



Moldalsknuten

Wind Resource and Production Assessment



To	Tore Ivar Slettemoen / Norsk Vind Energi AS
From	Meventus AS
Date	25.08.16
Report title	Moldalsknuten Wind Resource and Production Assessment
Report no	2015-004
Author	Anne Haaland Simonsen

	Name	Date	Signature
Prepared by	Anne Haaland Simonsen	30.08.2016	
Approved by	Kyle Brennan	30.08.2016	

Summary

The Moldalsknuten wind project and nearby wind measurements were assessed in order to provide an evaluation of the project.

As no wind measurements are available from within the project area, wind measurements from four 50 m measurement masts within the neighbor wind project area (Tellenes wind farm) were used for the evaluation. Three of the four masts measured for approximately two years each between 2005/2006 and 2008, while the fourth mast has measured for 9.5 years and is still in operation. Long term corrected mean wind speeds at a potential hub height of 90 m were estimated at 7.6 to 8.7 m/s at the four measurement positions. Low extreme wind speeds were estimated for the mast positions, indicating that Class II turbines are likely suitable for the site. The measured turbulence intensity is generally high and exceeding the limit for Class A turbulence for wind speeds higher than 10–15 m/s at all four mast positions. Class A turbines are therefore recommended as the turbulence levels are expected to increase when turbine wake generated turbulence is considered.

Two alternative turbine types, Senvion 3.6M114 and Siemens S113 3.2MW with power boost functionality, were evaluated using an optimized 11-turbine layout. The annual energy production was estimated at 116.1 GWh/year for the Senvion layout and 112.3 GWh/year for the Siemens layout, with an uncertainty of 14.9 % and 14.6 %, respectively.

Table of Contents

Summary	2
Table of Contents	3
1 Introduction and Background	5
2 Wind data assessment	6
2.1 Measurement campaign assessment	6
2.2 Measurement equipment	7
2.3 Data preparation and availability	7
Mast 329	8
Mast 330	8
Mast 333	8
Mast 334	9
Mast data used for analysis	9
2.4 Long term correction	10
3 IEC class and wind climate evaluation	13
3.1 Turbulence intensity	13
3.2 Extreme wind speed	15
3.3 Shear	17
4 Flow model	18
4.1 Terrain and roughness model	18
4.2 Wind field scaling	18
4.3 Model verification	18
Horizontal extrapolation	18
Vertical extrapolation	18
4.4 Uncertainty	20
Uncertainty in horizontal extrapolation	20
Uncertainty in vertical extrapolation	20
5 Wind resource assessment	23
5.1 Wind map	23

6	Production analysis	24
6.1	Layout	24
6.2	Production analysis	24
6.3	Loss estimates	25
	Wake effects	25
	Availability	26
	Electrical losses	26
	Turbine performance	26
	Environmental losses	26
	Curtailment losses	28
6.4	Bias	28
6.5	Uncertainty estimates	28
	Wind data	28
	Wind model	29
	Power conversion	30
	Loss and bias uncertainty	30
7	References	31
	Appendix A: Turbine positions	32
	Appendix B: WindPRO Loss and Uncertainty Report – 11xSE114 – 3.6MW	33
	Appendix C: WindPRO Loss and Uncertainty Report – 11xS113 – 3.2MW	38

1 Introduction and Background

The Moldalsknuten wind farm is planned in Sokndal municipality in Rogaland County, Norway. The project area is located in a mountainous area at elevations in the range of 350 to 460 m. The terrain within the area consists mainly of bare rock and sparse shallow vegetation, with some small lakes covering parts of the area.

The Moldalsknuten wind project is planned in the middle of Tellenes wind farm where 50 Siemens S113 turbines with 92.5 m hub height are currently being installed. The turbines at Tellenes wind farm are expected to have a relatively high impact on the flow conditions at Moldalsknuten.

While wind measurements are not available inside the Moldalsknuten planning area, data from four 50-meter masts were provided by the owner of the neighbor Tellenes wind project. These wind measurements began in 2005 and lasted for 2 years on three of the masts while one mast is still in operation. In addition, a short Lidar measurement campaign was conducted at Tellenes by Sgurr Energy during the winter and spring 2015.

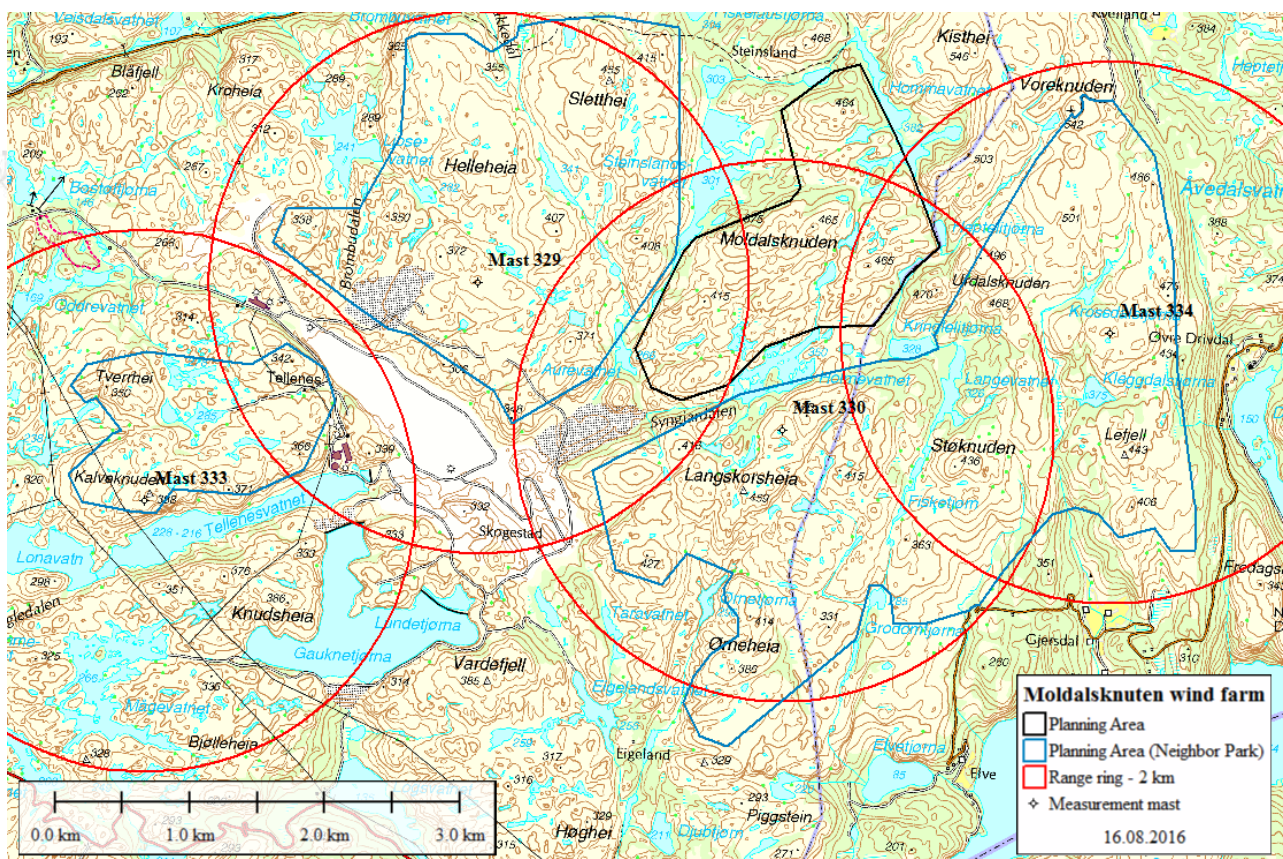


Figure 1 – Moldalsknuten planning area (black line) with Tellenes planning area (thin blue line) and measurement locations (and 2 km radius)

The current project planning area is depicted in Figure 1 (black line), together with the neighbor Tellenes project planning area (thin blue line) and the positions of the four measurement masts.

A mining area (Titania AS) is located southwest of the project area (the white area located between the two western planning areas at Tellenes in Figure 1). The deposit from the mining activities are changing the actual orography close to the southwestern part of the wind farm area. This in turn, may introduce some changes in the wind conditions on the site and have an impact on the energy production and loading of the turbines.

A layout consisting of 11 wind turbines was developed by Meventus AS in May 2016, suitable for wind turbines in the 3 MW class. In this report, two alternative wind turbines are evaluated, Senvion 3.6M114 with 93.0 m hub height and Siemens S113 3.2MW with Power Boost and 92.5 m hub height.

2 Wind data assessment

2.1 Measurement campaign assessment

The general recommendation for a wind measurement campaign is that there should be at least one year of measurements covered by at least two masts. MEASNET guidelines indicate that the representativeness of a mast in complex terrain is not expected to exceed 2 km from the mast position.

According to the MEASNET guidelines, the available measurements from masts 329, 330, 333 and 334 provide sufficient horizontal coverage of most of the planning area (see Figure 1), while the northern part of the planning area is outside the recommended 2 km maximum distance. Accordingly, a higher uncertainty in the horizontal extrapolation is expected in this area. Relatively low measurement height at all four masts (less than two thirds of the expected hub height) also introduces some uncertainty due to the required vertical extrapolation.

A short Lidar measurement campaign was carried out by Sgurr Energy at Tellenes from late December 2014 until May 2015 in order to provide wind data for CFD model validation. While measuring at four different locations within this period, each measurement period is considered too short for use in the production assessment. While a detailed description on the Lidar campaign is not included in this report, the Lidar data provides valuable information on the vertical wind shear in the area and the data from the first three Lidar locations was included in the evaluation of the flow model (section 4.3) together with the mast measurements. The Lidar campaign is documented in installation reports provided by Sgurr Energy (Sgurr 009, Sgurr 013 and Sgurr 016), and the data was provided in a processed and filtered format.

2.2 Measurement equipment

The masts included in the analysis were all 50 m tubular masts equipped primarily with NRG equipment and two Riso sensors at top height. The masts were installed and operated by Kjeller Vindteknikk. Three of the masts measured for approximately 2 years between 2005/2006 and 2008, while the fourth mast was installed in 2005 and is still in operation. A summary of the masts and respective instrumentation is included in Table 1 below.

Table 1 – Measurement summary (mast 329 – 334)

Equipment	Mast 329		Mast 330		Mast 333		Mast 334	
Coordinates (Zone 32, UTM WGS 84)	E349524 N6469865		E351782 N6468771		E347056 N6468254		E354204 N6469493	
Data Start Date	22.11.2005		15.12.2005		31.08.2006		27.09.2006	
Last Data Available for report	02.05.2015		02.07.2008		03.07.2008		01.07.2008	
Mast/Lidar type	50 m Tubular		50 m Tubular		50 m Tubular		50 m Tubular	
Anemometer	50.0 m	Riso P2546A	49.1 m	Riso P2546A	50.0 m	Riso P2546A	49.1 m	Riso P2546A
	50.0 m	Riso P2546A	49.1 m	Riso P2546A	50.0 m	Riso P2546A	49.1 m	Riso P2546A
	48.7 m	NRG #40	48.0 m	NRG #40	48.4 m	NRG #40	47.6 m	NRG #40
	30.0 m	NRG #40	30.0 m	NRG #40	30.0 m	NRG #40	30.0 m	NRG #40
	10.0 m	NRG #40	9.9 m	NRG #40	10.0 m	NRG #40	10.0 m	NRG #40
Wind Vane	43.1 m	NRG #200P	43.7 m	NRG #200P	44.5 m	NRG #200P	43.6 m	NRG #200P
	9.3 m	NRG #200P	9.2 m	NRG #200P	9.3 m	NRG #200P	9.3 m	NRG #200P
Temperature	2.0 m		2.0 m		2.0 m		2.0 m	
Pressure	-		-		-		-	
Relative Humidity	-		-		-		-	

2.3 Data preparation and availability

The measurement data was filtered in order to remove data where sensors were malfunctioning or influenced by icing.

The filtering of icing periods were performed by manual investigation of each time series using WindPRO version 3.0. Time series from all available heights were compared to better identify periods of icing. An icing period was defined as a period where the temperature was near or below 0 degrees, and any of the following criteria were present:

- A wind vane measured identical values for several time steps
- One or more anemometers measured 0 m/s
- Wind measurements from different anemometers had large and unrealistic deviations from each other

In some cases, where all anemometers measure near 0 m/s while the wind direction has little variation over several time steps, it is difficult to determine whether icing has occurred or there is just low wind speeds at the time. In these cases, a comparison with wind measurements from other sensors and other masts in the area may provide a better understanding of the situation. For each identified icing period, all wind speed data including several observations before and after the incident were filtered to ensure all icing influenced measurements were captured.

The time series of measurement data from each mast was handled individually in order to:

- Minimize the mast influence on the measurements (for the masts that have multiple anemometers at highest height).
- Select data with high availability during whole year periods to reduce seasonal influence on long term correction
- Use as much data from high class sensors as possible
- Utilize as much data as possible during the first two years of operation for each anemometer for masts where anemometers were not replaced after the recommended two years

With these criteria in mind, the following data was selected for further analysis.

