 17: Power curve of he designed wind turbine

Total Energy production = $\sum_{v=0}^{\infty} n_v \times p_v$

n : number of hours

p: power curve

v: wind speed

Annual Energy Yield: 10,323,474 kwh

Revenue: 825,878 Euro, 100% availability

Revenue: 784,584 Euro, 95% availability

Table 9 summarizes the operation benefit and condition fir a type class I-B turbine under free stream condition. It can be seen that the highest annual energy production occurs at a wind speed of 10 m/s. This is equal the rated wind speed. Compared with a wind speed of 5 m/s is can be seen that the wind speed of 10 m/s occurs less hours a year. But in case of 10 m/s more power can be extracted, indicated as a full load operation condition in case of 10 m/s.

Table 9: Calculated turbulence intensity, operation condition and operation benefit

v [m/s]	f (v)	f * hours/year	Turbine Power [W]	Annual Energy [kwh]	STD	Turbulence intensity	Operation condition
5	0.105724	926.14	344,165	318,746	1.309	0.2618	partial load
10	0.065504	573.81	2,753,317	1,579,884	1.834	0.1834	Full Load
15	0.013936	122.08	2,753,317	336,113	2.359	0.157266667	Full Load
20	0.001207	10.57	2,753,317	29,100	2.884	0.1442	Full Load
25	4.48E-05	0.39	2,753,317	1,081	3.409	0.13636	Full Load

The calculated Turbulence intensity is shown in the table above using the normal turbulence model.

Figure 18 shows that the effective turbulence is depicted for different wind speeds and for two turbine spacing of 4D and 8D. As we can see the effective turbulence decreases by wind speed. It also decreases when increasing the distance between neighbor turbines.

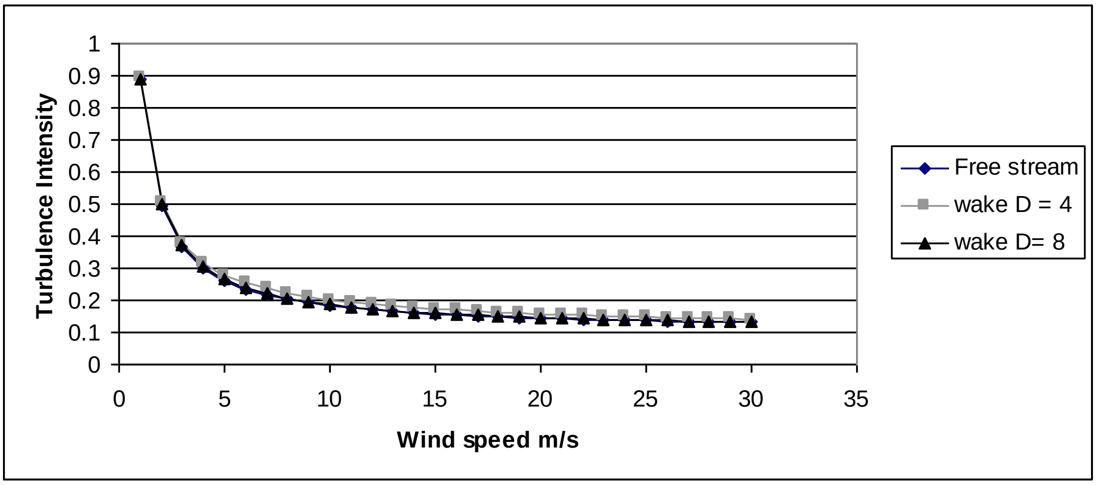


Figure 18: Turbulence intensity at different wind speeds under free stream and wake conditions. The distance between two turbines is 4/8 times the rotor diameter

Wind field is generated for different wind speeds using the following settings:

Turbulence model used	= IEC Kaimal
Turbulence characteristic	= B
IEC turbulence type	= Normal Turbulence Model
IEC standard	= IEC 61400-1 Ed. 3: 2005
Mean wind speed at hub height	= 5 m/s
Hub Height	= 100 m

Figure 19 shows the simulation of the wind fields in free stream and wake condition with distance from neighboring turbine 4*D and the average wind speed of 5 m/s. the amount of turbulence intensity at hub are calculated to be 30.2% in wake condition and 27.88% at free stream.

