CENTRALE EOLICA OFFSHORE “RIMINI” (330 MW)
ANTISTANTE LA COSTA TRA RIMINI E CATTOLICA

proponente:
EnergiaWind 2020 srl _ Riccardo Ducoli amministratore unico

STUDIO SPECIALISTICO _ ALLEGATO INTEGRAZIONI

STUDIO ANEMOLOGICO E PRODUCIBILITA' DELL'IMPIANTO _ LAYOUT B REV01

Autore:
DNV Italy S.r.l.

Maggio 2023

RIMINI OFFSHORE WIND FARM SITE

Energy Assessment Report

Energia Wind 2020 srl

Report No.: 01, Rev. C
Document No.: L220416-ITIM-R-01
Date: 26/04/2023

IMPORTANT NOTICE AND DISCLAIMER

1. This document is intended for the sole use of the Customer as detailed on the front page of this document to whom the document is addressed and who has entered into a written agreement with the DNV entity issuing this document (“DNV”). To the extent permitted by law, neither DNV nor any group company (the "Group") assumes any responsibility whether in contract, tort including without limitation negligence, or otherwise howsoever, to third parties (being persons other than the Customer), and no company in the Group other than DNV shall be liable for any loss or damage whatsoever suffered by virtue of any act, omission or default (whether arising by negligence or otherwise) by DNV, the Group or any of its or their servants, subcontractors or agents. This document must be read in its entirety and is subject to any assumptions and qualifications expressed therein as well as in any other relevant communications in connection with it. This document may contain detailed technical data which is intended for use only by persons possessing requisite expertise in its subject matter.

2. This document is protected by copyright and may only be reproduced and circulated in accordance with the Document Classification and associated conditions stipulated or referred to in this document and/or in DNV’s written agreement with the Customer. No part of this document may be disclosed in any public offering memorandum, prospectus or stock exchange listing, circular or announcement without the express and prior written consent of DNV. A Document Classification permitting the Customer to redistribute this document shall not thereby imply that DNV has any liability to any recipient other than the Customer.

3. This document has been produced from information relating to dates and periods referred to in this document. This document does not imply that any information is not subject to change. Except and to the extent that checking or verification of information or data is expressly agreed within the written scope of its services, DNV shall not be responsible in any way in connection with erroneous information or data provided to it by the Customer or any third party, or for the effects of any such erroneous information or data whether or not contained or referred to in this document.

4. Any wind or energy forecasts estimates or predictions are subject to factors not all of which are within the scope of the probability and uncertainties contained or referred to in this document and nothing in this document guarantees any particular wind speed or energy output.

Project name:	Rimini Offshore Wind Farm site	DNV - Energy Systems
Report title:	Energy Assessment Report	Project Development & Analytics
Customer:	Energia Wind 2020 srl,	DNV Italy s.r.l.
	Via Aldo Moro 28,	Via Cavour, 94, 40026
	25043 Comune di Breno (BS)	Imola BO, Italy
	Italy	Tel: +39 0542 21859
Customer contact:	Gabriele Felappi	
Date of issue:	26/04/2023	
Project No.:	L220416	
Organisation unit:	Renewables Advisory	
Report No.:	01, Rev. C	
Document No.:	L220416-ITIM-R-01	

Applicable contract(s) governing the provision of this Report: L220416-ITIM-P-01-D, L220416-ITIM-VO-04-A.

Objective:

Provide an Energy Assessment Report for the Rimini Offshore Wind Farm site

Prepared by:	Verified by:	Approved by:
Lorenzo Cantoni Engineer, Project Development & Analytics, Italy	Coline Daguet Engineer, Project Development & Analytics, France Jacopo Antonelli Engineer, Project Development & Analytics, Italy	Giacomo Rossitto Team Leader, Project Development & Analytics, Italy

DNV Distribution:

☐ Strictly Confidential
☐ Private and Confidential
☒ Commercial in Confidence
☐ DNV only
☐ Customer's Discretion

Keywords:
Energy Assessment, Rimini, Emilia-Romagna, Energia Wind 2020, WindFarmer, Offshore

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	2021-12-15	First issue	L. Cantoni	C. Daguet, J.Antonelli	A. Vergnani
B	2022-09-27	Update (Wind data and WT model)	L. Cantoni	C. Daguet, J.Antonelli	G.Rossitto
C	2023-04-26	New wind farm layout	J. Antonelli	G.Rossitto	G.Rossitto

Table of contents

List of abbreviations

Abbreviation	Meaning
AEP	Annual Energy Production
BOP	Balance of plant
CFD	Computational Fluid Dynamics
DNV	Garrad Hassan Italia Srl
DFW	Dry Friction Whip
ERA5	European Centre for Medium-Range Weather Forecasts (ECMWF) Re-Analysis 5
IEC	International Electrotechnical Commission
GEOS-5	Goddard Earth Observing System Data Assimilation System Version 5
MERRA-2	Modern-Era Retrospective analysis for Research and Applications 2
NASA	National Aeronautics and Space Administration
NOAA	National Oceanic and Atmospheric Administration
P50	Exceedance probability: The probability of reaching a higher or lower annual energy production is 50:50
P90	Exceedance probability: The probability of reaching a higher or lower annual energy production is 90%
PC	Power curve
PLF	Plant Load Factor (equivalent to Capacity Factor)
RD	Rotor Diameter
SPV	Special Purpose Vehicle
SRTM	Shuttle Radar Topography Mission
TI	Turbulence intensity
WAsP	Wind Atlas Analysis and Application Program
WRF	Weather Research and Forecasting
WSM	Wind Sector Management
WTG	Wind turbine Generator
MSL	Mean Sea Level

EXECUTIVE SUMMARY

Energia Wind 2020 srl (“Energia Wind” or the "Customer") retained DNV Italy S.r.l. (DNV), part of the DNV Group, to complete an independent analysis of the wind regime and energy production of the proposed Rimini Offshore Wind Farm site project (the Project).

DNV has previously undertaken an energy assessment of the Project for the Customer, as presented in the DNV report referenced L220416-ITIM-R-01 Revision B dated 2022-09-27 /1/. The updated results of this assessment are based on a new wind farm layout.

The Project is located in the Emilia-Romagna region, approximately 15 km off the Italian region coast in the Adriatic Sea.

The Customer has supplied valid data from one LiDAR unit installed at the Azalea B platform, approximately 15 Km from Rimini coast, referred to in this report as Azalea LiDAR, for the period from November 2012 to December 2014. In addition, DNV has considered Reanalysis historical data, MERRA-2 and ERA5 as potential sources of historical reference data.

One layout and one turbine model has been analysed, which have been supplied by the Customer.

The key findings of the analysis and factors affecting the analysis results are summarised below:

- The wind resource campaign used a fixed LiDAR with almost 2 years of measurements.
- Mesoscale wind flow modelling has been carried out to adjust the predicted long-term wind resource at the measurement location to be representative of each turbine location at the Rimini Offshore Wind Farm at the proposed hub height of 111 m MSL.
- No neighbouring wind farms have been included in the wake modelling.

The tables below summarize the project and the results of the wind resource and energy production analysis. This includes calculation of the wake and air density effects and assumptions or estimates for availability, electrical efficiency, turbine performance and environmental losses.

Project Summary	
Configuration	**A**
Turbine type	MySE6.45 - 180
Turbine hub height [m MSL]	111
Turbine rated power [kW]	6450
Number of turbines	51
Installed capacity [MW]	328.95
Wind Resource Summary	
Average air density at average hub elevation [kg/m^3]	1.211
Valid on-site measurement period [years]	1.9 year
Long-term reference period [years]	22.4 years
Average turbine hub-height wind speed [m/s]	5.8
Energy Assessment Summary	
Evaluation period	10 years
Gross energy [GWh/year]	865.9
P50 loss factors	
- Turbine interaction effects (wakes and blockage)	89.2%
- Availability	96.5%
- Electrical	97.5%
- Turbine performance	98.2%
- Environmental	100.0%
- Curtailment	100.0%
Total Losses	82.1%
Effect of asymmetric production	99.7%
P50 Net Energy [GWh/year]	711.2
P50 Net Capacity Factor	**24.7%**
P50 Net Equivalent Hours	**%2160**
P90 Net Energy [GWh/year]	599.6
P90 Net Capacity Factor	20.8%
P90 Net Equivalent Hours	1820

1 INTRODUCTION

Energia Wind 2020 srl (the "Customer") retained DNV Italy S.r.l. (DNV), part of the DNV Group, to complete an independent analysis of the wind regime and energy production of the proposed Rimini Offshore Wind Farm site project. This report is issued to Energia Wind 2020 srl pursuant to a written agreement dated 07 March 2023 arising from the Proposal L220416-ITIM-VO-04, revision A, dated 07 March 2023.

It is noted that DNV has previously undertaken an energy assessment of the Project for the Customer, as presented in the DNV report referenced L220416-ITIM-R-01 Revision B dated 2022-09-27 /1/. The updated results of this assessment are based on a new wind farm layout. This report is an update of /1/ considering a new wind farm layout.

The Project is located in the Emilia-Romagna region, approximately 15 km off the Rimini coast and comprises of 51 turbines with associated infrastructure.

This report presents a description of the project site and turbine configurations. It goes on to describe the available measurements and analysis of the wind data. DNV has analysed the wind data recorded at the site alongside with the wind data from various sources of long-term reference data, to predict the long-term wind speed at the Rimini Offshore Wind Farm.

The analysis is then followed by an evaluation of the expected project gross and net energy, as influenced by assumed losses and uncertainties.

Finally, the report presents DNV’s observations and recommendations.

2 PROJECT DESCRIPTION

2.1 General

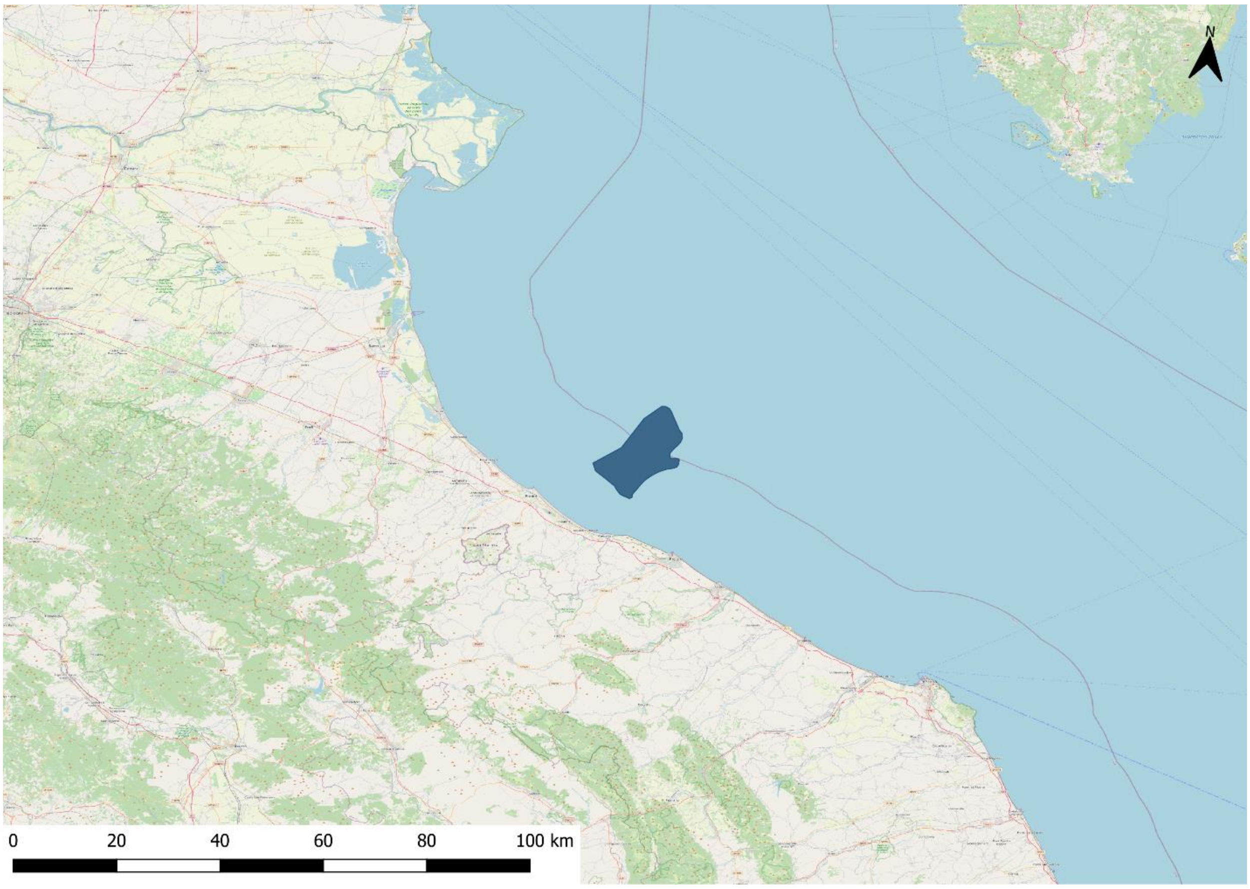
As shown in Figure 2-1, the Project is located in the Emilia-Romagna region, approximately 23 km off the Italian coast in the Adriatic Sea, and lies in international waters (more than 12 nautical miles from the coast of Italy). Measurements of the wind regime have been undertaken with a fixed LiDAR on the period from November 2012 to December 2014.

DNV has analysed one layout and one turbine model, provided by the Customer /3/. The proposed configuration is summarised in the table below.

Table 2-1 Proposed configurations

Layout	Number of turbines	Wind farm rated power [MW]	Turbine model	Turbine hub height [m]
B-bis	51	328.95	MySE6.45 - 180	111.0

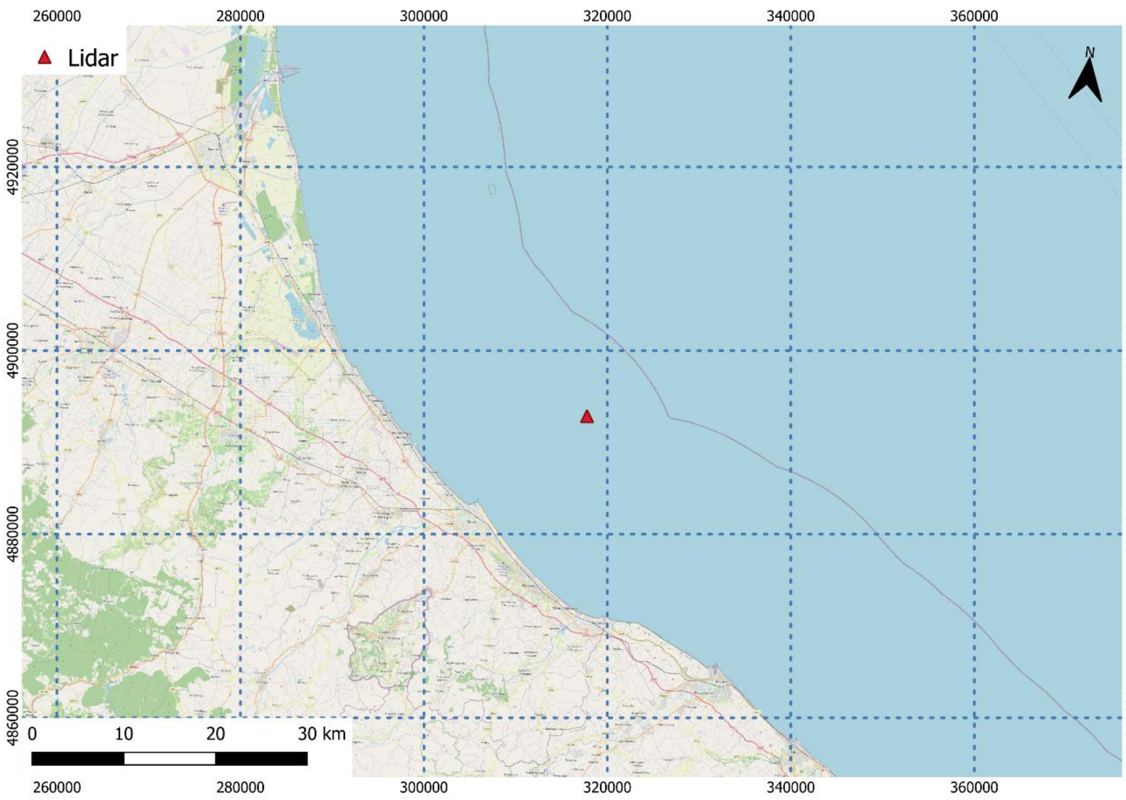
Figure 2-1 Location of the proposed Rimini Offshore Wind Farm site



2.2 Site description

A map showing the site is presented in Figure 2-2, including the locations of the Azalea LiDAR.

