Wind Power: Mini Project 1

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1 Mini Project 1

k-factor	Avg U(10m) (m/s)	Roughness z_0 (mm)	Downtime (%)	Diameter D_T (m)
1,7	6.6	72	5	50.9

Table 1: Personal data

1.1 Wind Resource

1.1.1 Calculation of average wind speed at hub height

The average wind speed at hub height, $H_h = 1.2 \cdot D = 61.08$ [m], can be estimated by the Power Law Profile

$$\frac{U(z)}{U(z_r)} = \left(\frac{z}{z_r}\right)^{\alpha} \tag{1}$$

where α is the power law exponent which can be estimated by (Counihan (1975))

$$\alpha = 0.096 \cdot log_{10} z_0 + 0.016 \cdot (log_{10} z_0)^2 + 0.24 \tag{2}$$

yielding $\alpha = 0.1512$ and $U(61.08) = 8.6770$ [m/s].
A surface roughness of 72 mm would represent a terrain with crops and/or few trees.

1.1.2 Weibull distribution and wind bins

The wind resource probability distribution, for wind speed denoted U, is given by the Weibull distribution

$$p(U) = \left(\frac{k}{c}\right)\left(\frac{U}{c}\right)^{k-1} e^{-\left(\frac{U}{c}\right)^k} \tag{3}$$

$$F(U) = 1 - e^{(-(\frac{U}{c})^k)} \tag{4}$$

The scale factor, c, is estimated as

$$c = \bar{U}(61.09) \cdot \left(0.568 + \frac{0.433}{k}\right)^{-\frac{1}{k}} \tag{5}$$

yielding $c = 9.7325$ and $F(U) = 1 - exp[-(\frac{U}{9.73})^{1.7}]$.

The number of hours of wind speed at each speed in bins is calculated using integers for wind speed and assuming that the 5% downtime is evenly distributed over the wind speed bins. The number of wind speed hours f_j in each bin j is calculated as $0.95 \cdot 8760 \cdot [F(j) - F(j-1)]$ such that the total number of wind hours, N, is given by

$$N = \sum_{j=1}^{N_b} f_j \tag{6}$$

where N_b is the total number of bins.

Using the bins the energy flux distribution $[kWh/m^2]$ is calculated as

$$\left(\frac{E}{A}\right)_j = (\frac{1}{2})\rho \cdot m_j^3 f_j \tag{7}$$

where m_j is the midpoint of bin j.

For reference the maximum amount of wind hours, f_j is found to be 666.27 hours occurring in bin number 6, i.e. for wind speeds between 5 and 6 (m/s). The maximum energy flux is found to be 506.38 $(kWh/m^2 \cdot year)$ in bin 15, i.e for wind speeds between 14 and 15 (m/s).

The total energy flux for all wind speeds over the whole year is 7458.3 $(kWh/m^2 \cdot year)$, i.e 20.43 $(kWh/m^2 \cdot day)$.

Rated wind speed is chosen such that the cumulative energy flux up to the rated wind speed is at least 33% of the total energy flux, yielding $\underline{v_r = 14 \text{ (m/s)}}$.

Cut-out wind speed is similarly chosen such that the cumulative energy flux up to the cut-out wind speeds corresponds to at least 90% of the total energy flux, yielding $\underline{v_c = 25 \text{ (m/s)}}$.