Mast 329

For mast 329, the total measurement period includes 9.5 years of data. However, due to low data availability during the first seven months of the measurement campaign, these months were not included in the analysis. Along with the measurement campaign, the Titania mining activity area has expanded towards the mast location and this may have influenced the wind field during the end of the measurement period. Due to this, the last months of data were also disregarded. With this in mind, only the data period from June 2006 until Nov 2014 was used in the analysis.

The mast has redundant top Riso sensors, both with high availability. The sensors were exchanged three times during the measurement period in accordance with MEASNET guidelines. The time series from the top two anemometers were “mixed”, where each sensors data was only used for wind directions within 90 degrees of its respective boom orientation, in order to minimize mast influence on the measurements. This mixed time series is subsequently referred to as “50.0 m – Riso Mix”.

Mast 330

Mast 330 measured for two years with generally high availability for the two top Riso anemometers. However, one of the anemometers malfunctioned towards the end of the time period, and both experienced problems during Dec 2006/Jan 2007. The time series were also mixed to minimize the mast influence and maximize availability. Two years of data, from June 2006 to June 2008 were used in the analysis. The mixed time series is subsequently referred to as “49.1 m – Riso Mix”.

Mast 333

Mast 333 measured for almost two years between September 2006 and July 2008. The availability was high for the two top anemometers during the whole measurement period, and all data could therefore be used for the analysis. The time series for the top anemometers were also mixed to minimize mast influence, the time series is subsequently referred to as “50.0 m – Riso Mix”.

Mast 334

Mast 334 measured for almost two years between October 2006 and July 2008. The availability and quality was high for the entire time period for the two top anemometers. The mixed time series is subsequently referred to as “49.1 m – Riso Mix”.

Mast data used for analysis

The data availability for the full measurement periods after filtering of the highest measurement height for each mast is provided in Table 2 below, while the data availability for the data periods selected for long-term correction is provided in Table 3. The total measurement period is used for the turbulence and extreme wind assessments.

Table 2 – Data availability (%) by mast for the total measurement period

Mast ID	Mast Name	Height [m]	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
329	Mast 1	50.0 m - Riso Mix	2005													96.5
			2006						100.0	100.0	98.3	100.0	98.3	100.0	97.4	
			2007	98.5	98.5	100.0	97.3	100.0	100.0	100.0	100.0	98.2	100.0	100.0	89.2	
			2008	98.3	97.3	95.7	96.8	100.0	100.0	100.0	100.0	100.0	98.1	97.5	84.3	
			2009	84.6	60.0	89.1	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	85.4	
			2010	92.5	92.3	98.5	99.3	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	
			2011	74.8	84.7	80.8	100.0	100.0	42.6	100.0	100.0	100.0	100.0	100.0	97.2	
			2012	96.1	77.9	100.0	98.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	89.4	
			2013	91.5	96.3	93.6	99.0	98.3	100.0	100.0	100.0	100.0	100.0	99.3	100.0	
			2014	99.1	84.0	98.9	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	94.2	
330	Mast 2	49.1 m - Riso Mix	2015	96.1	92.7	97.6	98.2	100.0								91.7
			2005													
			2006					100.0	100.0	100.0	100.0	100.0	98.0	90.9	0.8	
			2007	45.9	98.2	95.9	94.6	100.0	100.0	100.0	100.0	98.2	100.0	100.0	95.7	
333	Mast 3	50.0 m - Riso Mix	2008	92.2	95.5	96.6	98.1									98.1
			2005													
			2006									100.0	98.5	100.0	100.0	
			2007	100.0	98.5	99.1	98.2	100.0	100.0	100.0	100.0	98.2	100.0	100.0	83.6	
334	Mast 4	49.1 m - Riso Mix	2008	92.8	95.3	96.6	96.9	100.0	100.0							95.4
			2005													
			2006										98.2	99.7	98.0	
			2007	95.0	96.5	94.0	100.0	100.0	100.0	100.0	100.0	97.8	100.0	100.0	83.8	

Table 3 – Data availability (%) by mast during periods selected for long term correction

Mast ID	Mast Name	Height [m]	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
329	Mast 1	90.0 m - Riso Mix	2005													96.4
			2006						100	100	98.3	100	98.3	100	97.4	
			2007	98.5	98.5	100	97.3	100	100	100	100	98.2	100	100	89.2	
			2008	98.3	97.3	95.7	96.8	100	100	100	100	100	98.1	97.5	84.3	
			2009	84.6	60	89.1	100	100	100	100	100	100	100	100	85.4	
			2010	92.5	92.3	98.5	99.3	100	100	100	100	100	100	96.7	100	
			2011	74.8	84.7	80.8	100	100	42.6	100	100	100	100	100	97.2	
			2012	96.1	77.9	100	98	100	100	100	100	100	100	100	89.4	
			2013	91.5	96.3	93.6	99	98.3	100	100	100	100	100	99.3	100	
			2014	99.1	84	98.9	100	100	100	100	100	100	100			
330	Mast 2	90.0 m - Riso Mix	2005													90.9
			2006					100.0	100.0	100.0	100.0	100.0	98.0	90.9	0.8	
			2007	45.9	98.2	95.9	76.6	100.0	100.0	100.0	100.0	98.2	100.0	100.0	95.7	
			2008	92.2	95.5	96.6	98.1									
333	Mast 3	90.0 m - Riso Mix	2005													98.1
			2006									100.0	98.5	100.0	100.0	
			2007	100.0	98.5	99.1	98.2	100.0	100.0	100.0	100.0	98.2	100.0	100.0	83.6	
			2008	92.8	95.3	96.6	96.9	100.0	100.0							
334	Mast 4	90.0 m - Riso Mix	2005													94.2
			2006										98.2	99.7	96.7	
			2007	92.6	93.3	94.0	98.1	100.0	99.2	97.0	100.0	96.9	97.8	100.0	83.1	
			2008	79.2	89.5	76.0	93.9	92.5	100.0							

With a data availability for all masts exceeding 90 %, the time series are considered complete according to the MEASNET guidelines. The data availability is lower during the winter months for all masts leading to a small under representation of winter data. As high wind speeds are generally expected during winter seasons, this may lead to a reduction in the estimated long-term wind speed. As the general level of data loss during winter months for this project is comparable to similar projects included in previous sensitivity to winter data loss studies, the conclusion can be drawn that the possible effect will be negligible.

As the highest measurement heights at the masts are well below the potential turbine hub heights, the wind data had to be extrapolated vertically. This is normally performed at masts with reliable data in two or more heights using the measured wind shear. The wind shear for each 10 minute data point is then determined using a best fit of the available heights and the shear factor is then used to estimate the wind speed at the desired height. As the wind data from all four masts were found reliable in all three heights, the wind data was extrapolated to a potential hub height of 90 m prior to long term correction using the Riso Mix-time series. Further extrapolation was performed in the flow model.

As the vertical extrapolation based on the measured shear can only be performed at time stamps with concurrent data at all available heights, the availability of the extrapolated time series may be slightly reduced. There was no significant reduction in data availability for any of the masts.

2.4 Long term correction

Twenty years of downscaled ERA Interim data from ECMWF (European Center of Medium Range Forecasting) were used for long-term correction of the measurement data. The data set is provided by Storm Geo and contains 3-hour data at equally spaced grid points with a resolution of 0.7° (~78 km). The data is interpolated from the four closest grid points to each measurement mast position.

The sectoral regression MCP method was used for long-term correction of the wind data measured at the masts. In this method, the concurrent data between the wind measurements and reference data were analyzed using 24 wind direction sectors and a linear regression analysis. The relationship found for each sector is applied to the reference data for the entire reference data period. To prevent “noise” in the measurement data to introduce an unrealistic relation when correlating the two data sets, the measurement data was averaged over an hour before it was used in the analysis (centered at the reference data time step).

As described in section 2.3, the measurements from the four measurement masts were extrapolated to the expected hub height of 90 m using the measured shear. These shear extrapolated time series were used for the long term correction. A summary of the results is included in Table 4.

Table 4 – Results of long-term correction of measurement data

Mast/Lidar ID	Height [m]	Mean wind speed (measured) [m/s]	LTC wind speed [m/s]	Correlation – wind speed ¹	Correlation – wind speed ²	Std. Error – wind speed
329	50.0	7.17	7.09	0.8602	0.7958	2.3196
	90.0*	7.66	7.57	0.8556	0.7856	2.5214
330	49.1	8.01	8.00	0.8836	0.8245	2.3611
	90.0*	8.40	8.42	0.8771	0.8103	2.5902
333	50.0	8.33	8.12	0.8820	0.8284	2.4522
	90.0*	8.88	8.68	0.8737	0.8092	2.7147
334	49.1	7.70	7.30	0.8832	0.8176	2.7147
	90.0*	8.34	7.87	0.8804	0.8176	2.1679

¹ Correlation between reference data and measured data

² Correlation between long term corrected data and measured data

* Extrapolated from top measured height

As seen above, the ERA Interim data set provides a relatively good correlation with the measurement data, giving confidence in the long term corrected data. The wind resources are found to be good, with long-term corrected mean wind speeds at 90 meters between 7.6 and 8.7 m/s at the four mast positions.

The long-term distributions for the four masts are provided in Figure 2 to Figure 5 below.

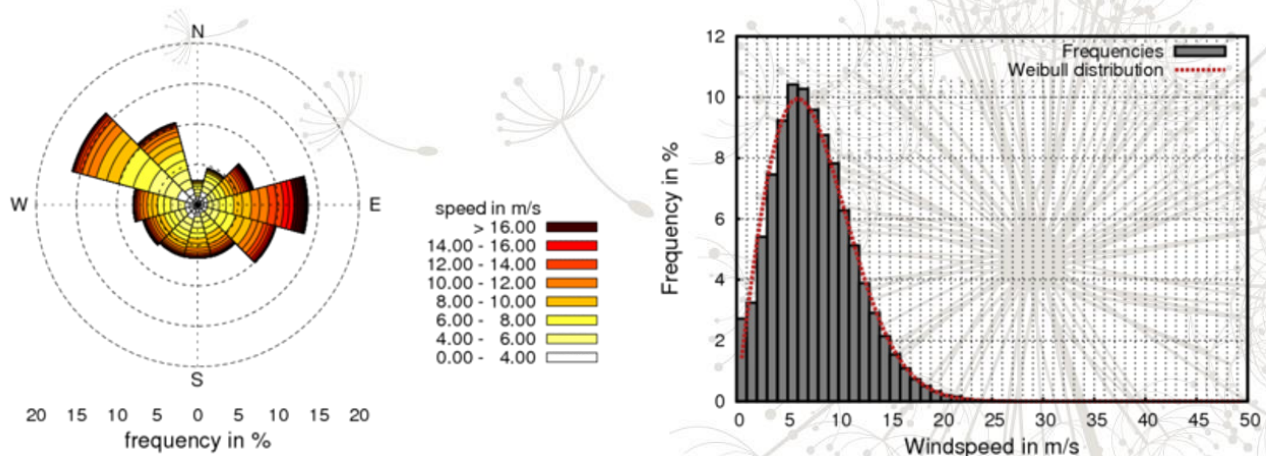


Figure 2 – Long term corrected wind rose and frequency distribution, mast 329 at 90 m

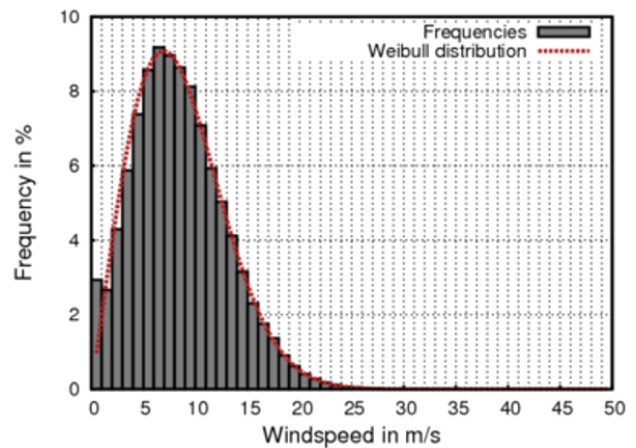
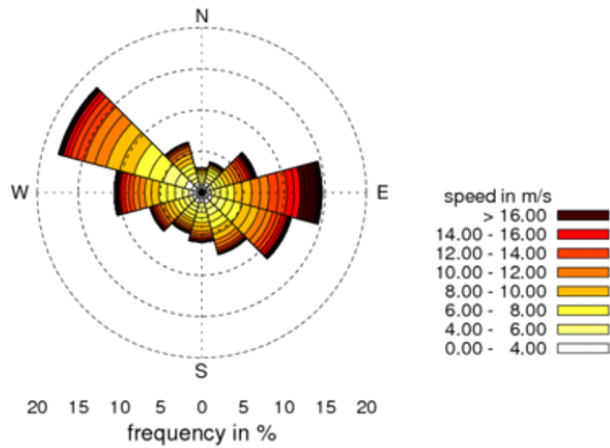