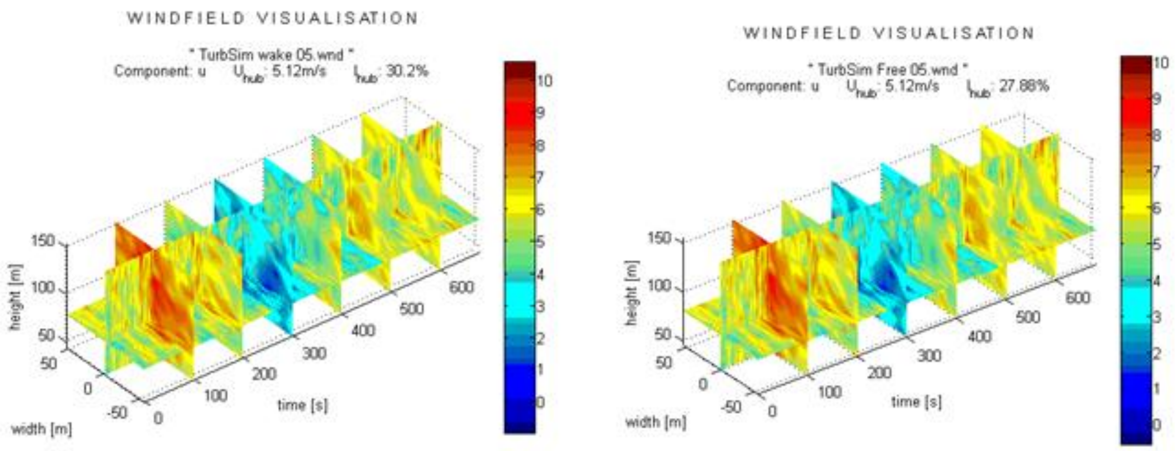


Figure 19: Winfield; left side wake conditions, right side free stream conditions

CIP 6 Fatigue and Extreme Loads

The simulations are done by using FAST. Figure 20 shows the used coordinate systems used in this code. Every blade has its own coordinate system. The origin of the coordinate system lies at the blade root and they pitch with the blades. The coordinate system of the tower base is fixed and the x-axis is parallel to the wind direction if there is no misalignment.

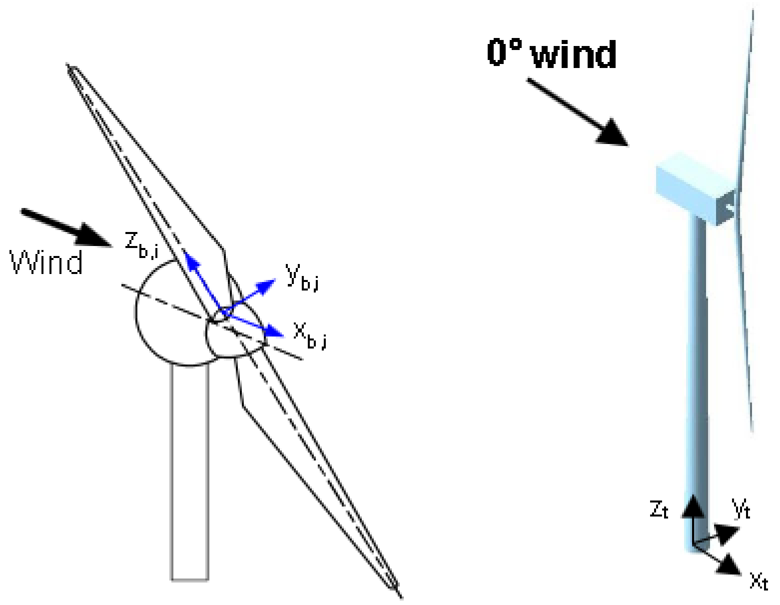


Figure 20: Coordinate systems which are used in FAST;
left side blade coordinate system, right side tower base coordinate system[4]

[4]Jason M. Jonkman, Marshall L. Buhl Jr.:FAST User's Guide,(http://wind.nrel.gov/public/bjonkman/TestPage/FAST.pdf)

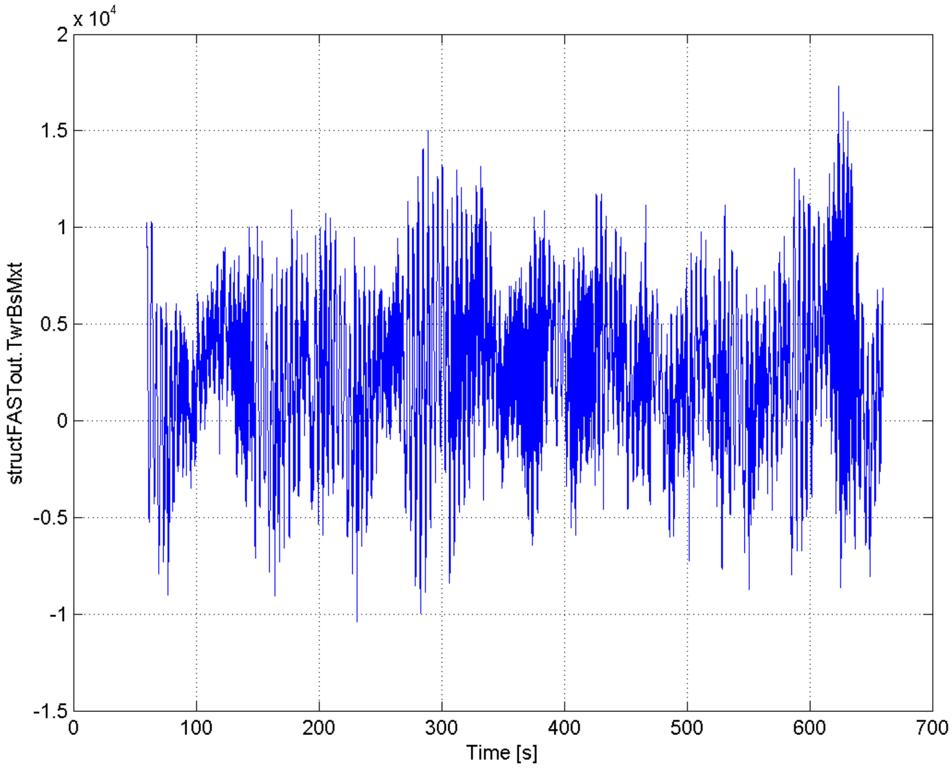


Figure 21: Tower base moment in x direction (side to side moment)