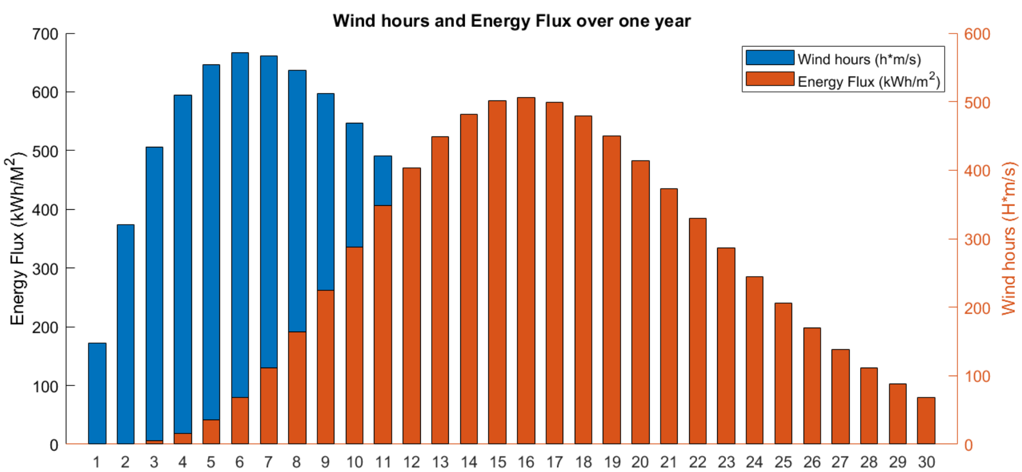

Figure 1: Plot of the wind hours and the distribution of available wind energy as functions of bins over the whole year.

1.2 Wind Energy Converter 'WEC'

Turbine Diameter D_T (m)	Tower height H_h (m)	C_p	η_{tot}
50.9	61.08	0.48	0.837

Table 2: WEC data

Rated power, i.e. the power at the rated wind speed, is calculated as

$$P_R = c_p \cdot \eta_{tot} \cdot \frac{1}{2} \cdot A \cdot v_r^3 = 1.2590 \text{ (MW)}. \tag{8}$$

Cut-in speed is selected as 1% of rated power.

$$0.1 P_R = c_p \cdot \eta_{tot} \cdot \frac{1}{2} \cdot A \cdot v_c^3 \tag{9}$$

Yielding: $v_c = 3$ (kW)

1.3 Energy production for one year

The total generated electric energy of the turbine over a year is calculated as

$$E_{tot} = C_p\eta\Big(\sum_{j=v_{cut-in}}^{v_{rated}} P_{rated} \cdot f_j + \sum_{j=v_r+1}^{v_{cut-off}-1} P_j \cdot f_j\Big) = 3.65 \text{ GWh} \tag{10}$$

where b_j is the amount of hours corresponding to power P_j.

The average power is calculated as

$$\bar{P} = \frac{E_{tot}}{8760} = 0.417 \text{ (MW)} \tag{11}$$

The amount of full load hours are, for v_{rated}=14 and $v_{cut-off} = 25$, found to be

$$FullLoadHours = \sum_{14}^{24} f_j = 1563.5 \text{ hours per year.} \tag{12}$$

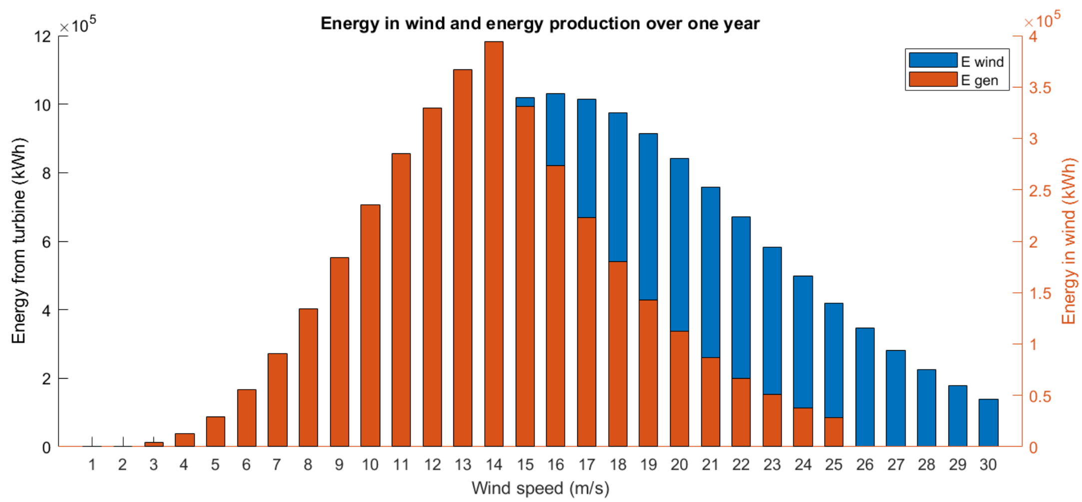

Figure 2: Plot of the energy in the wind and the produced energy as functions of bins over the whole year.

