Exh. DCG-11C
Dockets UE-170033/UG-170034
Witness: David C. Gomez
CONFIDENTIAL VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-170033 and UG-170034 (*Consolidated*)**

EXHIBIT TO
TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

PSE's Response to Staff DR No. 311, Preconstruction Forecasts; Hopkins Ridge, Wild Horse, Wild Horse Expansion, Lower Snake River and Klondike III, Attachments B through F

CONFIDENTIAL PER PROTECTIVE ORDER – CONFIDENTIAL VERSION

ASSESSMENT OF THE ENERGY PRODUCTION OF THE PROPOSED HOPKINS RIDGE WIND FARM

Client	**Puget Sound Energy**
Contact	Tom Hiester
Document No	4742/AR/01
Issue	A
Status	FINAL
Classification	Client's Discretion
Date	29 Nov 2004

Author:

Ryan Adams

Checked by:

Adam Schwarz

Approved by:

Peter Raftery

DISCLAIMER

Acceptance of this document by the client is on the basis that Garrad Hassan America are not in any way to be held responsible for the application or use made of the findings of the results from the analysis and that such responsibility remains with the client.

GH has not conducted wind measurements itself and cannot, therefore, be responsible for the accuracy of the data supplied to it.

Key To Document Classification

Strictly Confidential	:	Recipients only
Private and Confidential	:	For disclosure to individuals directly concerned within the recipient's organisation
Commercial in Confidence	:	Not to be disclosed outside the recipient's organisation
GH only	:	Not to be disclosed to non GH staff
Client's Discretion	:	Distribution at the discretion of the client subject to contractual agreement
Published	:	Available to the general public

Revision History

Issue	Issue date	Summary
A	29.11.04	Original Issue

Circulation:	Copy No:
Client	1 & 2
GH Bristol	3
GH San Diego	4

Copy No: ____

CONTENTS

		Page
1	**INTRODUCTION**	**1**
2	**DESCRIPTION OF THE SITE AND MONITORING EQUIPMENT**	**2**
2.1	The site	2
2.2	Monitoring equipment	2
3	**SELECTION OF A REFERENCE METEOROLOGICAL STATION**	**4**
4	**WIND DATA**	**5**
4.1	Wind data recorded at the site	5
5	**DESCRIPTION OF THE PROPOSED WIND FARM**	**6**
5.1	The wind turbine	6
5.2	Wind farm layout	6
6	**RESULTS OF THE ANALYSIS**	**7**
6.1	Long-term mean wind regime at Mast 37 at mast height	7
6.2	Long-term mean wind regime at Masts 87 and 153 at mast height	8
6.3	Hub height wind speeds	9
6.4	Site wind speed variations	9
6.5	Projected energy production	10
6.6	Uncertainty analysis	11
6.7	Seasonal and diurnal variation	12
7	**CONCLUSIONS AND RECOMMENDATIONS**	**13**

REFERENCES

LIST OF TABLES

LIST OF FIGURES

APPENDIX 1 Data analysis procedure

APPENDIX 2 Anemometer calibration certificates

1 INTRODUCTION

Renewable Energy Systems (RES) is developing the Hopkins Ridge Wind Farm in Washington. Puget Sound Energy (PSE), as potential investors, have retained Garrad Hassan America (GH) to carry out an independent assessment of the wind climate and expected energy production of the proposed wind farm. The results of the work are reported here.

A description of the long-term wind climate at a potential wind farm is best determined using wind data recorded at the site. RES has supplied approximately 3 years of data recorded at the Hopkins Ridge site to GH.

When only a short period of site data are available, it is usual to combine the site measurements with long-term measurements from a local meteorological station. RES has supplied data from a reference meteorological station located near Kennewick, however, given the poor level of correlation to the site, this reference has not been considered in the assessment. As a result, there is additional uncertainty associated with the assumption that the three year period of site data is representative of the long-term.

The proposed layout and turbine model currently under consideration have been supplied by RES. These have been analysed here, in conjunction with the results of the wind analysis, to predict the long-term energy output of the proposed wind farm.

2 DESCRIPTION OF THE SITE AND MONITORING EQUIPMENT

2.1 The site

The site is located in the southeast region of Washington State approximately 150 km south-southwest of Spokane, as shown in Figure 2.1.

The proposed wind farm is located to the northwest of the Blue Mountains and lies within an area comprised of rolling hills and several ridges of elevation between approximately 500 m and 800 m. The escarpments to the northeast of the site, dropping into the Tucannon River Valley, are aligned approximately perpendicular to the predominant south-southwest wind direction. The general terrain at the site can be described as complex with local vegetation consisting of winter wheat and hay fields throughout.

It is noted that there are areas of dense forest approximately 20 km to the south-southeast of the site. Due to this distance with regard to the predominant wind direction for this region this is not expected to have a significant impact on this assessment.

A more detailed map showing the site area is presented in Figure 2.2, which also shows the location of the anemometry masts. A view of the site is shown in Figure 2.3 as seen from Mast 35 facing southwest.

The surface roughness length of the site and surrounding area was assessed during a site visit made by GH staff. Following the Davenport classification [2.1], the following general figures are considered appropriate:

Site and surrounding areas	0.03 m
Wooded areas	0.3 m

2.2 Monitoring equipment

Details of the measurements recorded on site and the grid co-ordinates of each mast are presented in Table 2.1.

The wind data have been recorded using Campbell Scientific loggers throughout with Vector Instruments anemometers and wind vanes.

Campbell Scientific CR10X and CR510 data loggers have been utilised, programmed to record ten-minute mean wind speed and direction, wind speed and direction standard deviation, instantaneous gust and 3-second gust. It is noted that in the case of Mast 35 a short segment of five-minute data was recorded for the period of 8 September 2002 to 22 October 2002. The following transfer function was applied to the output signal from the anemometers by these data loggers:

Recorded wind speed [m/s] = 1 [m/s/Hz] x Data frequency [Hz] + 0 [m/s]

The anemometers on the site have been individually calibrated. The individual calibrations have been retrospectively applied by GH to all the data recorded on the site masts.

All of the anemometers used at the site have been calibrated by the Deutsches Windenergie-Institut GmbH, DEWI (German Wind Energy Institute), a MEASNET certified facility. Copies of the calibration certificates are included in Appendix 2.

Maintenance records for the site measurements have been provided. The standard of documentation is good and certainly sufficient to ensure full traceability of the instrumentation.

The site comprises of eight Rohn-25G lattice towers. The towers have a face width of 12 inches with the top of the towers at approximately 53 m height above ground level. All towers with the exception of Mast 153 have an additional top mount extension of 2.75 m resulting in a total tower height of approximately 56 m.

The exact heights of the instruments have been provided in the RES site masts commissioning forms [2.2]. Instruments mounted on Masts 33 and 35 include boom-mounted anemometers at 56 m and 30 m and a wind vane at 54 m. Instruments mounted on Masts 37, 85, 87, 88 and 154 include boom-mounted anemometers at 56 m and 35 m and a wind vane at 54 m with an additional wind vane at 34 m at Masts 85 and 154. Instruments mounted on Mast 153 include boom-mounted anemometers at 53 m and 36 m and wind vanes at 50 m and 34 m. All site masts include a temperature sensor at approximately 3 m and Masts 35 and 88 include a barometric pressure sensor at approximately 3 m.

All anemometers are mounted on booms approximately 3.5 to 5 mast face widths long oriented to the west at all masts except for Masts 33 and 35 where the booms are oriented to southwest. The booms are comprised of square stock approximately 1 inch square. The cups of the anemometers are approximately 10 boom diameters above the boom. These mounting arrangements are broadly consistent with the recommendations of the IEA [2.3].

It is noted that the Mast 35 CR10X data logger had failed and was replaced by a new CR10X data logger on 23 June 2003. The CR510 data loggers at Masts 153 and 154 were recalled by Campbell Scientific due to possible communication failures [2.2] and were subsequently replaced with new CR510 data loggers on 23 June 2003. It is assumed that these changes are not to have any effect with respect to the consistency or validity of the measurements.

It is noted that, as a consequence of the locations of Masts 35, 85, 88 and 154 with respect to the proposed turbine layout, these data were not required for the present analysis. Given the period of data from Mast 33, these data were retained for the assessment as an onsite reference only.

3 SELECTION OF A REFERENCE METEOROLOGICAL STATION

In the assessment of the wind regime at a potential wind farm site it is generally necessary to correlate data recorded on the site with data recorded from a nearby long-term reference meteorological station. Wind data at a site are often only recorded for a short period and such correlation is required to ensure that the estimates of the wind speeds at the site are representative of the long-term. When selecting an appropriate meteorological station for this purpose it is important that it should have good exposure and that data are consistent over the measurement period being considered.

A meteorological station located at Kennewick has been identified by RES as a potential reference station and wind data have been supplied to GH for the period from 1994 to 2004. This station is operated as part of the Oregon State University Energy Resources Research Laboratory network. This station is situated approximately 100 km west-southwest of the site. It is noted, however, that due to poor correlations between the Kennewick reference station and the site, Kennewick is not considered to be suitable as a quantitative long-term reference in this assessment.

The analysis of the long-term wind regime therefore relies on data recorded at the Hopkins Ridge site since July 2001. This data set is of shorter duration than that which is ideal, and the uncertainty associated with assuming this period to be representative of the long-term is considered in Section 6.

4 WIND DATA

4.1 Wind data recorded at the site

The data sets which have been used in the analysis described in the following sections are summarised in Table 2.1.

The wind data have been subject to a quality checking procedure by GH to identify records which were affected by equipment malfunction and other anomalies. The check of the site mast data revealed several hours where wind speed data were missing or suspect. These data were excluded from the analysis. The main periods for which valid data were not available are summarised below, together with details of the errors identified:

Mast 35

- Datalogger malfunction: 24 May 2003 to 23 June 2003.

Mast 37

- 56 m anemometer malfunction: 29 March 2002 to 17 May 2002.

The duration, basic statistics and data coverage for the Masts 33, 37, 87 and 153 data are summarised in Tables 4.1 through 4.4..

5 DESCRIPTION OF THE PROPOSED WIND FARM

5.1 The wind turbine

The turbine which is proposed for the Hopkins Ridge Wind Farm is the Vestas V80 IEC Class 1 machine. The basic parameters of the turbine are presented in Table 5.1.

The power curve used in this analysis has been supplied by RES [5.1] and is presented in Table 5.2. This power curve is for an air density of 1.15 kg/m³, and a turbulence intensity of 10 %.

The supplied power curve is based on measurement and exhibits a peak power coefficient, Cp, of 0.47. This is considered to be high but attainable for a modern wind turbine. No review of the supplied power curve against a measured power curve from an independent test of the performance of the wind turbine has been undertaken at this stage.

Using historical pressure and temperature records from nearby meteorological stations and standard lapse rate assumptions, GH has estimated the long-term mean air density at the site to be 1.152 kg/m³ at an average hub elevation of 712 m above sea level.

The supplied power curve used in this analysis has been adjusted to the predicted site air density, in accordance with the recommendations of [5.2]. This has been undertaken on an individual turbine basis.

5.2 Wind farm layout

RES have supplied the layout for the Wind Farm [5.1]. A map of the site showing the wind turbine locations is presented in Figure 5.1 with the grid reference of each of the turbines given in Table 5.3.

It is noted that inter-turbine spacing of as small as 1.9 rotor diameters is proposed. Even though these separations are in non-prevailing wind directions, the increased turbulence levels will increase fatigue loads. It is noted that at this stage GH is not aware of any wind sector management strategy that may be employed at the site. It is strongly recommended that the turbine supplier be approached at an early stage to gain approval for the proposed layout.

6 RESULTS OF THE ANALYSIS

The analysis of the wind farm involved several steps, which are summarised below:

- The long-term mean wind speed and direction frequency distribution at Mast 37 at 56 m height was derived for the period from September 2001 to August 2004.
- Data recorded at Masts 87 and 153 were correlated to data recorded at Masts 33 and 37, respectively. These correlations were used to synthesise data at Masts 87 and 153 to develop the long-term wind speed and direction frequency distributions.
- The measured shear derived at the masts was used to extrapolate the mast height long-term mean wind speed and direction frequency distributions to the proposed hub height of 67 m.
- Wind flow modelling was carried out to determine the hub height wind speed variations over the site relative to the anemometry masts.
- The energy production of the wind farm was calculated taking account of array losses, topographic effects, availability, electrical transmission efficiency, air density effects and other potential losses.
- An assessment of the uncertainty in the predicted wind farm energy production was undertaken.

A more complete description of the methods employed is included in Appendix 1.

6.1 Long-term mean wind regime at Mast 37 at mast height

As detailed in Section 4, wind measurements from Mast 37 over a period of approximately 2.8 years were available for the analysis. From the 2.8 years of measurements a total of approximately 2.6 years of valid wind data were available. As noted in Section 4, the 56 m anemometer malfunctioned in March 2002 and was replaced with a new anemometer in May 2002. In order to account for the missing wind speed measurements for this period, it is considered appropriate to synthesise missing data through a correlation analysis with the 35 m anemometer. The correlation of ten minute mean wind speeds on a directional basis was therefore undertaken between the 56 m and 35 m measurements and the results used to synthesise 10-minute data on a directional basis.

In order to avoid the introduction of bias into the annual mean wind speed estimate from seasonally uneven data coverage, the following procedure was followed:

- The mean wind speed and direction frequency distribution for each month was determined from the average of all valid data recorded in that month over the period. This was taken as the monthly mean thereby assuming that the valid data are representative of any missing data.
- The mean of the monthly means was taken to determine the annual mean ("mean of means") to eliminate the effect of seasonal bias in the data.

By this method, as shown in Table 6.1, the predicted long-term mean wind speed at Mast 37 at 56 m was found to be 7.4 m/s. The corresponding long-term joint wind speed and direction frequency distribution is presented in Table 6.2 and in Figure 6.1 in the form of a wind rose.

It is observed that the wind rose at Mast 37 has a predominance of winds from the south-southwest.

6.2 Long-term mean wind regime at Masts 87 and 153 at mast height

As described in Section 4, valid wind measurements at Masts 87 and 153 over periods of approximately 2.2 years and 1.5 years, respectively, were available for the analysis. In order to reference these data to the longer term, a correlation analysis between Masts 33 and 37 were undertaken. The correlations of ten-minute mean wind speeds on a directional basis were therefore undertaken between Masts 33 and 87 and between Masts 37 and 153.

Data have been recorded at Masts 87 since April 2002. In order to extend the duration of the reference period used for the analysis of the wind regime at the site a correlation approach described in Appendix 1 was used to synthesise the wind speed at Mast 87 at 56 m from data recorded at Mast 33 at 56 m over the period July 2001 through April 2002 and small intermittent periods continuing through August 2004. As a check of the validity of the synthesis methodology, synthesised data were compared with concurrent periods of measured data and were noted to be in close agreement. By combining the actual data recorded at Mast 87 at 56 m and the synthesised data from Mast 33, approximately 3.0 years of valid wind speed data were obtained. The long-term mean wind speed and direction frequency distribution for Mast 87 at 56 m was derived, as for Mast 37 above, from these data.