Figure 3 – Long term corrected wind rose and frequency distribution, mast 330 at 90 m

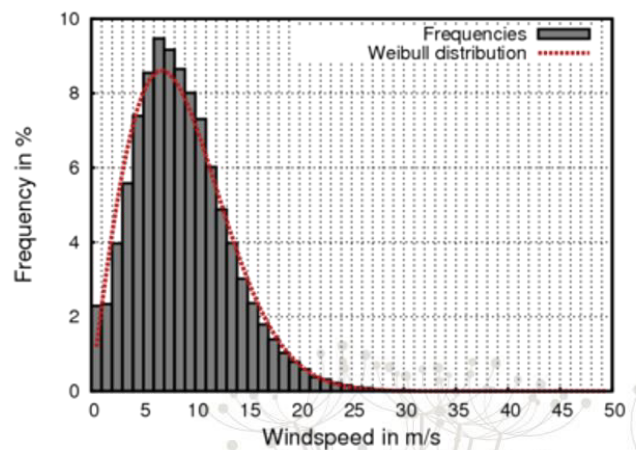
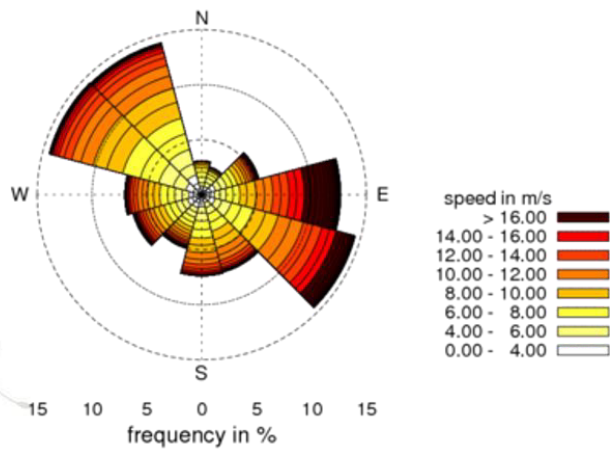


Figure 4 – Long term corrected wind rose and frequency distribution, mast 333 at 90 m

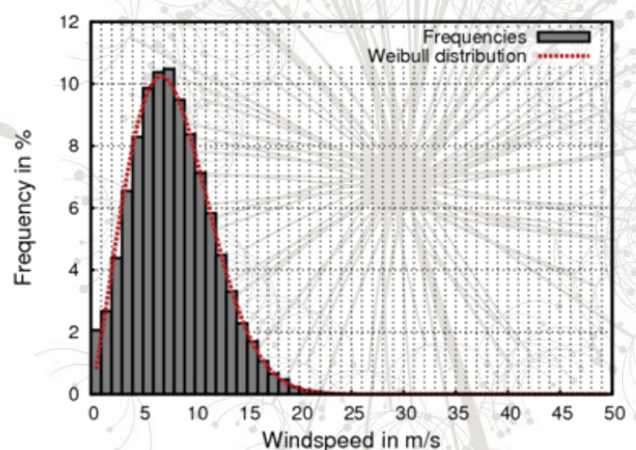
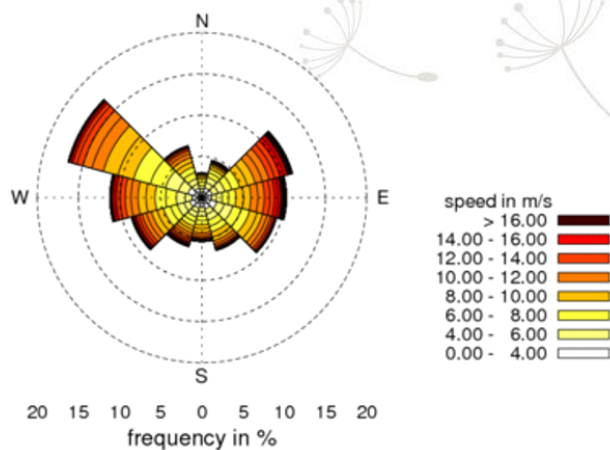


Figure 5 – Long term corrected wind rose and frequency distribution, mast 334 at 90 m

The predominant wind directions are ENE to ESE and WNW to NNW, with the highest wind speeds occurring within the same sectors.

3 IEC class and wind climate evaluation

3.1 Turbulence intensity

Figure 6 to Figure 9 depict the measured turbulence at the four measurement masts by speed compared to the IEC limits (left) and by direction (right).

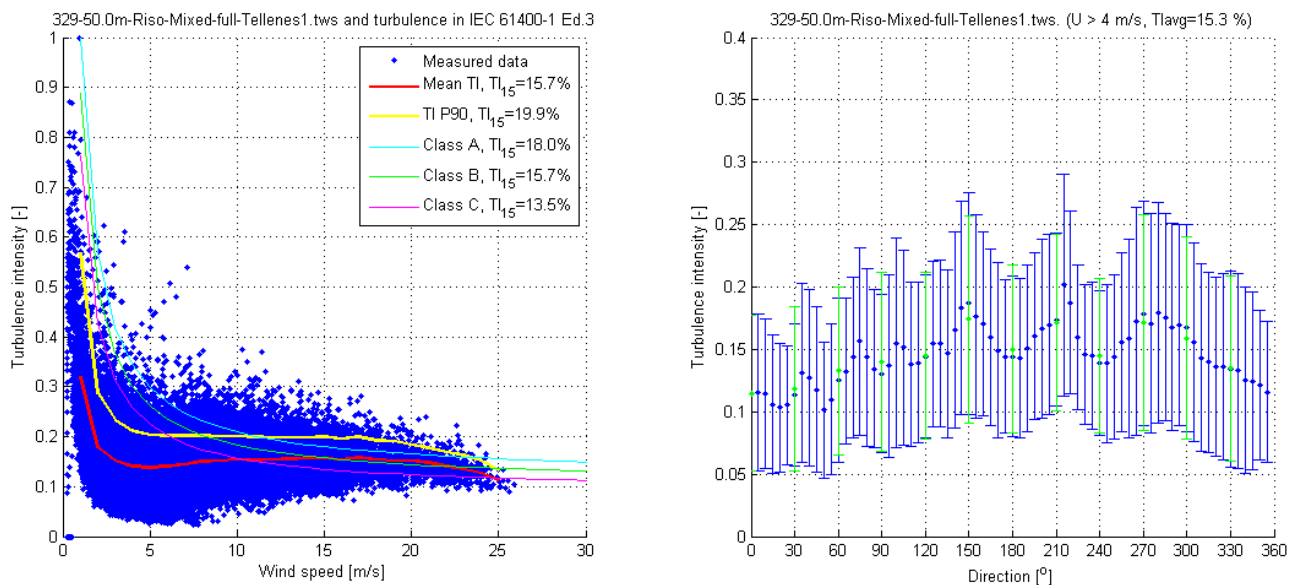


Figure 6 – Measured turbulence, mast 329 (Riso 50.0m)

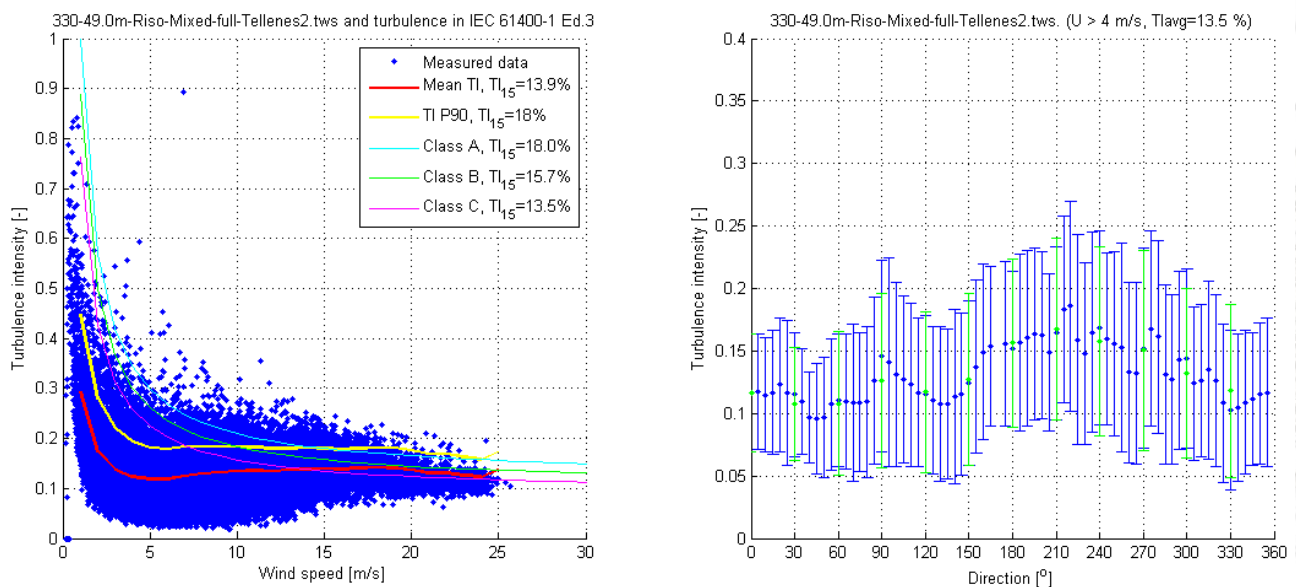


Figure 7 – Measured turbulence, mast 330 (Riso 49.1 m)

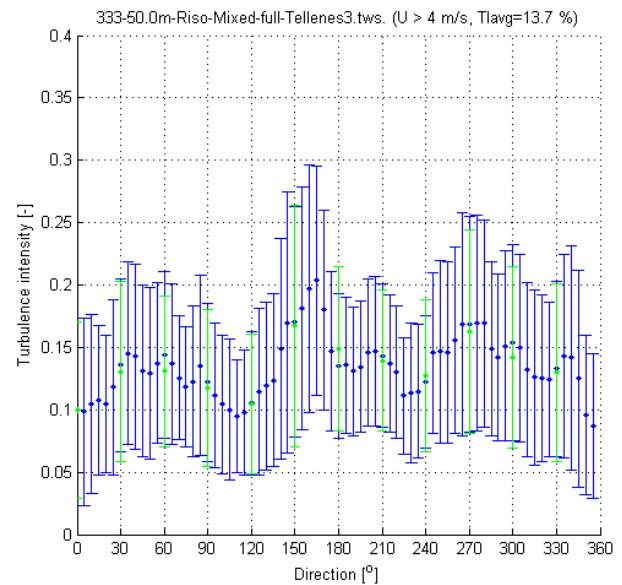
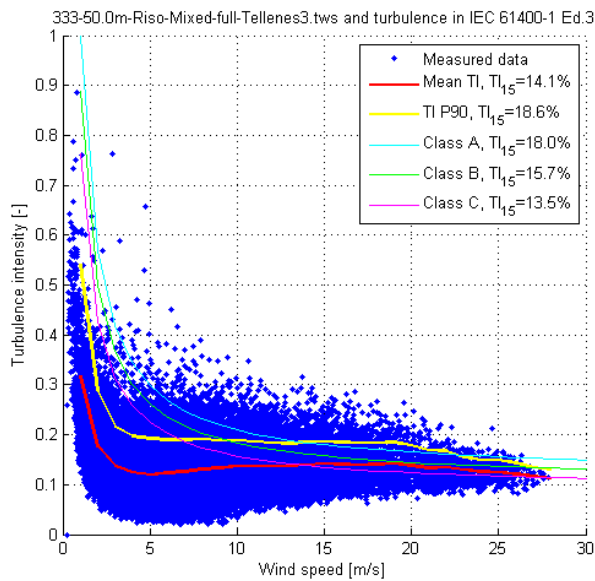


Figure 8 – Measured turbulence, mast 333 (Riso 50.0 m)