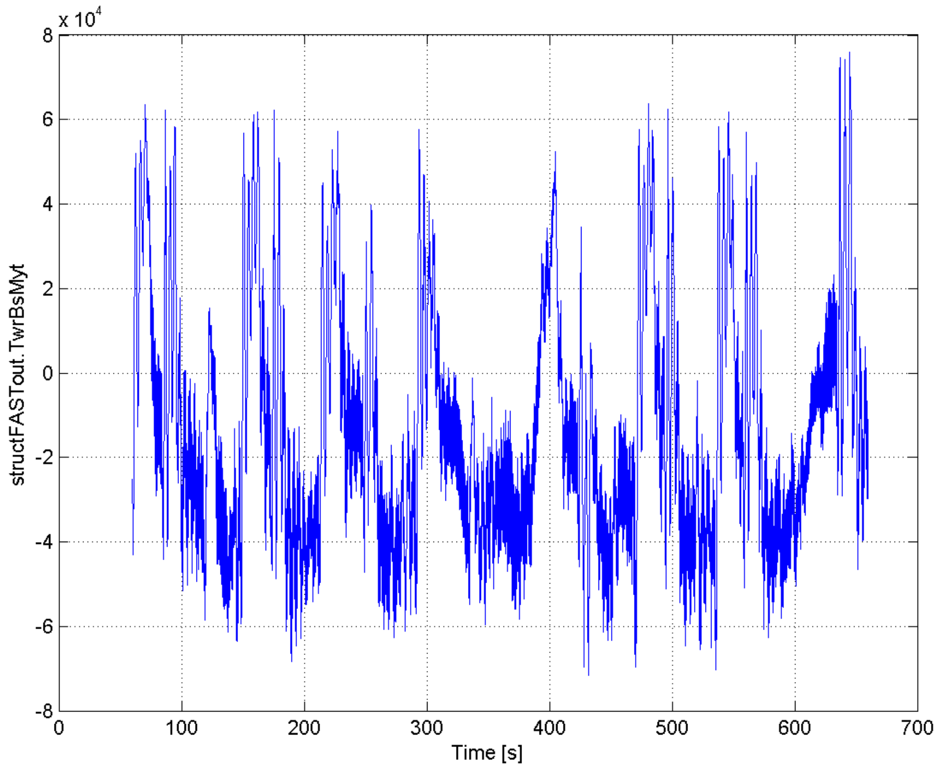


Figure 22: Tower base moment in y direction (fore-aft moment)

In the graphs above (figure 21 and figure 22) we can see the side to side and fore-aft moments on the tower base. As can be seen side to side moments are fluctuating in the range of -6e04 to 6e04 knm while fore-aft moments are in the range of -1e04 to 1.5e04 knm which shows that fore-aft moments are almost 5 times larger than side to side moments which makes sense.