Figure 2-2 Map of the Rimini Offshore Wind Farm site



DNV has not visited the Rimini Offshore Wind Farm site. DNV has relied on documentation provided by the Customer for the site and LiDAR descriptions.

2.3 Turbine model

Table 2-2 summarises the turbine model under consideration for the Rimini Offshore project.

Table 2-2 Proposed turbine model parameters

Turbine	Rated power [MW]	Hub height [m MSL]	Peak power coefficient [Cp]	PC air density [kg/m3]	Operational Temperature
MYSE6.45 - 180	6.45	111.0	0.46	1.225	-10 C to 45°C

Using historical pressure and temperature records from nearby meteorological stations and standard lapse rate assumptions, the long-term mean air density at the site is estimated to be 1.211 kg/m3 at an average hub elevation of 111 m above sea level.

The characteristics and performance data of the turbines are presented in Appendix B. The power curve used in this analysis has been supplied by the Customer /4/. The power curve is based on manufacturer's calculations and has been adjusted to the site density, as discussed in Appendix E. The following observations are made regarding the power curve, which have been considered in the energy analysis and associated uncertainties, as discussed in Section 5.2:

- The peak power coefficient is considered to be reasonable for modern wind turbines.

- Measured power curves from independent tests of the performance of the turbine have not been supplied; therefore, DNV has been unable to verify that the power performance levels stated by the turbine manufacturers are attainable. It is therefore recommended that formal independently measured power curves are obtained; ideally, undertaken at similar levels of air density and turbulence intensity.

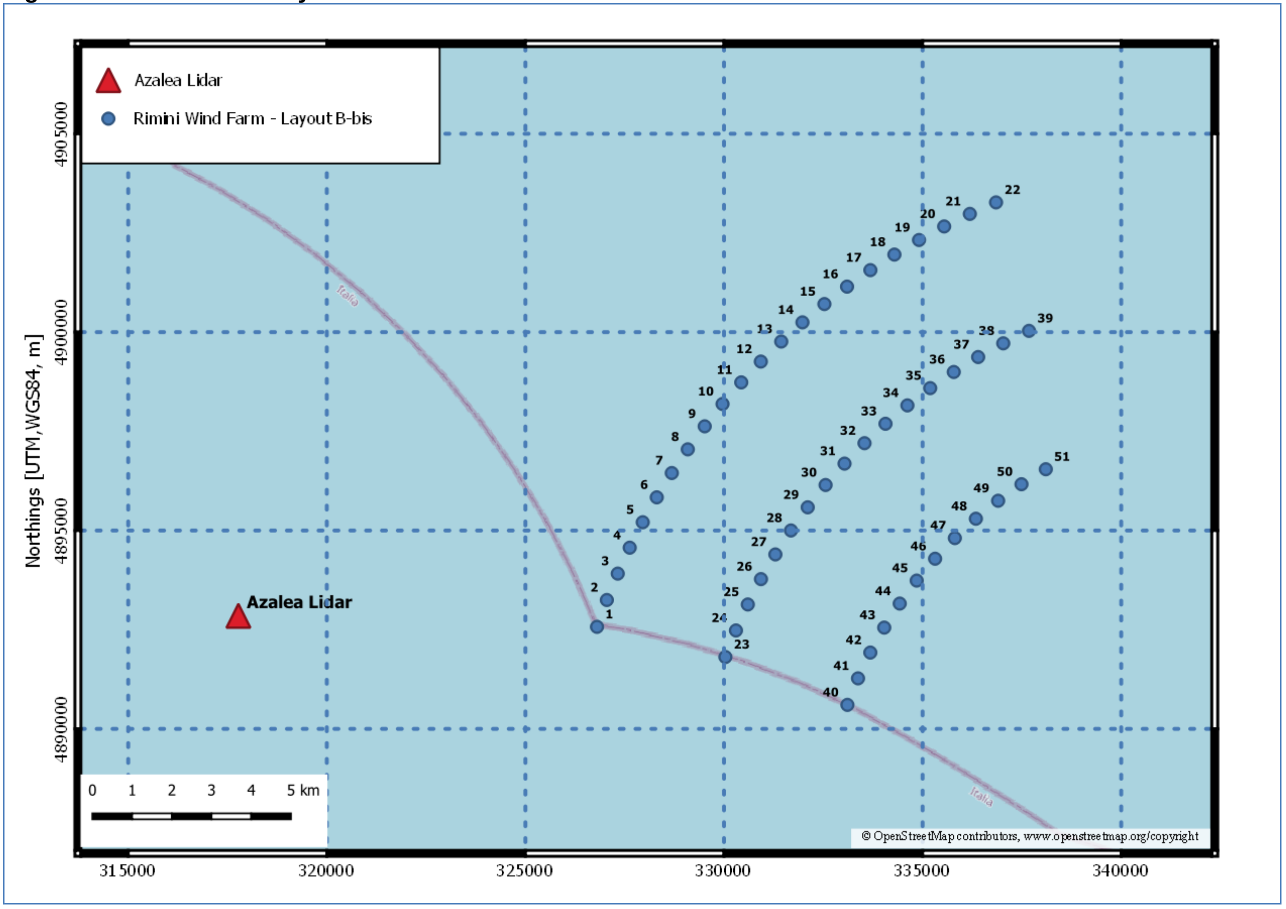
2.4 Turbine layout

The Customer has supplied one layout for the Rimini Offshore Wind Farm site consisting of 51 turbines /2/. A map showing the turbine locations is presented Figure 2-3. The grid coordinates of the turbines are given in Appendix A.

For any wind farm site, the minimum inter-turbine spacing selected for the turbines is an important design consideration. A balance needs to be struck between spacing turbines closely together to increase the installed capacity at a site and spacing the turbines out to minimise the wake effects. For offshore wind projects in Europe, DNV would recommend a nominal minimum spacing guideline of 6 D (six rotor diameters) in prevailing wind directions and 4 D (four rotor diameters) in non-prevailing directions. For the proposed layout, the minimum inter-turbine distance in prevailing wind directions is observed to be 18.3 D and 4 D in non-prevailing wind direction.

Therefore, the turbine separations at the Rimini Offshore Wind Farm site project for is close to what DNV would consider typical for an offshore project. The proposed separations are then considered to be generally reasonable. It is however recommended that the turbine manufacturer be approached at an early stage to confirm that the turbine spacing is acceptable, to gain approval for the proposed layout and ensure that sufficient warranty provisions are in place.

Figure 2-3 Wind turbine layout for the Rimini Offshore Wind Farm site



2.5 Neighbouring wind farms

Based on publicly available data sources and information supplied by the Customer, no operational wind farms have been identified in the vicinity of the Rimini Offshore Wind Farm site. Additionally, upon request of the Customer, any potential neighbouring wind farms in development in the vicinity of the project have not been considered.

3 ON-SITE WIND MONITORING

3.1 Wind resource measurements

Wind resource measurements provided by the Customer /3/ have been taken at the site with a fixed LiDAR, the Azalea LiDAR, located approximately 8 km west of the site, from November 2012 to December 2014 at several measurement heights as summarized in Table 3-1.

Table 3-1 Measurement summary for Azalea LiDAR

Device	Configured heights Wind speed and wind direction	LiDAR manufacturer and model	Period of measurement	Validation[2]
Azalea LiDAR	From 10 m to 100 m[1]	ZX Lidars Z300	2012-11-06 to 2014-12-01	Unknown[2]

1 - It is noted that the heights configured in the LiDAR units are different from the height above mean sea level (m MSL), due to the platform height on which the LiDAR is fixed. The following window heights have been considered: 27 m above mean sea level (MSL).
2 - Onshore validation means comparison of LiDAR data against a conventional meteorological mast according to the requirements of the IEC 61400-12-1 (Ed.2, FDIS, Annex L)

3.1.1 LiDAR Technology

LiDAR (Light Detection and Ranging) is an optical remote sensing technique that measures properties of scattered light to find the range and other information of a distant target. The Customer has provided valid data recorded from Z300 LiDAR technology from manufacturer ZX Lidars (Zephir). The devices emit laser beams upwards and measure the backscatter from natural aerosols in the atmosphere to assess the wind speed and direction at a range of heights.

DNV has monitored the development of this device with a view to their deployment in commercial wind resource assessment. Cup anemometers are the current industry standard for measuring wind speed at wind farm sites. Measurements from cup anemometers therefore must be considered the norm against which any new measurement device must be judged.

DNV has gained increasing experience in the operation of LiDAR device from deployments in the field. The largest body of data available is from sites located in simple terrain in Northern European locations which are typically characterised by a predominance of neutral stability atmospheric conditions. DNV's experiences are that the data recorded by the LiDAR in such conditions consistently lie within the error bar associated with industry best practice use of cup anemometers. DNV therefore considers for such conditions the LiDAR device may be considered to be proven for use in the assessment of wind farm sites for the purpose of wind farm development. Provided that the unit is tested and validated in such a way that its performance can be traced back to a reliable reference, it is expected that its measurement error bars would be similar to those assigned to high-quality calibrated mechanical anemometers.

The validation data sets provided demonstrate that the LiDARs are capable of adding value to wind farm developments with project finance requirements in non-complex terrain and offshore conditions if further conditions are met. The measurement campaign at the Azalea B platform site described above has been performed in offshore conditions that are suitable for remote sensing measurement techniques. Care is however required before data from remote sensing devices are relied upon for use in such analyses. In order to increase the confidence in the ability of LiDAR systems to measure valid data for the wind industry, it's important that the system is able to perform at a high standard measurement quality: DNV expects that the requirement of the IEC 61400-12-1 (Ed.2, FDIS, Annex L) /5/ and/or EU-FP7 Project NORSEWInD standard /6/, /7/are used to define acceptance level of performance for LiDAR systems. Therefore, DNV considers that an independent verification of the device against a conventional tall meteorological mast should be completed before deployment in the field and possibly after deployment. The test mast should be equipped with high quality, traceable and calibrated anemometry.

3.1.2 Azalea LiDAR

Raw data from the fixed LiDAR have been provided by the Customer. All information with regard to the installation height of the LiDAR with respect to the sea level has been assumed from documents supplied by the Customer. It has not been possible for DNV to independently verify this information. Therefore, DNV has relied upon its experience and the consistency of the information supplied by the Customer within this analysis and assumed that the installation height is 27 m above the sea level. Moreover, no pre-deployment validation report was provided to DNV and this additional uncertainty was considered during the analysis.

No directional offset has been observed in the LiDAR measurement data.

The wind data from the LiDAR have been recorded using the device internal logger. The data logger has been programmed to record, at ten-minute intervals, mean, standard deviation and maximum wind speed and mean wind direction at the heights as specified in Table 3-2.

Table 3-2 Measurement undertaken at the Azalea fixed LiDAR

Azalea fixed LiDAR Coordinates (317773.89, 4892855.16)[1] Measurement period: from November 2012 to December 2014	
Configured heights (as configured in the unit)	**Height above Mean Sea Level**
[m]	**[m MSL]**
10	37
20	47
30	57
38	65
40	67
50	77
60	87
70	97
80	107
90	117
100	127

1. Coordinate System is UTM Zone 33 with WGS84 Datum.

Since a suspicious behaviour of the measurement height of 80 m (WS80) was found in the first part of the measurement campaign (before the LiDAR maintenance), it was decided to exclude this height from the analysis. DNV recommends to the Costumer to further investigate this behaviour in order to decrease the measurement uncertainty of the analysis.

The findings on the measurement campaign have been considered in the uncertainty analysis, as described in Section 3.3.

3.2 Wind data quality control and processing

The wind data recorded by the LiDAR has been subject to a quality checking procedure by DNV to identify records which were affected by device malfunction and other anomalies. These records were excluded from the analysis.

DNV has only considered the horizontal component of the wind speed recorded by the fixed LiDAR. This is assumed to be generally representative of the behaviour of a modern cup anemometer. DNV has not considered the vertical wind speed in this analysis other than for filtering purposes.

3.2.1 Automated filters

First to improve the quality of data at each of the specified range gates, the raw data were filtered based on the following exclusion criteria for all the LIDARs units:

- Available data 80 % and lower within a 10-minute bin;
- Carrier to Noise Ratio (CNR) less than -22dB;
- Absolute vertical wind speed greater than 2.0 m/s;
- Vertical wind speed check: data are removed where vertical wind speed standard deviation is greater than 2.0 m/s.

These criteria are based on DNV best practice knowledge of the LiDAR technology. In addition to these filters, some data were excluded from the analysis after identifying period of erroneous records.

3.2.2 Statistics and data coverage

The duration, basic statistics and data coverage for the LiDAR are summarised in Appendix C. Overall data coverage levels for the key parameters at heights used in this analysis are shown in Table 3-3.

Table 3-3 Summary of the Azalea LiDAR data coverage

Device	Period	Parameter	Data Coverage [%]	Valid period [yrs]
Azalea LiDAR	2012-11-29 to 2014-12-01	WS at 100 m[1]	86.4	1.9
		WD at 100 m[1]	86.4	1.9
		WS at 90 m[1]	86.9	1.9
		WD at 90 m[1]	86.9	1.9

1. Heights as per LiDAR logger configuration

As reported in Table above, the data coverage is below 90% which is considered to be relatively low.

3.3 Site measurement uncertainties

Table 3-4 presents the site measurement uncertainties.

Table 3-4 Site measurement uncertainties

Uncertainty category	% wind speed Azalea LiDAR
Calibration uncertainty	3.0
Classification uncertainty /8/	2.5
Mounting uncertainty	0.3
Measurement uncertainty[1]	**3.9**

1 - Wind speed uncertainties are converted to energy uncertainties using the Sensitivity Ratio, as detailed in Sections 6.2 and 6.3.

Appendix E-9 provides a discussion of typical site measurement uncertainties and how they are determined. Site specific aspects of the values in Table 3-4 are as follows:

- The calibration uncertainty is based on the validation of the measurement campaign with a met mast. Since no information on the validation of Azalea LiDAR were provided, DNV standard uncertainty is 3%.
- The classification uncertainty is related to the typology of LiDAR, which is the same for all Zephir models.
- The mounting uncertainty depends on the documentation provided about the installation and the complexity of the site.

4 WIND ANALYSIS

The analysis of the wind regime at the Rimini Offshore Wind Farm site involved several steps, which are summarised below:

- Missing wind speed and direction data at the Lidar at 117 m MSL were synthesised from wind speed and direction data at the lower measurement heights.
- MERRA-2 /9/ and ERA-5 /10/ reanalysis data were correlated to the measured data at the Azalea LiDAR. Considering the quality of the correlations and representativeness of the series, DNV considered ERA-5 reanalysis data to be the most suitable source to derive the long-term mean wind speed at the site for the period from January 2000 to June 2022.
- Measured data at the LiDAR were used to derive boundary layer power law wind shear exponent. This shear estimate was used to extrapolate the long-term wind speed frequency distributions up to the proposed hub height on a time-series basis.
- Mesoscale modelling was carried out to determine the hub height wind speed variations between the Azalea LiDAR location and the Rimini Offshore Wind Farm turbine locations.

Appendix E summarises the wind data analysis process and the results for each step of the process are provided in the following sections.

4.1 Measurement height wind regime

4.1.1 Site period wind speeds

As noted in Section 3.1, data were recorded at Rimini Offshore site from November 2012 to December 2014 at the fixed Azalea LiDAR.

The site period annual average wind speed is shown in Table 4-1.

Table 4-1 Site period wind speed

LiDAR	Height [m]	Measured wind speed [m/s]
Azalea LiDAR	117	5.5

4.1.2 Extension of the site period to the reference period

The inclusion of quality reference data can reduce uncertainty when estimating the long-term wind regime at the site. When selecting appropriate reference data for this purpose, it is important that the wind regime for the reference data is driven by similar factors as the site wind regime and that the reference data are consistent over the period being considered.

This section describes the historical wind data or modelled data that are available for this region. These data are often available through public sources and are typically collected at meteorological stations or derived from weather prediction models. The on-site measurements, which are a critical part of the analysis, are discussed in Section 3.