1.4 Mechanics of tower

The tower is subjected to both **aerodynamic loads** and **weight loads** from the weight of the nacelle and from the weight of the tower on itself.

The diameter of the tower is $D = 3$ m and the inner diameter is denoted d.

The **tower top mass** is calculated to $m_{top} = 37.7 \cdot 10^3$ kg by assuming a nacelle weight (including rotor and blades) in respect to rated power of 30 kg/kW.

During rated power the tower is subjected to an aerodynamic load:

$$F_a = \frac{1}{2}C_p\rho A U^2 = 117.25 \text{ (kN)} \tag{13}$$

The maximum aerodynamic load is the storm load, which is

$$F_s = \frac{1}{2}C_D\rho\sigma A U^2 = 198.55 \text{ (kN)} \tag{14}$$

Calculating the thickness of the wall
The maximum stress is $\sigma_{max} = 160$ (MPa) where

$$\begin{cases} \sigma_{max} = \dfrac{M_{max} c}{I} & (15) \\ M_{max} = 0.5FL & (16) \\ I = \dfrac{\pi(D^4 - d^4)}{64} & (17) \end{cases}$$

The maximum stress is σ_{max}, the maximum bending moment M_{max} and the moment of intertia I. The parameter $c \approx R$. F is the storm load and L is the length of the tower i.e. the hub height.

Using this the inner diameter d can be expressed as

$$d = \left(D^4 - \frac{32 \cdot F_s \cdot H \cdot c}{\pi \cdot \sigma_{max}} \right)^{\frac{1}{4}} \tag{18}$$

Dimensioning the tower to withstand a storm load, and adding a factor of two for thickness, the

wall thickness is found to be $t = 2.156cm$

Verifying that the cross-section is less than the allowed maximum
The weight of the nacelle (including rotor and blades) and the tower exerts a downward force on the tower. The combined downward force is

$$F_{top} + F_{tower} = m_{top}g + (\pi R^2 - \pi r^2)L\rho g = 370.9 \cdot 10^3 + 102.64 \cdot 10^6 (\mathrm{N}) \approx 1 \cdot 10^8 \tag{19}$$

This yields a downward stress on the cross-section of

$$\sigma = \frac{F}{A} = \frac{10^8}{21.26} \approx 4.7 \text{ MPA} < 160 \text{ MPa} \tag{20}$$

Thus the downward stress is less than the maximum allowed stress, so the design is sound.

1.5 Efficiency of driveline

The total efficiency is

$$\eta_{tot} = 0.8375 = \eta_{driveline} \cdot \eta_{generator} \cdot \eta_{gridconnection}$$

If it is assumed that the generator is of permanent magnet type an efficiency $\eta_{generator} = 98\%$ is reasonable.
The efficiency of the driveline can be estimated to $\eta_{driveline} = 0.9$
The efficiency of the grid connection is then estimated to $\eta_{gridconnection} = 0.95$ which is also.

The efficiencies combines yields a total efficiency

$$\eta_{tot} = 0.9 \cdot 0.98 \cdot 0.95 = 0.8379 \approx 0.8375. \tag{21}$$

Mini Project 2

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March 2019

1 Lab 2: Wind Resource

1.1 Question 1

Calculation of mean wind speeds based on Weibull shape and scale parameters.

Table 1: Data mean wind speed from each cardinal point and Weibull scale parameters

Sector	c-pram	k-param	Frequency	$\bar{u}$
Mean	9.87	2.66	100	9.36
N	10.17	2.593	33.5	9.67
E	8.55	2.174	18.1	8.11
S	10.4	2.975	28.2	10.04
W	9.73	3.153	20.2	8.98

1.2 Question 2

The "mean wind velocity" dependent duration curve is closely related to the Weibull cumulative distribution function since it gives the probability of the mean wind speed being less or equal to any wind speed V. The shape of the "mean wind velocity" dependent duration curve can then be formed as (1-F(U)) where F(U) is the Weibull cumulative distribution function.