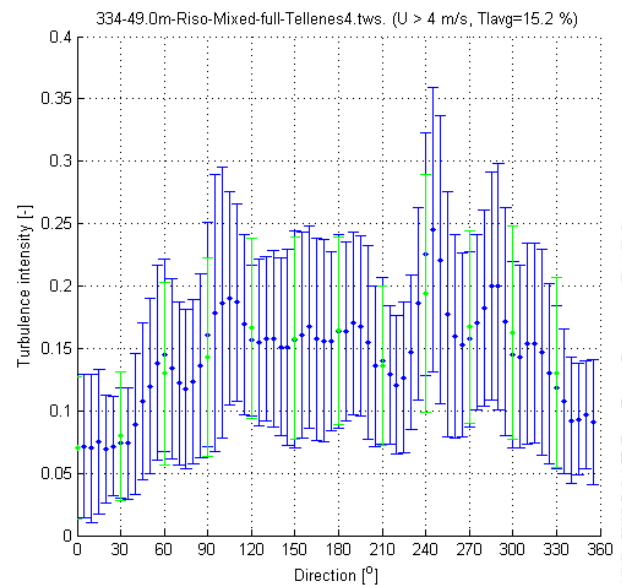
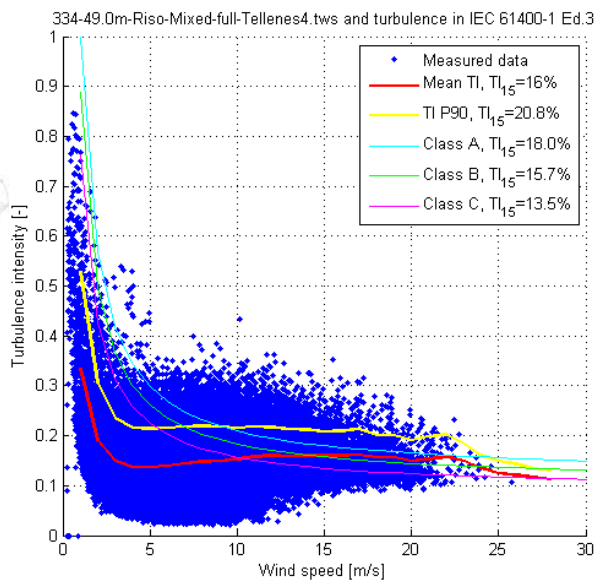


Figure 9 – Measured turbulence, mast 334 (Riso 49.1 m)

The turbulence intensity measured at the four measurement masts is generally high and exceeding the limit for class A turbulence for wind speeds higher than 10–15 m/s at all four mast positions. Winds from easterly and westerly directions appear to be most turbulent at all measurement positions. Class A turbines are recommended as the project generally has high mean wind speeds throughout the planning area and turbulence levels will increase when wake-induced turbulence from the planned turbines are taken into consideration.

3.2 Extreme wind speed

The 10-minute average maximum wind speed with a return rate of 50 years was calculated using the Gumbel-Lieblein method implemented in WindPRO.

Estimating a 50-year extreme event with a reasonable statistical certainty typically requires approximately 10 years of validated data. While time series of this length are generally not available for most wind projects under development, using the shorter time series (2–3 years) typically found is expected to give reasonable results. Estimates based on 1 year of measurement data or less should be avoided due to large variability (very high uncertainty), as they are highly dependent on the amount of high wind incidents captured during the specific year.

Long-term correction of the measured time series was not performed, as the methods for long-term correction are not expected to give a correct representation of the highest wind events. This is due to model deficiencies related to coarse resolution in time and space in available reference data sets.

To minimize the uncertainty in the calculations the extreme wind speed values were estimated using the full measurement series from all four masts. This gave a total length of measurements of 9.5 years for mast 329, 2 years for mast 330 and slightly below 2 years for mast 333 and 334.

The extreme wind was estimated at the highest sensor height and at a potential hub height of 90 m for all four masts. The estimated extreme wind is provided in Table 5 below.

Table 5 – Estimated extreme wind speeds at mast positions, 50 m and 90 m (extrapolated)

Mast ID	Measurement height [m]	Length of measurement period [years]	Extreme Wind		IEC VREF limits (m/s)		
			Max Measured [m/s]	V _{REF} [50 year wind] [m/s]	I	II	III
329	50.0	8.4	26.9	29.4	50.0	42.5	37.5
330	49.1	2.0	25.7	30.3			
333	50.0	1.8	29.1	36.0			
334	49.1	1.8	25.8	32.5			

Mast ID	Measurement height [m]	Length of measurement period [years]	Extreme Wind		IEC VREF limits (m/s)		
			Max Measured [m/s]	V _{REF} [50 year wind] [m/s]	I	II	III
329	90.0	8.4	28.4	30.5	50.0	42.5	37.5
330	90.0	2.0	27.8	34.6			
333	90.0	1.8	32.6	42.0			
334	90.0	1.8	27.3	36.1			

A detailed plot of the fitting to the Gumbel Distribution for mast 329 is shown in Figure 10.

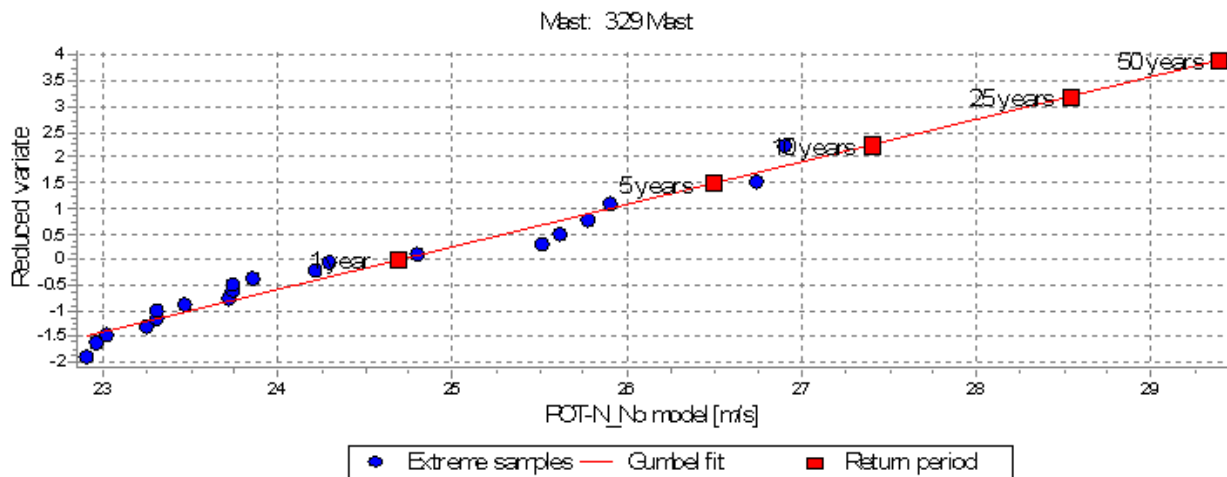


Figure 10 – Detailed plot of extreme wind assessment for masts 0329, 50m

The estimated extreme wind speeds are below Class III limits at all measurement positions at measurement height. When the extrapolated time series are used to evaluate the extreme wind at the potential hub height of 90 m, the level exceeds Class III level at mast 334, which is the mast furthest away from the Moldalsknuten project area and considered less representative compared to the other three masts. However, due to relatively high mean wind speeds expected at the planned turbine locations, class II turbines are recommended at this site.



3.3 Shear

The power law shear coefficients for the measured wind data were calculated based on wind speed data from all reliable NRG sensors at each of the masts. The calculated sector wise shear coefficients are shown in Table 6. Values in violation of IEC constraints are marked in red.

Table 6 – Summary of wind shear conditions at the masts used for analysis at Moldalsknuten

Sector	Shear coefficient (α)				IEC shear coefficient (α) limits
	329 (NRG)	330 (NRG)	333 (NRG)	334 (NRG)	
Average	0.0956	0.0587	0.1283	0.1035	
N	0.0504	0.0002	0.2102	-0.0658	$0 < \alpha < 0.2$
NNE	0.0806	0.0936	0.2042	0.0317	
ENE	0.1020	0.1048	0.1603	0.1029	
E	0.1160	0.0754	0.1657	0.0878	
ESE	0.0867	0.0346	0.0751	0.1372	
SSE	0.0989	0.0205	0.0657	0.1606	
S	0.0595	0.0719	0.0534	0.0970	
SSW	0.0404	0.0977	0.0877	0.1240	
WSW	0.0827	0.1064	0.1082	0.1890	
W	0.1556	0.0640	0.1550	0.1414	
WNW	0.1279	0.0179	0.1172	0.1247	
NNW	0.1460	0.0177	0.1365	0.1110	

As seen above, the wind shear coefficients based on the measurements from the four masts are within the acceptable interval given by the IEC standard in average and at all sectors, except from the N and NNE sectors for mast 333 and 334. However, as these are low frequency sectors and the deviation from the acceptable interval is small, this is not considered problematic. In addition, mast 333 is considered the least representative for the Moldalsknuten project area, with its location more than 4 km from the borderline of the planning area.

4 Flow model

4.1 Terrain and roughness model

The Windsim CFD flow model used for the wind resource analysis was based on high-resolution terrain data with 5 m contour separation, together with roughness data based on the N50 “Arealdekke” dataset from Statens Kartverk. A 10x10m digital terrain model was built and a GCV solver used for the calculation.

4.2 Wind field scaling

The CFD model described above was used to create a wind resource map corresponding to the 24 simulated wind direction sectors at potential hub heights. The wind field from the CFD flow model was scaled using extrapolated and long term corrected time series from the four measurement masts, extrapolated to 90 m height using the measured wind shear. An inversed weighting of the measurement data is performed in the process of generating the wind resource map. The final vertical extrapolation to the potential hub heights of 92 and 93 m was performed using the modeled wind shear.

4.3 Model verification

Horizontal extrapolation

With four masts within the model area, it is possible to perform a cross prediction check to assess the model. The results of the cross prediction check are presented in Table 7 .

Table 7 – Cross-prediction mean errors [%] between the measurement points included in the analysis

From\To	Mast 329	Mast 330	Mast 333	Mast 334
Mast 329	-	-1.6	1.1	0.7
Mast 330	3.4	-	4.4	4.2
Mast 333	2.1	-1.7	-	3.0
Mast 334	0.2	-0.6	1.6	-

Cross-prediction mean average errors between 0.2 and 4.4 % were found between the four masts. These error levels are considered low; indicating the terrain in the project area is well captured by the flow model.

Vertical extrapolation

Evaluations of vertical extrapolation is performed by assessing how well the mean measured shear comply with results from the flow model. A comparison of the mean measured shear (indicated by dots) against the modeled shear represented by the flow model (indicated by the black line) for the

four masts is presented in Figure 11 below. Only data from the NRG anemometers were used in the comparison.

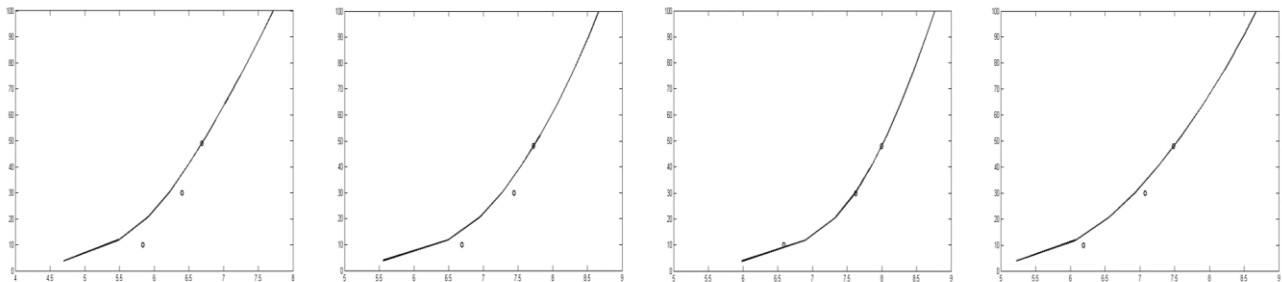


Figure 11 – Flow model mean wind shear compared against measured data at mast 329, 330, 333 and 334 (from left to right)

The measured mean wind shear is found to be relatively well captured by the flow model, although a slight overestimation of the wind shear is found at three of four mast positions (masts 329, 330 and 334). The deviations at low heights indicates that local speed-up effects are likely present. The measurements at the lowest height (10 m) are highly influenced by the terrain and are not representative for the wind flow at the heights of interest for wind turbines. Wind shear between the two upper heights is fairly well captured at all four mast positions, especially at mast 333.

The measured wind shear from the short Lidar time series at the first three Lidar locations at Tellnes shows a good correspondence with the modeled wind shear (see Figure 12 below).

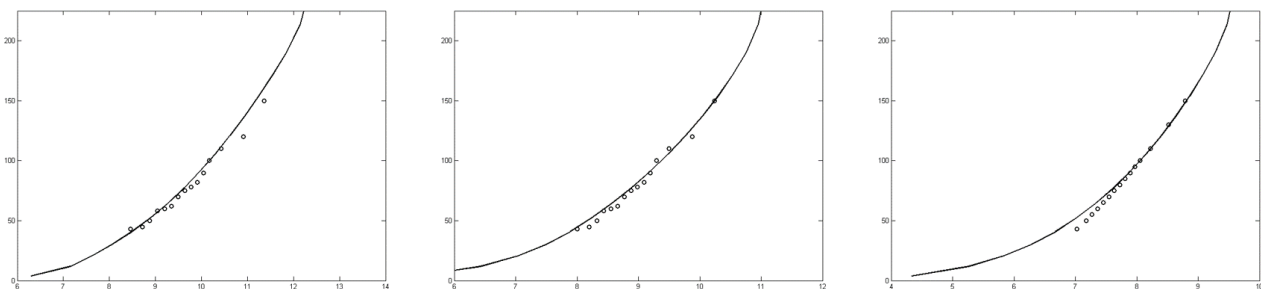


Figure 12 Flow model mean wind shear compared against measured data at Lidar first, second and third deployment at Tellnes (from left to right)

As the monthly variations in wind shear may be high, the good fit between the CFD modeled wind shear and the wind shear measured during the short Lidar time series may potentially be a coincidence and not representative for other periods throughout the year. However, the results from the Lidar campaign is a good indication that the model manages to capture the vertical wind shear at higher elevations at the site.