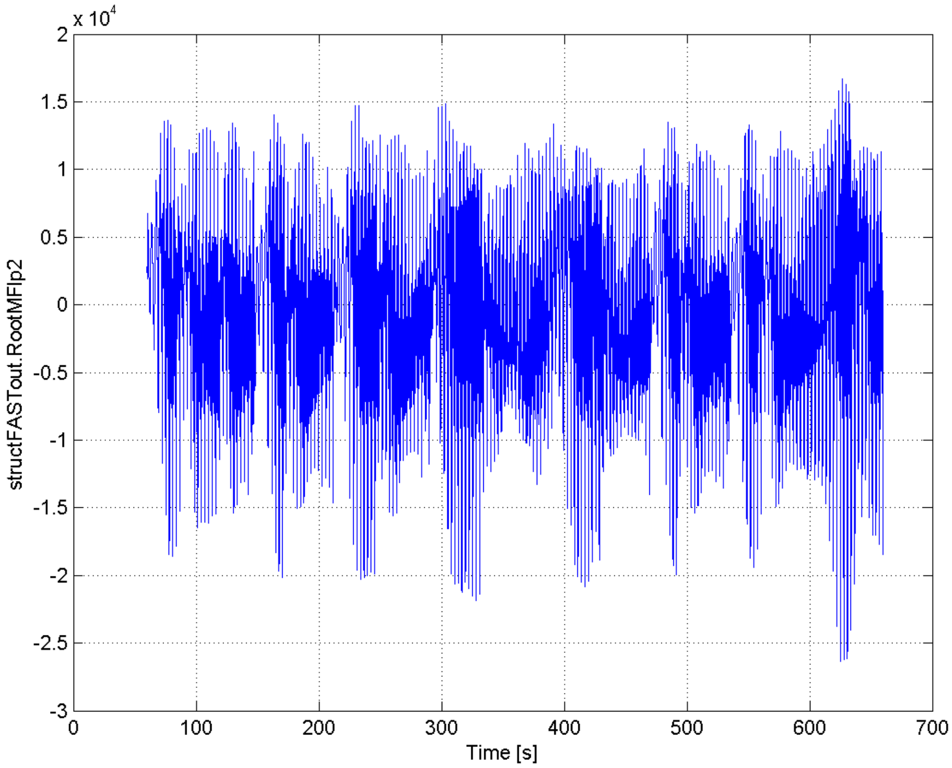


Figure 23: Blade root flawise bending moment

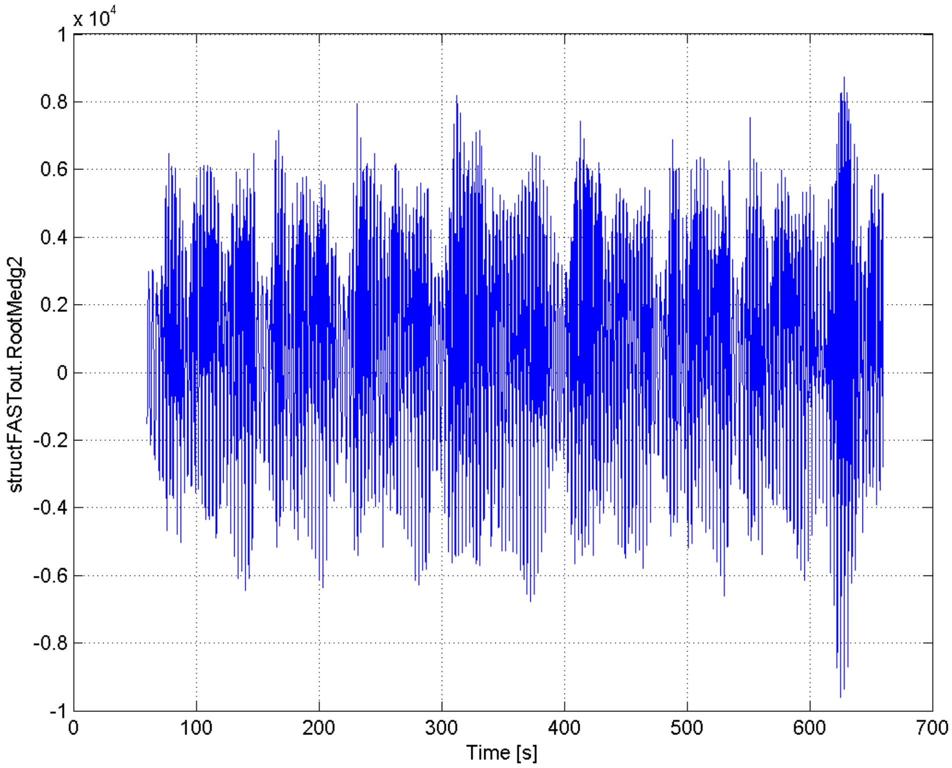


Figure 24: Blade root edgewise bending moment

In the figures above (figure 23 and figure 24) edgewise and flapwise moments at the blade root are depicted. As we can see the edgewise moments are fluctuating between -1.5e04 to 1e04 knm and edgewise moments are between -6000 to 6000 knm.

Table 10 shows damage equivalent loads for free stream and wake condition in 8 and 4 diameter distances between neighboring turbines. In all cases the equivalent loads in free stream condition are more than wake condition with 4 diameter distance and the loads in wake condition with 8 diameters are larger than both free stream case and wake condition with 4 diameters distance. These results are not as we expected. Because the turbulence intensity is higher in wake condition when the neighboring turbine distance is 4 diameters and we expect higher equivalent loads but the results by the FAST simulation are showing something different.

Table 10: Damage equivalent loads (DEL) for different conditions

DEL	Free stream	Wake condition in 4 diameters distance	Wake condition in 8 diameters distance
Damage_Eq_Loads.RootMFlp	$2.43 \cdot 10^4$	$2.41 \cdot 10^4$	$2.48 \cdot 10^4$
Damage_Eq_Loads.RootMedg	$1.07 \cdot 10^4$	$9.70 \cdot 10^3$	$9.73 \cdot 10^3$
Damage_Eq_Loads.TwrBsMyt	$3.92 \cdot 10^4$	$3.99 \cdot 10^4$	$4.26 \cdot 10^4$
Damage_Eq_Loads.TwrBsMxt	$1.02 \cdot 10^4$	$9.05 \cdot 10^3$	$9.57 \cdot 10^3$

CIP 7 Extreme Loads

During the live time different extreme loads are relevant. Table11 shows fife exemplary cases.