1.3 Question 3

By using the Weibull distribution,
a) Average velocity at this site is found to be 9 (m/s)

b) Number of hours per year that the wind speed will be between 6.5 and 7.5 m/s: 858.8 hours per year

c) The number of hours per year that the wind speed is equal to or above 16 m/s: 292 hours per year.

1.4 Question 4

Now again but using the Rayleigh distribution,
b) Number of hours per year that the wind speed will be between 6.5 and 7.5 m/s: 738 hours per year

c) The number of hours per year that the wind speed is equal to or above 16 m/s: 732 hours per year.

1.5 Question 5

A Rayleigh wind speed distribution is used to calculate:
a) The number of hours per year that the wind is below the cut-in speed: $u < 5$ (m/s) for 1886 hours per year

b) The number of hours per year that the machine will be shut down due to wind speeds above the cut-out velocity:

$u \geq 25$ m/s for 20 hours per year

c) Comparing the results agains the results from windPRO:
windPRO operational hours per year: 8422
a) and b) operational hours per year: 6854

1.6 Question 6

The average wind speed at 100 m using the power law profile and finding α. From this the surface roughness z is calculated.
Plot mean wind speed from log law and power law: 2 plots.
The power law yields:

$$U_X(z) = U_{ref}(\frac{z}{z_{ref}})^{\alpha} \tag{1}$$

The log law is defined as:

$$U_X(z) = U_{ref}\frac{ln(\frac{z}{z_0})}{ln(\frac{z}{z_{ref}})} \tag{2}$$

The power law yields higher estimates for mean wind speed as compared to using the Log law for hub height 0-50m and 125m and beyond. For height of 50-100 m its pretty accurate.

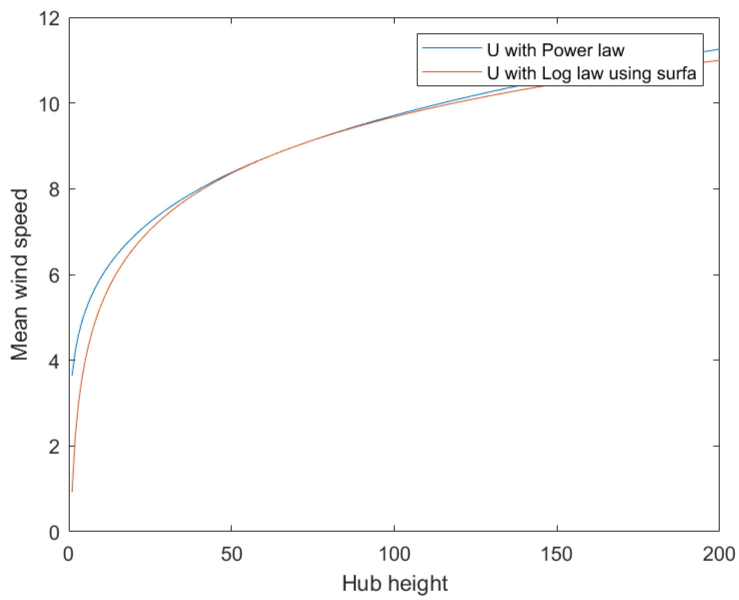

Figure 1: Plot of the mean wind speed as function of hub height

1.7 Question 7

Velocity duration curves for the cumulative Rayleigh and Weibull distributions over the year are computed and superimposed.

These curves are defined by the cumulative distribution function multiplied by the number of hours of a year. Rayleigh curve:

$$T_{Rayleigh}(U) = 8760hours \cdot e^{\left(-\frac{\pi}{4}\cdot\left(\frac{U}{\bar{U}}\right)^2\right)} \tag{3}$$

Weibull curve:

$$T_{Weibull}(U) = 8760hours \cdot e^{\left(-\left(\frac{U}{c}\right)^k\right)} \tag{4}$$