4.1.2.1 Reference data considered

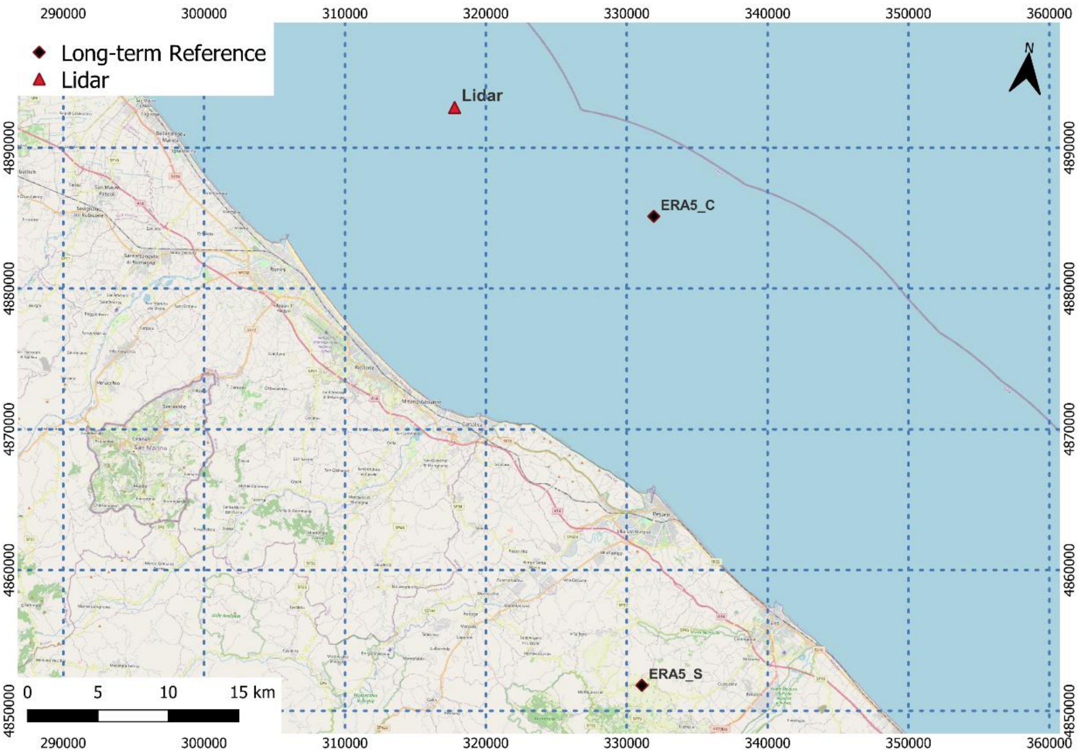
DNV has undertaken a review of MERRA-2 and ERA5 reanalysis data in order to identify appropriate long-term reference sources for this analysis.

Table 4-2 summarises the reference data considered, whilst Figure 4-1 shows the locations.

Table 4-2 Reference data sets considered for correlation to site data

Meteorological data source	Consistency dates
ERA5_C (N44.1, E12.9)	From 01/2000 to 06/2022
ERA5_S (N43.8, E12.9)	From 01/2000 to 06/2022

Figure 4-1 Location of the proposed Rimini Offshore Wind Farm site and reference sources



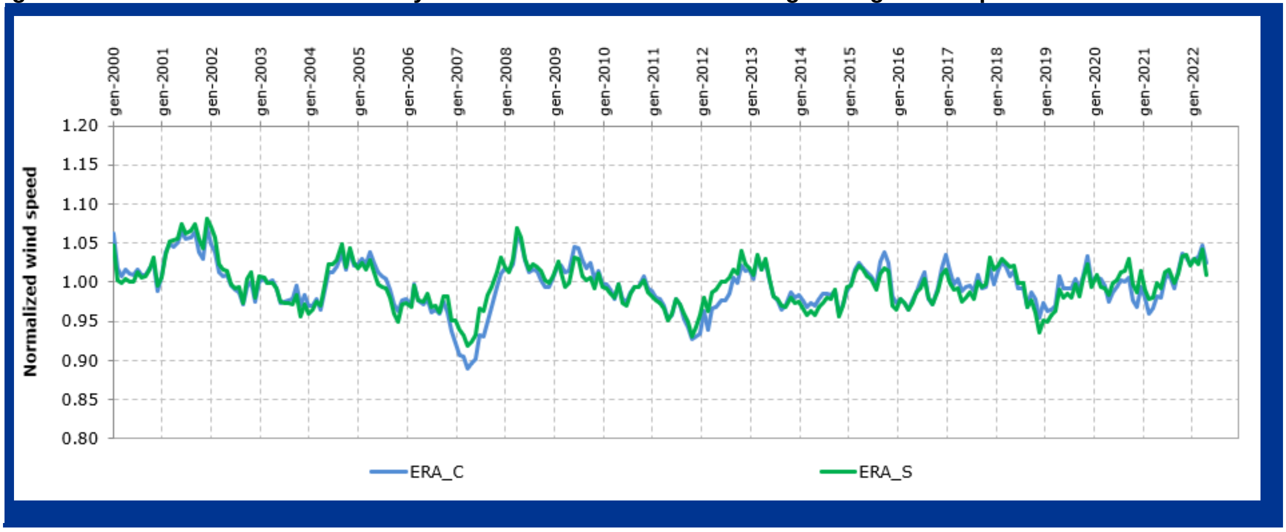
Note 1 – DNV has analysed the 9 closest MERRA-2 and ERA-5 grids to the site. The image shows only the nodes that presented the best correlation with the site data.

Further information regarding long-term reference data sources typically used by DNV is included in Appendix C. A review of the suitability and use of these sources of data reference in the analysis is provided below.

4.1.2.2 Reference data consistency

The consistency of each source of reference data was evaluated through a comparison with the regional trends. Figure 4-2 shows a plot of wind speed for each of the reference data sources.

Figure 4-2 Reference data seasonally – normalised 12 months moving average wind speeds



The following comments are made:

- ERA5 Reanalysis data were generally considered consistent since 2000 as explained in Appendix C.
- The relative trend of the wind data revealed no special reason of concern for Reanalysis data.

All reference data appear generally suitable for consideration as long-term references in the analysis and have been correlated to the site data as reported in Section 4.1.2.3.

4.1.2.3 Long-term wind extrapolation

To determine whether or not using the reference data will reduce uncertainty, correlations between the various sources of long-term reference data and the wind data recorded at Azalea LiDAR have been conducted on a monthly basis, resulting in the following correlation coefficient R^2 and adjustments, summarised in Table 4-3.

Table 4-3 Summary of correlations to site data

Long-term reference source	Correlation points	Correlation coefficient R^2	Period considered	Wind speed adjustment [%]
ERA5_C (N44.1, E12.9)	18	0.87	01/2000 to 06/2022	102.4
ERA5_S (N43.8, E12.9)	18	0.87	01/2000 to 06/2022	102.8

Having considered the merits of each of the above sources of reference data, DNV considers that the method with the lowest uncertainty at Azalea LiDAR is the averaging of all MERRA-2 and ERA5 datasets with R^2 higher that 0.85, resulting in an average adjustment of 102.6%.

The resulting estimated measurement height wind speed at the measurement location is shown in Table 4-4.

Table 4-4 Estimated measurement height long-term wind speeds

LiDAR	Height [m]	Measured wind speed [m/s]	Combined measured, synthesized and long-term period	Number of years of measured, synthesized and long-term corrected data	Long-term wind speed [m/s]
Azalea	117	5.5	01/2000 – 06/2022	22.4 years	5.7

4.1.3 Long-term wind regime uncertainties

Table 4-5 presents the uncertainties in determining the long-term measurement height wind speed for on-site measurement location.

Table 4-5 Long-term measurement height wind regime uncertainties

Uncertainty category	Uncertainty sub-category	Uncertainty [% wind speed] [2]
		LiDAR Azalea
Long-term measurement height wind regime	On-site Data Synthesis	0.0
	Variability of reference period	1.2
	Correlation to reference station	2.7
	Consistency of reference data	1.8
	Wind frequency distribution - past[1]	1.5

1 - Expressed as percentage of energy, not wind speed.
2 - Wind speed uncertainties are converted into energy uncertainties using the Sensitivity Ratio, as detailed in Sections 6.2 and 6.3.

Appendix E provides a discussion of uncertainties and how these are determined.

4.2 Hub-height wind regime

4.2.1.1 Hub height wind speed and direction distributions

DNV considers the lowest uncertainty methodology is to use the time series measured shear exponents values to interpolate wind speed values from the measured LiDAR height of 117 m MSL to the proposed hub height of 111 m MSL.

To interpolate the wind speed estimates from the measurement height to the proposed hub height, the time series shear analysis at the Azalea LiDAR has been evaluated between the measurement levels from 57 m MSL to 117 m MSL, and applied to the 117 m MSL level measurements at the LiDAR, as described in Appendix E.

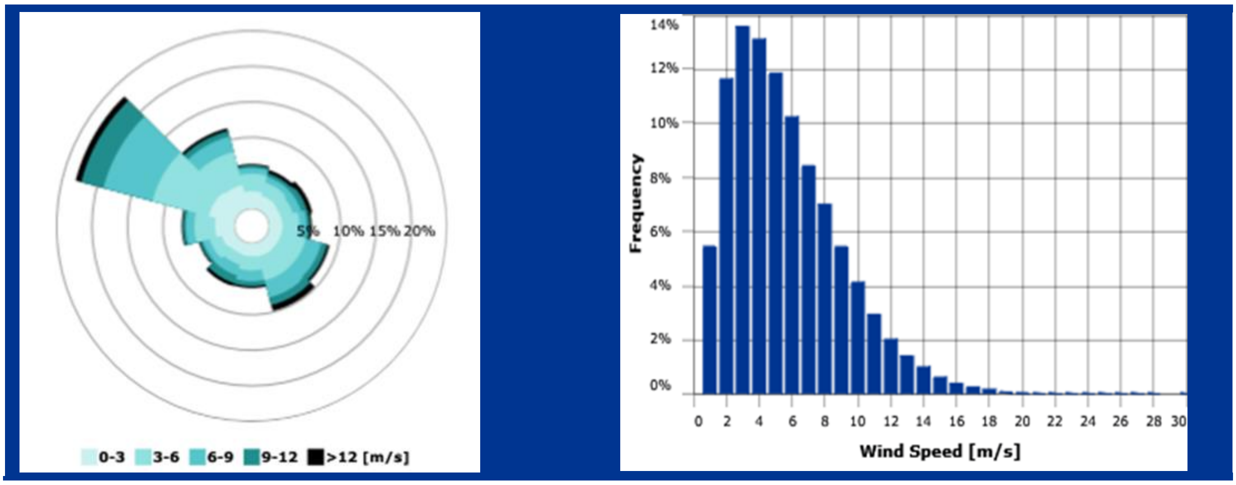
The long-term wind speed and direction frequency distribution derived at 117 m MSL at Azalea LiDAR has therefore been scaled to the predicted long-term hub height wind speeds, based on the time series shear method.

Table 4-6 Shear exponents and hub height wind speeds

LiDAR	Long-term measurement height wind speed [m/s]	Measured wind shear exponent	Wind speed at 111 m MSL [m/s]
Azalea LiDAR	5.7	0.03	5.6

Representative long-term hub-height wind rose and wind speed histogram for Azalea LiDAR at 111 m are shown in Figure 4-3.

Figure 4-3 Azalea LiDAR long-term hub-height frequency distribution and wind rose at 111 m MSL



4.2.2 Vertical extrapolation uncertainties

Table 4-7 presents the vertical extrapolation uncertainties estimated for the site. Appendix E provides a discussion of vertical extrapolation uncertainties and how these are determined.

Table 4-7 Vertical extrapolation uncertainties

Uncertainty category	Hub height [m MSL]	Azalea LiDAR [% wind speed]
Vertical extrapolation[1]	111	0.2

1 -Wind speed uncertainties are converted into energy uncertainties using the Sensitivity Ratio, as detailed in Sections 6.2 and 6.3.

4.3 Measured turbulence intensity

Turbulence intensity (TI) was calculated as the ratio of the wind speed standard deviation to the wind speed. TI is used in modelling wake and turbine performance-related losses and it informs turbine site suitability studies.

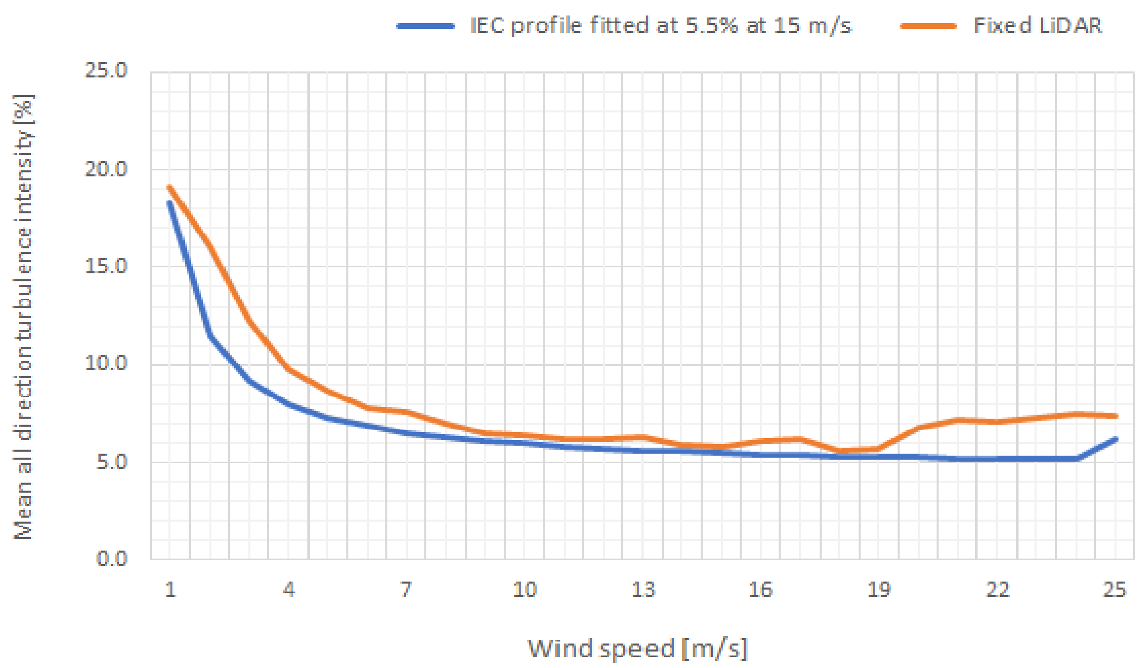
It should be noted that the turbulence measured by LiDAR devices are still subject to uncertainties due to the lack of validation. For this analysis, DNV has therefore considered an assumed TI based on the IEC profile with a value of 5.5 % at 15 m/s which is expected to be representative of the offshore conditions at the site. It is therefore recommended the results of this assessment are considered with suitable safety factors.

Table 4-8 Average ambient turbulence intensity at 15 m/s

LiDAR	Hub height [m]	Ambient TI [%]
Azalea	111	5.5

Figure 4-4 shows the variation in TI with wind speed for Azalea LiDAR, which is typical for an offshore site. DNV was not able to verify if the TI of the site is in the range of values or which the turbine power curve has been specified.

Figure 4-4 Turbulence intensity by wind speed at 111 m MSL



4.4 Wind regime across the site

4.4.1 Wind flow modelling

The large extent of the Rimini Offshore site requires careful consideration in the wind flow modelling. Wind speeds predicted may vary from the LiDAR location to the Rimini Offshore Wind Farm turbine locations and the prediction of the variation in wind speed over the wind farm is challenging.

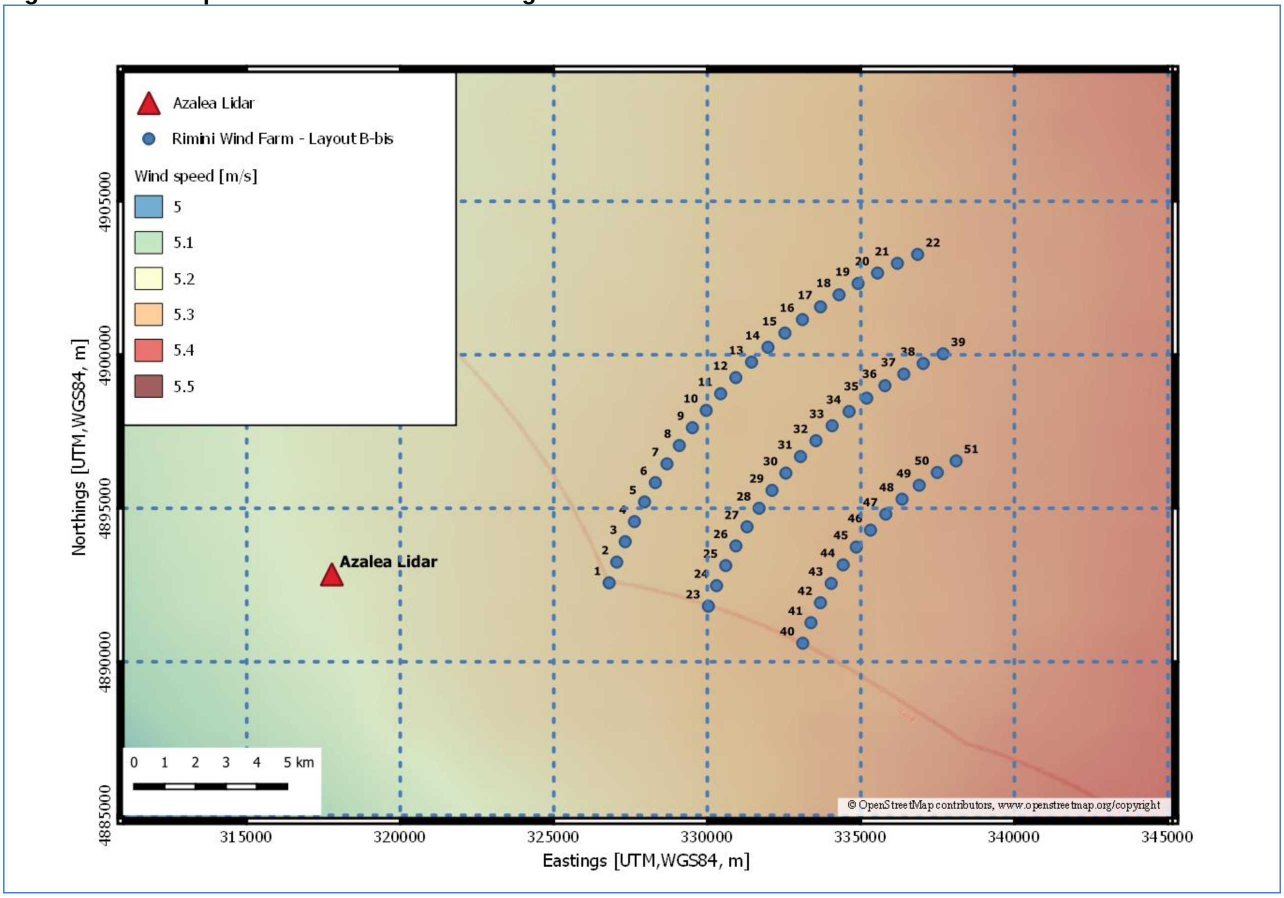
The variation in wind speed over the region of the wind farm site has been predicted using the Vortex FARM© mesoscale computational model /11/ at 100 m horizontal resolution and 110 m height.