4.4 Uncertainty

Uncertainty in horizontal extrapolation

While none of the wind data were measured within the Moldalsknuten project area, masts 329, 330 and 334 are all located relatively close to the border of the planning area and provide a relatively good horizontal coverage of measurement points in accordance with MEASNET standards. The northern part of the planning area, however, is outside the recommended maximum distance of 2 km from the closest mast in complex terrain, resulting in a higher uncertainty in the extrapolated wind data in this area.

The cross prediction assessment showed low mean errors (0.2 to 4.4 %) when using the flow model to predict the wind speed at one mast using the data from the other masts. Combining this with experience from similar projects, the distance related uncertainty is assumed to be in the order 3 % per km for this type of terrain.

Uncertainty in vertical extrapolation

Extrapolating wind data vertically adds uncertainty to the production estimates. As there are large variations in wind shear over time, it is preferred to use the measured shear for extrapolation instead of a flow model. This does, however, puts demands on the quality of the measurements, as a small error on lower heights can increase significantly when extrapolated.

To assess the potential error when extrapolating from the mast, the mean wind speed at 90 meters was estimated based on the measured wind shear (α) using different instruments. The results were compared to extrapolation based on the flow model, and an error estimate was based on the results (provided in Table 8 and Table 9 below).

Table 8 – Comparison of extrapolation results at 90 m based on wind data from selected heights

Extrapolation at mast		Extrapolation based on	Extrapolated measurements	Mean wind speed at 90 m [m/s]
329	NRG	10.0, 30.0, 49		7.687
		10, 49	Riso - Mix - 50.0 m	7.684
		30, 49		7.719
Variability in extrapolation results using combinations of sensors:				0.21%
330	NRG	9.9, 30, 48		8.395
		9.9, 48	Riso - Mix - 49.1 m	8.403
		30, 48		8.326
Variability in extrapolation results using combinations of sensors:				0.41%
333	NRG	10, 30, 48.4		9.005
		10, 48.4	Riso - Mix - 50.0 m	9.017
		30, 48.4		8.874
Variability in extrapolation results using combinations of sensors:				0.72%
334	NRG	10, 30, 47.6		8.345
		10, 47.6	Riso - Mix - 49.1 m	8.346
		30, 47.6		8.338
Variability in extrapolation results using combinations of sensors:				0.04%

Table 9 – Comparison of extrapolation result using measured wind shear versus flow model wind shear

Extrapolation at mast	Extrapolation based on	Extrapolated measurements	Mean wind speed at 90m [m/s]
329	30, 49	Riso - Mix - 50.0 m	7.70
	WindSim		8.11
	Variability in extrapolation results		2.6 %
330	30, 48	Riso - Mix - 49.1 m	8.33
	WindSim		8.69
	Variability in extrapolation results		2.1 %
333	30, 48.4	Riso - Mix - 50.0 m	8.87
	WindSim		8.94
	Variability in extrapolation results		0.4 %
334	30, 47.6	Riso - Mix - 49.1 m	8.34
	WindSim		8.70
	Variability in extrapolation results		2.1 %

As the lowest measurement height was only 10 meters above the ground and highly influenced by the terrain, the extrapolated time series used as input to the flow model was based on shear values from the upper measurement heights only. For the comparison with flow model, extrapolation based only on these heights were included.

The results presented in Table 8 and Table 9 show that the extrapolation results are fairly consistent when using data from different combinations of measurement heights. Higher deviations are found between the time series extrapolated using measured shear and the time series based on flow model wind shear. According to the results presented in section 4.3, the flow model tends to overestimate

the vertical wind shear compared to the measured data leading to a moderate uncertainty level for the vertical extrapolation.



5 Wind resource assessment

5.1 Wind map

The wind resources at the site were assessed by extrapolating the long-term corrected time series throughout the project area using the CFD flow model. A wind map giving the expected mean wind speed across the site at 93 m is presented in Figure 13. The Moldalsknuten project area is marked by the black line, while the borderline of Tellenes Wind Farm is marked by light blue.

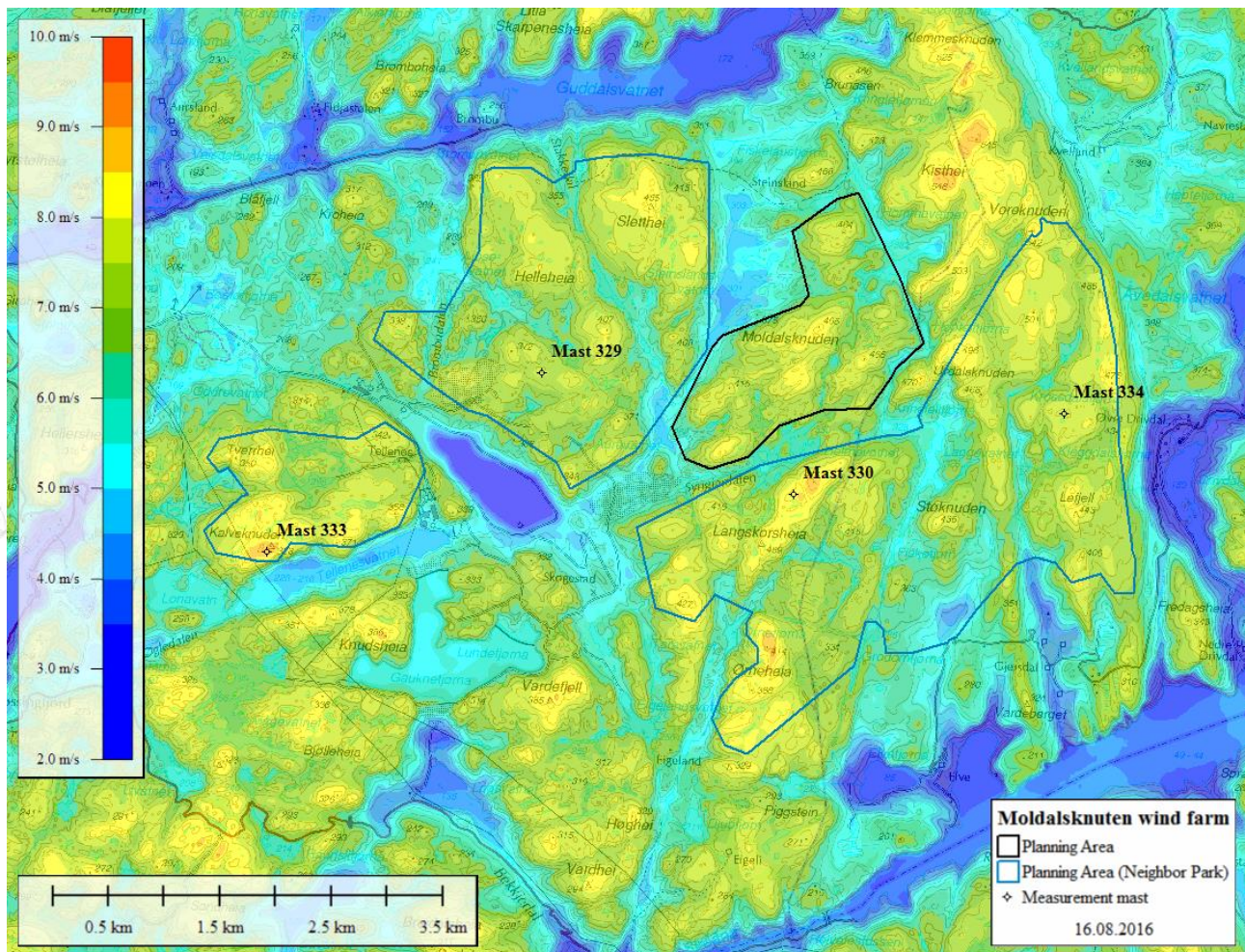


Figure 13 – Expected mean wind speed [m/s] at 93 meter height

As seen in Figure 13, there are relatively large variations in the wind conditions across the site. As expected, the windiest areas are found on the most exposed hilltops in the central part of the planning area, where mean wind speeds slightly above 8.0 m/s are expected.

6 Production analysis

6.1 Layout

A layout consisting of 11 turbines was developed by Meventus in May 2016. The layout was optimized with respect to energy production using a minimum distance of 2.7 RD (Rotor Diameters), with larger spacing used in the predominant wind directions.

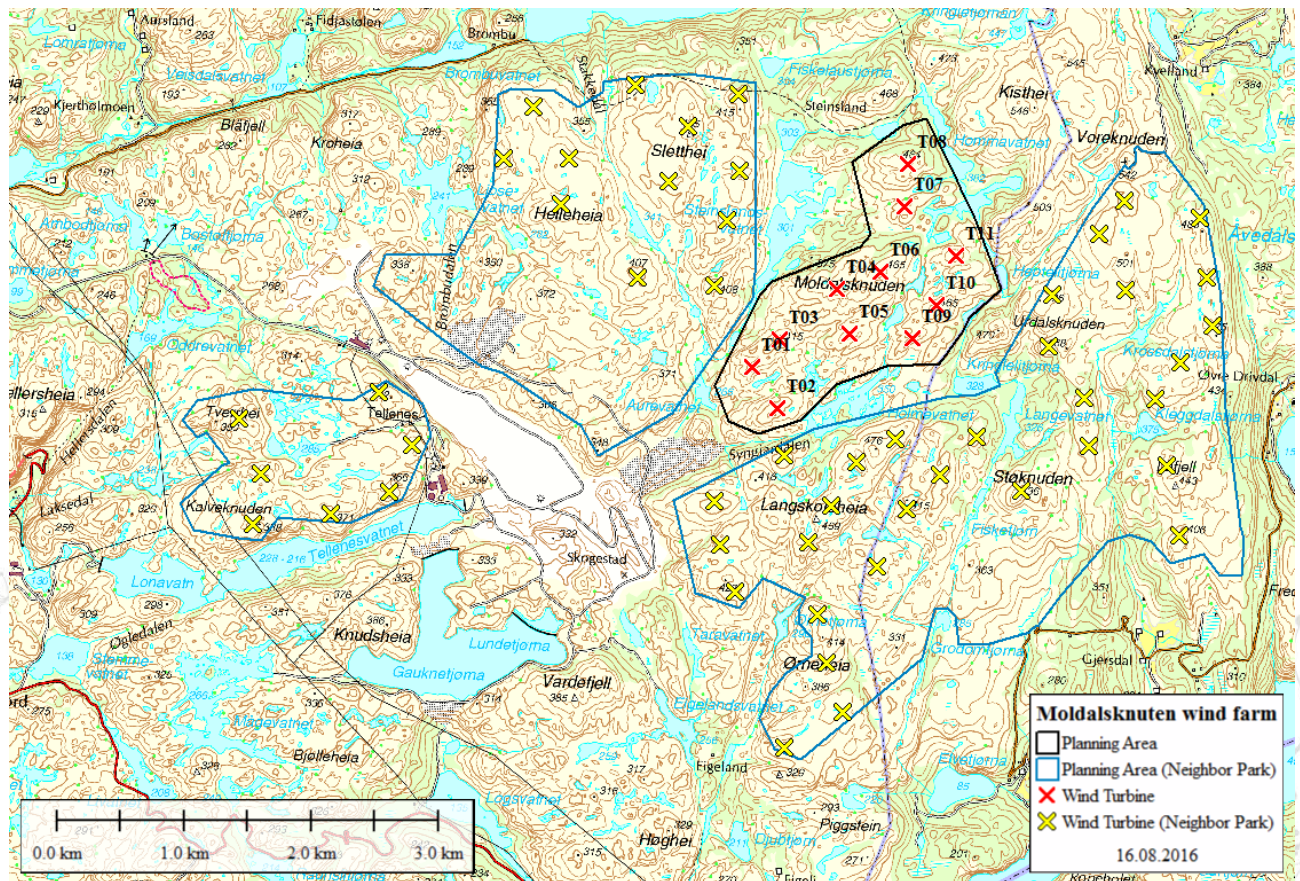


Figure 14 – Wind farm layouts consisting of 11 Moldalsknuten wind turbines (red) and 50 Tellnes turbines (yellow)

Two alternative wind turbines were evaluated using the presented turbine layout, Servion 3.6M114 with 93 m hub height and Siemens S113 3.2MW with Power Boost functionality and 92.5 m hub height.