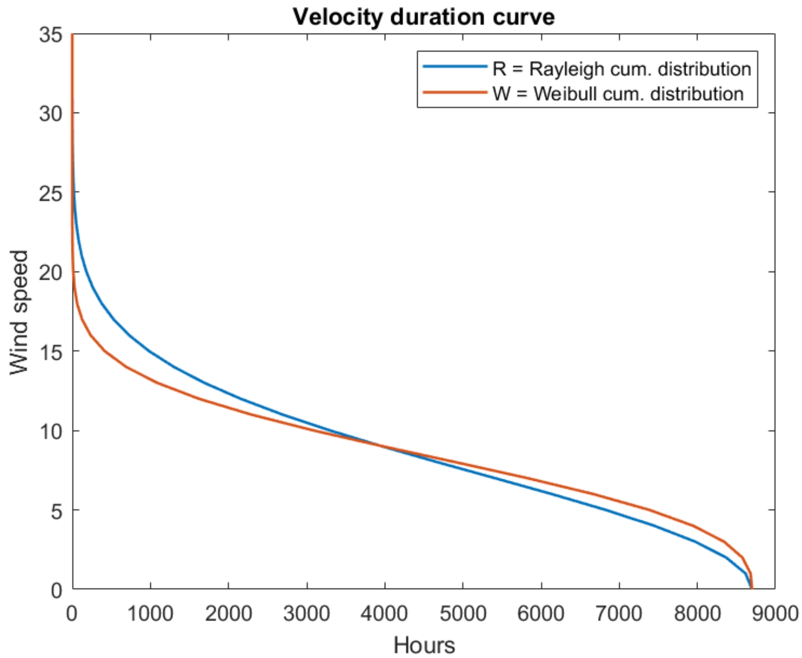

Figure 2: Velocity duration curve

The differences are that the Rayleigh curve yields higher probabilities for high wind speeds resulting in unrealistically high wind energy.

1.8 Question 8

The velocity deficit at a distance x downstream is given by (Jensen & Katic, 1986)

$$1 - \frac{U_X}{U_0} = \frac{1 - \sqrt{1 - C_T}}{(1 + 2k\frac{X}{D})^2} \tag{5}$$

For a downstream turbine $k \approx 0.11$ and upstream $k \approx 0.075$.
The downstream velocity deficit at a distance of 7 diameters, i.e. 560 meters, is calculated to 5.66%. The first Turbine is the north-most located turbine and the second one the south-most located one. The first Turbine thus suffers from a downstream velocity deficit of wind coming from the south direct, i.e. South-wind, and the second turbine suffers from North-wind.

The annual energy production AEP is:

$$AEP = \bar{P} \cdot 8760 \cdot frequency = \frac{1}{2}\rho A\bar{U}^3 C_p \cdot 8760 \cdot frequency \tag{6}$$

The power coefficient is estimated for the wind direction mean wind speeds.

Table 2: average wind speed and anual energy production for eahc cardinal point

Sector	$\bar{u}$ Turbine 1	$\bar{u}$ Turbine 2	AEP Turbine 1 (MWh)	AEP Turbine 2 (MWh)
N	9.03	8.40	2949	2403
E	7.57	7.57	991	991
S	8.60	9.28	2154	2665
W	8.71	8.71	1621	1621
Total Energy	NA	NA	7715	7680
Mean Wind Speed	8.58	8.56	NA	NA

1.9 Question 9

The average turbine power for a single turbine installed at the position of the met mast is defined by the following formula:

$$\overline{P} = \frac{AEP}{8760} \tag{7}$$

The total energy is calculated using two bins and it is defined as it follows:

$$AEP = C_{p1}P_1f_1 + C_{p2}P_2f_{12} \tag{8}$$

For this specific turbine, the cut-in speed is considered at 5 m/s, the rated speed is at 14 m/s and the cut-out speed is at 25 m/s.
So, P1 is the power in the wind of the midpoint of bin 1 (9.5 m/s) and P2 is the power of the midpoint of bin 2 (19.5 m/s). C_{p1} is the power coefficient corresponding to the wind speed of the midpoint of bin 1, and C_{p2} corresponds to bin 2.