Table11 extreme conditions relevant for wind turbines

Load case	Description
50 years gust	- Gust with a return period of 50 years -Duration (according to IEC 61400): 3 s -Causes high loadings on the blades and tower due to high wind speed for a short time
Grid failure	-The control system drops out du the absence of electric energy -Results in not tracking the wind direction change by the yaw system -Causes loadings on the blades due to misalignment
Control system fault	-Control system sops working due some internal error -Pitching and yawing will not executed anymore -Causes high loading on the blades
Loss of load	-The generator does not provide any resistance to the aerodynamic torque -The rotor begins to accelerate until breaking starts -Depending on speed of breaking response potential critical rotor loadings
Operational guest combined with an extreme change in wind direction	-A “standard” guest occurs and is combined with an extreme change in wind direction. -The yaw system needs some time to correct the misalignment -High loadings on the blades due to misalignment

It is also possible that some load cases occur at the same time. For example a 50 years gust can cause high loadings on the turbine and on the grid at the same time. This could result in a grid failure so these cases can happen at the same time with some probability.

To simulate the wind filed an IEC type class II with a turbulence intensity category B is assumed. The rotor diameter, rated wind speed and hub height is chosen with respect to table 2.

For the simulation of the designed turbine two load cases are considered.

Load case:

- 1.5 (power production plus extreme wind shear (EWS_R))
- 2.3 (power production plus fault and extreme operation gust)

Within the load case 2.3 two different gusts are used. On the one hand the 1-year return gust (EOG_1_R), on the other hand the 50-year return gust (EOG_50_R).In this load case the generator torque is set to zero then seconds after the gust hits the turbine.

All wind conditions are at rated wind speed. At load case 2.3 ten seconds after a guest hits the wind turbine the generator torque is set to zero.

The effect of extreme can be seen in figure 25. The event begins at 200 seconds and last for 12 seconds. The maximum linear vertical wind shear is 1.081 and occurs at 206 seconds. As can be seen on figure 25 the wind speed, depending on the region the blade is located, causes certain loading. One revolution takes about 4 seconds and the event takes 12 seconds. This can be seen as two mayor minimum and one maximum is evident on the left side of figure 25.The right side shows the change of rotational speed due to the wind shear.

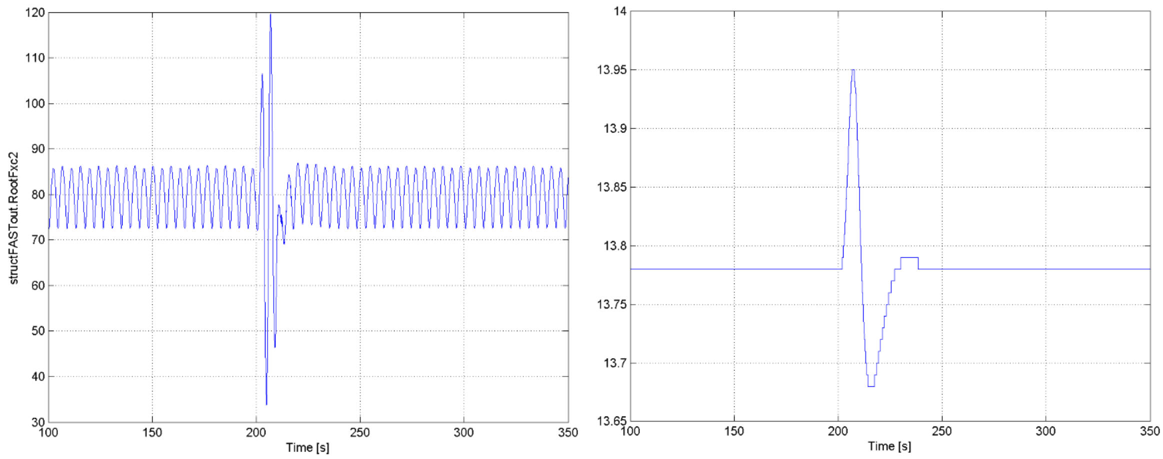


Figure 25: left side blade root force in x-direction, right side rotational speed

The controller compensates the change in rotational speed by pitching. In figure 25 it is shown that extreme wind shear conditions result in a minimum and a maximum of flapwise root bending moment. Figure 26 also shows that after the extreme wind shear hits the turbine pitching is started. Some seconds later (here around 40 seconds) the wind shear is compensated and standard operation mode is reached.