The measured wind speeds at Mast 87 at a height of 56 m in each of the twelve 30 degree direction sectors are compared to the concurrent wind speeds measured at Mast 33 at 56 m in Figure 6.2. The correlation of wind speeds is reasonable in all sectors, albeit with considerable levels of scatter for the most frequent direction sectors. It is noted that while the scatter within these correlations appears to be quite significant, the review and validation of the synthesis methodology indicates this method to be appropriate for use in this assessment.

Figure 6.3 presents the correlation of wind direction between the two masts. The data are observed to be well correlated, albeit with some non-linearity which has been corrected for in the prediction of wind direction frequency distribution at the target mast.

Directional speed-up factors have been calculated and are presented in Table 6.3. The factors for winds other than from the southwest show a significant deviation from the ratios in the other sectors. This phenomenon may be due to the limited data in these other sectors or the influence of one or both of the local exposure to the predominant wind flow or the vast differences in local terrain to the north through east. It is not expected to have any significant impact on the energy production analysis, as very little energy is available from these winds.

By this method the predicted long-term mean wind speed at Mast 87 at 56 m was found to be 7.3 m/s. The corresponding long-term joint wind speed and direction frequency distribution is presented in Table 6.4 and in Figure 6.4 in the form of a wind rose.

It is observed that the wind rose at Mast 87 has a predominance of winds from the south-southwest through west-southwest.

Data have been recorded at Masts 153 since November 2002. Similar to the process described above, in order to extend the duration of the reference period used for the analysis of the wind regime at the site a correlation approach was used to synthesise the wind speed at Mast 153 at 53 m from data recorded at Mast 37 at 56 m and 35 m over the period September 2001 through November 2002 and small intermittent periods continuing through August 2004. As a check of the validity of the synthesis methodology, synthesised data were compared with concurrent periods of measured data and were noted to be in close agreement. By combining the actual data recorded at Mast 153 at 53 m and the synthesised data from Mast 37, approximately 2.7 years of valid wind speed data were obtained. The long-term mean wind speed and direction frequency distribution for Mast 153 at 53 m was derived from these data.

The measured wind speeds at Mast 153 at a height of 53 m in each of the twelve 30 degree direction sectors are compared to the concurrent wind speeds measured at Mast 37 at 56 m in Figure 6.5. The correlation of wind speeds is good in all sectors, with reasonable levels of scatter for the most frequent direction sectors.

Figure 6.6 presents the correlation of wind direction between the two masts. The data are observed to be well correlated, albeit with some non-linearity which has been corrected for in the prediction of wind direction frequency distribution at the target mast.

Directional speed-up factors have been calculated and are presented in Table 6.5. The factors for winds other than from the west show a slight deviation from the ratios in the other sectors. This phenomenon may be due to the limited data in these other sectors or the influence of one or both of the local exposure to the wind flow or the differences in local terrain. It is not expected to have any significant impact on the energy production analysis, as very little energy is available from these winds.

By this method the predicted long-term mean wind speed at Mast 153 at 53 m was found to be 7.3 m/s. The corresponding long-term joint wind speed and direction frequency distribution is presented in Table 6.6 and in Figure 6.7 in the form of a wind rose.

It is observed that the wind rose at Mast 153 has a predominance of winds from the south-southwest with a significant amount from the west-southwest.

6.3 Hub height wind speeds

Measured wind speed data were used to derive the boundary layer power law exponents at each site mast. These values were used to predict the 67 m long-term mean wind speed at each mast. By this method, the measured vertical shear exponents for Masts 37, 87 and 153 were predicted to be 0.12, 0.15 and 0.18, respectively. The resulting 67 m long-term mean wind speed predictions are 7.6 m/s, 7.5 m/s and 7.7 m/s at Masts 37, 87 and 153, respectively.

6.4 Site wind speed variations

The variation in wind speed over the wind farm site has been predicted using the WAsP computational flow model as described in Appendix 1. The wind flow model has been initiated from the long-term mean wind speed and direction frequency distributions derived for Masts 37, 87 and 153 at 67 m.

Table 6.7 includes a comparison of predicted long-term mean wind speeds at the site masts derived above and using WAsP initiated from Mast 37 at 56 m. These results indicate that the model is predicting the wind speed predictions with reasonable accuracy to masts situated in similar terrain and within similar distances to the back edge of the site. However, with the limited number of site masts, this modelling validation is limited and should be treated as indicative only.

The wind farm is located within complex terrain which includes areas of steep slopes. The presence of steep slopes can cause localised separation of the flow. In regions of separated flow it is known that the accuracy of wind flow modelling is poor due to the formation of a separation bubble which reduces the effective slope, as described by Cook [6.1].

A review of the wind farm was therefore undertaken to establish whether such conditions were present. Areas of steep slopes were noted to be throughout the site, in particular to the north-northeast of the site as the ridge drops off into the Tucannon River Valley as well as to the south-southwest of the ridge features extruding off the main ridge near Turbines 1 to 9, 57 to 59, 69 and 70.

From this investigation it is considered that the conditions for possible over prediction of wind speeds by WAsP, as detailed above, may be present for only a few turbines at the site. The wind speed predictions at Turbines 1 through 9, 69 and 70 were subsequently reduced by 3 % and the wind speed predictions at Turbines 57 through 59 were reduced by 5 % to account for the likely over prediction at those locations. For the remainder of the site GH has initiated the WAsP model from masts most representative of each turbine location without further adjustment.

It is clear from the above that the prediction of the variation in wind speed over the site is challenging, particularly in the areas where the local terrain at the turbine locations is significantly different than that at the mast locations, and an additional allowance has been made for the uncertainty in the wind flow modelling, as detailed in Section 6.6.

In complex terrain, GH generally recommends that all proposed turbine locations are within 1 km of a measurement mast which is at least two thirds of the proposed turbine hub height. These conditions are not met at this site, in particular for Turbines 57 through 74 located in the northeast part of the site where the nearest site masts is located several kilometres away. There is therefore considerable uncertainty in predicting the variation in wind flow using the WAsP computational flow model. It is strongly recommended that additional measurements are conducted at the site to bring these uncertainties to within an acceptable level.

Table 5.3 shows the predicted long-term mean wind speed at each turbine location at hub height. The average long-term mean hub height wind speed for the wind farm as a whole was found to be 7.7 m/s.

6.5 Projected energy production

The energy production of the wind farm is detailed in the table below and definitions of the various loss factors are included in Appendix 1. The energy capture of individual turbines is given in Table 5.3.

Rated Power	**149.4**	**MW**
Ideal output	504.6	GWh/annum
Topographic effect	102.2 %	GH calculated
Wake effect	96.7 %	GH calculated
Electrical efficiency	97.0 %	GH assumption
Availability	97.0 %	GH assumption
Icing and blade degradation	99.0 %	GH assumption
High wind hysteresis	98.8 %	GH estimate
Substation maintenance	99.8 %	Typical value
Utility downtime	100.0 %	Not considered by GH
Power curve adjustment	100.0 %	Not considered by GH
Wind sector management	100.0 %	Not considered by GH
Net output	**457.9**	**GWh/annum**
Capacity factor	**35.0 %**	

The values for topographic and array effect have been calculated using the methods described in Appendix 1. It has been assumed that there are no other operational wind farms in the vicinity of the development.

The table above includes potential sources of energy loss that have been either estimated, assumed or not considered. It is recommended that the client consider each of these losses and the possible effect they may have on the wind farm.

6.6 Uncertainty analysis

The main sources of deviation from the central estimate have been quantified and are shown in Tables 6.8 to 6.10. The figures in each table are added as independent errors giving the following uncertainties in net energy production for the wind farm. These represent the standard deviation of what is assumed to be a Gaussian process:

In any one year period	51.5	GWh/annum
In any ten year period	42.2	GWh/annum

The uncertainties that have been considered in the analysis of the Hopkins Ridge Wind Farm include the following:

- Accuracy of the wind measurements;
- Correlation accuracy;
- The assumption that the period of data available to is representative of the long-term wind regime;
- The accuracy of the extrapolation of wind speeds from the mast height to hub height;
- The accuracy of the wind flow modelling;
- The accuracy of the wake modelling;
- The accuracy of the fiscal sub-station meter;
- The variability of the future annual wind speeds at the site.

There are a number of uncertainties that have not been considered at this stage, including those listed below. It is recommended that the client 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.

- Compliance with the assumed power curve;
- Turbine availability;
- Electrical losses;
- High wind hysteresis;
- Icing and blade degradation;
- Substation maintenance;
- Utility downtime;
- Wind sector management.

6.7 Seasonal and diurnal variation

The expected long-term average seasonal and diurnal variation in energy production has been approximately assessed from the available measured and synthesised site measurements at Masts 37, 87 and 153.

In order to establish the seasonal and diurnal variations in expected energy production, a time-series of air density was derived from on site temperature and pressure records from data recorded at Mast 88. These data were scaled to reflect the long-term site air density of 1.152 kg/m³. These data, together with expected wind speed variations, were used to model the expected variation in energy production on a seasonal and diurnal basis.

Based on the modelled sensitivity of energy production to wind speed, the expected seasonal and diurnal variation in energy production is presented in Table 6.11 in the form of a 12 x 24 matrix. It is noted that the uncertainty associated with the prediction of any given month or hour of day is significantly greater than that associated with the prediction of the mean annual production as presented above.

It is noted that these results presented are inclusive of the topographic effect and array losses only.

7 CONCLUSIONS AND RECOMMENDATIONS

Wind data have been recorded at the Hopkins Ridge site for a period of approximately 3 years. Based on the results from the analysis of these data the following conclusions are made concerning the site wind regime.

1. The long-term mean wind speeds are estimated to be 7.6 m/s, 7.5 m/s and 7.7 m/s at a height of 67 m above ground level at the locations of Masts 37, 87 and 153.

2. The standard error associated with these predictions of long-term mean wind speeds is 0.3 m/s at each mast. If a normal distribution is assumed, the confidence limits for the predictions are as given in the table below:

Probability of exceedance [%]	**Long-term mean wind speeds at site masts at 67 m [m/s]**		
	Mast 37	**Mast 87**	**Mast 153**
90	7.2	7.1	7.3
75	7.4	7.3	7.5
50	7.6	7.5	7.7

Site wind flow and array loss calculations have been carried out and from these we draw the following conclusions:

3. The long-term mean wind speed averaged over all turbine locations at hub height is estimated to be 7.7 m/s.

4. The projected energy capture of the proposed wind farm is 457.9 GWh/annum. This includes calculation of the topographical, array and air density effects and assumptions or estimates for electrical transmission losses, availability, power curve adjustment, high wind hysteresis, substation maintenance, and the effect of blade fouling or icing.

There are a number of other losses that could affect the net energy output of the wind farm, as detailed in Appendix 1, but these have not been considered here. It is recommended that the client considers each of these losses and the possible effect they may have on the net energy production.

The net energy prediction presented above represents the long-term mean, 50 % exceedance level, for the annual energy production of the wind farm. This value is the best estimate of the long-term mean value to be expected from the project. There is therefore a 50 % chance that, even when taken over very long periods, the mean energy production will be less than the value given.

5. The standard error associated with the prediction of energy capture has been calculated and the confidence limits for the prediction are given in the table below:

Probability of Exceedance [%]	Net energy output 1 year average [GWh/annum]	10 year average [GWh/annum]
90	391.9	403.7
75	423.1	429.4
50	457.9	457.9

There are a number of uncertainties that have not been considered at this stage, as detailed in Section 6. It is recommended that the client 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.

6. The manufacture-supplied power curve assumed in this assessment should be verified against an independently measured power curve.

7. It is noted that the prediction of wind speeds at the extremities of this site is particularly challenging as there are currently no meteorological masts in these regions. A significant extrapolation has therefore been required using the WAsP wind flow model, which is subject to large uncertainties in this type of flow regime. The model has been adjusted based on GH experience. Higher wind speeds are expected in these areas and the adjusted model is predicting this trend. However, in order to reduce the uncertainty associated with the energy predictions for turbines located significant distances from any site mast, in particular near Turbines 1 to 9 and 57 through 74, it is strongly recommended that additional masts be installed in the vicinity of these proposed turbine locations.

REFERENCES

2.1 "Wind speed profiles over terrain with roughness changes", Engineering Sciences Data , Item No. 84011, April 1993.

2.2 RES Hopkins Ridge site mast commissioning forms and maintenance records obtained from RES ftp site; ftp details provided via email from Andrew Oliver, RES, to Adam Schwarz, GH, 13 August 2004.

2.3 Recommended Practices for Wind Turbine Testing and Evaluation, "11. Wind speed measurement and use of cup anemometry", IEA, Edition 1, 1999.

5.1 Email from Andrew Oliver, RES, to Ryan Adams, GH, 8 November 2004.

5.2 "Wind turbine generator systems – Part 12: Wind turbine power performance testing", BS EN 61400-12: BSI, 1998.

6.1 Cook N J "The Designer's" guide to wind loading of building structures"., Part 1, Butterworths, 1985.

LIST OF TABLES

2.1 Summary of measurements made at the site

4.1 Measurements made at Mast 33 at a height of 56 m

4.2 Measurements made at Mast 37 at a height of 56 m

4.3 Measurements made at Mast 87 at a height of 56 m

4.4 Measurements made at Mast 153 at a height of 53 m

5.1 Main parameters of the wind turbine analysed – V80 IEC Class 1

5.2 Performance data for the wind turbine analysed – V80 IEC Class 1

5.3 Turbine layout with predicted individual turbine wind speed and energy production

6.1 Measured and synthesised monthly and annual mean wind speeds at Mast 37 at 56 m (2001 to 2004)

6.2 Measured and synthesised wind speed and direction frequency distribution at Mast 37 at 56 m

6.3 Directional correlation ratios between Mast 33 at 56 m and Mast 87 at 56 m

6.4 Measured and synthesised wind speed and direction frequency distribution at Mast 87 at 56 m

6.5 Directional correlation ratios between Mast 37 at 56 m and Mast 153 at 53 m

6.6 Measured and synthesised wind speed and direction frequency distribution at Mast 153 at 53 m

6.7 Predictions of the wind speeds at the site masts from Mast 37 at 67 m

6.8 Uncertainty in projected energy output of Turbines 1 to 30 and 51 to 56 based on Mast 37 at 67 m

6.9 Uncertainty in projected energy output of Turbines 57 to 100 based on Mast 87 at 67 m

6.10 Uncertainty in projected energy output of Turbines 31 to 50 based on Mast 153 at 67 m

6.11 Predicted seasonal and diurnal variation in energy production

LIST OF FIGURES

2.1 Location of the Wind Farm

2.2 Map of the site

2.3 View to the southwest of Mast 35

5.1 Layout of the proposed Hopkins Ridge Wind Farm

6.1 Measured annual wind rose for Mast 37 at 56 m

6.2 Correlation of ten-minute mean wind speed from Mast 87 at 56 m to Mast 33 at 56 m

6.3 Correlation of ten-minute mean wind direction from Mast 87 at 54 m to Mast 33 at 54 m

6.4 Predicted annual wind rose for Mast 87 at 56 m

6.5 Correlation of ten-minute mean wind speed from Mast 153 at 53 m to Mast 37 at 56 m

6.6 Correlation of ten-minute mean wind direction from Mast 153 at 50 m to Mast 37 at 54 m

6.7 Predicted annual wind rose for Mast 153 at 53 m

Location	Description of measurements	Period
Mast 33 (445944, 5133615)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 30 m height. Ten minute mean and standard deviation direction recorded at 54 m height.	1 Jul 2001 – 2 Aug 2004
Mast 35 (442882, 5140942)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 30 m height. Ten minute mean and standard deviation direction recorded at 54 m height.	30 Jun 2001 – 8 Sep 2002, 22 Oct 2002 – 2 Aug 2004
	Five minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 30 m height. Five minute mean and standard deviation direction recorded at 54 m height.	8 Sep 2002 – 22 Oct 2002
Mast 37 (434593, 5143903)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 35 m height. Ten minute mean and standard deviation direction recorded at 54 m height.	28 Sep 2001 – 3 Aug 2004