The Vortex FARM has been utilised to assess the horizontal variation in mean wind resource between the location of the LiDAR and the Rimini Offshore Wind Farm turbines. These variations are expressed in terms of a ratio between the long-term wind speeds at the turbines and the LiDAR location.

The horizontal adjustments were done on a per-turbine basis to capture the variation in wind resource within the wind farm site. The long-term mean wind speeds at the proposed hub height are summarised in Section 4.2 and are displayed in Figure 4-5. The adjustments and results for the turbines are also further given in Appendix D.

The assessment of the horizontal variation of the wind speed reveals that the predicted long-term mean wind speed at the LiDAR should be adjusted by factors varying between approximately: 101.5% at the southwest corner of the site (Turbine WTG01) to 102.7% at the east corner of the site (Turbine WTG51).

Figure 4-5 Wind speed variation across the region and site area



Note 1 – Wind speed variation based on Vortex Map

The predicted long-term mean wind speeds at each turbine, at the proposed hub height, are shown in Appendix D.

4.4.2 Spatial variation uncertainties

DNV's methods for estimating spatial variation uncertainties are included in Appendix E and Table 4-9 quantifies this uncertainty for the Rimini Offshore project, given the following considerations:

- The Azalea LiDAR is representative of all turbines in terms of elevation and exposure.

Table 4-9 Spatial extrapolation uncertainties

Uncertainty category	Uncertainty subcategory	[% wind speed]
Spatial extrapolation[1]	Model inputs	1.6
	Horizontal extrapolation	1.6

1 - Wind speed uncertainties are converted into energy uncertainties using the Sensitivity Ratio, as detailed in Section 6.2.

5 LONG-TERM ENERGY PRODUCTION PREDICTION

5.1 Gross and net energy production estimate

The gross energy production at the individual turbine locations has been calculated using the WindFarmer software /12/ using the association method and the results of the wind flow modelling, together with the turbine power curve, in accordance with the methodology in Appendix E. Table 5-1-1 and Table 5-1-2 provide the aggregated results for the project.

The projected net energy production of the wind farm, shown in Table 5-1, was calculated by applying a number of energy loss factors to the gross energy production. The predictions represent the estimate of the annual production expected over the first 10 years of operation.

Wind farms typically experience some time dependency in availability and other loss factors. A detailed definition of loss factors is included in Appendix E. Table 5-1include potential sources of energy loss that have been either assumed to be the DNV standard values or estimated for this project. The background and general basis for all loss estimates is provided in Appendix E and Table 5-2.

Table 5-1 Energy production summary

Configuration		Layout B-bis	
Wind Farm Rated Power		**328.95**	MW
Gross Energy Output		**865.9**	GWh/annum
1	**Turbine interaction effects**	**89.2**	**%**
1a	Internal wake and blockage	89.2	% Project Specific
1b	Wake effect external	100.0	% Project Specific
1c	Future wake effect	100.0	% Not considered
2	**Availability**	**96.5**	**%**
2a	Turbine availability	97.5	% Project Specific
2b	Balance of Plant availability	99.0	% DNV Standard
2c	Grid availability	100.0	% DNV Standard
3	**Electrical efficiency**	**97.5**	**%**
3a	Operational electrical efficiency	97.5	% Project Specific
3b	Wind farm consumption	100.0	% Not considered
4	**Turbine Performance**	**98.2**	**%**
4a	Power curve adjustment	100.0	% Project Specific
4b	High wind speed hysteresis	99.9	% Project Specific
4c	Site specific power curve adjustment	99.3	% Project Specific
4d	Sub-optimal performance	99.5	% DNV Standard
4e	Turbine drivetrain degradation	99.5	% DNV Standard
5	**Environmental**	**100.0**	**%**
5a	Performance degradation – icing	100.0	% Project Specific
5b	Icing Shutdown	100.0	% Project Specific
5c	Temperature shutdown	100.0	% Project Specific
5d	Site access	100.0	% Not considered
6	**Curtailments**	**100.0**	**%**
6a	Wind sector management	100.0	% Not considered
6b	Grid curtailment	100.0	% Not considered
6c	Noise, visual and environmental curtailment	100.0	% Not considered
	Total Losses	**82.1**	**%**
	Effect of asymmetric distributions	99.7	%
	Net Energy Output	**711.2**	**GWh/annum**
	Net Equivalent Hours	**2160**	**Hours**

The table above includes potential sources of energy loss that have been calculated, estimated, assumed or not considered within the scope of this work. The background and general basis for all loss estimates is provided in Appendix E-8. Project-specific aspects of the loss estimates made for the analysis here which are not included in the appendix are summarised in the following table. It is recommended that these loss factors be reviewed and considered carefully.

Table 5-2 Rationale for energy loss factors

Loss	Assumption for this analysis and rationale
1	**Wake effect**
1a	*The wake effects have been calculated using the DNV WindFarmer: Analyst Eddy Viscosity large wind farm wake model. The turbine interaction blockage effect has been estimated using an empirical model based on more than 50 CFD simulations /13/.*
1b	*No neighbouring operational wind farms have been identified.*
1c	*Upon request of the Customer, wind farms under development in the vicinity of the project have not been considered.*
2	**Availability** The availability loss factors presented here include turbine, balance of plant (BoP) and grid losses, and they have been applied on a project specific basis, taking into account the track record of the turbines under consideration. The details of the track record of the local grid system, and Operation and Maintenance arrangements have not been assessed. No detailed project specific engineering review has been undertaken, and these assumptions may change as part of such a review. This work is normally undertaken as part of a full due diligence exercise, although DNV can complete these reviews at an earlier stage of the project, if required. Project specifics for the availability values are detailed below. Terms are defined in the DNV white paper /14/
2a	*A turbine availability level of 97.5 % has been assumed as the annual average turbine availability over the first 10 years of operation. A detailed availability table can be found in Appendix D-2*
2b	*A BOP availability of 99.0 % has been assumed.*
2c	*A grid availability of 100.0 % has been assumed.*
3	**Electrical efficiency** The details of the specific balance of plant infrastructure and grid connection point have not been considered. The assumptions below would be subject to change, were a detailed assessment of the electrical infrastructure to be undertaken:
3a	*An electrical efficiency of 97.5 % has been assumed, considering one metering point, one stage of electrical transformation at the turbine before the metering point with an offshore substation.*
3b	*It is assumed that non-operational plant electrical consumption is an operational cost and not a loss factor.*
4	**Turbine performance** The power curves assumptions made here would be subject to change, were a thorough review of the Turbine Supply Agreement and supporting contract documentation to be undertaken
4a	*No generic adjustment to the power curve has been made.*
4b	*It has been assumed that the High Wind Speed Hysteresis effectively reduces the cut-out wind speed from 25 m/s to 21.5 m/s for the MySE6.45, between the actual turbine cut-out and re cut-in wind speed.*
4c	*Site-specific wind flow issues (atmospheric stability, turbulence, wind shear, and upflow angle) will adversely affect the performance of the turbines /15/. This loss factor also accounts for the average blockage effect inherent on power performance test measurements /11/. A loss factor of 99.3% was used to account for the individual blockage correction.*
4d	*A factor of 99.5 % has been assumed to account for sub-optimal performance.*
4e	*The performance of wind turbines can be affected by degradation of blades and other components. This includes the accretion of dirt, which may be washed off by rain from time to time, as well as physical degradation of the blade surface, such as leading-edge erosion, and other components, over prolonged operation. This is a time dependent phenomenon which DNV models as increasing linearly at a rate of 0.1% per year for 20 years, resulting in an average of 1% loss over 20 years. In harsh climates these values are increased by 0.3%.*
5	**Environmental**
5a	*It has been assumed that there will be no loss due to the effect of performance degradation due to ice accretion on the blades when the turbine is operational.*
5b	*It has been assumed that there will be no loss due to the energy effect of downtime due to ice accretion on the turbine causing the turbine to shut down or not to start.*
5c	*It has been assumed that there will be no energy loss from high temperature or low temperature shutdown.*
5d	*Site access due to the project being located offshore is accounted for as part of loss 2a – Availability.*
6	**Curtailments**
6a	*The possibility of wind sector management has not been considered.*
6b	*The possibility of grid curtailment has not been considered.*
6c	*The possibility of noise, visual or environmental curtailment has not been considered.*
	Asymmetric production effect *The effect of changes in wind speed has an asymmetric impact on project production, considering the non-linear relationship of wind speed to energy. Therefore, when wind speed variability risk is converted into production risk the resulting distribution is asymmetric, with a P50 (median) value that is less than the average.*

Individual turbine energy results are presented in Appendix D.

5.2 Uncertainty in loss factors

DNV's methods for estimating loss factor uncertainties are included in Appendix E-9. These uncertainties are quantified in the following tables for the project:

Table 5-3-1 Loss factor uncertainties for

Uncertainty category	Uncertainty subcategory	[% Energy]	
		Layout B-bis	
Loss factors	Turbine Interaction	3.0	
	Availability	2.8	
	Electrical	0.6	
	Turbine performance	3.3	
	Environmental	0.0	
	Curtailment	0.0	

It is recommended that each of the above uncertainties are considered carefully. They can often be mitigated to some extent, especially in early years of the project, through appropriate warranty provisions. Therefore, these uncertainties should be considered in detail in combination with these provisions, for instance as part of a full technical due diligence exercise.

6 UNCERTAINTY ANALYSIS

The main sources of deviation from the central estimate (P50) have been quantified using procedures described in Appendix E. These sources of uncertainty have been combined using a probabilistic model (the Monte Carlo uncertainty model) and assuming full independence between the sources.

The Monte Carlo uncertainty approach is a computational algorithm which relies on repeated random sampling to obtain numerical results; typically, one runs simulations many times over in order to obtain the distribution of an unknown probabilistic entity. In engineering-related problems, the Monte Carlo methods are widely used for sensitivity analysis.

6.1 Inter-annual variability

Even if the central estimate is perfectly defined, wind farm energy production varies from year-to-year due to a number of factors, including natural variation in the wind regime, variations in system availability, and variations in environmental losses. Appendix E provides a discussion of typical future wind speed variability, and how it is determined. Table 6-1 presents the inter-annual variability estimated for the site.

Table 6-1 Inter-annual variability

Uncertainty category	Uncertainty subcategory	%	Unit
Inter-annual variability	Wind frequency distribution - future	2.0	Energy
	Inter-annual variability of wind speed	5.5	Wind speed
	Environmental losses variability	0.0	Energy

6.2 Converting wind speed uncertainties to energy uncertainties

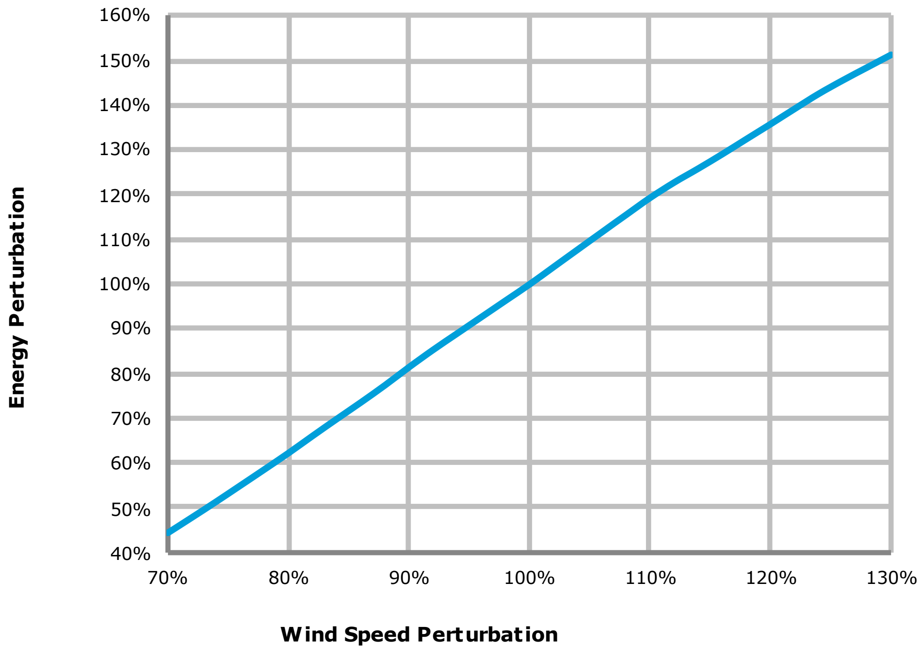
Uncertainties in estimating the site wind speed have been described in this report, above. Wind speed uncertainties are converted into energy uncertainties, using the Sensitivity Ratio. The Sensitivity Ratio shows how sensitive the net energy production is to changes in wind speed, and that it is dependent mainly on the wind speed distribution and power curve of the turbine. For example, with a sensitivity ratio of 1.50, a 2.0% reduction in wind speed would lead to a 3.0% reduction in net energy production. The Sensitivity Ratio is non-linear over large ranges of wind speed, which has been accounted for in this analysis as shown in the following exemplary graphs for Mingyang MySE6.45.

The average calculated sensitivity ratios for the Rimini project, for variations of up to 10 % in wind speed, is reported in Table 6-2.

Table 6-2 Average site sensitivity ratio

Configuration	Turbine model	Sensitivity Ratio
Layout B-bis	MySE6.45	1.90

Figure 6-1-1 Sensitivity Ratio shown for MySE6.45



6.3 Project uncertainties

A summary of the project uncertainties considered as part of this analysis is shown in Table 6-3. Differences between the P50 values for different averaging and sampling periods result from both time dependent losses and non-linearity in the inter-annual variation. Consideration of time dependent losses results in different mean losses over one exemplary year or the first 10 years, for example, and lead to differing P50 expectations for different averaging periods. Consideration of non-linearity in the inter-annual variation, both in the form of a non-linear Sensitivity Curve and a non-normal availability distribution, results in an asymmetric expected production curve; the asymmetry in this curve is decreased when the sampling period is increased (for example, considering the 10-year average versus the 1-year average).

Table 6-3 Uncertainty in the projected energy output for Layout B-bis

Source of uncertainty/variability	[GWh/annum]		Equivalent standard deviation [%]	
Measurement	51.9		7.3	
Long-term measurement height wind regime	46.1		6.5	
Vertical extrapolation	2.0		0.3	
Spatial extrapolation	29.4		4.1	
Loss factors	37.8		5.3	
Inter-annual variability	73.1		10.3	
Future period under consideration	*1 year*	*10 years*	*1 year*	*10 years*
Overall energy uncertainty	**114.2**	**87.1**	**16.1**	**12.2**

It is noted that the asymmetric production effect as described in Appendix E and time-dependent variations of loss factors cause discrepancies between the short-term and the long-term annual energy production.