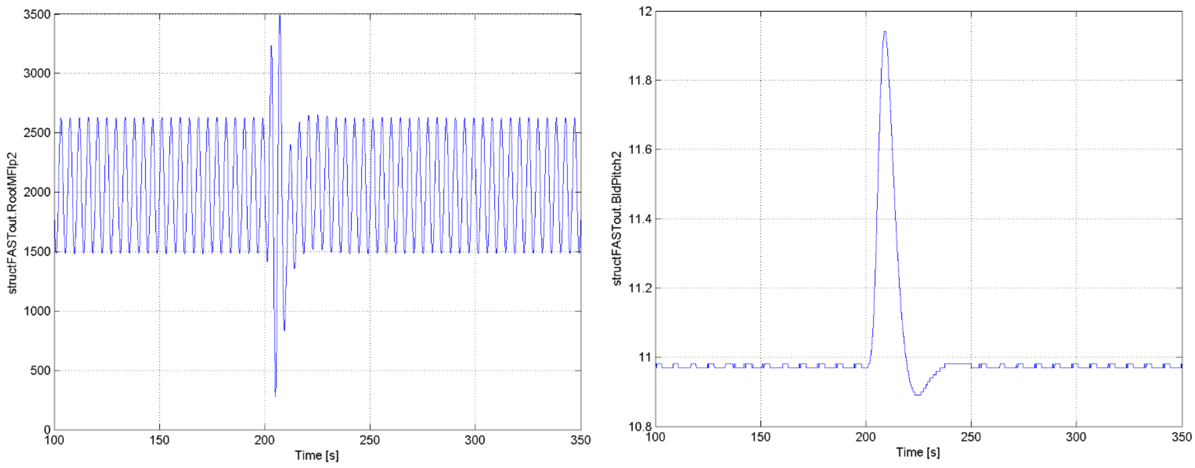


Figure 26:Left side: Flapwise root bending moment; right side: pitch angle.
1 year gust extreme condition at 200 seconds at both sides

Table 12 summarizes the results for the two considered load cases for the blade root. The dominant load case is 2.3. The 50 year returning gust causes higher loadings.

Table 12: Loads and load cases for the blade root

	Loadcase	Wind condition	F_x [kN]	F_y [kN]	F_z [kN]	M_x [kNm]	M_y [kNm]	M_z [kNm]
F_{min}	2.3	EOG_50_R	-20,48	-200,5	416,1	-2659	-588,2	-10,97
F_{max}	2.3	EOG_50_R	182,3	170,2	931	3095	4480	19,52
F_{min}	2.3	EOG_50_R	-20,48	-200,5	416,1	-2659	-588,2	-10,97
F_{max}	2.3	EOG_1_R	157,2	171,9	826,8	3094	3679	13,52
F_{min}	2.3	EOG_1_R	-13,49	-196,3	412,7	-2652	-341	-10,99
F_{max}	2.3	EOG_50_R	182,3	170,2	931	3095	4480	19,52
F_{min}	2.3	EOG_50_R	-20,48	-200,5	416,1	-2659	-588,2	-10,97
F_{max}	2.3	EOG_50_R	182,3	170,2	931	3095	4480	19,52
F_{min}	2.3	EOG_50_R	-20,48	-200,5	416,1	-2659	-588,2	-10,97
F_{max}	2.3	EOG_50_R	182,3	170,2	931	3095	4480	19,52
F_{min}	2.3	EOG_1_R	-13,49	-196,3	412,7	-2652	-341	-10,99
F_{max}	2.3	EOG_50_R	182,3	170,2	931	3095	4480	19,52

Table 13 summarizes the results for the two considered load cases for the tower base. The minimum and maximum load cases are similar to the blade root. The load case 2.3 is again the dominant one. The extreme wind shear load case is only at the maximum tower bending moment in x-direction and at the maximum tower bending moment in z-direction dominant.

Table 13: Loads and load cases for the tower base

	Loadcase	Wind condition	F_x [kN]	F_y [kN]	F_z [kN]	M_x [kNm]	M_y [kNm]	M_z [kNm]
F_{min}	2.3	EOG_1_R	-423,4	-50,52	-7325	-734,8	-42660	-510,8
F_{max}	2.3	EOG_1_R	651,3	17,89	-7284	2338	63260	274
F_{min}	2.3	EOG_50_R	-292,1	-58,32	-7333	-2162	-30660	-608,4
F_{max}	2.3	EOG_50_R	650,4	37,12	-7277	2679	64410	274,6
F_{min}	2.3	EOG_50_R	-292,1	-58,32	-7333	-2162	-30660	-608,4
F_{max}	2.3	EOG_50_R	650,4	37,12	-7277	2679	64410	274,6
F_{min}	2.3	EOG_50_R	-292,1	-58,32	-7333	-2162	-30660	-608,4
F_{max}	1.5	EWS_R	200,9	0,7372	-7302	3155	20690	282,9
F_{min}	2.3	EOG_1_R	-423,4	-50,52	-7325	-734,8	-42660	-510,8
F_{max}	2.3	EOG_50_R	650,4	37,12	-7277	2679	64410	274,6
F_{max}	2.3	EOG_50_R	-292,1	-58,32	-7333	-2162	-30660	-608,4
F_{min}	1.5	EWS_R	200,9	0,7372	-7302	3155	20690	282,9

On the left side in figure 27 it can be seen that when the torque due to the generator vanishes the rotational speed increases. A possible reason for no generator torque may be a grid failure .In that case braking deploys to reduce the rotational speed. Another consequence is that pitching starts which can be seen on the right side of Figure 27.Right after the generator drops out the pitch angle increases to around 16 °. After that it slowly decreases due to the breaking action.