Table 2.1 Summary of measurements made at the site (continued)

Location	Description of measurements	Period
Mast 85 (444185, 5135619)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 35 m height. Ten minute mean and standard deviation direction recorded at 54 m and 34 m height.	5 Apr 2002 – 2 Aug 2004
Mast 87 (440427, 5139611)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 35 m height. Ten minute mean and standard deviation direction recorded at 54 m height.	5 Apr 2002 – 8 Jul 2004
Mast 88 (441342, 5136954)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 35 m height. Ten minute mean and standard deviation direction recorded at 54 m height.	5 Apr 2002 – 8 Jul 2004
Mast 153 (436032, 5142356)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 53 m and 35 m height. Ten minute mean and standard deviation direction recorded at 50 m and 34 m height.	27 Nov 2002 – 10 Jul 2004

Table 2.1 Summary of measurements made at the site (continued)

Location	Description of measurements	Period
Mast 154 (438431, 5136106)	Ten minute mean, standard deviation, maximum and 3-second gust wind speed recorded at 56 m and 35 m height. Ten minute mean and standard deviation direction recorded at 54 m and 34 m height.	27 Nov 2002 – 8 Jul 2004

Table 2.1 Summary of measurements made at the site (concluded)

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Jul-01	6.1	98	98
Aug-01	5.4	100	100
Sep-01	5.8	100	100
Oct-01	8.3	100	100
Nov-01	7.5	100	100
Dec-01	7.5	98	98
Jan-02	8.8	98	98
Feb-02	6.9	100	100
Mar-02	9.1	92	92
Apr-02	7.2	100	100
May-02	7.1	100	100
Jun-02	6.4	100	100
Jul-02	6.5	100	100
Aug-02	6.0	100	100
Sep-02	6.0	100	100
Oct-02	4.9	95	95
Nov-02	6.2	100	100
Dec-02	8.6	69	69
Jan-03	6.6	78	78
Feb-03	6.6	100	100
Mar-03	6.9	13	13
Apr-03	6.4	99	99
May-03	6.3	100	100
Jun-03	6.6	100	100
Jul-03	6.2	100	100
Aug-03	5.8	100	100
Sep-03	6.4	100	100
Oct-03	7.1	100	100
Nov-03	7.9	100	100
Dec-03	6.3	99	99
Jan-04	7.0	92	92
Feb-04	5.7	100	100
Mar-04	8.2	100	100
Apr-04	5.9	100	100
May-04	7.3	100	100
Jun-04	6.0	100	100
Jul-04	6.2	100	100
Aug-04	4.2	4	4

Table 4.1 **Measurements made at Mast 33 at a height of 56 m**

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Sep-01	2.8	8	8
Oct-01	8.6	100	100
Nov-01	7.2	100	100
Dec-01	8.5	89	89
Jan-02	10.0	83	83
Feb-02	6.9	100	100
Mar-02	10.2	81	88
Apr-02	-	0	100
May-02	6.9	46	100
Jun-02	7.5	100	100
Jul-02	7.4	100	100
Aug-02	6.7	100	100
Sep-02	6.7	100	100
Oct-02	5.3	100	100
Nov-02	5.7	94	94
Dec-02	8.2	77	77
Jan-03	6.7	74	74
Feb-03	6.8	100	100
Mar-03	9.7	100	100
Apr-03	7.4	100	100
May-03	7.2	100	100
Jun-03	7.6	100	100
Jul-03	7.2	100	100
Aug-03	6.6	100	100
Sep-03	6.8	100	100
Oct-03	7.5	100	100
Nov-03	8.1	100	100
Dec-03	6.5	91	91
Jan-04	7.6	75	75
Feb-04	5.3	97	97
Mar-04	9.0	100	100
Apr-04	6.5	100	100
May-04	8.2	100	100
Jun-04	7.1	100	100
Jul-04	7.2	100	100
Aug-04	6.1	5	5

Table 4.2 **Measurements made at Mast 37 at a height of 56 m**

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Apr-02	8.5	85	85
May-02	7.6	100	100
Jun-02	7.1	100	100
Jul-02	7.2	100	100
Aug-02	6.5	100	100
Sep-02	6.7	100	100
Oct-02	5.3	100	100
Nov-02	6.0	96	96
Dec-02	8.5	71	71
Jan-03	7.1	71	71
Feb-03	7.0	100	100
Mar-03	9.8	100	100
Apr-03	6.9	100	100
May-03	6.8	100	100
Jun-03	7.3	100	100
Jul-03	6.9	100	100
Aug-03	6.4	100	100
Sep-03	6.9	100	100
Oct-03	7.6	100	100
Nov-03	8.4	100	100
Dec-03	6.4	96	96
Jan-04	7.5	79	79
Feb-04	5.7	100	100
Mar-04	9.0	100	100
Apr-04	6.3	100	100
May-04	8.0	100	100
Jun-04	6.7	100	100
Jul-04	9.0	24	24

Table 4.3 **Measurements made at Mast 87 at a height of 56 m**

UE-170033/UG-170034

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Dec-02	8.8	71	71
Jan-03	6.7	75	77
Feb-03	6.8	100	100
Mar-03	9.8	99	88
Apr-03	7.3	100	100
May-03	7.1	100	100
Jun-03	7.5	100	100
Jul-03	7.1	100	100
Aug-03	6.5	100	100
Sep-03	6.9	100	100
Oct-03	7.7	100	100
Nov-03	8.2	100	100
Dec-03	6.5	92	94
Jan-04	7.4	77	78
Feb-04	5.8	96	96
Mar-04	9.0	100	100
Apr-04	6.4	100	100
May-04	8.1	100	100
Jun-04	7.0	100	100
Jul-04	9.0	30	30

Table 4.4 Measurements made at Mast 153 at a height of 53 m

Diameter	80 m
Hub height	67 m
Rotor speed	16.8 rpm
Power regulation	Pitch
No. of blades	3
Nominal rated power	1800 kW

Table 5.1 Main parameters of the wind turbine analysed – V80 IEC Class 1

Wind speed [m/s at hub height]	**Electrical power [kW]**
3	0
4	0
5	89
6	233
7	431
8	689
9	959
10	1270
11	1579
12	1759
13	1795
14	1801
15	1802
16	1802
17	1802
18	1802
19	1802
20	1802
21	1802
22	1802
23	1802
24	1800
25	1800

Performance for air density 1.15 kg/m^3 and 10 % turbulence intensity

Table 5.2 Performance data for the wind turbine analysed– V80 IEC Class 1

Turbine	Easting[1] [m]	Northing[1] [m]	Mean hub-height wind speed[2] [m/s]	Energy output[3] [GWh/annum]
T1	432520	5145114	8.0	6.1
T2	432701	5145089	8.0	6.1
T3	432914	5145094	8.2	6.2
T4	433078	5145050	8.5	6.5
T5	433269	5144951	8.3	6.3
T6	433437	5144920	8.1	6.1
T7	433634	5144890	8.2	6.2
T8	433793	5144852	8.0	6.1
T9	433959	5144798	8.0	6.2
T10	434082	5144644	8.1	6.2
T11	434227	5144569	8.0	6.1
T12	434341	5144395	7.7	5.9
T13	434455	5144221	7.7	5.9
T14	434574	5144115	7.7	6.0
T15	434714	5144010	7.6	6.0
T16	434989	5144056	7.7	6.0
T17	435126	5143986	7.8	6.1
T18	435263	5143915	7.7	6.1
T19	435408	5143863	7.6	5.9
T21	435898	5143863	7.6	5.9
T22	436030	5143784	7.7	6.0
T23	432007	5144430	7.7	6.1
T24	432089	5144299	7.6	6.1
T26	432281	5143981	7.3	5.9
T27	432722	5143868	7.5	5.8
T28	432797	5143733	7.5	5.9
T29	432872	5143599	7.5	5.9
T30	432947	5143464	7.5	6.0
T31	433647	5143811	7.7	6.1
T32	433768	5143715	7.7	6.1
T33	433893	5143625	7.5	6.1
T34	434571	5142305	7.6	6.1
T35	434704	5142228	7.6	6.1
T36	434838	5142151	7.6	6.0
T37	434971	5142074	7.6	6.1
T41	435544	5142716	7.7	5.9
T42	435681	5142645	7.7	6.1
T43	435795	5142542	7.7	6.1
T44	435910	5142439	7.7	6.1

Notes
1 Co-ordinate system is UTM NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production (continued)

Turbine	Easting[1] [m]	Northing[1] [m]	Mean hub-height wind speed[2] [m/s]	Energy output[3] [GWh/annum]
T45	436024	5142336	7.7	6.1
T46	436136	5142230	7.7	6.1
T47	436264	5142145	7.7	6.2
T48	436392	5142059	7.8	6.3
T49	436521	5141974	7.8	6.3
T50	436648	5141889	7.8	6.3
T51	437143	5142264	7.8	5.9
T52	437221	5142131	7.8	6.0
T53	437297	5141997	7.8	6.0
T54	437372	5141862	7.6	6.1
T55	437013	5142925	7.6	5.7
T56	437211	5142852	7.7	5.8
T57	438184	5143876	8.4	6.2
T58	438380	5143782	8.2	6.1
T59	438571	5143647	8.3	6.2
T60	438562	5143160	8.3	6.2
T61	438698	5143087	8.2	6.1
T62	438981	5143127	8.4	6.2
T63	439092	5143020	8.3	6.2
T64	439238	5142959	8.1	6.1
T67	439382	5142055	7.8	6.1
T68	439512	5141958	7.8	6.1
T69	437941	5142371	7.7	5.8
T70	438028	5142245	7.6	5.8
T71	438287	5142175	7.5	5.8
T72	438396	5142067	7.5	5.9
T73	438615	5142016	7.5	5.8
T74	438769	5141960	7.5	5.8
T77	439676	5141294	7.7	6.0
T78	439842	5141250	7.7	5.9
T81	437248	5139664	7.5	5.9
T82	437374	5139577	7.6	5.9
T83	437501	5139491	7.5	5.9
T84	437629	5139405	7.4	5.8
T85	437757	5139319	7.4	5.8
T88	438799	5139023	7.3	5.7
T89	439010	5138969	7.4	5.7
T90	439221	5138915	7.4	5.8
T95	440006	5139723	7.4	5.7

Notes

1 Co-ordinate system is UTM NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production (continued)

Turbine	Easting[1] [m]	Northing[1] [m]	Mean hub-height wind speed[2] [m/s]	Energy output[3] [GWh/annum]
T96	440124	5139621	7.4	5.7
T97	440272	5139577	7.4	5.6
T98	440417	5139526	7.5	5.7
T99	440562	5139474	7.4	5.8
T100	440707	5139423	7.4	5.8

Notes
1 Co-ordinate system is UTM NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production (concluded)

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
January	8.2	77	77
February	6.4	99	99
March	9.6	96	96
April	7.3	100	100
May	7.8	100	100
June	7.4	100	100
July	7.3	100	100
August	6.6	100	100
September	6.6	100	100
October	7.1	100	100
November	7.0	98	98
December	7.7	85	85
Mean of means	**7.4**		

Table 6.1 **Measured and synthesised monthly and annual mean wind speeds at Mast 37 at 56 m (2001 to 2004)**

Site: Mast 33 at 56 m **Period:** Annual (2001 to 2004)

Wind Speed (m/s)	Wind Direction (degrees)												No Direction	Total (%)
	0	30	60	90	120	150	180	210	240	270	300	330		
0	0.04	0.06	0.06	0.04	0.03	0.04	0.06	0.06	0.07	0.06	0.03	0.03		0.58
1	0.60	0.64	0.66	0.69	0.51	0.49	0.67	0.74	0.83	0.69	0.50	0.54		7.55
2	0.94	0.70	0.92	0.98	0.48	0.44	0.79	1.35	1.24	0.97	0.90	0.79		10.49
3	0.68	0.51	0.71	1.04	0.37	0.29	0.81	1.85	1.31	0.93	1.13	0.75		10.39
4	0.38	0.32	0.56	0.91	0.28	0.24	0.95	2.10	1.47	0.72	0.62	0.37		8.91
5	0.24	0.28	0.41	0.76	0.18	0.23	1.04	2.09	1.53	0.43	0.24	0.11		7.51
6	0.10	0.20	0.29	0.58	0.16	0.23	1.00	2.02	1.41	0.24	0.09	0.04		6.34
7	0.03	0.09	0.17	0.37	0.10	0.21	1.06	2.04	1.23	0.14	0.03	0.01		5.47
8	0.02	0.04	0.12	0.19	0.10	0.17	0.91	2.33	0.91	0.07	0.02	0.01		4.88
9	0.01	0.01	0.09	0.11	0.05	0.12	0.89	2.66	0.72	0.05	0.01	0.01		4.71
10		0.01	0.04	0.07	0.02	0.12	0.89	2.95	0.60	0.04	0.01	+		4.76
11	+	0.01	0.03	0.03	0.01	0.10	0.76	3.21	0.44	0.02	0.01			4.62
12		+	0.03	0.01	0.01	0.08	0.68	3.42	0.33	0.01	+			4.58
13		+	0.02	0.01	+	0.04	0.56	3.44	0.22	0.01	+			4.30
14			+	+	+	0.04	0.42	3.17	0.14	0.01				3.78
15					+	0.03	0.39	2.80	0.11	0.01				3.33
16						0.01	0.33	2.17	0.06	0.01				2.58
17						0.01	0.22	1.58	0.06	0.01				1.87
18						0.01	0.13	1.05	0.04	+				1.23
19						0.01	0.07	0.66	0.02	+				0.76
20						0.01	0.05	0.41	0.02	+				0.48
21						0.01	0.03	0.28	0.01					0.32
22						+	0.02	0.19	0.01	+				0.22
23							0.02	0.10	0.01					0.13
24						+	0.02	0.07	0.01					0.09
25							0.01	0.06	+					0.07
26							+	0.03	+					0.03
27							+	0.01	+					0.02
28							+	0.01						0.01
29								+						+
30														
31														
32														
33														
34														
35														
36														
37														
38														
39 - 44														
45 and over														
Total (%)	3.03	2.88	4.09	5.78	2.31	2.90	12.79	42.81	12.80	4.39	3.59	2.64		100
Av.Speed (m/s)	2.72	3.05	3.62	3.98	3.47	5.24	8.04	10.54	6.03	3.46	2.93	2.57	0.00	7.42

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

Table 6.2 **Measured and synthesised wind speed and direction frequency distribution at Mast 37 at 56 m**