Yearly Energy Prod.	Hrs. per year from cut-in to rated	Hrs. per year from rated to cut-out
9083 MWh	6741	695

This yields **Average machine power** $\bar{P} = 1.04$ MW.

1.10 Question 10

The data from WindPro yielded an annual energy production of 8264.6 MWh for the unwaked case and 7860 MWh for the waked case. The differences arise from taking the velocity deficits in north- and southbound directions into account which decrease the annual energy production for the waked case.

As far as the calculated and simulated results for the waked scenario, the annual energy production results from the calculated values decrease significantly in the wind sectors where there is an obstacle before, in this case another wind turbine of the park, which takes part of the kinetic energy from the wind and therefore produces a decay of the average wind speed.

Additionally, The difference of production between the two turbines in the simulated values are almost the same, however for the calculated results there is a difference of aprox. 150 MWh.

Table 3: Data from WindPro

Sector	$\bar{u}$ Turbine 1	$\bar{u}$ Turbine 2	AEP Turbine 1	AEP Turbine 2
N	9.03	9.03	2762.8	2674.6
E	7.57	7.57	1097.5	1098.1
S	9.28	9.28	2395.3	2477.8
W	8.71	8.71	1604.3	1605.2
Total Energy	NA	NA	7859.9	7855.8
Mean Wind Speed	8.77	8.77	NA	NA

Table 4: Data obtained from calculations in question 8

Sector	$\bar{u}$ Turbine 1	$\bar{u}$ Turbine 2	AEP Turbine 1 (MWh)	AEP Turbine 2 (MWh)
N	9.03	8.40	2949	2403
E	7.57	7.57	991	991
S	8.60	9.28	2154	2665
W	8.71	8.71	1621	1621
Total Energy	NA	NA	7715	7680
Mean Wind Speed	8.58	8.56	NA	NA

1.11 Question 11

In this part the annual energy production of turbine 1 is calculated using ideal horizontal axis wind turbine Glauert theory. The table is calculated employing derivation of maximum C_p and C_T. No wake effects from a second turbine are considered, it is calculated as if it were stand-alone. Max C_p is found by evaluating (8)

between upper boundary $x = 0.25$ and lower boundary $x = (1 - 3 \cdot a_2)$.

$$C_{P,max} = \frac{8}{729^2} \cdot \frac{64}{5}x^2 + 72x^4 + 124x^3 + 38x^2 - 63x - 12[ln(x)] - 4x^{-1}$$

(9)

The maximum value of the thrust coefficient is

$$C_{T,max} = 4a(1 - a) = 0.887 \tag{10}$$

Table 5: Energy production for turbine 1

Sector	Mean wind speed	Annual Energy Production (MWh)
N	9.03	3751
E	7.57	1194
S	9.28	3427
W	8.71	2030
Total Energy	NA	10401
Mean Wind Speed	8.77	NA

2 Lab 3: Power System Integration Analysis

2.1 Question 1

The output from the eGrid windPRO report file is analyzed and potential design improvements are suggested. The results from the power analysis shows that the total losses amount to 1% wherein the internal transformers consitute 98% of the losses.

Potential design improvements

- The losses from the 20 kV cables going from the turbines to transformer can be reduced by changing to cables with a larger cross-section area.
- The losses can also be reduced by stepping up the voltage from 0.7 kV to 110 kV directly, and then placing a 110/20 kV transformer at the site of the external load.

- Another idea to reduce losses are to place the 20/110 kV transformer in between the two turbines so the 20 kV lines are shortened and thus the line losses are reduced. However the 20 kV line losses from the turbines to the 20 kV source will be increased, but they may be small.
- Perhaps the internal transformers can be replaced to more efficient ones thus reducing the losses.

2.2 Question 2

The voltage levels of the turbine generator in relation to the grid side is investigated. The voltage drop and the fault current is calculated.