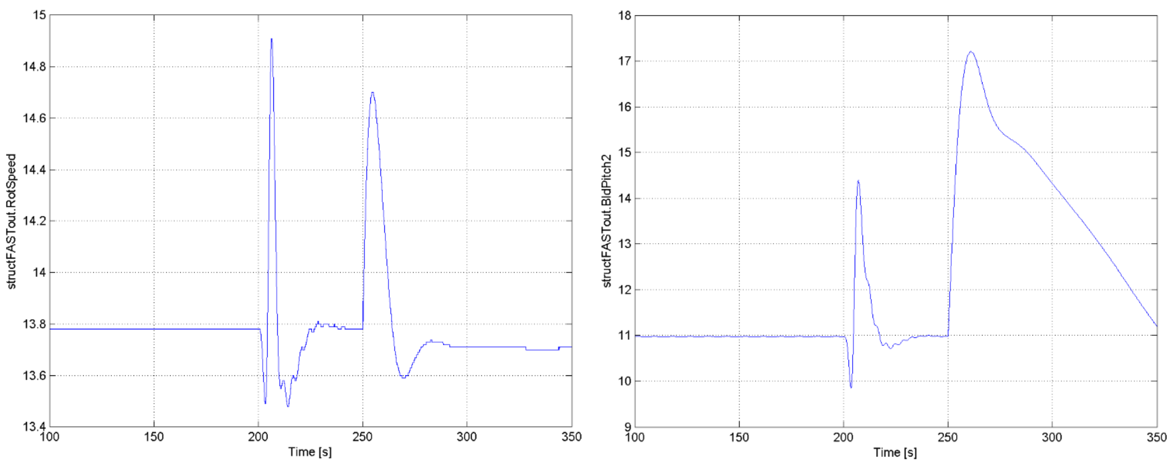


Figure 27: Left side rotational speed -time diagram, right side: Blade pitch – time diagram; break torque at both figures: 20 kNm, Generator turn off at 250 seconds

Figure 28 shows basically the same relation. But in this case the torque of the brake is increased by a factor of six compared to figure 27. This results in a slight decrease of the rotational speed while the pitch angle decreases rapidly until the minimum pitch angle is reached (2.6 °in this simulation).If the minimum pitch angle is reached the rotational speed of the rotor starts to drop significantly.

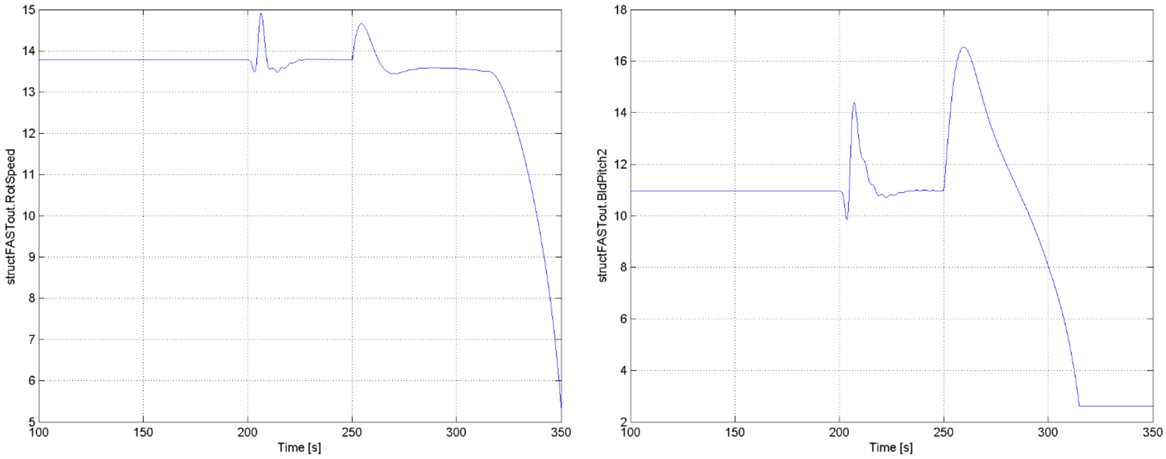


Figure 28: Left side rotational speed -time diagram, right side: Blade pitch – time diagram;
break torque at both figures: 60 kNm, no generator torque at 250 seconds, 1 year returning gust at 200 seconds

The deploying of the brake leads to significant increase of loads. This is indicated in figure 29. This loading is caused by the braking process which is higher than the loading due to the gust.