Direction sector [degrees]	Number of records	Correlation ratio
345 – 15	852	1.06
15 – 45	1280	0.96
45 – 75	1019	1.02
75 – 105	1249	1.03
105 – 135	4099	0.96
135 – 165	3123	0.94
165 – 195	5535	0.97
195 – 225	27265	1.15
225 – 255	26581	1.08
255 – 285	4040	0.93
285 – 315	983	0.98
315 – 345	797	0.99

Table 6.3 Directional correlation ratios between Mast 33 at 56 m and Mast 87 at 56 m

Site: Mast 87 at 56 m **Period:** Annual (2001 to 2004)

Wind Speed (m/s)	Wind Direction (degrees)												No Direction	Total (%)
	0	30	60	90	120	150	180	210	240	270	300	330		
0	0.03	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.04		0.27
1	0.51	0.47	0.50	0.55	0.54	0.42	0.49	0.45	0.46	0.38	0.34	0.45		5.55
2	1.01	0.69	0.54	0.89	1.10	0.93	0.88	0.80	0.82	0.72	0.70	0.76		9.84
3	1.07	0.66	0.31	0.64	1.63	1.43	1.12	1.01	1.19	0.99	0.76	0.85		11.64
4	0.66	0.50	0.25	0.42	1.54	1.12	1.14	1.29	1.56	1.06	0.52	0.46		10.51
5	0.27	0.30	0.24	0.29	1.02	0.52	0.82	1.51	1.93	0.76	0.22	0.15		8.03
6	0.06	0.16	0.20	0.17	0.32	0.16	0.71	1.67	2.25	0.49	0.07	0.04		6.28
7	0.02	0.07	0.12	0.10	0.09	0.06	0.62	2.09	2.32	0.28	0.03	0.02		5.82
8	0.01	0.02	0.08	0.08	0.03	0.03	0.59	2.32	2.12	0.13	0.02	+		5.41
9	+	0.01	0.04	0.05	0.02	0.02	0.46	2.54	2.18	0.07	0.01	+		5.39
10		+	0.02	0.03	+	0.01	0.41	2.86	2.10	0.03	0.01	+		5.47
11		+	0.01	0.01	0.01	0.01	0.34	2.90	1.72	0.02	0.01	+		5.04
12		+	+	0.01	+	0.01	0.27	2.89	1.42	0.02	+			4.61
13			+	+	+	+	0.21	2.67	1.07	0.01	+	+		3.97
14					+	+	0.16	2.28	0.88	0.01				3.33
15			+	+	+	+	0.11	1.90	0.61	0.01	+			2.63
16						+	0.09	1.37	0.41	0.01	+			1.89
17						+	0.07	0.98	0.28	0.01				1.34
18						+	0.05	0.70	0.21	+				0.96
19						+	0.04	0.45	0.12	+	+			0.61
20						+	0.04	0.33	0.09	+				0.46
21							0.02	0.23	0.07	+				0.32
22							0.01	0.17	0.06	+				0.24
23							0.01	0.11	0.03					0.15
24							+	0.07	0.03					0.10
25								0.04	0.02					0.06
26								0.03	0.01					0.04
27								0.01	0.01					0.02
28						+		0.01	0.01					0.02
29								+	+					0.01
30								+						+
31								+	+					+
32								+						+
33														
34														
35														
36														
37														
38														
39 - 44														
45 and over														
Total (%)	3.62	2.91	2.33	3.25	6.32	4.74	8.66	33.69	23.99	5.00	2.72	2.77		100
Av.Speed (m/s)	2.83	3.13	3.49	3.28	3.47	3.37	6.36	10.56	8.54	4.17	3.06	2.73	0.00	7.28

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

Table 6.4 **Measured and synthesised wind speed and direction frequency distribution at Mast 87 at 56 m**

Direction sector [degrees]	Number of records	Correlation ratio
345 – 15	733	0.98
15 – 45	822	1.00
45 – 75	1702	1.03
75 – 105	2679	1.02
105 – 135	959	1.05
135 – 165	1451	0.98
165 – 195	8584	0.95
195 – 225	32093	0.97
225 – 255	7900	1.06
255 – 285	1484	1.11
285 – 315	742	1.03
315 – 345	467	1.01

Table 6.5 Directional correlation ratios between Mast 37 at 56 m and Mast 153 at 53 m

Site: **Mast 153 at 53 m** **Period:** **Annual (2001 to 2004)**

Wind Speed (m/s)	Wind Direction (degrees)												No Direction	Total (%)
	0	30	60	90	120	150	180	210	240	270	300	330		
0	0.03	0.04	0.04	0.03	0.03	0.03	0.03	0.05	0.06	0.04	0.03	0.03		0.43
1	0.54	0.50	0.61	0.64	0.53	0.40	0.48	0.75	0.85	0.66	0.36	0.46		6.74
2	0.93	0.72	0.88	0.92	0.70	0.44	0.63	1.29	1.35	1.00	0.64	0.70		10.20
3	0.75	0.59	0.74	0.91	0.60	0.34	0.59	1.76	1.57	1.07	0.69	0.71		10.31
4	0.37	0.36	0.50	0.81	0.47	0.30	0.59	2.31	1.67	0.86	0.39	0.33		8.97
5	0.17	0.26	0.35	0.65	0.36	0.25	0.61	2.44	1.77	0.66	0.16	0.09		7.76
6	0.07	0.14	0.27	0.48	0.29	0.20	0.65	2.40	1.75	0.36	0.05	0.04		6.70
7	0.01	0.06	0.19	0.31	0.23	0.17	0.57	2.53	1.56	0.21	0.02	0.01		5.86
8	0.01	0.02	0.10	0.20	0.16	0.10	0.43	2.88	1.36	0.12	0.01	0.01		5.38
9	+	0.01	0.05	0.11	0.08	0.07	0.43	3.09	1.14	0.07	0.01	+		5.06
10		0.01	0.04	0.08	0.05	0.05	0.36	3.54	1.10	0.04	+	+		5.26
11	+	+	0.02	0.04	0.03	0.03	0.25	3.88	0.91	0.04	+			5.21
12			0.02	0.02	0.01	0.01	0.23	3.84	0.69	0.02	+			4.84
13			0.01	0.01	0.01	0.01	0.18	3.53	0.53	0.01	+	+		4.28
14			+	+	+	0.01	0.17	3.10	0.38	0.01	+			3.68
15			+	+	+	+	0.14	2.58	0.25	0.01	+			2.98
16			+		+	0.01	0.10	1.97	0.18	0.01	+			2.26
17			+			+	0.09	1.24	0.11	0.01	+			1.45
18						+	0.05	0.79	0.10	+				0.94
19						+	0.04	0.50	0.07					0.60
20							0.03	0.31	0.03	+				0.38
21						+	0.03	0.18	0.03	+				0.24
22						+	0.02	0.12	0.03					0.17
23							0.01	0.08	0.01					0.11
24							0.01	0.05	0.02					0.08
25							0.01	0.04	0.01					0.05
26							+	0.02	+					0.02
27							+	0.01	+					0.01
28						+		0.01	+					0.01
29								+	+					+
30									+					+
31														
32														
33														
34														
35														
36														
37														
38														
39 - 44														
45 and over														
Total (%)	2.88	2.69	3.83	5.22	3.54	2.43	6.70	45.26	17.53	5.19	2.37	2.37		100
Av.Speed (m/s)	2.64	2.97	3.57	4.02	3.90	4.20	7.00	10.14	6.98	3.77	2.90	2.61	0.00	7.35

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

Table 6.6 **Measured and synthesised wind speed and direction frequency distribution at Mast 153 at 53 m**

Mast	Hub height [m]	Long-term mean wind speed MCP [m/s]	WAsP [m/s]
37*	67	7.6	7.6
87	67	7.5	7.4
153	67	7.7	7.5

* indicates WAsP initiation mast

Table 6.7 **Predictions of the wind speeds at the site masts from Mast 37 at 67 m**

Source of uncertainty	**Wind speed** [%]	[m/s]	**Energy output** [1] [%]	[GWh/annum]
Anemometer accuracy	2.0	0.15		
Correlation accuracy 35 m to 56 m	0.0	0.00		
Shear extrapolation to 67 m	1.0	0.08		
Variability of 2.7 year period	3.6	0.28		
Overall historical wind speed		**0.32**		**8.6**
Substation metering			0.3	0.6
Wake and topographic calculation			8.0	15.1
Future wind variability (1 year)	6.0			12.1
Future wind variability (10 years)	1.9			3.8
Overall energy uncertainty (1 year)				**21.2**
Overall energy uncertainty (10 years)				**17.8**

Note: Sensitivity of net production to wind speed is calculated to be 26.6 GWh/annum.(m/s)

Table 6.8 **Uncertainty in projected energy output of Turbines 1 to 30 and 51 to 56 based on Mast 37 at 67 m**

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.0	0.15		
Correlation accuracy Mast 33 to Mast 87	0.4	0.03		
Shear extrapolation to 67 m	1.0	0.07		
Variability of 3.0 year period	3.4	0.26		
Overall historical wind speed		**0.31**		**8.4**
Substation metering			0.3	0.5
Wake and topographic calculation			8.0	13.9
Future wind variability (1 year)	6.0			12.3
Future wind variability (10 years)	1.9			3.9
Overall energy uncertainty (1 year)				**20.4**
Overall energy uncertainty (10 years)				**16.7**

Note: Sensitivity of net production to wind speed is calculated to be 27.3 GWh/annum.(m/s)

Table 6.9 Uncertainty in projected energy output of Turbines 57 to 100 based on Mast 87 at 67 m

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.0	0.15		
Correlation accuracy Mast 37 to 153	0.3	0.03		
Correlation accuracy Mast 37 to 153	0.0	0.00		
Shear extrapolation to 67 m	1.0	0.08		
Variability of 2.7 year period	3.6	0.28		
Overall historical wind speed		**0.33**		**4.7**
Substation metering			0.3	0.3
Wake and topographic calculation			6.0	5.7
Future wind variability (1 year)	6.0			6.6
Future wind variability (10 years)	1.9			2.1
Overall energy uncertainty (1 year)				**10.0**
Overall energy uncertainty (10 years)				**7.7**

Note: Sensitivity of net production to wind speed is calculated to be 14.4 GWh/annum.(m/s)

Table 6.10 Uncertainty in projected energy output of Turbines 31 to 50 based on Mast 153 at 67 m

	Energy production[1] [%]											
Hour	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
0000	0.38	0.29	0.57	0.34	0.44	0.39	0.46	0.41	0.39	0.31	0.33	0.39
0100	0.39	0.28	0.56	0.38	0.43	0.43	0.48	0.44	0.43	0.31	0.31	0.39
0200	0.39	0.28	0.57	0.40	0.43	0.45	0.52	0.45	0.41	0.33	0.31	0.39
0300	0.39	0.28	0.55	0.37	0.44	0.48	0.53	0.46	0.41	0.34	0.32	0.38
0400	0.40	0.30	0.53	0.37	0.45	0.48	0.50	0.46	0.40	0.34	0.33	0.36
0500	0.40	0.30	0.53	0.36	0.43	0.46	0.48	0.41	0.37	0.33	0.35	0.39
0600	0.41	0.32	0.52	0.37	0.40	0.44	0.45	0.37	0.35	0.33	0.34	0.36
0700	0.43	0.32	0.51	0.36	0.42	0.43	0.42	0.37	0.33	0.34	0.33	0.39
0800	0.42	0.30	0.52	0.39	0.43	0.38	0.39	0.33	0.31	0.34	0.30	0.39
0900	0.39	0.31	0.53	0.39	0.43	0.33	0.36	0.26	0.30	0.32	0.33	0.41
1000	0.39	0.32	0.56	0.37	0.43	0.29	0.31	0.22	0.29	0.32	0.34	0.38
1100	0.38	0.34	0.58	0.34	0.42	0.27	0.28	0.20	0.27	0.32	0.35	0.38
1200	0.36	0.31	0.58	0.29	0.41	0.25	0.26	0.19	0.27	0.31	0.34	0.37
1300	0.40	0.28	0.57	0.26	0.38	0.24	0.26	0.18	0.26	0.28	0.33	0.33
1400	0.38	0.26	0.54	0.25	0.35	0.21	0.25	0.17	0.25	0.26	0.31	0.31
1500	0.35	0.22	0.52	0.24	0.34	0.20	0.24	0.16	0.26	0.24	0.30	0.32
1600	0.37	0.19	0.48	0.26	0.34	0.21	0.24	0.15	0.24	0.25	0.30	0.32
1700	0.38	0.20	0.47	0.22	0.30	0.21	0.20	0.15	0.22	0.23	0.31	0.33
1800	0.38	0.19	0.45	0.21	0.30	0.21	0.18	0.15	0.24	0.23	0.31	0.35
1900	0.40	0.21	0.44	0.21	0.32	0.25	0.21	0.17	0.26	0.23	0.30	0.35
2000	0.45	0.21	0.43	0.22	0.34	0.30	0.26	0.21	0.27	0.26	0.32	0.36
2100	0.45	0.21	0.46	0.26	0.40	0.33	0.30	0.25	0.32	0.28	0.35	0.39
2200	0.43	0.23	0.51	0.28	0.42	0.36	0.38	0.31	0.36	0.30	0.35	0.41
2300	0.45	0.27	0.55	0.31	0.45	0.37	0.45	0.36	0.36	0.31	0.34	0.41
Total	9.59	6.41	12.51	7.46	9.50	7.98	8.38	6.83	7.57	7.10	7.81	8.86

Note Energy production has been modelled using the Hopkins Ridge 83 x V80 layout at 67 m. The values presented are inclusive of topographical and array losses only.

Table 6.11 Predicted seasonal and diurnal variation in energy production

APPENDIX 1

Data analysis procedure

1. Correlation of wind speed and direction.
2. Site wind speed variations.
3. Projected energy production
4. Confidence analysis
5. References

1 Correlation of wind speed and direction

The method used to determine the long-term mean wind speed for a "target" site from a "reference" site is based on the Measure-Correlate-Predict approach, which is outlined below.

The first stage in the approach is to measure, over a period of about one year, concurrent wind data from both the "target" site and the nearby "reference" site for which well established long-term wind records are available. The short-term measured wind data are then used to establish the correlation between the winds at the two locations. Finally, the correlation is used to adjust the long-term historical data recorded at the "reference" site to calculate the long-term mean wind speed at the site.

The concurrent data are correlated by comparing wind speeds at the two locations for each of twelve 30 degree direction sectors, based on the wind direction recorded at the "reference" site. 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. Only those records with speeds in excess of 5 m/s at both locations are used.

- Wind speed ratios are determined for each of the direction sectors using a principal component analysis with the solution forced through the origin. This method is equivalent to a linear least-squared regression forced through the origin minimising the orthogonal offset.

In order to minimise the influence of localised winds on the wind speed ratio, the data are screened to reject records where the speed recorded at the "reference" site falls below 3 m/s or a slightly different level at the "target" site. The average wind speed ratio is used to adjust the 3 m/s wind speed level for the "reference" site to obtain the higher level for the "target" site, to ensure unbiased exclusion of data. The wind speed at which this level is set is a balance between excluding low winds from the analysis and still having sufficient data for the analysis. The level used excludes only winds below the cut-in wind speed of a wind turbine which do not contribute to the energy production.