6.2 Production analysis

The annual energy production was estimated using the standard industry software WindPRO version 3.0.654, and is based on the estimated wind resource map and turbine information provided by the respective turbine manufacturer.

The annual energy production was estimated at 116.1 GWh/year for the Senvion layout and 112.3 GWh/year for the Siemens layout, with an uncertainty of 14.9 % and 14.6 %, respectively. The estimated production for the two layouts, including losses and uncertainty estimates, is presented in Table 10 below.

Table 10 – Production estimates for evaluated layouts

Turbine		Layout information	
Turbine Type	-	SE114	S113
Capacity	MW	3.6	3.2
Hub height	m	93	92.5
Turbine class (IEC)	-	IIA	IIA
Total number of turbines	#	11	11
Park capacity	MW	39.6	35.2
Annual energy production	GWh/yr	116.1	112.3
Uncertainty	%	14.9	14.6
Wake losses (Internal)	%	6.2	6.8
Wake losses (External)		7.8	7.6
Other losses	%	8.7	8.7
Full load hours	h/yr	2932	3190
Mean wind speed at turbines	m/s	8.0	8.0
Wake loss increase in Tellenes	%	1.0	1.2

As seen in Table 10 the neighbor wind farm at Tellenes results in an additional wake loss of 7.8 and 7.6 % for the two layouts at Moldalsknuten, respectively. Moldalsknuten wind farm will also affect the wind conditions at Tellenes, leading to an additional wake loss of 1.0 and 1.2 %, depending on the turbine layout.

Loss and uncertainty figures used in this estimate are described in detail in the subsequent sections. See Appendix A and B for detailed reports of production (including P75 and P90 estimates), loss and uncertainty.

6.3 Loss estimates

Wake effects

The wake losses are estimated using the PARK-model in WindPRO. The wake decay parameter was set to 0.075 based on the roughness conditions and background turbulence at the site. The estimated wake losses includes both the internal wake losses and wake losses caused by the wind turbines at Tellenes Wind Farm.

Availability

Information on the warranted turbine availability was provided by the turbine manufacturers following an energy-based availability warranty concept. The warranted turbine availability was 97.5% for the Senvion 3.6M114 and 97.0 % for the Siemens S113 3.2MW-layout. It is assumed that the actual availability will be equal to the warranted over the lifetime of the turbines.

Electrical losses

Electrical losses include the production lost from the turbine to the point of revenue metering. This does not include electrical losses in the turbine, as these are normally included in the power curve. Detailed calculations of the electrical system was performed by Jøsok Prosjekt AS. Based on their analysis an electrical loss of 1.68 % was assumed.

Turbine performance

The calculations of the energy yield from the wind turbines are based on the warranted power curves provided by the manufacturers. However, as the warranty is only valid for a given set of conditions (often called the “inner range”), the wind turbine will not necessarily perform as well when exposed to the site-specific conditions.

During a power curve measurement the wind turbine performance in the inner range is tested. Based on evaluations of historical power curve measurements, it is expected that the wind turbines in average will perform up to 99 % of the warranted power curve.

The site-specific conditions (often called “outer range”) will often be less favorable than the warranted conditions, leading to sub-optimal performance. The larger the gap between the outer and inner range, the larger the turbine performance loss will be. As the Moldalsknuten wind project is located in a relatively complex terrain, turbulence levels not accounted for in the warranted power curves are expected, and a loss related to sub-optimal performance is included. This wind flow performance loss is estimated to 1 % for both layouts.

The production lost between turbine shutdown and subsequent startup after a high wind speed event exceeding the turbine’s shut-down criteria, was calculated in WindPRO using a generated time-variation file based on one year of wind data from mast 329. The high wind hysteresis loss was calculated at 0.6 % for the SE114-layout and 0 % for the S113-layout due to the high cut-out wind speed (32 m/s) for the HWRT version of this turbine used in the evaluation.

Environmental losses

The primary environmental impact on the wind farm production is expected to be caused by icing. The expected production loss depends on turbine type, hub height, the surrounding terrain etc., and the annual variability is relatively high. Expected site-specific icing losses are generally estimated based on observed anemometer icing and experience from similar projects. It should be

noted that anemometer icing can not be converted into expected power production loss without significant uncertainty.

As the project is located close to the coastline in the southernmost part of Norway, the risk of icing is expected to be low at Moldalsknuten. However, with elevations ranging from 350 to 460 m and with planned hub heights exceeding 90 m, some icing is expected. An investigation of the measurement data indicates that instrumental icing occurs approximately 2.1 % of the time (180 hours per year) in this area. The periods of icing are found to be short and not very intensive and it is therefore assumed that low amounts of ice will accumulate on the blades during an icing period.

The amount of observed icing on the sensors is in agreement with results found in NVE icing potential mapping in Norway, where it is estimated that the frequency of icing > 10 g/hour will occur between 140 and 230 hours per year at the planned turbine locations at Moldalsknuten.

According to the above considerations and the IEA Task 19 (Wind Energy in Cold Climates) Ice Classification System, shown in see Table 11 below, the project may be categorized within ice class 2, where between 0.5 and 5 % production loss is expected.

Table 11 – IEA Wind, Task 19 Ice Classification System (2012)

IEA Wind Ice Classification System			
IEA Wind Ice Class	Meteorological icing (% of year)	Instrumental icing (% of year)	Production loss (% of annual production)
5	> 10	> 20	> 20
4	5 - 10	10 - 30	10 - 25
3	3 - 5	6 - 15	3 - 12
2	0.5 - 3	1 - 9	0.5 - 5
1	0 - 0.5	< 1.5	0 - 0.5

An evaluation of the temperature and production data during icing conditions at the Mehuken wind farm in Sogn og Fjordane County showed a production loss due to icing of 0.5 %. While these turbines are located at slightly lower elevations than the planned turbines at Moldalsknuten, the proximity to the coastline is about the same and they give an indication of what can be expected at Moldalsknuten.

Based on the above considerations a total icing loss of 2 % is assumed for the planned wind turbines at Moldalsknuten, where 1 % is related to the performance degradation caused by icing and 1 % loss is related to shutdown of the turbines.

In addition to the icing losses, an additional environmental loss related to the expected reduction of the aerodynamic efficiency of the turbine blades leading to contamination and veer is included for both layouts. A standard estimate of 0.3 % is assumed over the lifetime of the turbines.

Curtailment losses

The terrain complexity at the site likely causes some challenging flow conditions that are not captured by flow modeling. If turbines are located in positions where the wind conditions cause too high loading, curtailment may be needed to reduce the load. However, for this analysis no load curtailment losses were included for any of the turbine layouts.

Potential noise and shadow flicker impact on the wind farm neighbors is not evaluated in this analysis. With more than 2 km distance between the planning area and the closest neighbors, noise and shadow flicker curtailment is not likely for the turbines at Moldalsknuten.

6.4 Bias

The industry standard methodology used for calculating the expected annual production is deterministic, and does not account for the effect of uncertainties in wind speed and loss estimates. Due to the non-linearity of the power curve, and the distribution of the loss uncertainties, the probability distribution of the production estimate is skewed in cases where the uncertainty is high, or the average wind speed is high compared to the rated wind speed of the wind turbine. To account for this, Meventus has developed a Monte Carlo simulation tool that estimates the difference between the probabilistic and deterministic production estimate (Lund, 2013).

Based on the calculated Weibull parameters for each turbine and the respective power curve, the bias was calculated to -1.3 % for the Senvion layout and -1.2 % for the Siemens layout.

6.5 Uncertainty estimates

Wind data

The uncertainty assessment of the expected wind speed was estimated by considering the uncertainty from four categories: Wind Data, Data Handling/Analysis, Correlation and Long Term Extrapolation, and Year-to-Year Variability. The total uncertainty of each of these categories is determined by taking the root sum square of each sub-component uncertainty.

The Wind Data and Data Handling/Analysis uncertainty was estimated using MEASNET recommendations and the IEC Standard 61400-12-1 ed. 1 as guidelines. The Correlation and Long Term Extrapolation uncertainty was determined from the MCP analysis and evaluation of the long-term reference data.

The year-to-year variability was assessed by evaluating trends in the long-term corrected time series. The variability for a longer period (x) is determined by dividing the annual year-to-year variability value by the square root of x .

The wind data uncertainty for each of the masts included in the production analysis is presented in Table 12 below.

Table 12 – Wind data uncertainty

Uncertainty Component		Uncertainty [%] - wind speed			
		Mast 0329	Mast 0330	Mast 0333	Mast 0334
Wind Data - Measurement Setup					
	Instrument Calibration/Verification	1	1	1	1
	Instrument Class	2	2	2	2
	Measurement set-up (mast or terrain influence)	2	2	2	2
Wind Data - Data Handling/Analysis					
	Data Integrity (Uncertainty substitution value (MEASNET chp 8.1))	1	1	1	1
	Uncertainties from data filtering	2	2	2	2
	Uncertainties from data filling	0	0	0	0
	Terrain complexity and flow correction method (CFD, FCR etc.)	-	-	-	-
	Wind data Total	3.7	3.7	3.7	3.7
Correlation and Long Term Extrapolation					
	Reference data quality (consistency, length of series)	2	2	2	2
	Period of concurrent data 1 (Short term extension)	-	-	-	-
	Period of concurrent data 2 (Long term extension)	0.5	1.3	1.5	1.6
	Correlation between long term corrected and measured data	1.5	1.5	1.5	1.5
	Method	1	1	1	1
	Correlation and LT Extrapolation Total	2.7	3.0	3.1	3.1
Year to Year Variability					
	Year to Year variability (1 yr)	3.20	3.18	3.26	2.98
	Year to Year variability (20 yr)	0.7	0.7	0.7	0.7
Future climate (Past as predictor of future)		1.5	1.5	1.5	1.5
Total Uncertainty on Wind Speed (20 yr)		5.83	5.94	6.03	5.91

As each mast has its own associated uncertainty, the wind data uncertainty for a specific layout is dependent on how many of the turbine locations are reliant on data from each respective mast used to make the wind resource file. Each layout is evaluated to determine the proportion of turbines located nearest each mast, and the individual mast uncertainties are then combined based on these proportions. Table 13 below provides the combined wind data uncertainty, by component, for the two evaluated layouts. As the same turbine positions are used for both turbine types, the resulting wind data uncertainty is the same for both layouts.

Table 13 – Wind data uncertainty for the evaluated layouts at Moldalsknuten

Contributions to wind data uncertainty	Layout 11xSE114 - 3.6MW 93m HH	Layout 11xS113 - 3.2MW 92.5m HH
Wind data	3.74	3.74
Long term correction	2.99	2.99
Year-to-year variability	3.18	3.18
Future climate	1.50	1.50
Uncertainty in wind data (total) [%]	5.94	5.94

Wind model

With 9 of 11 turbines located within 2 km of a measurement point, the distance related uncertainty is calculated at 4.2 %. The flow model accuracy is set to 2.6 % based on the resolution of the terrain and roughness data and the refinement of the CFD grid. Based on the convergence and the climatic conditions the CFD solution accuracy is set to 2.8 %.

The vertical uncertainty is based on several factors, with the extrapolation distance from highest measurement height to the potential hub height(s) as the most significant. Other factors depend on the extrapolation method used (measured shear or WindSim), an engineering assessment of the expected accuracy of the respective method depending on the terrain complexity of the measurement position, the measurement data quality, and representativeness of the flow model (when relevant).

The resulting uncertainty is presented in Table 14.

Table 14 – Wind model uncertainty for the evaluated layouts at Moldalsknuten

Contributions to wind model uncertainty	Layout	Layout
	11xSE114 - 3.6MW 93m HH	11xS113 - 3.2MW 92.5m HH
Distance related uncertainty [%]	4.2 %	4.2 %
Flow model accuracy [%]	2.6 %	2.6 %
CFD solution accuracy [%]	2.8 %	2.8 %
Uncertainty in horizontal extrapolation [%]	5.7 %	5.7 %
Extrapolation distance and method related uncertainty [%]	4.5 %	4.4 %
Variability in extrapolation results	2.2 %	2.2 %
Special conditions	0.0 %	0.0 %
Uncertainty in vertical extrapolation [%]	5.0 %	4.9 %

Power conversion

Uncertainty in power conversion is related to inaccuracies in the power curve and the power conversion algorithms used. This is given a general uncertainty of 2 %.

Loss and bias uncertainty

Loss uncertainty is calculated based on assumed uncertainties for the loss estimates. A 25 % uncertainty is assumed for the turbine availability loss, the electrical losses and the bias correction, while a higher uncertainty of 50 % is assumed for the wake effects, the turbine performance and the environmental losses.