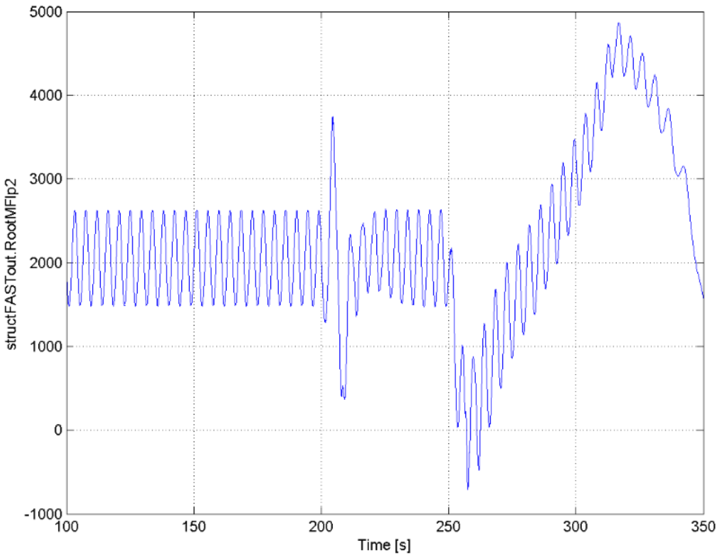


Figure 29: Flapwise blade root bending moment,
brake torque is equal to 60 kNm, no generator torque at 250 seconds

Another parameter which can be adjusted is the point when the brake starts to deploy and when it is fully deployed, which means the total braking torque is applied. The timing of the deployment basically changes the timing when the pitch angle reaches its minimum. The later the brake is deployed the later the pitch angle reaches its minimum.

Figure 28 shows that the change in rotational speed due to the gust and the change in rotational speed due to the dropping out of the generator do not significantly influence each other. 50 seconds buffer between these events are enough to not superimpose the loads of these events. Figure 30 it is indicated that if the gust and the generator fault happen at the same time the change in rotational speed superimposes. In this case the rotational speed decrease due to the beginning of the gust and the rotational speed increase by the dropping out of the generator compensate each other. This can be seen on the left side of figure 30. Another possibility would be that the generator fault happens just a few seconds after the gust. In this case the increase of rotational speed would add each other. So a combined wind gust and a generator fault can ether increase or decrease the rotational speed and thus the loading, depending on the timing.

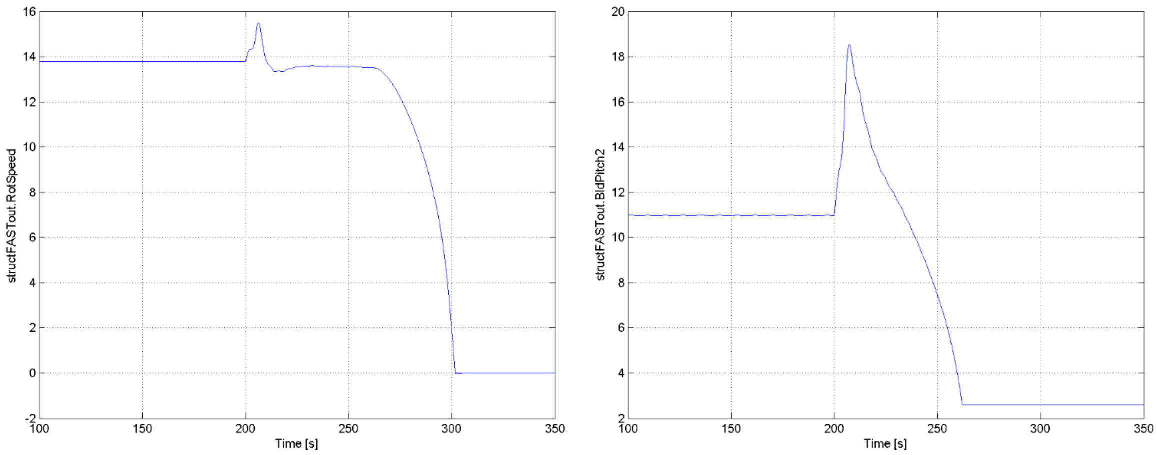


Figure 30 Left side rotational speed -time diagram, right side: Blade pitch – time diagram; break torque at both figures: 60 kNm, no generator torque at 200 seconds, 1 year returning gust at 200 seconds

Summary

This report shows the complexity of the design process of a wind turbine. At first the side conditions have to be clear to investigate the possible energy gain of the turbine and thus the financial revenue. Also the performance depends on the available wind, the design of the rotor blade and at mechanical and electrical efficiency. It is also shown the dynamics of a wind turbine are a significant factor. For example a fixed rotor speed would make this part easier but it would decrease the energy gain. The last part deals with load analysis. In that case for designing a real turbine additional effort is needed because not all values were adjusted to the designed turbine, thus just a qualitative wise analysis is possible.

List of Symbols

A	Area	$[m^2]$
D	Diameter	$[m]$
E	E-modulus	$\left[\frac{N}{m^2}\right]$
H	Height	$[m]$
I	Moment of inertia	$[m^4]$
P	Power	$[W]$
R	Radius	[m]
S	Thrust	$[N]$
f	Frequency	$[Hz]$
k	Stiffness	$\left[\frac{N}{m}\right]$
m	Mass	$[kg]$
n	Rotational speed	$[rpm]$
t	Wall thickness	$[m]$
v	Velocity	$\left[\frac{m}{s}\right]$
ρ	Material Density	$\left[\frac{kg}{m^3}\right]$
τ	Torque	$[Nm]$
ω	Angular velocity	$\left[\frac{rad}{s}\right]$

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