The result of the analysis described above is a table of wind speed ratios, each corresponding to one of twelve direction sectors. These ratios are used to factor the wind data measured at the "reference" site over the historical reference period, to obtain the long-term mean wind speed at the "target" site.

2 Site wind speed variations

To calculate the variation of mean 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 [1].

The inputs to the model are a digitised map of the topography and surface roughness length of the terrain for the site and surrounding area. A digitised map of an area surrounding the site of 30 km x 30 km was derived from USGS 1:24000 scale maps. Although this domain size is much larger than the area of the site itself, such an area is necessary since the flow at any point is dictated by the terrain several kilometres upwind.

Wind flow is affected by the roughness of the ground. The surface roughness length of the site and surrounding area has been estimated, as detailed in the main text.

The wind flow calculations were carried out for 30 degree steps in wind direction corresponding to the measured wind rose and results were produced as speed-up factors relative to the mast location for a grid encompassing the site area.

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

3 Projected energy production

The components of the derivation of the wind farm net energy output prediction are listed and described below:

Ideal energy output

The ideal energy production is the theoretical output of the wind farm with the hub height wind speeds at the appropriate mast location applied for all associated turbines. Any density adjustment required due to a difference between the air density at hub height at the reference mast location and that assumed for the turbine power curve is applied as discussed in the main body of the report and included in the ideal energy output.

Topographic and wake effect calculations

The first step in modelling flow through an array of wind turbines is the calculation of the flow in the wake of a single machine. Immediately downstream of the rotor, there is a momentum deficit with respect to free stream conditions, which is equal to the thrust force on the machine. As the flow proceeds downstream, there is a spreading of the wake and recovery to free stream conditions. Turbulent momentum transfer is important in this process.

The model used here, WindFarmer, has been developed by GH and validated using measurements on both full-scale machines and on wind-tunnel models [2, 3, 4].

The model is employed in a scheme which, taking each wind speed and direction in turn calculates the power production of the wind farm. The important parameters used in this process are:

- array layout
- upstream mean wind speed
- ambient turbulence
- wind turbine thrust characteristic
- wind turbine power characteristic
- rotor speed
- topographical speed-up factors from site wind flow calculations

Topographical effects are accounted for in the model using the speed-up factors calculated by the wind flow model described above. Any air density adjustments required due to differences between the hub height air density at the turbine locations and that at the reference mast location is applied as discussed in the main body of the report and included in the topographic effect. The array model is used to calculate the wind speed in the turbine wakes, assuming the terrain is flat, and the wind speed is adjusted by the speed-up factor when the wake reaches a downstream turbine.

Electrical transmission efficiency

A figure of 97 % has been assumed for the electrical efficiency of the wind farm based on GH's experience of typical wind farm electrical distribution system designs. A formal calculation of the electrical loss should be undertaken when the electrical system has been defined.

Turbine availability

A figure of 97 % has been assumed for turbine availability based on data from modern operational wind farms. However, availability may be a matter of warranty between the owner and the turbine supplier and the assumed figure should be reviewed when the terms of that warranty are clear.

Blade degradation and fouling

The turbine production may be affected by the build up of insects, dirt or ice on the blades. This build up will change the characteristics of the blade and therefore effect the performance of the blades and the turbine output.

An adjustment has been included to allow for lost production due to blade fouling. A figure of 1 % has been assumed to be appropriate for the pitch regulated turbines.

High wind hysteresis

This is caused by the turbine cut in and cut out control criteria for high wind speeds. The magnitude of this loss is influenced by three factors.

1 The turbine will cut out when the maximum mean wind speed is exceeded and it will not cut in again until this mean wind speed is below a mean wind speed level lower than the cut out mean wind speed.

2 The turbine will cut out if the instantaneous gust wind speed exceeds a maximum level and the turbine will not cut in until the wind speed drops to a lower value.

3 The accuracy of the calibration of the instruments that are determining the wind characteristics at the turbine.

These three effects will cause the turbine to possibly lose production for some proportion of high mean wind speed occurrences. The magnitude of this lost production has been estimated by GH by repeating the analysis using a power curve with the cut out wind speed reduced by 2.5 m/s.

Substation maintenance

Net wind farm production may be reduced due to the electrical output not being transferred to the grid network while the substation is shutdown for maintenance. A typical figure of 99.8 % is assumed in this analysis to represent one day per year of planned maintenance. This is included as scheduled maintenance can not generally be accurately planned to occur on a day with low wind speeds.

Utility downtime

Net wind farm production will be reduced if the grid is not available for the wind farm to output electricity to it. This type of loss must be considered on a site specific basis. It has not been considered in this analysis.

Power curve adjustment

Adjustment to the energy prediction to account for variations in the actual turbine performance in comparison to the supplied power curve. This may be a matter of warranty between the owner and the turbine supplier and the estimated figure should be reviewed when the terms of that warranty are clear and a detailed assessment of this issue has been conducted.

Wind sector management

If wind turbine spacing is close the site conditions may exceed the wind conditions within the wind turbine certification criteria. In these circumstances it may be necessary to shut down some turbines which are closely spaced when the wind direction is parallel to the line of turbines. This issue has not been considered in this analysis.

4 Confidence analysis

There are 5 categories of uncertainty associated with the site wind speed prediction at the proposed site:

1. There is an uncertainty associated with the measurement accuracy of the anemometers. The instruments used have been individually calibrated. The mounting arrangements of the instruments are not to industry standards. A figure of 2.0 % is assumed here to account for these and other second order effects such as over-speeding, degradation, air density variations and additional turbulence effects.

2. The long-term mean wind speed and direction frequency distributions at Masts 87 and 153 were derived from measured and synthesised data through correlation analyses, using Masts 33 and 37 as long-term references. The uncertainty associated with correlating and extrapolating between masts is evaluated from the statistical scatter in the correlation plots. These uncertainties were applied to the ratio of data that were used to develop the long-term wind speed and direction frequency distributions at Masts 87 and 153.

3. There is uncertainty associated with the derivation of the wind shear between heights on the masts and the assumption that this is representative of the wind flow at heights up to hub height. A figure of 1.0 % is assumed here for all the site mast extrapolations from mast height to 67 m.

4. There is an uncertainty associated with the assumption made here that the historical period at the meteorological site is representative of the climate over longer periods. A study of historical wind records indicates a typical variability of 6 % in the annual mean wind speed

[5]. This figure is used to define the uncertainty in assuming the long-term mean wind speed is defined by a period approximately 3 years in length.

5. Additionally, even if the long-term mean wind speed were perfectly defined there will be variability in future mean wind speeds observed at the wind farm site. The variability in future mean wind speeds is dependant on the period considered. Performance over one and ten years of operation are therefore included in the uncertainty analysis. Account is taken of the future variability of wind speed in the energy confidence analysis but not the wind speed confidence analysis.

It is assumed that the time series of wind speed is random with no systematic trends. Care was taken to ensure that consistency of the reference measurement system and exposure has been maintained over the historical period and no allowance is made for uncertainties arising due to changes in either.

For each mast, uncertainties type 1 to 4 from above are added as independent errors on a root-sum-square basis to give the total uncertainty in the mast wind speed prediction for the historical period considered.

It is considered here that there are 5 categories of uncertainty in the energy output projection:

1. Long-term mean wind speed dependent uncertainty is derived from the total wind speed uncertainty (types 1 to 4 above) using a factor for the sensitivity of the annual energy output to changes in annual mean wind speed. This sensitivity is derived by a perturbation analysis about the central estimate.

2. Wake and topographic modelling uncertainties. Validation tests of the methods used here, based on full-scale wind farm measurements made at small wind farms have shown that the methods are accurate to 2 % in most cases. For this development an uncertainty in the wake and topographic modelling of 6 % to 8 % is assumed due to the expanse of distance and difference in local exposure and topographical features between the site masts and the associated proposed turbine locations.

3. Future wind speed-dependent uncertainties described in 5 above have been derived using the factor for the sensitivity of the annual energy output to changes in annual mean wind speed.

4. Accuracy of the fiscal substation energy meter. An uncertainty of 0.3 % is assumed here based on typical utility meter accuracy.

5. Turbine uncertainties are generally the subject of contract between the developer and turbine supplier and we have therefore made no allowance for them in this work.

For each mast, those uncertainties which are considered are added as independent errors on a root-sum-square basis to give the total uncertainty in the projected energy output for turbines initiated from each mast.

5 References

1. I Troen and E L Petersen, "European Wind Atlas", Risø National Laboratory, Denmark, 1989.

2. U Hassan, A G Glendinning and C A Morgan, " A Wind Tunnel Investigation of the wake structure and machine loads within small wind turbine farms", Proc of the 12th BWEA Wind Energy Conference, IMechE, 1990.

3. J Højstrup, "Turbulence measurements in a windfarm", Proc. EWEA Wind Energy Conference, Madrid, 1990.

4. J G Warren et al. "Performance of wind farms in complex terrain", Proc. Of the 17th BWEA Wind Energy Conference, 1995.

5. P Raftery, A J Tindal and A D Garrad, "Understanding the risks of financing windfarms", Proc. EWEA Wind Energy Conference, Dublin, 1997.

APPENDIX 2

Anemometer calibration certificates

ASSESSMENT OF THE ENERGY PRODUCTION OF THE PROPOSED WILD HORSE WIND FARM

Client	**Puget Sound Energy**
Contact	Tom Hiester
Document No	4743/AR/01
Issue	B
Status	FINAL
Classification	Client's Discretion
Date	09 September 2005

Author:

R Sweet, D Weiss

Checked by:

C Johnson

Approved by:

A Schwarz

DISCLAIMER

Acceptance of this document by the client is on the basis that Garrad Hassan America are not in any way to be held responsible for the application or use made of the findings of the results from the analysis and that such responsibility remains with the client.

GH has not conducted wind measurements itself and cannot, therefore, be responsible for the accuracy of the data supplied to it.

Key To Document Classification

Strictly Confidential	:	Recipients only
Private and Confidential	:	For disclosure to individuals directly concerned within the recipient's organisation
Commercial in Confidence	:	Not to be disclosed outside the recipient's organisation
GH only	:	Not to be disclosed to non GH staff
Client's Discretion	:	Distribution at the discretion of the client subject to contractual agreement
Published	:	Available to the general public

Revision History

Issue	Issue date	Summary
A	07 Oct 04	Original Issue
B	09 Sept 05	Update to original issue with Vestas V80 turbine option

Circulation:	Copy No:
Client	1 & 2
GH Bristol	3
GH San Diego	4

Copy No: ____

CONTENTS

		Page
1	**INTRODUCTION**	**1**
2	**DESCRIPTION OF THE SITE AND MONITORING EQUIPMENT**	**2**
	2.1 The site	2
	2.2 Monitoring equipment	2
3	**SELECTION OF A REFERENCE METEOROLOGICAL STATION**	**4**
4	**WIND DATA**	**5**
	4.1 Wind data recorded at the site	5
5	**DESCRIPTION OF THE PROPOSED WIND FARM**	**6**
	5.1 The wind turbine	6
	5.2 Wind farm layout	6
6	**RESULTS OF THE ANALYSIS**	**8**
	6.1 Long-term mean wind regime at site masts	8
	6.2 Hub height wind speeds	9
	6.3 Site wind speed variations	10
	6.4 Projected energy production	11
	6.5 Uncertainty analysis	12
7	**CONCLUSIONS AND RECOMMENDATIONS**	**13**

REFERENCES

LIST OF TABLES

LIST OF FIGURES

APPENDIX 1 Data analysis procedure

1 INTRODUCTION

Zilkha Renewable Energy (Zilkha) is developing the Wild Horse Wind Farm and has submitted the project in response to a recent RFP from Puget Sound Energy (PSE). PSE have instructed Garrad Hassan and Partners (GH) to carry out an independent assessment of the wind climate and expected energy production of the proposed wind farm. The results of the work are reported here.

A description of the long-term wind climate at a potential wind farm is best determined using wind data recorded at the site. Zilkha has supplied 2.6 years of data recorded at the Wild Horse site to GH.

At present, no suitable source of long-term reference wind data has been identified. As a result of this, there is considerable uncertainty associated with the assumption that the site data are representative of the long-term and these uncertainties are included in the present assessment.

The proposed layout and turbine model currently under consideration have been supplied by Zilkha. These have been analyzed here, in conjunction with the results of the wind analysis, to predict the long-term energy output of the proposed wind farm.

2 DESCRIPTION OF THE SITE AND MONITORING EQUIPMENT

2.1 The site

The site is located above the Kittitas Valley on the eastern edge of a major pass through the Cascade Range, approximately 125 km east of Seattle, as shown in Figure 2.1.

The proposed wind farm lies just east of the town of Ellensburg and at the foot of the Wenatchee Mountains. The terrain on site is complex, consisting of a broad, elevated plateau from which two parallel ridges aligned north-northwest to south-southeast extend in the southern portion of the site and several smaller ridges aligned west to east extend in the northern extent of the site. A large number of the proposed turbine sites are situated on these steep ridgelines.

The site elevation ranges from 1100 m on the plateau to 840 m at the foot of one of the principal ridgelines at the southern extent of the proposed wind farm. The ground cover on the site comprises primarily a mixture of short grasses and sagebrush less than 1 m in height. Much of the surrounding area consists of irrigated wheat fields interspersed by homes, outbuildings, and small stands of deciduous trees. Extensive coniferous forests are situated outside of the valley to the north and northwest of the project boundary.

A more detailed map showing the site is presented in Figure 2.2, which also shows the locations of the anemometry masts. A view of the site is shown in Figure 2.3 as seen facing east from Mast 309.

The surface roughness length of the site and surrounding area was assessed during a site visit made by GH staff. Following the Davenport classification [2.1], the following general figures are considered appropriate:

Areas of grasses and sagebrush	0.02 m
Cultivated farmland	0.05 m
Forested areas and towns	0.4 m
Water	0.0002 m

2.2 Monitoring equipment

Details of the measurements recorded on site and the grid co-ordinates of each mast are presented in Table 2.1.

The wind data have been recorded using NRG systems throughout with Maximum 40 anemometers and 200 P wind vanes. Zilkha has provided mast installation documents from which, in combination with details from the site visit, the following information is derived.

Primarily, NRG Symphonie data loggers have been utilized, programmed to record hourly mean wind speed and direction, wind speed and direction standard deviation and 3-second gust measurements. Masts 301, 310 and 311 employed NRG 9300 data loggers which did not include gust measurements. The following transfer function was applied to the output signal from the anemometers by both types of data loggers:

Recorded wind speed [m/s] = 0.765 x Data frequency [Hz] + 0.35 m/s

The anemometers on the site have not been individually calibrated. An investigation of the calibration of 472 NRG Maximum 40 anemometers has been reported in [2.2], the results of which include a proposed consensus transfer function for this model of anemometer. Since the applied transfer function is equivalent to the consensus calibration, no adjustment of the mean wind speed was necessary.

With the exception of Masts 301, 302, 303, 310 and 311, instruments are mounted on NRG 50 m guyed towers and include two boom-mounted anemometers at both 49 m and 30 m, one boom-mounted anemometer at 10 m, and wind vanes at approximately 40 m and 10 m. Mast 301 has a similar configuration with the exception of two boom-mounted anemometers at 50 m instead of 49 m.