The data given from the simulation and the question are:

- P, active power of the wind generator = 0.8 MWh
- Q, reactive power of the wind generator = 0 MWh
- V_g, voltage from the wind generator = 20 kV
- PF, power factor = 1
- R, resistance of the line = 0.037 Ω
- Q, reactance of the line = 0.013 Ω

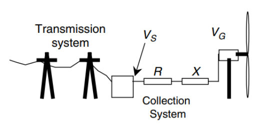

Figure 3: System schema

$$V_G^4 + V_G^2[2 \cdot (QX - PR) - V_S^2] + (QX - PR)^2 + (PX - QR)^2 = 0 \tag{11}$$

The voltage drop is defined by the following formula:

$$\Delta V = \frac{V_G - V_S}{V_G} \tag{12}$$

The voltage drop is calculated to 0.0074 % which is relatively close to the results obtained from the simulation which show a voltage drop of 0.0067 %.

The fault level at the generator is determined as

$$M = I_F \cdot V_S \tag{13}$$

Where I_F is the the short circuit current at the wind turbine, also called fault current. This yields that the fault current at the generator is determined as

$$I_F = \frac{V_S}{\sqrt{R^2 + X^2}} \tag{14}$$

The fault current obtained is 51 kA which contributes to obtain a fault level of 10.2 GVA

3 Lab 4: Sound and Noice

The acoustics of a wind farm is assessed.

3.1 Question 1

For distances up to 1000 meters the official Swedish method for estimating wind turbine noice is by

$$L_A = L_w - 8 - 20 \cdot log_{10}(d) - 0.005d \quad (15)$$

where $L_w = 99.2$ db is the Sound power level.

For distances after 1000 meters wind turbine noice is estimated by:

$$L_A = L_w - 8 - 20 \cdot log_{10}(d) - 0.005d - \Delta L_A + 10 \cdot log_{10}(d/100)) \quad (16)$$

where aa=0.0001 is the air absorption coefficient and $\Delta L_A = 10 \cdot log_{10}(10^{\frac{L_w}{10}}) - 10 \cdot log_{10}(10^{\frac{L_w - \sqrt{d}aa}{10}})$.

The sound levels of a turbine for up to 8000 meters is calculated and plotted, as is shown in figure 4.

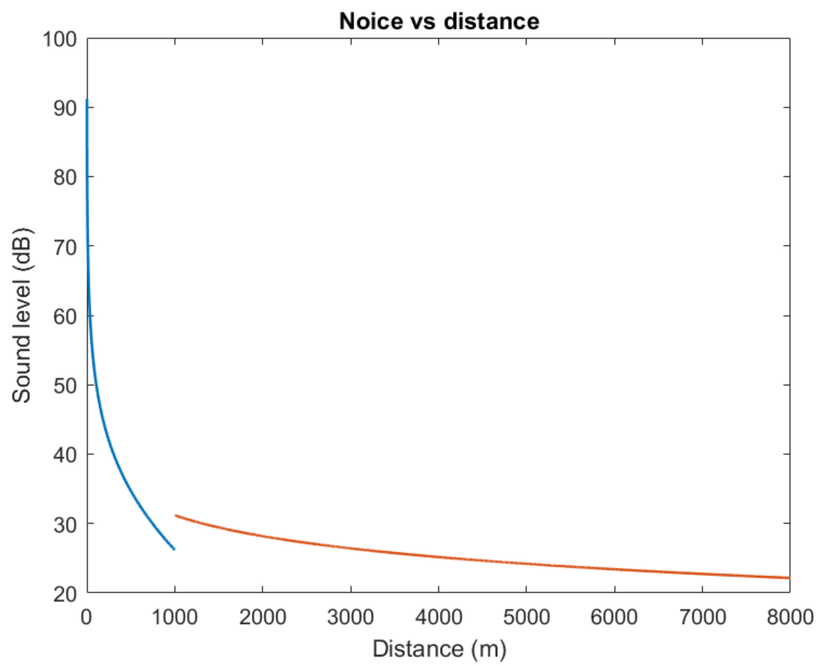

Figure 4: Noice vs distance

Comparing the graph with the results of the simulation, one can see that 1 km away from the wind turbine the simulation expects a noise between 35dB - 40dB. However, on the graph the values are below 35dB. On the other hand, closer to the emitting of noise the curve of the graph gets values close to 90dB whereas the simulation shows values around 50dB and 55dB.