7 References

IEC 61400 – 1	Wind turbines – Part 1: Design requirements, Edition 3, 2005–08
IEC 61400-12-1	Wind turbines – Part 12-1: Power performance measurements of electricity producing wind turbines, Edition 1, 2005–12
Lund, 2013	Modeling AEP Uncertainty: How uncertainty adds bias to your project, EWEA 2013
Sgurr 009	Zephyr Tellenes Galion Location 1 Installation Report, 13/6631/001/GLA/0/R/009
Sgurr 013	Zephyr Tellenes Galion First Redeployment Report, 13/6631/001/GLA/0/R/013
Sgurr 016	Zephyr Tellenes Galion Second Redeployment Report, 13/6631/001/GLA/0/R/016
MEASNET, 2009	Evaluation of site-specific wind conditions, Version 1, November 2009
MEV 2015-007	Tellenes Wind Resource and Production Assessment
NVE	Wind Map for Norway, Icing Map at 80m height

Appendix A: Turbine positions

Table 15 – Turbine positions – Moldalsknuten – 11 turbine layout

Turbine nr.	Coordinates (UTM zone 32, WGS 84)		Z
	X	Y	
T01	350980	6469519	390.0
T02	351186	6469200	410.0
T03	351201	6469736	410.0
T04	351649	6470131	450.0
T05	351748	6469777	428.1
T06	351994	6470271	460.0
T07	352181	6470777	415.0
T08	352209	6471110	456.0
T09	352247	6469749	429.8
T10	352429	6470002	460.0
T11	352582	6470396	450.0

Appendix B: WindPRO Loss and Uncertainty Report - 11xSE114 - 3.6MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Kongsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:34/3.0.654

Loss&Uncertainty - Main result

Calculation: 201608 11xSE114 - 3.6MW - 93m HH

Main data for PARK

PARK calculation 3.0.654: 201608_11xSE114 - 3.6MW - 93m HH

Count 11

Rated power 39.6 MW

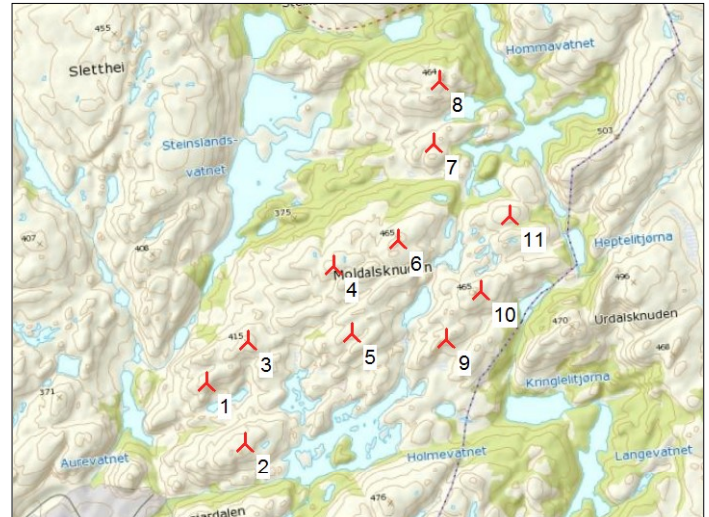
Mean wind speed 8.0 m/s at hub height

Sensitivity 1.4 %AEP / %Mean Wind Speed

Expected lifetime 20 Years

RESULTS

		P50	P75	P90
NET AEP	[GWh/y]	116.1	104.4	93.9
Capacity factor	[%]	33.5	30.1	27.1
Full load hours	[h/y]	2,932	2,637	2,372

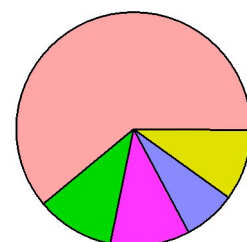


Scale: 40,000

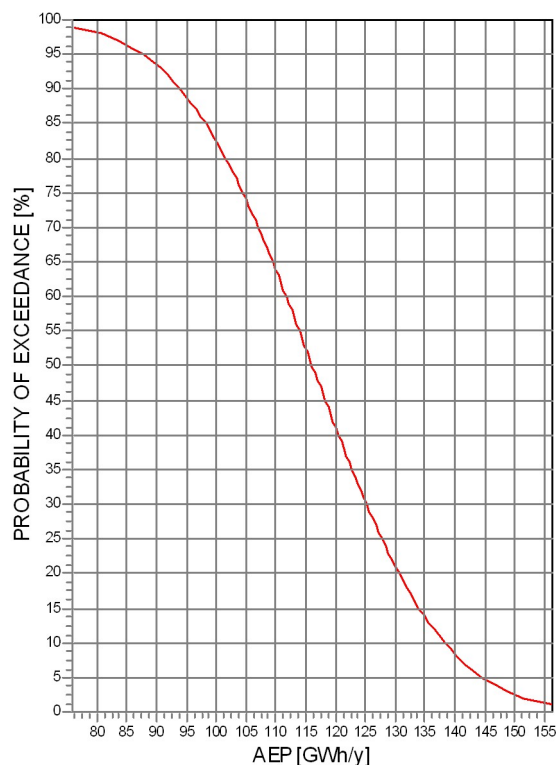
Result details

	P50	Uncertainty
GROSS AEP *)	149.8 GWh/y	13.1 %
Bias correction	-1.9 GWh/y -1.3 %	0.3 %
Loss correction	-31.7 GWh/y -21.5 %	7.1 %
Wake loss	-14.0 %	
Other losses	-8.7 %	
NET AEP	116.1 GWh/y	14.9 %

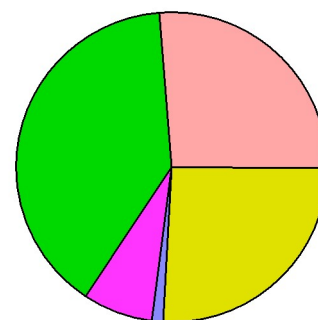
Loss: 21.5 %



1. Wake effects	14.0 %
2. Availability	2.5 %
3. Turbine performance	2.6 %
4. Electrical	1.7 %
5. Environmental	2.3 %
6. Curtailment	0.0 %
7. Other	0.0 %



Uncertainty: 14.9 %



A. Wind data	7.2 %	B. Wind model	10.8 %
C. Power conversion	2.0 %	D. BIAS	0.3 %
E. LOSS	7.1 %		

*) Calculated Annual Energy Production before any bias or loss corrections
Assumptions: Uncertainty and percentiles (PXX values) are calculated for the expected lifetime

Appendix B: WindPRO Loss and Uncertainty Report - 11xSE114 - 3.6MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Konsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:34/3.0.654

Loss&Uncertainty - Assumptions and results

Calculation: 201608 11xSE114 - 3.6MW - 93m HH

ASSUMPTIONS

BIAS

	Method *)	Correction, wind speed [%]	Correction, AEP [%]	Std dev**) [%]	Comment
Other bias	Estimate	-0.9	-1.3	25.0	Estimated P50 bias
BIAS, total			-1.3	0.3	

LOSS

	Method *)	Loss [%]	Loss [GWh/y]	Std dev**) [%]	Comment
1. Wake effects					
Wake effects, all WTGs	Calculation	14.0	20.6	50.0	
2. Availability					
Turbine availability	Estimate	2.5	3.7	25.0	
3. Turbine performance					
Power curve	Estimate	1.0	1.5	50.0	Standard estimate
High wind hysteresis	Calculation	0.6	0.9	50.0	Calculated
Wind flow	Estimate	1.0	1.5	50.0	Turbulence and wind conditions outside envelope
4. Electrical					
Electrical losses	Estimate	1.7	2.5	25.0	Standard estimate
5. Environmental					
Performance degradation not due to icing	Estimate	0.3	0.4	50.0	Blade degradation
Performance degradation due to icing	Estimate	1.0	1.5	50.0	
Shutdown due to icing, lightning, hail, etc.	Estimate	1.0	1.5	50.0	
6. Curtailment					No input
7. Other					No input
LOSS, total		21.5	31.7	7.1	

UNCERTAINTY

	Method *)	Std dev, wind speed [%]	Std dev, AEP [%]	Comment
A. Wind data				
Wind measurement/Wind data	Estimate	3.7	5.3	
Long term correction	Estimate	3.0	4.2	
Year-to-year variability	Estimate	3.2	4.5	
Future climate	Estimate	1.5	2.1	
Other wind related				
B. Wind model				
Vertical extrapolation	Estimate	5.0	7.1	
Horizontal extrapolation	Estimate	5.7	8.1	
Other wind model related				
C. Power conversion				
Power curve uncertainty	Estimate		2.0	
Metering uncertainty				
Other AEP related uncertainties				
D. BIAS, total uncertainty			0.3	
E. LOSS, total uncertainty			7.1	
UNCERTAINTY, total (1y average)			15.5	
UNCERTAINTY, total (20y average)			14.9	

VARIABILITY

Years	Variability (std dev) [%]	Total std dev [%]
1	4.51	15.5
5	2.02	15.0
10	1.43	14.9
20	1.01	14.9

Appendix B: WindPRO Loss and Uncertainty Report - 11xSE114 - 3.6MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Konsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:34/3.0.654

Loss&Uncertainty - Assumptions and results

Calculation: 201608 11xSE114 - 3.6MW - 93m HH

RESULTS

AEP versus exceedance level / time horizon

PXX	1 y	5 y	10 y	20 y
[%]	[MWh/y]	[MWh/y]	[MWh/y]	[MWh/y]
50	116,112	116,112	116,112	116,112
75	103,946	104,363	104,417	104,443
84	98,174	98,790	98,868	98,908
90	92,995	93,789	93,890	93,941
95	86,441	87,461	87,590	87,656

*) Calculation means that a calculation method available in the windPRO software is used. This still typically involve a user judgement and user data where the quality of those decides the accuracy. If calculation method is used, the values will often be different from turbine to turbine, here the average is shown, but at page "WTG results" the individual turbine results are shown.

**) For totals the std dev refers to the full AEP, otherwise std dev refers to the bias or loss component which is a fraction of the total AEP.

Appendix B: WindPRO Loss and Uncertainty Report - 11xSE114 - 3.6MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Konsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:34/3.0.654

Loss&Uncertainty - WTG results

Calculation: 201608 11xSE114 - 3.6MW - 93m HH

Main data for PARK

PARK calculation 3.0.654: 201608_11xSE114 - 3.6MW - 93m HH

Count

11

Rated power

39.6 MW

Mean wind speed

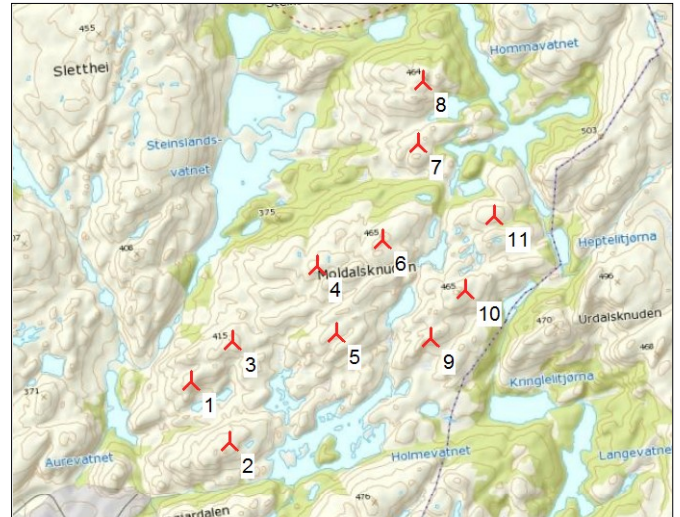
8.0 m/s at hub height

Sensitivity

1.4 %AEP / %Mean Wind Speed

Expected lifetime

20 Years



Scale: 40,000

Expected AEP per WTG including bias, loss and uncertainty evaluation

Description	User label	Calculated GROSS*) [MWh/y]	Bias [%]	Loss [%]	20 years averaging			
					Unc. [%]	P50 [MWh/y]	P75 [MWh/y]	P90 [MWh/y]
1 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2208)	T01	13,287.4	-1.3	20.3	14.2	10,452.7	9,450.8	8,549.1
2 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2209)	T02	13,931.4	-1.3	20.8	14.1	10,895.0	9,860.6	8,929.6
3 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2210)	T03	13,494.4	-1.3	23.3	15.2	10,212.5	9,165.3	8,222.8
4 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2211)	T04	14,024.2	-1.3	23.8	15.3	10,547.9	9,460.3	8,481.6
5 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2212)	T05	13,879.9	-1.3	22.5	14.3	10,620.2	9,597.6	8,677.2
6 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2213)	T06	14,702.0	-1.3	21.4	14.3	11,399.1	10,296.3	9,303.8
7 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2214)	T07	12,541.0	-1.3	18.5	15.8	10,083.4	9,006.9	8,038.1
8 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2215)	T08	13,614.5	-1.3	16.3	14.1	11,253.7	10,179.7	9,213.1
9 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2216)	T09	13,306.2	-1.3	23.9	15.8	9,997.8	8,935.0	7,978.4
10 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2217)	T10	14,111.1	-1.3	23.0	15.1	10,718.0	9,625.7	8,642.7
11 Servion 3.6M114-Moldalskn 3600 114.0 !O! hub: 93.0 m (TOT: 150.0 m) (2218)	T11	12,916.8	-1.3	22.1	16.2	9,934.6	8,851.4	7,876.5
PARK		149,808.8	-1.3	21.5	14.9	116,112.5	104,443.5	93,941.0