Mast 302 consists of an NRG 60 m guyed tower with two boom-mounted anemometers at 60 m and 50 m and one boom-mounted anemometer at 30 m and 10 m. Wind vanes are mounted at 40 m and 10 m.

Mast 303 consists of an NRG 15 m guyed tower with two boom-mounted anemometers at 15 m and a wind vane at 13 m.

From documentation provided in [2.3], it is understood that Mast 310 was originally configured with one boom-mounted and one top-mounted anemometer at 49 m, two boom-mounted anemometers at 30 m, a boom-mounted anemometer at 10 m, and wind vanes at approximately 40 m and 10 m. In May 2004, the top-mounted anemometer was moved to a south-facing boom at 49 m. The west-oriented anemometer at 49 m is assumed to have remained consistent throughout the entire measurement period.

Mast 311 consists of an NRG 30 m guyed tower with two boom-mounted anemometers at 30 m and 20 m and one boom-mounted anemometer at 10 m. Wind vanes are mounted at 29m and 10 m.

With the exception of the top-mounted anemometer at Mast 310, all anemometers are mounted on booms approximately 7 mast diameters long oriented primarily to the west and south. The cups of the anemometers are at least 6 boom diameters above the boom. These anemometer mounting arrangements are not considered to be consistent with IEA recommendations [2.4] and therefore additional uncertainty has been associated with the measurements as detailed in Section 6.

Detailed documentation describing the top-mount configuration at Mast 310 is not available. Furthermore, since the configuration of Mast 310 was modified prior to the GH site visit, the original mounting arrangements have not been independently verified by GH. As a consequence of the uncertainty regarding the original installation, data recorded by the top-mounted anemometer at Mast 310 have not been used as absolute measurements in the current assessment.

It is also noted that prior to the site inspection performed by GH, Mast 301 was removed after falling and has since not been replaced. In addition, Masts 307 and 309 were no longer at their original locations as they were moved to other locations on site. Consequently, GH was unable to independently verify the measurement configuration of these masts.

3 SELECTION OF A REFERENCE METEOROLOGICAL STATION

In the assessment of the wind regime at a potential wind farm site it is generally necessary to correlate data recorded on the site with data recorded from a nearby long-term reference meteorological station. Wind data at a site are often only recorded for a short period and such correlation is required to ensure that the estimates of the wind speeds at the site are representative of the long-term. When selecting an appropriate meteorological station for this purpose it is important that it should have good exposure and that data are consistent over the measurement period being considered.

GH has reviewed potential sources of long-term meteorological data, including the National Weather Service ASOS station located at the Bowers Field Airport in Ellensburg, Washington. Wind data are available from the Bowers Field ASOS station starting in October 1998. However, between May 2001 and February 2002 a change in measurement consistency was identified in the data. In addition, wind speed correlation analyses conducted between the reference and the site masts exhibited poor correlation. Consequently, the Bowers Field ASOS station was not considered suitable as a quantitative reference.

The analysis of the long-term wind regime therefore relies on data recorded at the Wild Horse site since December 2002. This data set is of shorter duration than that which is ideal, and the uncertainty associated with assuming this period to be representative of the long-term is considered in Section 6.

It is worth noting that recent research [3.1] suggests that the Pacific Northwest experienced below average wind speeds during the 2004/2005 winter season, due largely to the presence of El Nino conditions. Since this analysis relies on the relatively short period of data recorded on site, the long-term predictions presented in this report may be potentially biased low due to the inclusion of the 2004/2005 winter period in this data set. Given the lack of suitable long-term references in the vicinity of the Wild Horse site however, GH has not quantified the magnitude of this potential bias, and no adjustments to the long-term predictions have been applied in this assessment at this stage.

4 WIND DATA

4.1 Wind data recorded at the site

The data sets which have been used in the analysis described in the following sections are summarized in Table 2.1.

The wind data have been subject to a quality checking procedure by GH to identify records which were affected by equipment malfunction and other anomalies. Characteristic of this region, the instruments on all masts experienced significant periods of icing, resulting in erroneous or inconsistent data during the winter months. These data were excluded from the analysis. The main periods for which valid data were not available are summarized below, together with details of the errors identified:

- Mast 306, 20 Jun 2004 to 31 Jul 2005 – anemometer malfunction wind speed 49 m west and 30 m south;
- Mast 308, 04 Oct 2004 to 20 Oct 2004 – logger malfunction all sensors;
- Mast 310, 11 Oct 2003 to 31 Jul 2005 – anemometer malfunction wind speed 30 m south.

As noted in Section 2, redundant anemometers at the upper two measurement heights were installed at all 60 m, 50 m and 30 m masts. In an attempt to reduce mast effects from the measured wind speed data, measurements recorded by these south and west oriented boom-mounted anemometers at a given height were averaged. Missing data were synthesized from the redundant sensor where necessary before averaging. Hereafter, data presented from such a mast configuration refers to the averaged data set unless stated otherwise.

The duration, basic statistics and data coverage for each mast are summarized in Tables 4.1 to 4.14.

5 DESCRIPTION OF THE PROPOSED WIND FARM

5.1 The wind turbine

The turbine which is proposed for the Wild Horse Wind Farm is the Vestas V80 1800 kW with a hub height of 67 m. The basic parameters of the turbine are presented in Table 5.1.

The power curve used in this analysis has been supplied by Zilkha [5.1] and is presented in Table 5.2. This power curve is for an air density of 1.12 kg/m³, and is valid for turbulence intensity of 10 %. It is noted that the actual turbulence intensity across the site at 15 m/s is approximately 7 % based on ten-minute averaging periods. It is recommended that the turbine manufacturer provide a power curve based on the site turbulence intensity.

The supplied power curve is based on calculations and exhibits a peak power coefficient, Cp, of 0.46. This is considered to be high but attainable for a modern wind turbine.

A measured power curve from an independent test of the performance of the turbine has been obtained [5.2]. This has been produced for an air density of 1.11 kg/m³. The turbulence intensity during the measurements was not stated.

A comparison between the supplied and the measured power curves has been conducted and this generally supports the assumption that the supplied power curve is achievable.

Using historical pressure and temperature records from nearby meteorological stations and standard lapse rate assumptions, GH has estimated the long-term mean air density at the site to be 1.116 kg/m³ at an average hub elevation of 1070 m above sea level.

The supplied power curve used in this analysis has been adjusted to the predicted site air density, in accordance with the recommendations of [5.3]. This has been undertaken on an individual turbine basis.

5.2 Wind farm layout

Zilkha has supplied the layout for the wind farm [5.1]. A map of the site showing the wind turbine locations is presented in Figure 5.1 with the grid reference of each of the turbines given in Table 5.3.

It is noted that an inter-turbine spacing of as small as 1.5 rotor diameters is proposed for the Vestas V80 layout. Consequently, it is understood that a Wind Sector Management (WSM) strategy is to be implemented in order to reduce fatigue loads on the turbines and Zilkha has supplied a WSM strategy [5.4] for the current V80 layout. An energy loss figure associated with WSM has therefore been estimated within the analysis of the expected energy production presented in Section 6.

It is recognized that the close spacing of turbines also results in a reduction to the rate of recovery of the wakes from individual turbines compared to that modelled by the existing industry standard wake models, including the Eddy Viscosity model employed here. This is believed to be due to the lack of free-stream flow between the turbines and results in increased wake losses for turbines downwind of such closely-spaced turbine rows. Such conditions exist for the prevailing wind directions for a number of turbines on the Wild Horse site and the additional loss associated with this expected under-prediction of wake loss has been estimated and is included in Section 6.

6 RESULTS OF THE ANALYSIS

The analysis of the wind farm involved several steps, which are summarized below:

- Data at each mast were correlated to other nearby site masts. These correlations were used to synthesize data and thereby extend the period of data available at each mast.
- The wind speed and direction frequency distributions at each mast, as detailed in Table 2.1, at the highest measurement height were derived from the period of measured and synthesized data.
- Boundary layer power law shear exponents at all site masts were estimated using the measured data at two different heights at each of these masts. These were used to extrapolate the long-term wind speed and direction frequency distribution to the proposed hub height of 67 m.
- Wind flow modelling was carried out to determine the hub height wind speed variations over the site relative to the anemometry masts.
- The energy production of the wind farm was calculated taking account of array losses, topographic effects, availability, electrical transmission efficiency, wind sector management, air density effects and other potential losses.
- An assessment of the uncertainty in the predicted wind farm energy production was undertaken.

A more complete description of the methods employed is included in Appendix 1.

6.1 Long-term mean wind regime at site masts

Data have been recorded on-site, as detailed in Section 2, since December 2002. In order to maximize the duration of the reference period used for the analysis of the wind regime at each mast, the correlation analysis described below was used to synthesize the wind speeds across the site.

As an example of a correlation used at the Wild Horse site, the measured wind speeds at Mast 312 at a height of 49 m in each of the twelve 30 degree direction sectors are compared to the concurrent wind speeds measured at Mast 309 at 49 m in Figure 6.1. The correlation of wind speeds is acceptable in all sectors, with mild scatter in the most frequent direction sectors.

Figure 6.2 presents the correlation of wind direction between these two masts. The data are observed to be correlated, albeit with some non-linearity which has been accounted for in the prediction of wind direction at the target mast.

The following check on the correlation was undertaken. Wind data from Mast 309 at 49 m were factored by the directional speed up ratios determined in the correlation to the Mast 312 at 49 m. These figures are presented in Table 6.1. If the correlation is reliable then the mean wind speed of the synthesized wind data would be similar to the actual data for exactly the same period. This was the case and therefore the correlation has been deemed appropriate for this analysis.

The same process was repeated for each correlation step presented in Table 6.2.

The resulting speedup factors were then applied to the hourly data at each reference mast in order to synthesize the wind speed at each target mast. When combining the measured data with the synthesized data to create the long-term time series at each mast, the measured data were used whenever possible. After combining the actual data recorded at each mast with the synthesized data, approximately 2.6 years of data are obtained comprising 2.5 years of valid wind speed data. The long-term mean wind speed and direction frequency distribution at each mast were then derived from these data sets.

In order to avoid the introduction of bias into the annual mean wind speed estimate from seasonally uneven data coverage, the following procedure was followed for each mast:

- The mean wind speed and direction frequency distribution for each month was determined from the average of all valid data recorded in that month over the period. This was taken as the monthly mean thereby assuming that the valid data are representative of any missing data.

- The mean of the monthly means was taken to determine the annual mean ("mean of means") to eliminate the effect of seasonal bias in the data.

Tables 6.3 to 6.14 present the predicted long-term mean wind speed across the site at each mast using this methodology.

As mentioned in Section 2, the wind speeds recorded at Mast 310 by the 49 m top-mounted anemometer were excluded in preference to the two boom-mounted anemometers at 49 m. In order to extend the period of data available at the south-facing anemometer at 49 m, data were correlated between the 49 m west-oriented anemometer and the 49 m south-oriented anemometer. From this correlation, data from the 49 m south-facing anemometer were synthesized over the period for which the top-mounted anemometer was present.

It is noted that Masts 303 and 311, as a consequence of their low measurement heights, were not used in the analysis, nor were they updated with the latest June and July 2005 data.

6.2 Hub height wind speeds

The ratio of concurrent measured mean wind speeds between the two highest wind speed measurement heights was used to derive boundary-layer power-law shear exponents at each mast location. These values were applied to extrapolate the long-term mean wind speed and direction frequency distribution at each of the site masts to the 67 m hub height. It is noted that for Mast 302, the power law shear exponent was calculated between the 60 m and 30 m heights rather than the two highest heights of 60 m and 50 m. In addition, due to data being available from only one anemometer at the 30 m level at Masts 302 and 310, shear calculations employed only measurements from the anemometer at the highest height with the same orientation as the 30 m anemometer, rather than the average of the wind speed measurements as described in Section 4, in order to avoid introducing any potential bias due to differing exposure and mast effects.

As an example, the resultant corresponding long-term joint wind speed and direction frequency distribution at Mast 304 at 67 m is presented in Table 6.15 and in Figure 6.3 in the form of a wind rose.

It is observed that the wind rose at the Wild Horse site has a predominance of winds from the west, with a significant proportion from the northeast.

A summary of the estimated shear exponent and extrapolated hub height mean wind speed for each mast is presented in Table 6.16.

6.3 Site wind speed variations

The variation in wind speed over the wind farm site has been predicted using the WAsP computational flow model as described in Appendix 1. The wind flow model has been initiated from the long-term mean hub height wind speed and direction frequency distributions derived for each mast.

The wind farm is located within complex terrain which includes areas of steep slopes. The presence of steep slopes can cause localized separation of the flow. In regions of separated flow it is known that the accuracy of wind flow modelling is poor due to the formation of a separation bubble which reduces the effective slope, as described by Cook [6.1].

For turbine locations with slopes significantly in excess of 17 degrees in the prevailing wind directions, to a greater extent than at the initiation anemometry mast location, there is a tendency for the WAsP model to over-predict the wind speed and consequently energy production of such turbines. Conversely, if the initiation anemometry mast is located in an area more heavily influenced by slopes in excess of 17 degrees than the turbine locations, there is a tendency for the WAsP model to under-predict the wind speed at such turbines.

A review of the wind farm was therefore undertaken to establish whether such conditions were present. Areas of steep slopes are marked as grey shaded areas in Figure 6.4 and it can be seen that there are steep slopes along the majority of the principal ridges, the severest slopes lying between the 'C' and 'D' row of turbines and to the north of the project.

From this investigation it is considered that the conditions for possible over or under prediction of wind speeds by WAsP, as detailed above, are present for only a few turbines at the site. The wind speed predictions at Turbines C4 to C9 were subsequently reduced by 1.5% to account for the likely over prediction at those locations. For the remainder of the site GH has initiated the WAsP model from masts most representative of each turbine location without further adjustment.

It is clear from the above that the prediction of the variation in wind speed over the site is challenging and an additional allowance has been made for the uncertainty in the wind flow modelling, as detailed in Section 6.5.

Table 5.3 shows the predicted long-term mean wind speed at each turbine location at hub height. The average long-term mean hub height wind speed for the wind farm as a whole was found to be 7.8 m/s.

6.4 Projected energy production

The energy production of the wind farm is detailed in the table below and definitions of the various loss factors are included in Appendix 1. The energy capture of individual turbines is given in Table 5.3.

Rated Power	**228.6**	**MW**
Ideal output	**782.6**	GWh/annum
Topographic effect	98.3%	GH calculated
Array effect	92.3%	GH calculated
Electrical transmission efficiency	97.9%	PSE Value [6.2]
Availability	97.0%	GH assumption
Icing and blade degradation	98.0%	GH assumption
High wind hysteresis	98.6%	GH estimate
Substation maintenance	99.8%	Typical value
Utility downtime	100.0%	Not considered by GH
Power curve adjustment	100.0%	Not considered by GH
Wind sector management	99.5%	GH estimate
Net output	**646.7**	**GWh/annum**
Net capacity factor	**32.3%**	

The values for topographic and array effect have been calculated using the methods described in Appendix 1. It has been assumed that there are no other operational wind farms in the vicinity of the development.

The table above includes potential sources of energy loss that have been estimated, assumed or not considered. It is recommended that the client consider each of these losses and the possible effect they may have on the wind farm.