7 CONCLUSIONS AND RECOMMENDATIONS

DNV makes the following observations and recommendations regarding this analysis:

1. There are a number of losses and uncertainties, either for which DNV's standard assumptions have been made at this stage as detailed in Appendix E, or for which an analysis was outside of DNV's scope of work. These include:
    a. Availability
    b. Electrical line losses
    c. Curtailment

    It is recommended that the Customer considers these points carefully. DNV recommends that these losses be calculated or reviewed by an independent third-party to confirm the figures used in this analysis. The availability assumptions may vary materially and can often be mitigated to some extent, especially in the early years of a project, through appropriate contractual provisions.
2. DNV notes the following observations and opinions regarding uncertainty:
    a. Uncertainty in the analysis is driven by wind inter-annual variability
    b. There are a number of uncertainties for which only pragmatic assumptions have been made at this state. It is recommended that the Customer consider each of these uncertainties carefully. They can often be mitigated to some extent, especially in early years of the project, through appropriate warranty provisions. Therefore, these uncertainties should be considered in combination with these provisions, for instance as part of a full technical due diligence exercise.
    c. No pre-deployment or post-deployment validation campaign report for the Azelea LiDAR was provided by the Customer to DNV, resulting in an increasing of measurement uncertainties.
3. Measured power curves from independent tests of the performance of the turbine have not been supplied; therefore, DNV has been unable to verify that the power performance levels provided by the turbine manufacturer are attainable. It is recommended that independently measured power curves for the specific turbine model proposed for the site are obtained, in order to confirm the performance levels supplied.
4. It should be noted that the turbulence measured by LiDAR devices are still subject to uncertainties due to the lack of validation. For this analysis, DNV has therefore considered an assumed TI based on the IEC profile with a value of 5.5 % at 15 m/s which is expected to represent the offshore conditions at the site. It is therefore recommended the results of this assessment are considered with suitable safety factors.
5. A Vortex FARM has been utilised to assess the horizontal variation in mean wind resource between the location of the Azalea LiDAR and the Rimini Offshore Wind Farm turbines.
6. It is noted that no future neighbouring wind farms have been considered in the analysis herein. The current assessment should be updated if any proposed neighbouring wind farms are confirmed.

8 REFERENCES

/1/ DNV, “Energy Assessment Report – Rimini Offshore Wind Farm site”, ref. L220416-ITIM-R-01-B, dated 2022-09-27

/2/ E-mail from Daniela Moderini, Energia Wind 2020, to Jacopo Antonelli, DNV, on 2023-02-07.

/3/ E-mails from Gabriele Felappi, Energia Wind 2020, to Lorenzo Cantoni and Alice Vergnani, DNV

/4/ “Annex 2 – Technical Specification of MySE6.45 - 180”, ref. M0000016045, dated 2019-08-23

/5/ IEC 61400-12-1:2005(E), “Wind turbines - Part 12-1: Power performance measurements of electricity producing wind turbines”.

/6/ Carbon Trust, “Carbon Trust Offshore Wind Accelerator Roadmap for the Commercial Acceptance of Floating LIDAR Technology”, Version 2.0, 2018-10-09

/7/ Kindler, D., "Best Practice Test and Verification Procedure for Wind Lidars on the Høvsøre Test Site”, GL GH-D Report WT 6960/09 for EU-Project NORSEWInD, Deliv. 1.1, June 2009

/8/ Rafael T. “Remote Sensing Device Type-specific Classification Summary”, DNV, November 2018

/9/ National Aeronautics and Space Administration, MERRA-2, MDISC website: http://disc.sci.gsfc.nasa.gov/mdisc/, MERRA-2 tavg1_2d_slv_Nx: 2d,1-Hourly,Time-Averaged,Single-Level,Assimilation,Single-Level Diagnostics V5.12.4 (M2T1NXSLV), 1980-present.

/10/ The European Centre for Medium-Range Weather Forecasts (ECMWF); ERA 5; website at https://www.ecmwf.int/en/forecasts/datasets/archive-datasets/reanalysis-datasets/era5

/11/ Vortex FARM validation and description, available at: https://vortexfdc.com/knowledge/vortex-farmremodelled-validation/

/12/ Garrad Hassan and Partners Ltd, “WindFarmer Theory Manual”, January 2011.

/13/ Bleeg. J et al, “Wind Farm Blockage and the Consequences of Neglecting Its Impact on Energy Production”, June 2018.

/14/ DNV White Paper, “Definitions of Availability Terms for the Wind Industry”, Document No. EAA-WP-15, issue A, dated 9 August 2017.

/15/ Geer, T. “How well are we predicting turbine performance”, DNV, EWEA, November 2015.

APPENDIX A - WIND FARM SITE INFORMATION

Table A-1 Turbine coordinates of Rimini Offshore Wind Farm - Layout B-bis

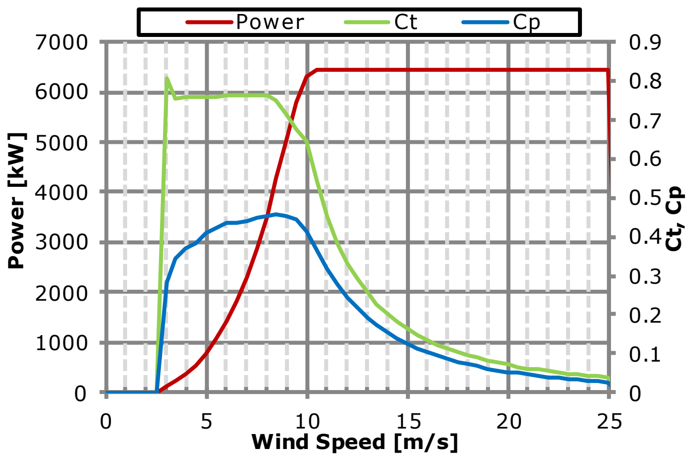
Turbine	Easting[1] [m]	Northing[1] [m]	Turbine	Easting[1] [m]	Northing[1] [m]
WTG01	326801	4892577	WTG27	331292	4894402
WTG02	327049	4893253	WTG28	331685	4895006
WTG03	327324	4893918	WTG29	332107	4895589
WTG04	327626	4894572	WTG30	332557	4896152
WTG05	327954	4895213	WTG31	333034	4896691
WTG06	328307	4895841	WTG32	333537	4897206
WTG07	328685	4896453	WTG33	334065	4897695
WTG08	329087	4897051	WTG34	334616	4898158
WTG09	329513	4897631	WTG35	335190	4898593
WTG10	329962	4898194	WTG36	335784	4899000
WTG11	330434	4898738	WTG37	336398	4899376
WTG12	330927	4899263	WTG38	337029	4899722
WTG13	331440	4899767	WTG39	337677	4900037
WTG14	331974	4900251	WTG40	333106	4890610
WTG15	332526	4900712	WTG41	333374	4891279
WTG16	333097	4901152	WTG42	333683	4891929
WTG17	333685	4901567	WTG43	334033	4892558
WTG18	334289	4901959	WTG44	334423	4893163
WTG19	334908	4902326	WTG45	334850	4893743
WTG20	335542	4902668	WTG46	335314	4894294
WTG21	336189	4902984	WTG47	335811	4894814
WTG22	336848	4903274	WTG48	336341	4895302
WTG23	330034	4891817	WTG49	336901	4895755
WTG24	330300	4892486	WTG50	337488	4896171
WTG25	330599	4893141	WTG51	338101	4896549
WTG26	330930	4893780			

1 - Coordinate system is UTM, Zone 33, WGS84 datum

APPENDIX B WIND TURBINE DATA

Table B-1 Turbine data for Mingyang MySE6.45

Manufacturer	Mingyang	Hub height wind speed [m/s]	Electrical power [kW]	Thrust coefficient [-]
Turbine	MySE6.45 -180	1	0.0	0.000
Power control	Pitch	2	0.0	0.000
Rated power	6450 kW	3	117.0	0.807
Diameter	178 m	4	360.0	0.758
Hub height	111 m	5	779.0	0.761
Rotor speed	Unknown	6	1431.0	0.762
Air density	1.225 kg/m3	7	2311.0	0.762
Turbulence intensity	14%	8	3539.0	0.762
Peak Cp	0.46	9	5011.0	0.713
Cut-out 10-minute mean wind speed	25 m/s	10	6320.0	0.645
Restart 10-minute mean wind speed	21.5 m/s	11	6450.0	0.452
		12	6450.0	0.332
		13	6450.0	0.255
		14	6450.0	0.202
		15	6450.0	0.164
		16	6450.0	0.135
		17	6450.0	0.113
		18	6450.0	0.096
		19	6450.0	0.082
		20	6450.0	0.071
		21	6450.0	0.062
		22	6450.0	0.055
		23	6450.0	0.049
		24	6450.0	0.043
		25	6450.0	0.039



Source: /2/

APPENDIX C WIND DATA

C-1 Azalea LiDAR

C-2 Reference wind data

C-1 Azalea LiDAR

Table C-1 Azalea LiDAR data statistics (Mean Wind Speed [m/s])

Month	Mean Wind Speed [m/s]										
	100 m [1]	90 m [1]	80 m [1]	70 m [1]	60 m [1]	50 m [1]	40 m [1]	38 m [1]	30 m [1]	20 m [1]	10 m [1]
Nov-12	6.1	6.1	4.9	6.1	6.1	6.0	6.0	6.0	6.0	5.9	5.0
Dec-12	6.4	6.4	4.9	6.4	6.4	6.4	6.4	6.4	6.4	6.3	6.1
Jan-13	5.8	5.8	4.5	5.7	5.7	5.7	5.7	5.7	5.7	5.6	5.4
Feb-13	7.2	7.2	5.8	7.1	7.1	7.1	7.1	7.1	7.1	6.9	6.6
Mar-13	6.4	6.4	5.4	6.3	6.2	6.2	6.1	6.1	6.0	5.9	5.2
Apr-13	5.6	5.5	4.8	5.5	5.5	5.4	5.4	5.4	5.3	5.2	4.5
May-13	6.0	6.0	5.0	6.0	5.9	5.9	5.9	5.9	5.8	5.7	5.1
Jun-13	4.3	4.4	3.7	4.4	4.4	4.4	4.4	4.4	4.4	4.3	3.9
Jul-13	4.3	4.3	3.7	4.3	4.3	4.3	4.3	4.3	4.3	4.2	3.9
Aug-13	4.7	4.7	4.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.3
Sep-13	4.5	4.5	3.7	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.0
Oct-13	6.3	6.3	5.0	6.3	6.3	6.3	6.3	6.3	6.3	6.2	5.8
Nov-13	5.5	5.5	5.6	5.6	5.6	5.6	5.7	5.7	5.7	5.6	5.3
Dec-13	6.2	6.2	6.1	6.1	6.0	5.9	5.7	5.7	5.7	5.6	5.0
Jan-14	5.8	5.8	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.5	4.6
Feb-14	6.1	6.1	6.0	6.0	5.9	5.9	5.8	5.8	5.8	5.7	5.0
Mar-14	6.2	6.2	6.1	6.1	6.0	6.0	5.9	5.9	5.8	5.7	5.3
Apr-14	5.6	5.6	5.6	5.6	5.5	5.5	5.5	5.4	5.4	5.3	4.7
May-14	5.9	5.9	5.8	5.8	5.8	5.8	5.7	5.7	5.7	5.6	5.1
Jun-14	4.7	4.7	4.7	4.7	4.7	4.6	4.6	4.6	4.6	4.6	4.2
Jul-14	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.8	4.4
Aug-14	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.7	4.3
Sep-14	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.2	4.8

Month	Mean Wind Speed [m/s]										
	100 m [1]	90 m [1]	80 m [1]	70 m [1]	60 m [1]	50 m [1]	40 m [1]	38 m [1]	30 m [1]	20 m [1]	10 m [1]
Oct-14	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.7	5.2
Nov-14	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.3	4.3
Dec-14	9.3	8.8	8.8	8.7	8.5	8.2	7.8	7.5	7.7	7.0	2.5

1. Heights as per LiDAR logger configuration

Table C-2 Azalea LiDAR data statistics (Wind Speed and Wind Direction Data Coverage [%])

Month	Wind Speed and Wind Direction Data Coverage [%]										
	100 m [1]	90 m [1]	80 m [1]	70 m [1]	60 m [1]	50 m [1]	40 m [1]	38 m [1]	30 m [1]	20 m [1]	10 m [1]
Nov-12	79.8	80.0	79.8	79.7	79.7	79.6	79.8	79.9	80.1	79.6	69.2
Dec-12	91.5	92.4	93.6	95.0	96.5	97.4	97.3	97.7	96.7	95.8	90.2
Jan-13	93.7	94.6	95.3	96.2	97.0	97.3	97.2	97.4	97.0	96.3	88.9
Feb-13	95.5	96.0	96.2	97.0	97.6	97.8	97.6	97.7	97.1	96.6	92.4
Mar-13	94.9	95.3	95.5	95.6	95.9	96.0	96.0	96.0	95.3	95.3	81.3
Apr-13	96.4	96.6	96.5	96.5	96.2	96.5	96.4	96.6	96.0	96.3	83.0
May-13	96.7	96.9	97.1	97.0	96.9	97.0	97.2	97.2	97.2	97.9	85.6
Jun-13	99.1	99.2	99.2	99.1	99.1	99.1	99.1	99.2	99.0	99.2	91.9
Jul-13	99.4	99.4	99.3	99.4	99.3	99.3	99.2	99.2	99.1	99.4	91.8
Aug-13	99.6	99.6	99.6	99.6	99.6	99.7	99.8	99.7	99.6	99.7	93.6
Sep-13	98.8	99.1	99.3	99.2	99.2	99.1	99.0	99.1	98.8	98.9	87.9
Oct-13	50.8	50.9	51.1	51.1	51.1	51.0	51.1	51.1	51.1	50.8	45.9
Nov-13	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.6
Dec-13	83.0	83.9	84.2	84.6	85.6	89.4	93.4	94.0	93.4	91.9	85.2
Jan-14	92.7	94.4	95.0	95.8	96.6	96.8	96.7	96.8	95.9	94.3	81.1
Feb-14	91.6	93.5	94.1	94.4	95.0	95.0	94.6	95.0	93.9	93.2	78.9
Mar-14	94.7	94.7	95.3	95.5	95.9	96.3	97.0	97.1	97.8	98.0	93.2

Month	Wind Speed and Wind Direction Data Coverage [%]										
	100 m [1]	90 m [1]	80 m [1]	70 m [1]	60 m [1]	50 m [1]	40 m [1]	38 m [1]	30 m [1]	20 m [1]	10 m [1]
Apr-14	95.0	95.4	95.4	95.6	95.7	96.1	95.6	95.9	95.4	96.6	85.8
May-14	98.0	98.3	98.3	98.3	98.2	98.3	98.3	98.4	98.3	99.0	86.3
Jun-14	79.1	79.2	79.2	79.1	79.1	79.2	79.3	79.4	79.1	79.0	74.1
Jul-14	52.5	52.6	52.6	52.6	52.6	52.6	52.4	52.4	52.1	52.0	47.7
Aug-14	96.4	96.5	96.5	96.4	96.4	96.4	96.4	96.4	96.3	96.2	86.4
Sep-14	65.9	66.0	66.0	66.0	66.0	66.2	66.1	66.2	66.0	66.6	59.6
Oct-14	98.4	98.5	98.3	98.3	98.3	98.2	97.9	98.2	97.7	97.7	87.9
Nov-14	94.8	96.0	96.5	96.6	97.1	97.2	97.0	97.1	96.9	96.1	77.9
Dec-14	1.0	1.1	1.0	0.9	0.9	1.0	1.0	1.1	1.0	1.1	0.5

1. Heights as per LiDAR logger configuration

C-2 Reference wind data

C-2.1 Reanalysis data

Reanalysis data are compiled using meteorological data from a number of sources as inputs to a numerical atmospheric model to produce a description of the state of atmosphere including wind speed. DNV has some concerns over the long-term consistency of reanalysis data, and hence the long-term reference period currently considered is from January 2000 to the present.

C-2.1.1 MERRA-2 Data

The Modern Era Retrospective-analysis for Research and Applications, Version 2 (MERRA-2) data set has been produced by the National Aeronautics and Space Administration (NASA) by assimilating satellite observations with conventional land-based meteorology measurement sources using the Goddard Earth Observing System Data Assimilation System Version 5.12.4 (GEOS-5.12.4) atmospheric data assimilation system. The analysis is performed at a spatial resolution of 0.625° longitude by 0.5° latitude. MERRA-2 replaces the MERRA dataset previously produced by NASA. DNV procured hourly time series of two-dimensional diagnostic data, at a surface height of 50 m for the nine grid points nearest to the project site.

C-2.1.2 ERA-5

ERA-5 is the fifth generation of European Centre for Medium Range Weather Forecasting (ECMWF) atmospheric reanalyses of the global climate. It provides data at a considerably higher spatial and temporal resolution than its predecessor ERA-Interim: hourly analysis fields are available at a horizontal resolution of 31 km and include wind data at 100 m above ground level, as well as surface air temperature and air pressure. ERA5 incorporates vast amounts of historical measurement data, including both satellite-based, commercial aircraft, and ground-based data.