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Kongsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:35/3.0.654

Loss&Uncertainty - Main result

Calculation: 201608 11xS113 - 3.2MW - 92.5m HH - PB

Main data for PARK

PARK calculation 3.0.654: 201608_11xS113 - 3.2MW - 92.5m HH - PB

Count

11

Rated power

35.2 MW

Mean wind speed

8.0 m/s at hub height

Sensitivity

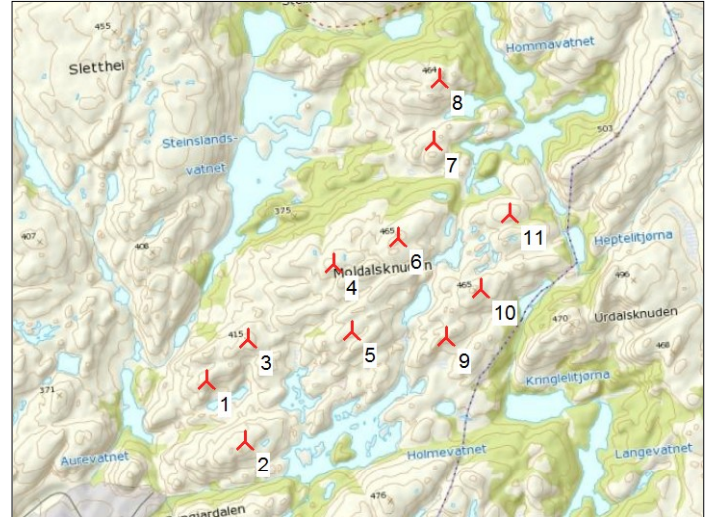
1.4 %AEP / %Mean Wind Speed

Expected lifetime

20 Years

RESULTS

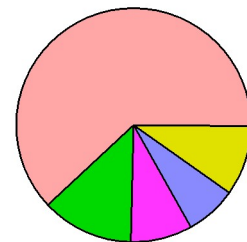
		P50	P75	P90
NET AEP	[GWh/y]	112.3	101.3	91.3
Capacity factor	[%]	36.4	32.8	29.6
Full load hours	[h/y]	3,190	2,877	2,595



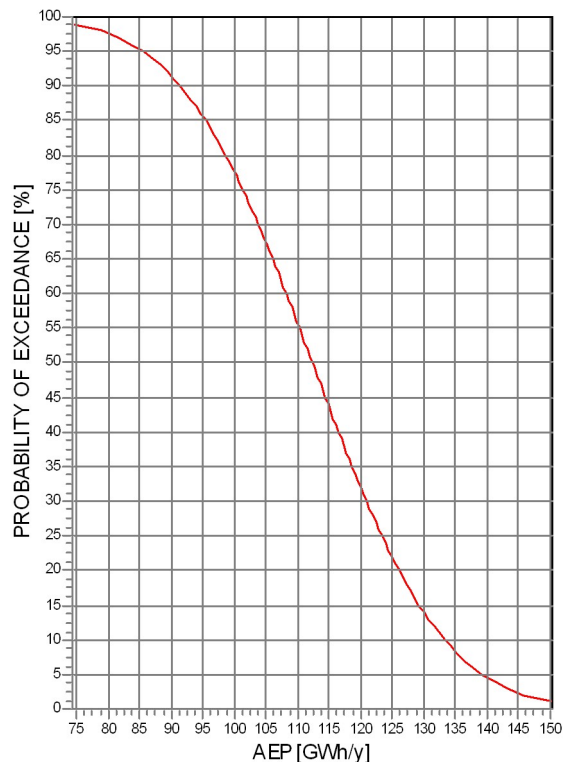
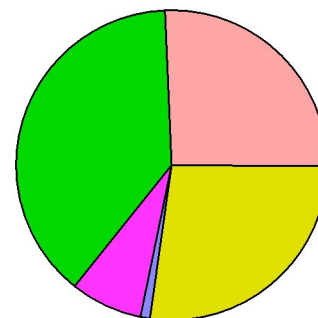
Scale: 40,000

Result details

	P50	Uncertainty
GROSS AEP *)	145.4 GWh/y	12.6 %
Bias correction	-1.7 GWh/y -1.2 %	0.3 %
Loss correction	-31.4 GWh/y -21.8 %	7.3 %
Wake loss	-14.4 %	
Other losses	-8.7 %	
NET AEP	112.3 GWh/y	14.6 %

Loss: 21.8 %


1. Wake effects	14.4 %
2. Availability	3.0 %
3. Turbine performance	2.0 %
4. Electrical	1.7 %
5. Environmental	2.3 %
6. Curtailment	0.0 %
7. Other	0.0 %


Uncertainty: 14.6 %


A. Wind data	6.9 %	B. Wind model	10.3 %
C. Power conversion	2.0 %	D. BIAS	0.3 %
E. LOSS	7.3 %		

*) Calculated Annual Energy Production before any bias or loss corrections

Assumptions: Uncertainty and percentiles (PXX values) are calculated for the expected lifetime

Appendix C: WindPRO Loss and Uncertainty Report - 11xS113 - 3.2MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Konsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:35/3.0.654

Loss&Uncertainty - Assumptions and results

Calculation: 201608 11xS113 - 3.2MW - 92.5m HH - PB

ASSUMPTIONS

BIAS

	Method *)	Correction, wind speed [%]	Correction, AEP [%]	Std dev**) [%]	Comment
Other bias	Estimate	-0.9	-1.2	25.0	Estimated P50 bias
BIAS, total			-1.2	0.3	

LOSS

	Method *)	Loss [%]	Loss [GWh/y]	Std dev**) [%]	Comment
1. Wake effects					
Wake effects, all WTGs	Calculation	14.4	20.7	50.0	
2. Availability					
Turbine availability	Estimate	3.0	4.3	25.0	
3. Turbine performance					
Power curve	Estimate	1.0	1.4	50.0	Standard estimate
High wind hysteresis	Calculation	0.0	0.0	50.0	Calculated
Wind flow	Estimate	1.0	1.4	50.0	Turbulence and wind conditions outside envelope
4. Electrical					
Electrical losses	Estimate	1.7	2.4	25.0	Standard estimate
5. Environmental					
Performance degradation not due to icing	Estimate	0.3	0.4	50.0	Blade degradation
Performance degradation due to icing	Estimate	1.0	1.4	50.0	
Shutdown due to icing, lightning, hail, etc.	Estimate	1.0	1.4	50.0	
6. Curtailment					No input
7. Other					No input
LOSS, total		21.8	31.4	7.3	

UNCERTAINTY

	Method *)	Std dev, wind speed [%]	Std dev, AEP [%]	Comment
A. Wind data				
Wind measurement/Wind data	Estimate	3.7	5.1	
Long term correction	Estimate	3.0	4.1	
Year-to-year variability	Estimate	3.2	4.4	
Future climate	Estimate	1.5	2.1	
Other wind related				
B. Wind model				
Vertical extrapolation	Estimate	4.9	6.7	
Horizontal extrapolation	Estimate	5.7	7.8	
Other wind model related				
C. Power conversion				
Power curve uncertainty	Estimate		2.0	
Metering uncertainty				
Other AEP related uncertainties				
D. BIAS, total uncertainty			0.3	
E. LOSS, total uncertainty			7.3	
UNCERTAINTY, total (1y average)			15.2	
UNCERTAINTY, total (20y average)			14.6	

VARIABILITY

Years	Variability (std dev) [%]	Total std dev [%]
1	4.36	15.2
5	1.95	14.7
10	1.38	14.6
20	0.97	14.6

Appendix C: WindPRO Loss and Uncertainty Report - 11xS113 - 3.2MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Konsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:35/3.0.654

Loss&Uncertainty - Assumptions and results

Calculation: 201608 11xS113 - 3.2MW - 92.5m HH - PB

RESULTS

AEP versus exceedance level / time horizon

PXX	1 y	5 y	10 y	20 y
[%]	[MWh/y]	[MWh/y]	[MWh/y]	[MWh/y]
50	112,294	112,294	112,294	112,294
75	100,803	101,188	101,237	101,262
84	95,352	95,920	95,992	96,029
90	90,460	91,193	91,286	91,333
95	84,271	85,211	85,331	85,391

*) Calculation means that a calculation method available in the windPRO software is used. This still typically involve a user judgement and user data where the quality of those decides the accuracy. If calculation method is used, the values will often be different from turbine to turbine, here the average is shown, but at page "WTG results" the individual turbine results are shown.

**) For totals the std dev refers to the full AEP, otherwise std dev refers to the bias or loss component which is a fraction of the total AEP.

Appendix C: WindPRO Loss and Uncertainty Report - 11xS113 - 3.2MW

Project:

Moldalsknuten

Description:

- 1) Wind data onsite: 15.12.2005 - present (9.5 years), 50m, 4 masts
- 2) Data availability: > 95%
- 3) Long term correction: Yes (ERA Interim - lin.reg)
- 4) IEC Class of turbine: IIA
- 5) Model: WindSim
- 6) Constraints included: none

Licensed user:

Meventus AS

Konsgård Allé 59

NO-4632 Kristiansand

+47 3860 7115

Anne Haaland Simonsen / anne@meventus.com

Calculated:

29.08.2016 12:35/3.0.654

Loss&Uncertainty - WTG results

Calculation: 201608 11xS113 - 3.2MW - 92.5m HH - PB

Main data for PARK

PARK calculation 3.0.654: 201608_11xS113 - 3.2MW - 92.5m HH - PB

Count

11

Rated power

35.2 MW

Mean wind speed

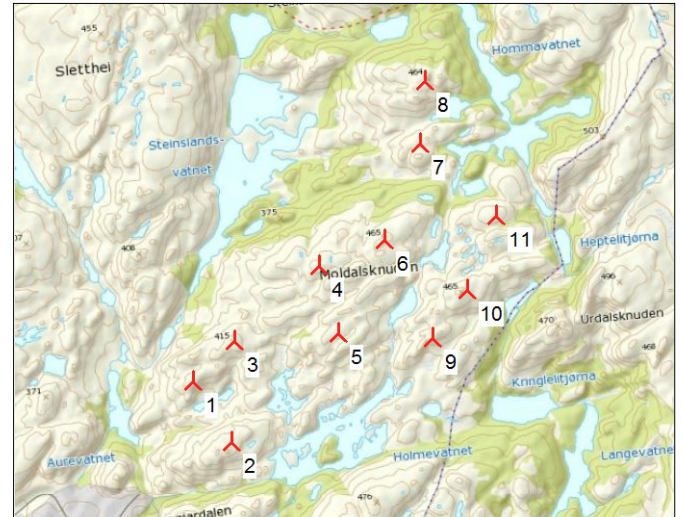
8.0 m/s at hub height

Sensitivity

1.4 %AEP / %Mean Wind Speed

Expected lifetime

20 Years



Scale: 40,000

Expected AEP per WTG including bias, loss and uncertainty evaluation

Description	User label	Calculated GROSS*) [MWh/y]	20 years averaging					
			Bias [%]	Loss [%]	Unc. [%]	P50 [MWh/y]	P75 [MWh/y]	P90 [MWh/y]
1 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2219)	T01	12,935.7	-1.2	20.5	13.9	10,159.3	9,206.5	8,348.9
2 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2220)	T02	13,513.0	-1.2	20.8	13.8	10,572.3	9,589.2	8,704.3
3 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2221)	T03	13,112.1	-1.2	23.6	14.9	9,893.2	8,897.0	8,000.4
4 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2222)	T04	13,605.8	-1.2	24.1	15.0	10,199.4	9,166.5	8,236.8
5 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2223)	T05	13,490.3	-1.2	22.8	14.1	10,288.9	9,307.6	8,424.5
6 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2224)	T06	14,213.3	-1.2	21.8	14.1	10,984.5	9,942.2	9,004.1
7 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2225)	T07	12,194.0	-1.2	19.2	15.2	9,732.4	8,732.7	7,833.0
8 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2226)	T08	13,201.3	-1.2	16.4	13.6	10,897.6	9,895.9	8,994.4
9 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2227)	T09	12,940.5	-1.2	24.5	15.5	9,657.7	8,649.5	7,742.2
10 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2228)	T10	13,670.5	-1.2	23.5	14.9	10,333.9	9,298.2	8,366.0
11 Siemens SWT-3.2-113-MK-PB 3200 113.0 !-! hub: 92.5 m (TOT: 149.0 m) (2229)	T11	12,545.6	-1.2	22.8	15.7	9,574.9	8,560.3	7,647.1
PARK		145,422.3	-1.2	21.8	14.6	112,294.0	101,262.1	91,333.0