It is noted that due to the separation of 1.5 rotor diameters between turbines within rows, wind sector management is understood to be employed to reduce turbine loading. GH has received a WSM strategy for the current V80 layout and has estimated the magnitude of the expected losses using this strategy.

Furthermore, due to close turbine spacing, an additional pragmatic loss factor has been included in the array effect to account for the likely reduced rate of wake recovery compared to that modelled as discussed in Section 5.

6.5 Uncertainty analysis

The main sources of deviation from the central estimate have been quantified and are shown in Tables 6.17 to 6.28. The figures in each table are added as independent errors giving the following uncertainties in net energy production for the wind farm. These represent the standard deviation of what is assumed to be a Gaussian process:

In any one year period	80.7	GWh/annum
In any ten year period	63.2	GWh/annum

The uncertainties that have been considered in the analysis of the wind farm include the following:

- Accuracy of the wind measurements;
- Correlation accuracy;
- The assumption that the period of data available to is representative of the long-term;
- The accuracy of the extrapolation of wind speeds from the mast height to hub height;
- The accuracy of the wind flow modelling;
- The accuracy of the wake modelling;
- The accuracy of the fiscal sub-station meter;
- The variability of the future annual wind speeds at the site.

There are a number of uncertainties that have not been considered at this stage, including those listed below. It is recommended that the client 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.

- Compliance with the assumed power curve;
- Turbine availability;
- Electrical losses;
- High wind hysteresis;
- Icing and blade degradation;
- Substation maintenance;
- Utility downtime;
- Wind sector management.

7 CONCLUSIONS AND RECOMMENDATIONS

Wind data have been recorded at the Wild Horse site for a period of approximately 2.6 years. Based on the results from the analysis of these data the following conclusions are made concerning the site wind regime.

1. The long-term mean wind speed at a height of 67 m above ground level is presented in the table below for each mast. Also included are the standard errors associated with each of these predictions. If a normal distribution is assumed, the confidence limits for the predictions are presented for the P50, P75 and P90 exceedance levels.

Probability of exceedance [%]	Long-term mean wind speed at 67 m [m/s]											
	301	302	304	305	306	307	308	309	310	312	313	314
90	7.7	7.0	7.8	7.7	7.7	8.1	7.3	7.4	7.1	7.9	7.2	6.9
75	7.9	7.3	8.1	7.9	8.0	8.4	7.5	7.6	7.4	8.2	7.5	7.1
50	8.2	7.5	8.4	8.2	8.3	8.7	7.8	7.9	7.6	8.4	7.7	7.4
Standard Error	0.43	0.37	0.43	0.42	0.42	0.44	0.40	0.40	0.39	0.43	0.39	0.38

Site wind flow and array loss calculations have been carried out and from these we draw the following conclusions:

2. The long-term mean wind speed averaged over all turbine locations at hub height is estimated to be 7.8 m/s.

3. The projected energy capture of the proposed wind farm is 646.7 GWh/annum. This includes calculation of the topographical, array and air density effects and assumptions or estimates for electrical transmission losses, availability, power curve adjustment, high wind hysteresis, wind sector management, substation maintenance, and the effect of blade fouling or icing.

   There are a number of other losses that could affect the net energy output of the wind farm, as detailed in Appendix 1, but these have not been considered here. It is recommended that the client considers each of these losses and the possible effect they may have on the net energy production.

   The net energy prediction presented above represents the long-term mean, 50% exceedance level, for the annual energy production of the wind farm. This value is the best estimate of the long-term mean value to be expected from the project. There is therefore a 50% chance that, even when taken over very long periods, the mean energy production will be less than the value given.

4. The standard error associated with the prediction of energy capture has been calculated and the confidence limits for the prediction are given in the table below :

Probability of Exceedance [%]	Net energy output 1 year average [GWh/annum]	Net energy output 10 year average [GWh/annum]
90	543.3	565.7
75	592.3	604.1
50	646.7	646.7

There are a number of uncertainties that have not been considered at this stage, as detailed in Section 6. It is recommended that the client 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.

5. In order to reduce the uncertainty in the expected energy production it is recommended that the analysis be updated once additional data have been recorded on site or should a suitable source of longer-term reference data be identified.

REFERENCES

2.1 "Wind speed profiles over terrain with roughness changes", Engineering Sciences Data, Item No. 84011, April 1993.

2.2 Lockhart T J and Bailey B H, "The Maximum Type 40 Anemometer Calibration Project", Proceedings of the AWEA Conference, California 1998.

2.3 Letter from Eli Reich, GEC to Andrew Young, Zilkha, 14 November 2003

2.4 Recommended Practices for Wind Turbine Testing and Evaluation, "11. Wind speed measurement and use of cup anemometry", IEA, Edition 1, 1999.

3.1 Storck, P and Hiester, T, "Integrating wind energy resource assessment and forecasting strategies to provide medium range forecasts of wind energy output", Proceedings of the AWEA Conference, Colorado 2005.

5.1 Email from Matthew Hendrickson, Zilkha to Regina Sweet, GH, 02 September 2005.

5.2 "Power Performance Test at Pincher Creek", AB, Vestas, 952407.R3, 13 February 2003.

5.3 "Wind turbine generator systems – Part 12: Wind turbine power performance testing", BS EN 61400-12: BSI, 1998.

5.4 "Site Layout Approval Wild Horse – Washington", Vestas, WS-9016SLA, 02 September 2005.

6.1 Cook N J "The Designer's" guide to wind loading of building structures", Part 1, Butterworths, 1985.

6.2 Email from Tom Hiester, PSE to Clint Johnson, GH, 31 August 2005.

LIST OF TABLES

2.1 Summary of measurements made at the site.

4.1 Measurements made at Mast 301 at a height of 50 m.

4.2 Measurements made at Mast 302 at a height of 60 m.

4.3 Measurements made at Mast 303 at a height of 14.6 m.

4.4 Measurements made at Mast 304 at a height of 49 m.

4.5 Measurements made at Mast 305 at a height of 49 m.

4.6 Measurements made at Mast 306 at a height of 49 m.

4.7 Measurements made at Mast 307 at a height of 49 m.

4.8 Measurements made at Mast 308 at a height of 49 m.

4.9 Measurements made at Mast 309 at a height of 49 m.

4.10 Measurements made at Mast 310 at a height of 49 m.

4.11 Measurements made at Mast 311 at a height of 30 m.

4.12 Measurements made at Mast 312 at a height of 49 m.

4.13 Measurements made at Mast 313 at a height of 49 m.

4.14 Measurements made at Mast 314 at a height of 49 m.

5.1 Main parameters of the Vestas V80 wind turbine analyzed.

5.2 Performance data for the Vestas V80 wind turbine analyzed.

5.3 Turbine layout with predicted individual turbine wind speed and energy production.

6.1 Directional correlation ratios between Masts 309 at 49 m and 312 at 49 m.

6.2 Synthesis steps to predict the long-term mean wind speed at each mast location.

6.3 Predicted monthly and annual mean wind speeds at Mast 301 at 50m (Dec 2002 to Jul 2005).

6.4 Predicted monthly and annual mean wind speeds at Mast 302 at 60m (Dec 2002 to Jul 2005).

6.5 Predicted monthly and annual mean wind speeds at Mast 304 at 49m (Dec 2002 to Jul 2005).

6.6 Predicted monthly and annual mean wind speeds at Mast 305 at 49m (Dec 2002 to Jul 2005).

6.7 Predicted monthly and annual mean wind speeds at Mast 306 at 49m (Dec 2002 to Jul 2005).
6.8 Predicted monthly and annual mean wind speeds at Mast 307 at 49m (Dec 2002 to Jul 2005).
6.9 Predicted monthly and annual mean wind speeds at Mast 308 at 49m (Dec 2002 to Jul 2005).
6.10 Predicted monthly and annual mean wind speeds at Mast 309 at 49m (Dec 2002 to Jul 2005).
6.11 Predicted monthly and annual mean wind speeds at Mast 310 at 49m (Dec 2002 to Jul 2005).
6.12 Predicted monthly and annual mean wind speeds at Mast 312 at 49m (Dec 2002 to Jul 2005).
6.13 Predicted monthly and annual mean wind speeds at Mast 313 at 49m (Dec 2002 to Jul 2005).
6.14 Predicted monthly and annual mean wind speeds at Mast 314 at 49m (Dec 2002 to Jul 2005).
6.15 Predicted wind speed and direction frequency distribution at Mast 304 at 67 m.

6.16 Predictions of the wind speeds at the site masts.

6.17 Uncertainty in projected energy output of Turbines A1 to A2 based on Mast 301.

6.18 Uncertainty in projected energy output of Turbines D1 to D2, E1B to E10B, K1 to K6, L1 to L4, M1 to M6 and P1 to P2 based on Mast 302.
6.19 Uncertainty in projected energy output of Turbines C1 to C8 based on Mast 304.

6.20 Uncertainty in projected energy output of Turbines C9 to C18 based on Mast 305.

6.21 Uncertainty in projected energy output of Turbines D3 to D9 and J1A to J4B based on Mast 306.
6.22 Uncertainty in projected energy output of Turbines D10 to D18 based on Mast 307.

6.23 Uncertainty in projected energy output of Turbines F2 to F5, G4 to G7 and I1 to I2 based on Mast 308.
6.24 Uncertainty in projected energy output of Turbines D19 to D23 based on Mast 309.

6.25 Uncertainty in projected energy output of Turbines A3 to A8, B1 to B2 and Q1 to Q5 based on Mast 310.
6.26 Uncertainty in projected energy output of Turbines D24 to D37 based on Mast 312.

6.27 Uncertainty in projected energy output of Turbines F1, G1 to G3 and H1 to H3 based on Mast 313.
6.28 Uncertainty in projected energy output of Turbines N1 to N4 and O1 to O4 based on Mast 314.

LIST OF FIGURES

2.1 Location of the Wild Horse site.

2.2 Location of the Wild Horse meteorological masts.

2.3 View of the Wild Horse site from Mast 309 looking east.

5.1 Wild Horse Wind Farm proposed turbine layout.

6.1 Correlation of hourly mean wind speed at Mast 309 at 49 m and Mast 312 at 49 m.

6.2 Correlation of hourly mean wind direction at Mast 309 and Mast 312.

6.3 Annual wind rose from Mast 304 at 67 m.

6.4 Areas of steep slopes on the Wild Horse site.

Location	Description of measurements	Period
Mast 301 (710972,5211103)	Hourly mean wind speed recorded at 50, 30 and 10m. Hourly mean wind direction recorded at 40 and 10m.	01 Apr 2003 –22 Dec 2003
Mast 302 (712062,5213150)	Hourly mean wind speed recorded at 60, 50, 30 and 10m. Hourly mean wind direction recorded at 40 and 10m.	08 Apr 2003 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 60, 50, 30 and 10m. Ten-minute mean wind direction recorded at 40 and 10m.	01 Aug 2004 – 31 Jul 2005
Mast 303 (709876,5214436)	Hourly mean wind speed recorded at 14.6m. Hourly mean wind direction recorded at 13.4m.	30 Mar 2003 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 14.6m. Ten-minute mean wind direction recorded at 13.4m.	01 Aug 2004 – 31 Jul 2005
Mast 304 (712791,5210161)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 41 and 10m.	13 Dec 2002 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 41 and 10m.	01 Aug 2004 –31 Jul 2005
Mast 305 (714630,5208226)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 40 and 10m.	09 Oct 2003 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 40 and 10m.	01 Aug 2004 – 31 Jul 2005
Mast 306 (713536,5212669)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 41 and 10m.	14 Dec 2002 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 41 and 10m.	01 Aug 2004 – 31 Jul 2005
Mast 307 (714054,5211405)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 41 and 10m.	16 Dec 2002 – 12 Jun 2004
Mast 308 (713786,5213767)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 41 and 10m.	19 Dec 2002 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 41 and 10m.	01 Aug 2004 – 31 Jul 2005
Mast 309 (714472,5210705)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 41 and 10m.	17 Dec 2002 – 11 Jun 2004

Table 2.1 Summary of measurements made at the site - continued.

Location	Description of measurements	Period
Mast 310 (711112,5209695)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 41 and 10m.	11 Oct 2003 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 41 and 10m.	01 Aug 2004 – 30 Jun 2005
Mast 311 (711801,5211724)	Hourly mean wind speed recorded at 30, 20 and 10m. Hourly mean wind direction recorded at 29 and 10m.	08 Oct 2003 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 30, 20 and 10m. Ten-minute mean wind direction recorded at 29 and 10m.	01 Aug 2004 – 30 Jun 2005
Mast 312 (715094,5209643)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 40 and 10m.	21 Nov 2003 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 40 and 10m.	01 Aug 2004 – 31 Jul 2005
Mast 313 (713687,5214300)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 40 and 10m.	12 Jun 2004 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 40 and 10m.	01 Aug 2004 – 31 Jul 2005
Mast 314 (711594,5214646)	Hourly mean wind speed recorded at 49, 30 and 10m. Hourly mean wind direction recorded at 40 and 10m.	12 Jun 2004 – 31 Jul 2004
	Ten-minute mean wind speed recorded at 49, 30 and 10m. Ten-minute mean wind direction recorded at 40 and 10m.	01 Aug 2004 – 31 Jul 2005

Table 2.1 Summary of measure ments made at the site - concluded

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Apr 2003	7.8	96.9	96.9
May 2003	7.7	100.0	100.0
Jun 2003	8.1	100.0	100.0
Jul 2003	7.6	100.0	100.0
Aug 2003	7.3	100.0	100.0
Sep 2003	8.6	100.0	100.0
Oct 2003	9.8	100.0	100.0
Nov 2003	9.3	96.9	97.4
Dec 2003	8.3	52.0	47.7

Table 4.1 Measurements made at Mast 301 at a height of 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Apr 2003	7.0	76.7	76.7
May 2003	7.2	100.0	100.0
Jun 2003	7.6	100.0	100.0
Jul 2003	7.2	100.0	100.0
Aug 2003	6.8	100.0	100.0
Sep 2003	7.8	100.0	100.0
Oct 2003	8.8	100.0	100.0
Nov 2003	8.6	100.0	100.0
Dec 2003	7.2	61.6	61.6
Jan 2004	9.2	42.5	42.5
Feb 2004	5.2	73.6	73.6
Mar 2004	9.0	97.7	97.7
Apr 2004	6.2	98.8	98.8
May 2004	8.1	100.0	100.0
Jun 2004	6.7	100.0	100.0
Jul 2004	7.2	100.0	100.0
Aug 2004	6.6	100.0	100.0
Sep 2004	7.7	99.7	99.7
Oct 2004	7.9	100.0	100.0
Nov 2004	6.7	95.7	95.7
Dec 2004	8.1	73.7	73.7
Jan 2005	6.7	71.2	71.2
Feb 2005	6.1	95.1	95.1
Mar 2005	7.9	97.6	97.6
Apr 2005	7.3	100.0	100.0
May 2005	6.6	100.0	100.0
Jun 2005	7.6	100.0	100.0
Jul 2005	7.7	100.0	100.0