APPENDIX D WIND FARM ANALYSIS AND RESULTS

D-1. LiDAR long-term wind regime

D-2. Time-dependent loss factors

D-3. Energy results

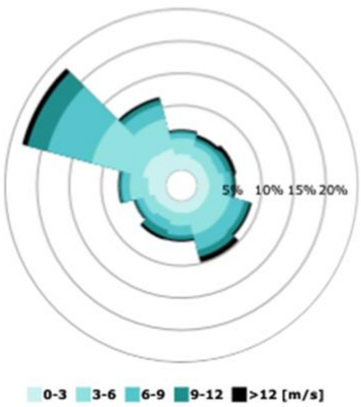
D-1 LiDAR Long-Term Wind Regime

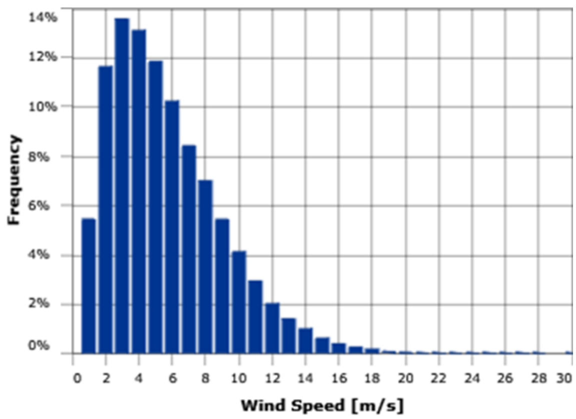
Table D-1 Azalea LiDAR Long-term wind speed and frequency distribution at 111 m

Period: 01/2000 to 06/2022

Monthly mean wind speeds

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	5.8	2.0	2.0
February	6.7	2.0	2.0
March	6.3	2.0	2.0
April	5.7	2.0	2.0
May	6.1	2.0	2.0
June	4.6	1.8	1.8
July	4.7	1.5	1.5
August	4.9	2.0	2.0
September	5.0	1.7	1.7
October	6.1	1.5	1.5
November	5.8	1.9	1.9
December	6.2	2.0	2.0
Annual	5.6		





Wind speed and direction frequency distribution

Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330		Total [%]
0														
1	0.50	0.39	0.36	0.34	0.35	0.33	0.42	0.45	0.48	0.56	0.64	0.65		5.46
2	1.08	0.93	0.80	0.77	0.72	0.78	0.71	0.67	0.88	1.25	1.56	1.51		11.64
3	1.15	0.84	0.78	0.94	0.89	1.01	0.81	0.62	0.74	1.24	2.53	2.03		13.59
4	0.92	0.71	0.70	0.91	1.19	1.22	0.75	0.51	0.61	1.06	2.81	1.72		13.11
5	0.75	0.60	0.47	0.76	1.33	1.23	0.57	0.47	0.56	0.88	2.72	1.51		11.85
6	0.46	0.42	0.42	0.53	1.14	1.10	0.54	0.53	0.44	0.69	2.81	1.17		10.24
7	0.27	0.29	0.43	0.33	0.82	0.92	0.54	0.53	0.38	0.48	2.63	0.82		8.44
8	0.24	0.24	0.40	0.28	0.66	0.75	0.53	0.51	0.28	0.30	2.24	0.61		7.01
9	0.17	0.22	0.34	0.25	0.45	0.55	0.38	0.46	0.21	0.21	1.77	0.44		5.46
10	0.12	0.17	0.33	0.17	0.31	0.38	0.26	0.46	0.16	0.16	1.28	0.33		4.13
11	0.09	0.15	0.26	0.11	0.24	0.32	0.18	0.35	0.11	0.11	0.83	0.20		2.95
12	0.08	0.13	0.19	0.10	0.18	0.27	0.13	0.24	0.07	0.08	0.43	0.12		2.03
13	0.06	0.12	0.15	0.07	0.12	0.22	0.11	0.15	0.06	0.05	0.20	0.11		1.42
14	0.04	0.10	0.14	0.04	0.07	0.19	0.06	0.09	0.04	0.03	0.13	0.08		1.01
15	0.02	0.08	0.11	0.03	0.04	0.13	0.02	0.05	0.02	0.02	0.07	0.05		0.63
16	0.02	0.06	0.06	0.03	0.02	0.08	0.01	0.03	0.01	0.02	0.04	0.04		0.40
17	0.02	0.04	0.03	0.03	0.01	0.05	+	0.02	0.01	0.01	0.03	0.03		0.26
18	0.02	0.02	0.01	0.01	+	0.03		0.01	+	+	0.06	0.02		0.18
19	+	0.01	+	0.01	+	0.02		+	+	+	0.05	0.01		0.10
20	+	+	+		+	+		+	+	+	0.02	+		0.03
21		+	+					+		+	+	+		0.01
22			+					+			+	+		+
23			+								+	+		+
24		+	+								+			0.01
25		+	+								+			+
26			+											+
27		+	+											+
28		+	+											+
29														
30		+												+
30+														
Total [%]	6.00	5.52	5.98	5.69	8.54	9.58	6.01	6.15	5.06	7.13	22.87	11.47		100.00
Mean Speed	4.56	5.51	6.20	5.15	5.77	6.37	5.61	6.42	4.90	4.58	6.20	5.05	-	5.65

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

D-2 Time-dependent loss factors

The results presented in the main text of this report represent annual average energy production values for a wind farm averaged over the first 10 years of operation. However, for some wind farms there will be loss factors which change over time such as the availability of the wind farm and the influence of trees (if any). The following table present the specific values that have been assigned for each year.

Table D-2 Time-dependent loss factors

Year	Turbine availability (2a) [%]	Turbine Degradation (4e) [%]
	Mingyang MySE6.45	
1	95.4	99.9
2	96.0	99.8
3	96.6	99.7
4	97.2	99.6
5	97.8	99.5
6	98.4	99.4
7	98.4	99.3
8	98.4	99.2
9	98.4	99.1
10	98.4	99.0
Loss factor averaged over 10 years	**97.5**	**99.5**

D-2 Energy results

Table D-3 Energy Results, Layout B-bis

Turbine	Turbine model	Hub height [m]	Initiation LiDAR	Adjustment to the LiDAR wind speed [%]	Long-term wind speed at hub height[1] [m/s]	Energy output[2] [GWh/annum]	Turbine interaction factor[3] [%]
WTG01	MySE6.45-180	111	Azalea	101.5%	5.7	14.8	95.3
WTG02	MySE6.45-180	111	Azalea	101.6%	5.7	14.4	92.8
WTG03	MySE6.45-180	111	Azalea	101.6%	5.7	14.3	92.5
WTG04	MySE6.45-180	111	Azalea	101.7%	5.7	14.3	91.9
WTG05	MySE6.45-180	111	Azalea	101.7%	5.7	14.2	91.5
WTG06	MySE6.45-180	111	Azalea	101.7%	5.7	14.1	91.0
WTG07	MySE6.45-180	111	Azalea	101.7%	5.7	14.1	91.0
WTG08	MySE6.45-180	111	Azalea	101.7%	5.8	14.1	90.6
WTG09	MySE6.45-180	111	Azalea	101.8%	5.8	14.1	90.8
WTG10	MySE6.45-180	111	Azalea	101.9%	5.8	14.0	90.2
WTG11	MySE6.45-180	111	Azalea	101.8%	5.8	14.0	90.1
WTG12	MySE6.45-180	111	Azalea	101.9%	5.8	14.1	90.5
WTG13	MySE6.45-180	111	Azalea	101.9%	5.8	14.0	90.2
WTG14	MySE6.45-180	111	Azalea	102.0%	5.8	14.2	90.8
WTG15	MySE6.45-180	111	Azalea	102.0%	5.8	14.1	90.6
WTG16	MySE6.45-180	111	Azalea	102.1%	5.8	14.2	91.1
WTG17	MySE6.45-180	111	Azalea	102.2%	5.8	14.2	91.0
WTG18	MySE6.45-180	111	Azalea	102.1%	5.8	14.3	91.5
WTG19	MySE6.45-180	111	Azalea	102.2%	5.8	14.4	92.1
WTG20	MySE6.45-180	111	Azalea	102.3%	5.8	14.4	92.1
WTG21	MySE6.45-180	111	Azalea	102.4%	5.8	14.5	92.6
WTG22	MySE6.45-180	111	Azalea	102.5%	5.8	14.9	94.7
WTG23	MySE6.45-180	111	Azalea	102.1%	5.8	14.2	91.1
WTG24	MySE6.45-180	111	Azalea	102.0%	5.8	13.8	88.2
WTG25	MySE6.45-180	111	Azalea	102.0%	5.8	13.7	87.8
WTG26	MySE6.45-180	111	Azalea	102.0%	5.8	13.7	87.5
WTG27	MySE6.45-180	111	Azalea	102.0%	5.8	13.6	86.9
WTG28	MySE6.45-180	111	Azalea	102.1%	5.8	13.5	86.7
WTG29	MySE6.45-180	111	Azalea	102.1%	5.8	13.5	86.6
WTG30	MySE6.45-180	111	Azalea	102.1%	5.8	13.5	86.4
WTG31	MySE6.45-180	111	Azalea	102.2%	5.8	13.4	85.9
WTG32	MySE6.45-180	111	Azalea	102.2%	5.8	13.4	85.8
WTG33	MySE6.45-180	111	Azalea	102.2%	5.8	13.5	86.0
WTG34	MySE6.45-180	111	Azalea	102.2%	5.8	13.4	85.8
WTG35	MySE6.45-180	111	Azalea	102.3%	5.8	13.5	85.9
WTG36	MySE6.45-180	111	Azalea	102.3%	5.8	13.6	86.7
WTG37	MySE6.45-180	111	Azalea	102.4%	5.8	13.7	86.9
WTG38	MySE6.45-180	111	Azalea	102.5%	5.8	13.8	87.8
WTG39	MySE6.45-180	111	Azalea	102.6%	5.8	14.2	90.0
WTG40	MySE6.45-180	111	Azalea	102.4%	5.8	14.1	89.6
WTG41	MySE6.45-180	111	Azalea	102.4%	5.8	13.7	87.2
WTG42	MySE6.45-180	111	Azalea	102.4%	5.8	13.6	86.8
WTG43	MySE6.45-180	111	Azalea	102.3%	5.8	13.6	87.0
WTG44	MySE6.45-180	111	Azalea	102.4%	5.8	13.7	87.1
WTG45	MySE6.45-180	111	Azalea	102.4%	5.8	13.6	86.7
WTG46	MySE6.45-180	111	Azalea	102.4%	5.8	13.7	87.1
WTG47	MySE6.45-180	111	Azalea	102.4%	5.8	13.7	87.2
WTG48	MySE6.45-180	111	Azalea	102.4%	5.8	13.8	87.6
WTG49	MySE6.45-180	111	Azalea	102.5%	5.8	13.8	87.5
WTG50	MySE6.45-180	111	Azalea	102.6%	5.8	13.9	88.0
WTG51	MySE6.45-180	111	Azalea	102.7%	5.8	14.2	89.8
Average					5.8	13.9	89.2
Total						**711.2**	

1- Wind speed at the location of the turbine, not including wake effects.
2 - Individual turbine output figures include all wind farm losses.
3 - Individual turbine wake loss including all wake effects

APPENDIX E ANALYSIS METHODOLOGY

E-1 Wind data analysis process overview

The analysis of the wind data involves several steps, which are summarised below:

1. The raw wind speed data from the site are processed and evaluated to identify periods with missing or erroneous data due to instrument failures, icing, or other factors.
2. Missing wind speed and direction data at the primary anemometer and wind vane at each site mast are synthesized from data recorded at the same mast where available, or from others on-site masts, to create a full record for the site period (site period wind speed and direction).
3. The on-site measurements are correlated with the sources of long-term reference wind data, and the results evaluated, to develop an estimate of reference period wind speeds at measurement height.
4. Uncertainties in the site period wind speeds and reference period wind speeds, as well as the relationships between the two are analysed to ascertain which methodology results in the best estimate of the true long-term wind speeds with the lowest bias and uncertainty.
5. The measurement height estimate of long-term wind speeds is extrapolated to hub height using power law wind shear exponent and the associated uncertainties are assessed.
6. Long-term hub-height wind speed and direction frequency distribution estimates at each measurement location are derived from the measured and synthesized data.
7. The wind regime at the proposed turbine locations is assessed using wind flow models and DNV experience and judgment.
8. The uncertainties in the resulting hub-height wind speeds at the turbine locations are assessed.

E-2 Met mast data processing and validation

Meteorological data should be provided in a raw form, preferably encrypted. Sufficient documentation should be provided to ensure the data integrity.

When calibration certificates from a Measnet-accredited facility have been supplied, DNV applies these in order to convert the raw data into wind speeds. For anemometers where calibration data are not provided, DNV applies a model-specific calibration.

Meteorological data are subject to a quality checking procedure by DNV to identify records which were affected by equipment malfunction, icing, and other anomalies. These records are considered invalid and excluded from the analysis.

All data from NRG #40 anemometers manufactured between mid-2006 and January 2009 are evaluated for evidence of a problem described in a technical note from NRG issued in spring 2008 /E1/. In this technical note, NRG described the problem, which manifests itself as intermittent under-speeding or dragging. After investigation, NRG concluded that the degrading and under-speeding was due to a phenomenon known as "dry friction whip". All anemometers manufactured by NRG after 1 January 2009 featured modifications aimed at reducing or eliminating the occurrence of this behaviour. The conclusions of NRG's investigation and the subsequent design changes are discussed in more detail in /E2/, presented by NRG at the AWEA annual conference in early May 2009. DNV examines potentially affected wind data to identify and remove periods affected by this issue. Any periods which are clearly affected are removed from the analysis and the additional uncertainty associated with either data removal or the inclusion of suspect data in the wind analysis is estimated. Rimini Offshore Wind Farm site project have NRG anemometers therefore this process has been followed.

To minimise the impact of the mast structure on the measured wind speed data, data recorded at levels with redundant instruments are “selectively averaged”. In direction sectors where an anemometer is affected by the wake of the mast, the unaffected anemometer is selected; in direction sectors where both anemometers are valid, the measurements are averaged.

E-3 Remote sensing data processing and validation

In order to evaluate the quality of a remote sensing device, several parameters may be reviewed. These include:

- Carrier-to-noise ratio (CNR)
- Signal-to-noise ratio (SNR)
- Wiper count
- Availability
- Amplitude signal
- Signal level
- Noise
- Echo suppression
- Valid count or recovery rate
- Standard deviation
- Turbulence intensity
- Beam component wind speed

Of these the CNR or SNR provides vital information about the quality of the beam propagation. The CNR or SNR generally decreases with height. If a significant number of points deviate from this, it can indicate signal noise contamination.

The first order quality control is generally an automatic procedure that is carried out by the manufacturer's online software program. Data are then filtered with in-house software using following data quality tests:

- Data with poor reliability, quality, or availability are removed;
- Horizontal wind speed (0 to 60 m/s) and direction validation (0 to 360°);
- Vertical wind speed validation (between -2 and 2 m/s);
- Horizontal and vertical standard deviation validation (<5 m/s).

Following automated data processing, all remote sensing datasets are checked manually to ensure that the results are sensible. This includes an assessment of the consistency between measurement heights and consistency relative to the associated met mast anemometry, if possible.

E-4 Data correlation and prediction

The period of data available at the site masts can be extended through establishing relationships between two data sets, using correlations to synthesize the missing data at the site. In this procedure, concurrent wind data from a “target” sensor and a “reference” sensor are compared. The reference sensor may be on the same mast or at a different measurement location. The reference sensor is chosen to be one for which wind records are available for the period being synthesized. The concurrent measured wind data are then used to establish the correlation between the winds at the two locations. This correlation is then used to synthesize data at the “target” location from the “reference” location.

The following methods are used to extend the period of record available at a mast.

E-4.1 Ten-minute or hourly synthesis method

In the correlation of 10-minute or hourly data, the concurrent data are correlated by comparing wind speeds at the two locations for each of twelve 30° direction sectors, based on the wind direction recorded at the “reference” location. This correlation involves two steps:

- Wind directions recorded at the two locations are compared to determine whether there are any local features influencing the directional results. Typically, only those records with speeds in excess of 5 m/s at both locations are used.
- Wind speed relationships are determined for each of the direction sectors using a principal component analysis.

The result of the analysis described above is a series of wind speed relationships, “speed-up ratios”, each corresponding to one of twelve direction sectors. These relationships are used to factor the wind data measured at the “reference” mast location, thereby obtaining synthesised wind data for the period of missing data at the “target” mast location.

In order to retain as much measured data at the target location as possible, the synthesized wind data are only used to fill in gaps in the measured data series.

E-4.1.1Correlation check

To check the quality of a correlation between the reference and target, the concurrent measured and synthesized wind data at the target are compared. If the energy content of the synthesized time series is within acceptable bounds, the data are considered well correlated.

E-4.2 Daily synthesis method

In the correlation of daily wind speeds, the concurrent daily wind speeds are compared in one of two ways:

- If there is a seasonal trend between the target and reference, the daily correlation can be divided into 12 separate correlations, based on the calendar month. In this “Daily-by-Month” method, 12 separate correlations are established.
- If there is no seasonal trend, or less than a year of concurrent data, a single “all-data” daily correlation is derived.

The results of these analyses are either a single correlation slope and offset or a set of twelve correlation slope and offset values, each corresponding to one of twelve calendar months. These slope and offset values are applied to the wind data measured at the “reference” mast location, thereby obtaining synthesized daily wind data for the period of missing data at the “target” mast location.

The measured and synthesised daily wind speed time series are combined, with priority given to the measured data. The long-term wind speed is then derived from this combined measured and synthesised daily time series.

E-4.3 Monthly synthesis method

In the correlation of monthly wind speeds, the concurrent monthly wind speeds are compared to establish a single correlation slope and offset. The slope and offset values are applied to the wind data measured at the “reference” mast location, thereby obtaining synthesized monthly wind data for the period of missing data at the “target” mast location.

The measured and synthesised monthly wind speed time series are combined, with priority given to the measured data. The long-term wind speed is then derived from this combined measured and synthesised monthly time series.

E-4.4 Mean of monthly means

In order to avoid the introduction of seasonal bias into estimates of the annual wind speed as well as wind speed and direction distributions from seasonally uneven data coverage, the following procedure is followed:

- The wind speed or distribution for each month is determined from the average of all valid data recorded in that month over the period. This is taken as the monthly mean, thereby assuming that the valid data are representative of any missing data.
- The mean of the monthly means, weighted by the number of days in a month, is taken to determine the annual mean ("mean of means").

E-5 Hub-height wind speed and direction distributions

E-5.1 Shear power law

The boundary layer power law shear exponents at the site masts are derived from the available measurements. The power law relates the ratio of measured wind speeds, U_1/U_2, to the ratio of the measurement heights, z_1/z_2, using the wind shear exponent, α, as follows:

$$\frac{\bar{U}(z_1)}{\bar{U}(z_2)} = \left(\frac{z_1 - d}{z_2 - d}\right)^{\alpha}$$

where

α is power law wind shear exponent,
$\bar{U}$ is the wind speed,
z is the height above ground level, and
d is the effective flow displacement height, if any.

The boundary-layer power law shear exponent was derived for each mast location using the ratios of measured concurrent wind speed data recorded at multiple measurement heights.

E-5.2 Directional shear method

The relationship between two or more heights on a mast is established for each of twelve 30° direction sectors, using the technique described in Section E-4.1. These relationships are used to derive the boundary-layer power law shear exponent in each of twelve direction sectors, which are then used to extrapolate data recorded at the upper measurement height to the target hub height, on a directional basis.

The annual average wind speed frequency and direction distributions at measurement height are determined from the site period wind speed data using the mean of monthly means approach described in Section E-4.4. The resulting distributions in each direction sector are then scaled to the predicted long-term hub height wind speed(s).

E-5.3 Time series method

The boundary-layer power law shear exponent is derived between two measurement heights for each 10-minute, or hourly, time step. A time series of wind speed at the target hub height is calculated by extrapolating the upper measurement height using the instantaneous boundary-layer power law shear exponent. The Mean of Monthly Means procedure is used to avoid the introduction of bias into the annual wind regime prediction from seasonally uneven data coverage at each mast as discussed in Section E-4.4.

E-5.4 Annual shear method

The relationship between two, or more, heights on a mast is established using the concurrent mean of monthly means technique described in Section E-4.4. These relationships are used to derive the boundary-layer power law shear exponent, which is then used to extrapolate data recorded at the upper measurement height to the target hub height.

E-6 Wind flow modelling

The project wind speed is typically modelled using either the WAsP model or the DNV CFD model as described in the following sections. Other models may be applied in cases where significant errors are apparent or expected from these models. These models may be exposure-based models, experience-based models or other models that DNV expects to reduce uncertainty or bias in the results. Where multiple site masts are available, typically these models initially generate set of predictions initiated from each site mast. From any given site mast, the primary output from the models is a set of wind speed ratios for each of the twelve 30° direction sectors between the initiating mast and other locations, typically either mast or turbine locations, at the same height.

In order to validate the flow model, the following procedure is undertaken. For a given mast pair, a prediction error is determined for each direction sector by comparing the modelled wind speed ratio to the wind speed ratio derived from measurements. A root-mean-square (RMS) of the twelve prediction errors is performed, weighted by the directional frequency distribution, in order to calculate an overall directional speed-up error.

E-6.1 WAsP approach

To calculate the variation of wind speed over the site, the computer wind flow model, WAsP, is used. Details of the model and its validation are given by Troen and Petersen /E4/.

The inputs to the model are a map of the topography and surface roughness length of the terrain for the site and surrounding area. A digital map of an area extending at least 10 km from the site in all directions is normally used and the inputs for this project are listed in Section 2 of the main body of the report. Although the domain size is much larger than the area of the site itself, such an area is necessary because the flow at any point is dictated by the terrain several kilometres upwind.

Wind flow is affected by the roughness of the ground and, therefore, the surface roughness length of the site and surrounding area is estimated following the Davenport classification /E5/, as detailed in Section 2 of the main body of the report.

The wind flow calculations are carried out using the same 30-degree steps in wind direction for which the measured wind rose is defined, and results are produced as speed-up factors relative to the mast location for a grid encompassing the site area.

To determine the long-term wind speed at any location, the speed-up factor for each wind direction is weighted with the measured probability previously derived for the mast location. All directions are then summed to obtain the long-term wind speed at the required location.

E-6.1.1Forestry representation within the WAsP approach

Where obstacles to the flow are present, such as trees in proximity to a mast or turbine, it is necessary to consider the effect of these on the wind flow model. When using the WAsP wind flow model, the following methodology is therefore adopted:

- Areas of forestry and land cover are analysed to establish both the location and height of trees.
- Forestry less than 5 m in height is assumed to not cause a flow displacement and is modelled as a terrain roughness only.
- For forestry, greater than 5 m of equal height, a flow displacement is assumed. To account for the influence of the trees as an obstacle to the wind flow at the mast and turbine locations an effective reduction in the hub height of each mast or turbine is estimated. The magnitude of each hub height reduction is based on the flow displacement height of the trees, the proximity of the mast or turbine to the trees, and the frequency of occurrence of the relevant wind directions. The following relationship /E3/ is used to calculate the effective flow displacement height for each direction sector at each mast and turbine location:

  $$d(\theta_i) = d(\theta_i)_{\text{tree}} - D(\theta_i)/50$$

  where *d* is the effective flow displacement height at the mast or turbine location;
  d_{tree} is the flow displacement height of the surrounding trees; and
  D is horizontal distance from surrounding trees.

- By weighting each sector's effective flow displacement height by the frequency of winds in that sector, a weighted displacement height is calculated for each individual site mast and turbine.

$$d = \sum_{i} f(\theta_i) d(\theta_i)$$

Where appropriate, an indicative energy loss factor profile is derived to account for the impacted of expected tree growth or felling over the operational period of the wind farm.

E-6.2 DNV CFD modelling

The DNV CFD methodology is based around STAR-CCM+, a commercial computational fluid dynamics (CFD) software package and produces simulations of the Atmospheric Boundary Layer (ABL) for wind power applications. The CFD software solves the time averaged equations of mass and momentum conservation. An energy conservation equation is also solved when modelling atmospheric stability. The DNV CFD methodology has been validated for a number of academic cases and well over 100 real wind farm sites /E7/. These studies show that on average the DNV CFD method offers substantially improved wind speed predictions as compared with WAsP.

The CFD approach requires significantly more computational resource than a classical WAsP analysis as the calculations are significantly more complex. A flow domain is created and defined by a set of boundary conditions which control the air flows in and out of the domain. A 3D mesh is created within the domain and the conservation and turbulence equations are solved at each discrete point on the mesh. Due to this construction, the model is subject to discretization errors and can only evaluate wind from a single direction at a time. Hence, a separate simulation is undertaken for all wind directions, typically at intervals of 6 to 25 degrees, depending on the wind direction and frequency at the site. The results are averaged to derive 30-degree direction sector speed-ups from the masts to the turbine locations. These speed-ups are then combined with the measurement-based wind resource at each mast to predict the wind resource at each turbine location.

The turbine and mast locations are at least 10 km away from the edge of the computational domain for each calculation. The horizontal spacing of the mesh near points of interest is 12.5 m to 50 m, depending upon the complexity of the local terrain. Mesh independence studies have shown that such tight mesh spacing is necessary to resolve flows at microscale.

For sites, where atmospheric stability significantly affects wind speeds, DNV employs a stability-enabled CFD analysis. The spatial variation of wind speed over topography is often very different during stable atmospheric conditions as compared to unstable conditions. Traditional wind flow models that assume a neutral atmosphere can provide reasonable predictions of unstable and near-neutral flows, but the predictions of stably stratified flows are comparatively poor. Thus, the stability-enabled CFD analysis, includes two sets of CFD calculations: a neutral CFD analysis to represent unstable and near-neutral flows and a stable CFD analysis, which directly models buoyancy effects, to represent stable flows. The results from the two sets of calculations are combined to produce an overall wind flow model for the site. Extensive validation has demonstrated that the stability-enabled CFD analysis provides significantly improved wind speed predictions at sites where stability effects are important /E8/.

E-6.2.1 Forestry representation within the DNV CFD approach

Where appropriate, the CFD model used by DNV includes a canopy model designed to reproduce within the Reynolds-averaged Navier-Stokes (RANS) simulations the turbulence generation and aerodynamic drag associated with forestry and can therefore model the resulting flow perturbation /E9/. Canopy model source terms are added to the governing equations within the volume occupied by the forestry, i.e. between ground level and the approximate height of the canopy, as described in /E10/ and /E11/. Inputs to the canopy model include tree height, coefficient of drag, and foliage density of the forestry.

E-7 Gross energy output

The gross energy production is the energy production of the wind farm obtained by calculating the predicted free stream hub height wind speed distribution at each turbine location and the manufacturer-supplied turbine power curve. In defining the gross energy output, it is assumed that there are no wake interactions between the turbines and no energy loss factors are applied. This calculation is undertaken within the WindFarmer computational model /E12/, /E13/ and includes adjustments to the power curve to account for differences between the predicted long-term annual turbine location air density and the air density to which the power curve is referenced.

E-8 Losses and net energy output

The net energy output is estimated by deducting expected losses from the estimated gross energy output. DNV uses a standard detailed set of six energy loss factors which aims to ensure that all potential sources of energy loss are considered by the relevant parties. For some projects, certain loss factors will not be relevant in which case an efficiency of 100% is assumed. Additionally, some losses may only be sensibly estimated when comprehensive information is available from a project and review of such documentation is within the scope of DNV's work. To add clarity for the reader regarding the level of detail considered, DNV has three categories of loss estimates used in Energy Assessments. These are:

- DNV standard: These are values that DNV has estimated as appropriate for typical projects in the region of the world in which a project is located. There may be regional difference in these estimates.
- Project specific: These are values for which DNV has made a project specific estimate. The basis of this estimate is provided in the body of the report.
- Out of scope: These are values for which making estimate has not been included in the Scope of Work that DNV has been authorized to complete.

Each of the loss factors that are used to derive the estimated wind farm net energy output prediction are described below. For each loss factor a general description of the loss, its typical values, and associated uncertainties are given.

E-8.1 Turbine interaction effects

Wind turbines extract energy from the wind and downstream there is a wake from the wind turbine where the wind speed is reduced. As the flow proceeds downstream, there is a spreading of the wake and the wake recovers towards free stream conditions. The wake effect loss is the aggregated influence on the energy production of the wind farm which results from the changes in wind speed caused by the impact of the turbines on each other. These effects are calculated using the WindFarmer computational model. The eddy viscosity model within WindFarmer is employed using a site specific definition of the turbulence intensity as an input, combined with a Large Wind Farm Wake Model developed by DNV /E12/, /E13/, /E14/.

In addition, turbine interaction also includes lateral as well as upstream effects, which together contribute to a resistance, or blockage, on the wind flow, deflecting some of the flow above and around the wind farm. Consequently, the first-row turbines produce less than they each would operating in isolation. DNV has developed an empirical model based on over 50 CFD simulations of generic wind farm configurations to capture the impact of wind farm blockage /E15/.

E-8.1a Internal wake and blockage effects

This is the effect that the wind turbines within the wind farm being considered have on each other. This loss factor also includes turbine interaction blockage effects.

E-8.1b Wake effect external

This is the effect that the wind turbines from neighbouring wind farms (if any) have on the wind farm being considered. These are calculated in the same way as internal wake effects.

E-8.1c Future wake effect

Where future wind farms are to be constructed in the vicinity of the project under consideration, the wake effect of these may be estimated and taken into account if sufficient information is available.

E-8.2 Availability

The wind turbines, the balance of plant infrastructure, and the electrical grid will not be available the entire duration of a project's life. Three sources of availability losses are discussed below. The mean values for these sources are combined to estimate overall system availability.

E-8.2a Turbine availability

This factor defines the expected average turbine availability of the wind farm over the first 10 years of operation of the project. Various measures of availability are discussed within different documents and contracts within the industry. For the avoidance of doubt, availability measure assumed here represents, as a percentage, the factor which needs to be applied to the gross energy to account for the loss of energy associated with the amount of time the turbines are unavailable to produce electricity. Where possible DNV will employ turbine availability projections as arrived at from extensive global industry experience.

E-8.2b Balance of plant availability

This factor defines the expected availability of the turbine transformers, the on-site electrical infrastructure, and the substation infrastructure up to the point of connection to the grid of the wind farm. It represents, as a percentage, the factor which needs to be applied to the gross energy to account for the loss of energy associated with the downtime of the balance of plant.

E-8.2c Grid availability

This factor defines the expected grid availability for the wind farm in mature operation. This factor relates to the grid being outside the operational parameters defined within the grid connection agreement as well as actual grid downtime. This factor also accounts for delays in the wind farm coming back to full operation following a grid outage. It represents, as a percentage, the factor which needs to be applied to the gross energy to account for the loss of energy associated with the downtime of the grid. Typical reasons for this downtime include grid preventive maintenance, failures and associated repair time, and outages related to construction.

E-8.3 Electrical transmission efficiency

There will be electrical losses experienced between the low voltage terminals of each of the wind turbines and the wind farm point of connection, which is usually located within a wind farm switching station.

E-8.3a Operational electrical efficiency

Electrical losses represent the difference between energy measured at each wind turbine and energy measured at the project substation (or other point where energy is metered for transaction purposes). Actual losses will depend on the efficiency of the transformers used at the facility, collection system wire sizing, and internal parasitic consumption "behind the meter" in very low wind conditions. This is presented as an overall electrical efficiency and is based on the long-term average expected production pattern of the wind farm.

E-8.3b Wind farm consumption

This factor defines the electrical efficiency due to the electrical consumption of the non-operational wind farm due to transformer no load losses and consumption by electrical equipment within the turbines and substation. For most wind farms this value is set to 100% and this impact on wind farm energy production is considered as a wind farm operational cost rather than an electrical efficiency factor. However, for some metering arrangements it may be appropriate to include this as an electrical efficiency factor rather than an operational cost and therefore this factor is available to apply if warranted.

E-8.4 Turbine performance

In an energy production calculation, a power curve supplied by the turbine supplier is used within the analysis. It is usual for the supplied power curve to represent accurately the power curve which would be achieved by a wind turbine on a simple terrain test site, assuming the turbine is tested under an IEC power curve test. The actual performance of the turbine may vary from the supplied power curve as a result of different factors, which are discussed below. These factors, considered together, represent the overall turbine performance efficiency.

E-8.4a Generic power curve adjustment

For certain turbine models, there may be reason to expect that the supplied power curve does not accurately represent the power curve which would be achieved by a wind turbine on a simple terrain site under an IEC power curve test. In such a situation, a power curve adjustment is applied. This may be thought of as estimating that a turbine would not meet the turbine sales power curve in an IEC power curve test on a simple terrain turbine test site.

E-8.4b High wind hysteresis

Most wind turbines will shut down when the wind speed exceeds a certain limit. High wind speed shut down events can cause significant fatigue loading. Therefore, to prevent repeated start up and shut down of the turbine when winds are close to the shutdown wind speed threshold hysteresis is commonly introduced into the turbine control algorithm. Where a detailed description of the wind turbine cut-in and cut-out parameters are available this is used to estimate the loss of production due to high wind hysteresis by repeating the analysis using a power curve with a reduced cut-out wind speed. If such information is unavailable, then an estimate is made based on DNV experience with similar turbines in similar environments.

E-8.4c Site-specific power curve adjustment

Certain wind farm sites may experience wind flow conditions that materially differ from the wind flow conditions seen at simple terrain and neutral condition test sites. Where it is considered that the meteorological parameters in some areas of a site differ from those at a typical wind turbine test station, then the impact on energy production of the difference in meteorological parameters at the site compared with a typical power curve test site is estimated. This adjustment is typically made when atmospheric stability, turbulence, wind shear or upflow angle conditions at the wind farm site are considered to be materially different to that which is experienced at a typical test site.

E-8.4d Sub-optimal performance

Previously discussed performance losses are relative to the sales power curve, which assumes that the turbine controls are optimally configured and maintained. In DNV’s experience there are material performance deviations from the optimal power curve due to software or instrumentation issues which cause the machines to not reach their intended power curve or operate in a non-optimal way and it takes time and considerable focus to ensure wind turbines continuously operate as they should. In order to capture these effects, a typical loss factor of between 0.5% and 1.0% of annual energy production is assumed for the life of the project.

E-8.4e Turbine degradation

The performance of wind turbines can be affected by degradation of blades and other components. This includes the accretion of dirt, which may be washed off by rain from time to time, as well as physical degradation of the blade surface, such as leading-edge erosion, and other components, over prolonged operation. This is a time dependent phenomenon which DNV models as increasing linearly at a rate of 0.1% per year for 20 years, resulting in an average of 1% loss over 20 years. In harsh climates these values are increased by 0.3%.

E-8.5 Environmental

The following environmental influences on the wind farm performance are considered in a standard DNV analysis. The environmental loss consists of several subcategories as discussed below. The product of the subcategory losses represents the overall environmental loss estimate.

E-8.5a Performance degradation - icing

Small amounts of icing on the turbine blades can change the aerodynamic performance of the machine resulting in loss of energy. This loss, and the associated uncertainty distribution, is typically calculated on a site-specific basis.

E-8.5b Icing shutdown

As ice accretion gets more severe wind turbines will shut down or will not start. Icing can also affect the anemometer and wind vane on the turbine nacelle which also may cause the turbine to shut down. This loss and associated uncertainty distribution are typically calculated on a site-specific basis.

E-8.5c Temperature shutdown

Turbines are designed to operate over a specific temperature range. For certain sites this range may be exceeded and for periods when the permissible temperature range is exceeded the turbine will be shut down or curtailed. For such sites, an assessment is made to establish the frequency of temperatures outside of the operational range of the turbine and the correlation of such conditions with wind speed. From this the impact on energy production is estimated. This loss and associated uncertainty distribution are typically calculated on a site-specific basis.

E-8.5d Site access

Severe environmental conditions can influence access to more remote sites which can impact availability. An example of this might be an area prone to severe snow drifts in winter. As the impact on energy will be dependent on the Operation and Maintenance arrangements a factor will only usually be included where DNV has reviewed the operations and maintenance arrangements for the wind farm.

E-8.5e Tree growth/felling

For wind farm sites located within or close to forestry or areas of trees, the impact of tree growth or felling on the wind flow over the site, and consequently the energy production of the wind farm, should be considered. If sufficient information about the expected growth rate of the trees, or any future felling, is available then the impact of these can be modelled. This loss is typically calculated on a site-specific basis.

E-8.6 Curtailments

Some or all of the turbines within a wind farm may need to be shut down, or their energy output curtailed, to mitigate issues associated with turbine loading, export to the grid or certain planning conditions. If sufficient information is available about any proposed wind farm curtailment strategies, then these losses can be calculated on a site-specific basis.

E-8.6a Wind sector management

Turbine loading is influenced by the wake effects from nearby machines. For some wind farms with particularly close machine spacing it may be necessary to shut down certain turbines for certain wind conditions. This is referred to as wind sector management and will generally result in a reduction in the energy production of the wind farm.

E-8.6b Maximum Export Capacity (MEC) Constraint

Typical grid connection agreements require that the output of the wind farm be constrained at a Maximum Export Capacity (MEC). Under the condition that the MEC is below the rated capacity of a wind farm, the wind farm is considered to be constrained and will experience a subsequent loss. This loss is considered here.

E-8.6c Noise, visual, and environmental curtailment

In certain jurisdictions, there may be requirements to shut down turbines during specific meteorological conditions to meet defined noise emission, shadow flicker criteria at nearby dwellings, or environmental conditions due to such aspects as birds or bats.

E-8.7 Asymmetric production effect

The effect of changes in wind speed, whether through variability or deviations from the mean, has an asymmetric impact on project production because of the non-linear relationship of wind speed to energy. At high wind speeds the power curve flattens, so an increase in wind speed results in little or no increase in energy. At lower wind speeds the power curve is steep so a small change in wind speed results in a larger change in energy. Thus, when wind speed variability risk is converted to energy production risk, the resulting distribution is asymmetric, with a P50 (median) value that is less than the average. This difference is considered here.

Additionally, some of the uncertainty distributions applied to the loss factors described above are asymmetric in nature and some are truncated to prevent modelling of impossible conditions (losses less than zero). The impact of this asymmetry is captured in uncertainty analysis, as well as the P50, as described above.

E-9 Uncertainty analysis

The uncertainty in the net energy estimates provides a metric to determine the downside and upside production risk of a project over a specified time period. The inputs into the uncertainty analysis include uncertainties around the wind speed inputs and modelling, uncertainty around the energy loss factors, and the inter-annual variability of production. These inputs, as well as the site-specific wind speed sensitivity, are combined to generate a probability distribution for annual project net energy production using a propriety Monte-Carlo uncertainty model.

E-9.1 Wind speed uncertainty

There is uncertainty in the measurement device wind speed estimates due to a variety of factors described below. Uncertainties are estimated as a percentage of the wind speed, except where noted, and are assumed to be normally distributed. The uncertainty values referenced below and elsewhere in the report represent one standard deviation.

E-9.1.1Measurement accuracy

There is an uncertainty associated with the accuracy of the wind speed measurements. This estimate typically includes instrument accuracy, Measurement interference, and consistency of measurement, as described below.

Instrument Accuracy

This uncertainty is to account for the calibration accuracy of the instrument and to include an allowance for second order effects such as over-speeding, degradation, air density variations, and additional turbulence effects. An uncertainty of 2.0% on wind speed is typical for anemometers calibrated in a Measnet facility. An uncertainty of 2.5% is typical for non-calibrated anemometers. Multiple independent measurements of wind speed at the same height on a measurement device reduce the overall uncertainty. Typically, this benefit is a reduction of between 0.2% and 0.3%.

An instrument accuracy uncertainty estimated on remote sensing measurements is based on the quality of the verification against the associated met mast and DNV's experience verifying the remote sensing equipment at other sites. The following five levels of verification are typically seen by DNV. They are listed in order of increasing uncertainty.

- The remote sensing device was verified against a tall, co-located, on-site met mast. The met mast was well-instrumented (i.e., IEC 61400-12-compliant anemometry) and the remote sensing device was located in as representative a position as the manufacturer's guidelines and local terrain permit. DNV verified data from multiple measurement heights for a sufficient period to get a good distribution of wind speeds and wind direction sectors. This typically requires a verification measurement period of at least six to twelve weeks.
- The verification was conducted using an on-site met mast; however, the configurations of the met mast or verification campaign were inconsistent with DNV recommendations regarding levels of instrumentation, data capture, duration, or other factors.
- No on-site verification was undertaken, however the results of an off-site verification against at tall, well-instrumented met mast are available;
- No on-site verification was undertaken. The results of a recent factory validation are available, or an off-site met mast verification is available but are not recent;
- No verification of the remote sensing device has been undertaken.

Measurement interference

There is an uncertainty associated with the effects of mounting anemometers on towers; even when mounted according to industry-standard procedures, as small speed-up and slow-down effects are seen on measurements on tubular towers, lattice towers and in the presence of lightning finials. DNV estimates the measurement interference uncertainty based on a review of the data, observations during the site visit and a review of the documentation of the mounting arrangements on the towers.

A measurement interference uncertainty for remote sensing data is based on the potential impact of the following:

- Fixed echoes from nearby hard surfaces such as tree trunks and exposed rock (that were not captured in the filtering process, Sodar only);
- Background noise interference (that was not captured in the filtering process, Sodar only);
- Light beam interference such as prevalence of dense fog (that was not captured in the filtering process, Lidar only);
- Complex flow regimes; and
- Changes in the Sodar/Lidar settings and processing software.

Consistency of measurement

Poor data recovery and poor documentation make it difficult to confirm the consistency of a measurement. When substantial periods of data are missing, or removed due to icing, equipment malfunction and other issues, there is additional uncertainty in the measurement. There is also uncertainty associated with the quality of the documentation of the met masts and instrumentation. This uncertainty is estimated based on DNV's review of the data, information from any site visit, any supplied documentation, and the data recovery percentages.

E-9.1.2Long-term measurement height wind regime

On-site data synthesis

DNV estimates, based on statistical methods, the uncertainty associated with the relationships used to synthesise wind data by the methodology described in Section E-4. The magnitude of this uncertainty is based on the quality of the correlations and the amount of data synthesized.

Representativeness of period of data

The uncertainty associated with how well the period of record represents the long-term wind conditions is estimated by dividing the inter-annual variability by the square root of the number of years of data used in the analysis. The period of record includes any data synthesised from a long-term reference in the derivation of the long-term measurement height wind regime.

Correlation to reference station

DNV estimates the uncertainty on the relationships used to describe the wind conditions between the site measurements and reference data based on the quality of the correlations and the amount of data synthesised.

Consistency of reference data

The uncertainty associated with the consistency of the reference data is assigned based on the level of regional validation available, the metadata available for the data, and the nature of the long-term reference data.

The agreement of multiple reference data sources, particularly when they are from different networks, reduces the risk of an undetected consistency change impacting the site wind speeds.

Wind frequency distribution - past

The wind frequency distribution varies from year to year such that for a given annual wind speed the energy production may be higher or lower than expected due to a more or less favourable distribution of wind speeds. For example, a year with several intense storms may record substantial time at wind speeds above the turbine cut-out speed, thereby increasing the overall average wind speed but not increasing the energy production. This category represents the uncertainty on the distribution measured over the period of data collection at the site and is estimated as a percent of energy. DNV estimates this uncertainty as 2% divided by the square root of the number of years of on-site data.

E-9.1.3 Vertical extrapolation

There is uncertainty as to whether the measured shear values represent the wind shear above the upper measurement height. To estimate the uncertainty associated with vertical extrapolation, DNV evaluates the accuracy of the shear measurement and the magnitude of the extrapolation. Additionally, the consistency of shear between the towers, available information concerning atmospheric stability, and the measurement configurations can influence the vertical extrapolation uncertainty.

E-9.1.4 Spatial extrapolation

This uncertainty represents the uncertainty in the ability to extrapolate from the measurement locations to the wind turbine locations. DNV estimates this uncertainty based on the wind flow models' ability to cross-predict wind speeds at measurement locations, the differences in wind speeds at met masts, how representative the measurement locations are of turbine locations, the reliability of the model inputs, variations in ground cover and the complexity of the terrain and wind flow at the site.

E-9.2 Loss factor uncertainty

E-9.2.1 Wakes

The wakes uncertainty is modelled as a normal distribution centred on the median estimate. The standard deviation of the distribution depends on site specific conditions but is typically between 25% and 35% of the overall wake effect.

E-9.2.2 Availability

The project availability is modelled as a Weibull distribution with a standard deviation of 3% for each analysed wind farm year and is assumed to be independent from year-to-year.

E-9.2.3 Electrical

To acknowledge the uncertainty on this estimate, a normal distribution is assumed with a standard deviation of 0.3% to 0.6% depending on the level of review undertaken.

E-9.2.4 Turbine performance

The uncertainty on this overall turbine performance loss estimate is modelled as a normal distribution which typically results in a standard deviation of between 2% and 3%. The magnitude of this uncertainty depends on the confidence DNV has in the turbine's ability to achieve the claimed level of performance and site wind conditions. Turbines with a body of evidence supporting the claimed performance level through measured power curves, for instance, will have a lower uncertainty.

E-9.2.5 Environmental

The uncertainty on the overall environmental loss estimate is typically modelled as a normal distribution and is dependent on the level and complexity of the project environmental losses.

E-9.2.6 Curtailment

The uncertainty on the overall curtailment loss estimate is typically modelled as a normal distribution and is dependent on the level and complexity of the project curtailment.

E9.3 Inter-annual variability

E-9.3.1 Wind frequency distribution - future

This category represents the year-to-year variability in energy due to changes in the wind speed distribution. DNV typically estimates this value to be 2.0% on energy.

E-9.3.2 Inter-annual variability of the wind

The inter-annual variability of project wind speed represents the expected range of variation in annual average wind speed from year to year.

The inter-annual variability accounts for uncertainty on the one-year wind speed and is an input in the uncertainty model. DNV typically uses data from long-term reference stations as well as knowledge of the region when estimating this value, which typically ranges between 4% and 6% /E16/.

On longer time scales, there is some related uncertainty associated with whether or not the true long-term wind speed will occur during that period due to the year-to-year variations in wind. Over many years, wind variations tend to average out such that the long-term uncertainty is less than the one-year variability. For example, the 20-year uncertainty can be estimated by dividing the inter-annual variability by the square root of 20.

Year-to-year variations in wind speed result from a variety of phenomena, potentially including climate change. DNV has researched the literature regarding the impact of climate change on wind speeds and concluded that while available modelling tools are predicting material changes in some atmospheric characteristics, such as temperature, no similar pattern is apparent with regard to wind speeds. The majority of models predict small changes which are well within the historic inter-annual variability and there isn’t agreement among models regarding the direction of any changes.

E-9.3.3 Environmental losses variability

This category represents the year-to-year variability in energy losses due to changes in the amount and severity of icing observed or changes in the temperature leading to variable amounts of temperature shutdown. This value is highly dependent on the site-specific conditions and the magnitude of the losses.

E-10 References

/E1/ NRG Systems, “NRG Technical support bulletin 008”, 22 May 2008

/E2/ Clark, S.H. et al., “Investigation of the NRG #40 Anemometer Slowdown”, Proceedings of the AWEA Conference, Chicago 2009.

/E3/ Cook, N.J., “The Designer’s guide to wind loading of building structures: Part 1”, London: Butterworths, 1985.

/E4/ Troen, I., Petersen, E.L., “European Wind Atlas”, Risø National Laboratory, Denmark, 1989.

/E5/ ESDU, “Wind speed profiles over terrain with roughness changes”, Item No. 84011 Amendments A to D, ESDU International: London, 1993.

/E6/ Corbett, J.F., Landberg, L., “Optimising the parameterisation of forests for WAsP wind speed calculations: A retrospective empirical study”, EWEA 2012 Conference, April 2012”

/E7/ Manning, J., Woodcock, J., Corbett, J-F., Whiting, R., Bleeg, J., Landberg, L., Tindal, A. – Validation and challenges of CFD in complex terrain for real world wind farms, EWEC 2011.

/E8/ Bechmann, A., et.al. – Results of the Blind Comparison, Bolund Workshop, December 3-4, 2009, Risø DTU National Laboratory for Sustainable Energy.

/E9/ Medici, D., Digraskar, D., Bleeg, J., Corbett, J.F., “Investigating the treatment of forestry in CFD wind flow models”, CanWEA 2012 conference, October 15, 2012, Toronto, Canada.

/E10/ Svensson, U., Häggkvist, K., “A two-equation turbulence model for canopy flows”, J. Wind Eng. Ind. Aerodyn. 35 (1990) 201–211.

/E11/ Costa et al, “Computer simulations of atmospheric flows over real forests for wind energy resource evaluation”, J. wind Eng. Ind. Aerodyn,94 (2006), pp 603-620.

/E12/ “WindFarmer 5, Theory Manual”, GL Garrad Hassan, January 2013.

/E13/ “WindFarmer 5, User Manual”, GL Garrad Hassan, January 2013.

/E14/ Schlez, W.; Neubert, A., " New Developments in Large Wind Farm Modeling", EWEC 2009, Marseilles, France.

/E15/ Bleeg, J.; Purcell, M.; Ruisi, R.; Traiger, E. “Wind Farm Blockage and the Consequences of Neglecting Its Impact on Energy Production”. Energies 2018, 11, 1609. Available at http://www.mdpi.com/1996-1073/11/6/1609

/E16/ Raftery, P., Tindal, A.J., Garrad, A.D., “Understanding the risks of financing windfarms”, Proc. EWEA Wind Energy Conference, Dublin, 1997.

About DNV

DNV is a global quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable our customers to advance the safety and sustainability of their business. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil & gas, power and renewables industries. We also provide certification, supply chain and data management services to customers across a wide range of industries. Operating in more than 100 countries, our experts are dedicated to helping customers make the world safer, smarter and greener.