Table 4.2 Measurements made at Mast 302 at a height of 60 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Mar 2003	11.3	4.8	4.8
Apr 2003	5.7	99.4	99.4
May 2003	5.7	100.0	100.0
Jun 2003	6.0	100.0	100.0
Jul 2003	5.5	100.0	100.0
Aug 2003	5.0	100.0	100.0
Sep 2003	6.3	100.0	100.0
Oct 2003	7.2	100.0	100.0
Nov 2003	7.4	100.0	100.0
Dec 2003	5.3	49.2	49.2
Jan 2004	6.4	58.7	58.7
Feb 2004	4.4	85.1	85.1
Mar 2004	7.5	95.7	95.7
Apr 2004	4.8	98.5	98.5
May 2004	6.4	100.0	100.0
Jun 2004	5.6	100.0	100.0
Jul 2004	5.9	100.0	100.0
Aug 2004	5.1	100.0	100.0
Sep 2004	6.0	100.0	100.0
Oct 2004	6.6	98.9	99.3
Nov 2004	4.7	97.5	97.5
Dec 2004	6.2	67.6	67.9
Jan 2005	5.5	77.2	77.2
Feb 2005	5.1	95.4	95.4
Mar 2005	6.3	97.5	97.5
Apr 2005	6.2	99.0	99.0
May 2005	5.3	100.0	100.0
Jun 2005	8.2	6.4	6.4

Table 4.3 Measurements made at Mast 303 at a height of 14.6 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Dec 2002	7.9	25.9	25.9
Jan 2003	8.3	55.9	55.9
Feb 2003	6.6	80.1	80.1
Mar 2003	9.6	92.9	92.9
Apr 2003	7.8	98.9	98.9
May 2003	7.9	100.0	100.0
Jun 2003	8.4	100.0	100.0
Jul 2003	7.9	100.0	100.0
Aug 2003	7.6	100.0	100.0
Sep 2003	8.7	100.0	100.0
Oct 2003	9.5	100.0	100.0
Nov 2003	9.6	100.0	100.0
Dec 2003	7.8	75.4	75.4
Jan 2004	8.8	64.7	64.7
Feb 2004	6.0	78.2	78.2
Mar 2004	9.7	98.8	98.8
Apr 2004	6.6	98.3	98.3
May 2004	8.7	100.0	100.0
Jun 2004	7.4	100.0	100.0
Jul 2004	8.1	100.0	100.0
Aug 2004	7.2	100.0	100.0
Sep 2004	8.4	100.0	100.0
Oct 2004	8.6	100.0	100.0
Nov 2004	7.2	97.6	97.6
Dec 2004	8.5	78.6	78.6
Jan 2005	7.3	71.2	71.2
Feb 2005	6.5	100.0	100.0
Mar 2005	8.8	97.7	97.7
Apr 2005	8.2	100.0	100.0
May 2005	7.2	100.0	100.0
Jun 2005	8.4	100.0	100.0
Jul 2005	8.5	100.0	100.0

Table 4.4 Measurements made at Mast 304 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Oct 2003	9.7	72.7	72.7
Nov 2003	9.1	100.0	100.0
Dec 2003	7.8	69.8	70.4
Jan 2004	8.8	56.3	57.0
Feb 2004	6.0	77.6	78.2
Mar 2004	9.6	98.8	98.8
Apr 2004	6.9	99.9	99.9
May 2004	9.0	100.0	100.0
Jun 2004	7.5	100.0	100.0
Jul 2004	8.5	100.0	100.0
Aug 2004	7.5	100.0	100.0
Sep 2004	8.6	100.0	100.0
Oct 2004	8.5	100.0	100.0
Nov 2004	6.5	100.0	100.0
Dec 2004	8.3	70.7	70.7
Jan 2005	6.5	86.3	86.3
Feb 2005	6.4	97.6	97.6
Mar 2005	8.7	100.0	100.0
Apr 2005	7.9	100.0	100.0
May 2005	7.3	100.0	100.0
Jun 2005	9.0	100.0	100.0
Jul 2005	8.9	100.0	100.0

Table 4.5 Measurements made at Mast 305 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Dec 2002	7.4	50.1	50.1
Jan 2003	8.0	58.2	58.2
Feb 2003	7.6	98.4	98.4
Mar 2003	10.3	100.0	100.0
Apr 2003	7.8	98.9	98.9
May 2003	8.0	100.0	100.0
Jun 2003	8.5	100.0	100.0
Jul 2003	8.1	100.0	100.0
Aug 2003	7.7	100.0	100.0
Sep 2003	8.5	100.0	100.0
Oct 2003	9.4	100.0	100.0
Nov 2003	9.3	100.0	100.0
Dec 2003	7.5	60.9	60.9
Jan 2004	10.8	39.4	39.4
Feb 2004	5.5	78.9	78.9
Mar 2004	9.9	100.0	100.0
Apr 2004	6.8	100.0	100.0
May 2004	9.0	100.0	100.0
Jun 2004	7.3	100.0	100.0
Jul 2004	8.0	100.0	100.0
Aug 2004	7.2	100.0	100.0
Sep 2004	8.4	100.0	100.0
Oct 2004	8.4	100.0	100.0
Nov 2004	6.7	100.0	100.0
Dec 2004	8.2	76.2	76.2
Jan 2005	6.9	75.4	75.4
Feb 2005	6.4	95.8	95.8
Mar 2005	8.9	100.0	100.0
Apr 2005	7.7	100.0	100.0
May 2005	7.1	100.0	100.0
Jun 2005	8.6	100.0	100.0
Jul 2005	8.6	100.0	100.0

Table 4.6 **Measurements made at Mast 306 at a height of 49 m.**

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Nov 2002	8.6	68.8	68.8
Dec 2002	8.4	59.4	59.4
Jan 2003	8.1	95.7	95.7
Feb 2003	10.9	98.9	98.9
Mar 2003	8.1	98.8	98.8
Apr 2003	8.6	100.0	100.0
May 2003	8.9	100.0	100.0
Jun 2003	8.6	100.0	100.0
Jul 2003	8.1	100.0	100.0
Aug 2003	9.0	99.9	99.9
Sep 2003	9.7	99.6	99.6
Oct 2003	9.8	99.9	99.9
Nov 2003	8.2	71.8	71.8
Dec 2003	12.4	35.5	35.5
Jan 2004	5.6	83.3	83.3
Feb 2004	10.6	100.0	100.0
Mar 2004	7.0	100.0	100.0
Apr 2004	9.6	100.0	100.0
May 2004	8.7	67.3	67.3

Table 4.7 Measurements made at Mast 307 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Dec 2002	6.7	34.5	34.5
Jan 2003	7.0	68.3	68.3
Feb 2003	6.9	100.0	100.0
Mar 2003	9.9	98.5	98.5
Apr 2003	7.3	98.8	98.8
May 2003	7.5	100.0	100.0
Jun 2003	7.9	100.0	100.0
Jul 2003	7.6	100.0	100.0
Aug 2003	7.3	100.0	100.0
Sep 2003	7.9	100.0	100.0
Oct 2003	8.8	100.0	100.0
Nov 2003	8.7	100.0	100.0
Dec 2003	7.2	72.0	72.0
Jan 2004	9.6	46.0	46.0
Feb 2004	4.9	91.1	91.1
Mar 2004	9.5	100.0	100.0
Apr 2004	6.4	99.9	99.9
May 2004	8.6	100.0	100.0
Jun 2004	6.9	100.0	100.0
Jul 2004	7.6	100.0	100.0
Aug 2004	6.9	100.0	100.0
Sep 2004	8.1	100.0	100.0
Oct 2004	8.9	46.6	46.6
Nov 2004	6.3	100.0	100.0
Dec 2004	7.3	81.1	81.1
Jan 2005	6.3	78.0	78.0
Feb 2005	5.9	98.4	98.4
Mar 2005	8.4	100.0	100.0
Apr 2005	7.3	100.0	100.0
May 2005	6.7	100.0	100.0
Jun 2005	8.1	100.0	100.0
Jul 2005	8.1	100.0	100.0

Table 4.8 Measurements made at Mast 308 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Dec 2002	6.5	36.3	36.3
Jan 2003	6.7	62.2	62.2
Feb 2003	7.0	100.0	100.0
Mar 2003	9.9	100.0	100.0
Apr 2003	7.5	98.8	98.8
May 2003	7.9	100.0	100.0
Jun 2003	8.3	100.0	100.0
Jul 2003	8.1	100.0	100.0
Aug 2003	7.6	100.0	100.0
Sep 2003	8.2	100.0	100.0
Oct 2003	8.7	100.0	100.0
Nov 2003	8.5	100.0	100.0
Dec 2003	6.9	78.9	78.9
Jan 2004	9.3	49.7	49.7
Feb 2004	4.9	87.1	91.2
Mar 2004	9.5	100.0	99.9
Apr 2004	6.5	100.0	100.0
May 2004	8.8	100.0	100.0
Jun 2004	8.0	24.6	24.6

Table 4.9 Measurements made at Mast 309 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Oct 2003	9.0	66.3	66.3
Nov 2003	9.0	100.0	100.0
Dec 2003	7.3	71.6	71.6
Jan 2004	7.9	63.2	63.2
Feb 2004	5.6	85.9	85.9
Mar 2004	9.3	100.0	100.0
Apr 2004	6.0	100.0	100.0
May 2004	8.3	100.0	100.0
Jun 2004	6.8	100.0	100.0
Jul 2004	7.5	100.0	100.0
Aug 2004	6.5	100.0	100.0
Sep 2004	7.7	100.0	100.0
Oct 2004	8.3	100.0	100.0
Nov 2004	5.9	100.0	100.0
Dec 2004	7.1	86.3	86.3
Jan 2005	6.1	92.2	92.2
Feb 2005	6.4	94.9	94.9
Mar 2005	8.3	100.0	100.0
Apr 2005	7.8	99.7	99.7
May 2005	6.8	77.3	77.3
Jun 2005	7.8	100.0	100.0

Table 4.10 Measurements made at Mast 310 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Oct 2003	7.8	75.4	75.4
Nov 2003	7.3	95.0	95.0
Dec 2003	5.6	66.9	66.9
Jan 2004	7.9	42.5	42.5
Feb 2004	4.1	79.5	79.5
Mar 2004	7.9	100.0	100.0
Apr 2004	5.4	99.9	99.9
May 2004	7.2	100.0	100.0
Jun 2004	6.0	100.0	100.0
Jul 2004	6.7	100.0	100.0
Aug 2004	5.9	100.0	100.0
Sep 2004	6.8	100.0	100.0
Oct 2004	6.9	100.0	100.0
Nov 2004	5.4	99.0	99.0
Dec 2004	6.2	79.3	79.3
Jan 2005	5.4	76.9	76.9
Feb 2005	5.1	87.4	87.4
Mar 2005	6.8	95.7	95.7
Apr 2005	6.2	100.0	100.0
May 2005	5.3	93.5	93.5

Table 4.11 Measurements made at Mast 311 at a height of 30 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Nov 2003	10.1	31.3	31.3
Dec 2003	8.4	77.2	77.2
Jan 2004	10.1	52.7	52.7
Feb 2004	5.6	80.5	80.5
Mar 2004	10.3	100.0	100.0
Apr 2004	7.0	100.0	100.0
May 2004	9.6	100.0	100.0
Jun 2004	7.6	100.0	100.0
Jul 2004	8.6	100.0	100.0
Aug 2004	7.9	100.0	100.0
Sep 2004	9.0	100.0	100.0
Oct 2004	8.9	100.0	100.0
Nov 2004	6.4	100.0	100.0
Dec 2004	8.0	73.7	73.7
Jan 2005	6.9	74.9	74.9
Feb 2005	6.3	97.2	97.2
Mar 2005	9.2	100.0	100.0
Apr 2005	8.0	100.0	100.0
May 2005	7.4	100.0	100.0
Jun 2005	9.3	100.0	100.0
Jul 2005	9.2	100.0	100.0

Table 4.12 Measurements made at Mast 312 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Jun 2004	5.9	61.4	61.4
Jul 2004	7.5	100.0	100.0
Aug 2004	6.9	100.0	100.0
Sep 2004	8.1	100.0	100.0
Oct 2004	8.1	100.0	100.0
Nov 2004	6.2	100.0	100.0
Dec 2004	7.1	80.7	80.7
Jan 2005	6.0	75.0	75.0
Feb 2005	5.8	98.1	98.1
Mar 2005	8.3	100.0	100.0
Apr 2005	7.2	100.0	100.0
May 2005	6.6	100.0	100.0
Jun 2005	8.1	100.0	100.0
Jul 2005	8.1	100.0	100.0

Table 4.13 Measurements made at Mast 313 at a height of 49 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Jun 2004	5.7	61.0	61.0
Jul 2004	7.0	100.0	100.0
Aug 2004	6.3	100.0	100.0
Sep 2004	7.4	100.0	100.0
Oct 2004	7.6	100.0	100.0
Nov 2004	6.3	98.2	98.2
Dec 2004	7.2	77.8	77.8
Jan 2005	6.5	73.7	73.7
Feb 2005	5.8	95.8	95.8
Mar 2005	7.6	98.0	98.0
Apr 2005	6.9	100.0	100.0
May 2005	6.3	100.0	100.0
Jun 2005	7.4	100.0	100.0
Jul 2005	7.5	100.0	100.0

Table 4.14 Measurements made at Mast 314 at a height of 49 m.

Diameter	80	m
Hub height	67	m
Rotor speed	16.8	rpm
Power regulation	Pitch	-
Nominal rated power	1800	kW

Table 5.1 Main parameters of the Vestas V80 wind turbine analyzed.

Wind speed [m/s at hub height]	**Electrical power [kW]**
4	0
5	84
6	223
7	417
8	670
9	935
10	1239
11	1555
12	1753
13	1794
14	1801
15	1802
16	1802
17	1802
18	1802
19	1802
20	1802
21	1802
22	1802
23	1802
24	1800
25	1800

Performance for air density 1.12 kg/m³ and 10 % turbulence intensity

Table 5.2 Performance data for the Vestas V80 wind turbine analyzed.

Turbine	Easting [1] [m]	Northing [1] [m]	Mean hub-height wind speed [2] [m/s]	Energy output [3] [GWh/annum]
A1	711042	5210530	7.7	5.9
A2	711073	5210409	7.7	5.9
A3	711134	5210298	7.7	5.7
A4	711170	5210165	7.7	5.9
A5	711200	5210043	7.7	5.8
A6	711211	5209908	7.7	5.8
A7	711104	5209668	7.6	5.6
A8	711123	5209538	7.5	5.6
B1	711987	5210378	7.9	5.6
B2	712021	5210160	7.8	5.4
C1	712917	5210298	8.4	6.0
C2	712970	5210160	8.6	6.2
C3	713012	5210022	8.6	6.3
C4	713332	5209851	8.8	6.2
C5	713387	5209712	8.9	6.6
C6	713440	5209575	9.0	6.7
C7	713492	5209438	9.0	6.8
C8	713546	5209304	8.8	6.8
C9	713766	5209045	9.2	6.8
C10	713812	5208905	8.9	6.6
C11	713847	5208777	8.6	6.4
C12	714111	5208594	8.2	6.2
C13	714151	5208458	8.1	6.2
C14	714641	5208284	8.2	6.1
C15	714670	5208145	8.3	6.3
C16	714881	5207980	8.4	6.4
C17	714916	5207853	8.3	6.4
C18	715450	5207664	8.4	6.5
D1	712777	5213525	7.6	4.7
D2	712837	5213403	7.7	4.8
D3	712936	5213246	7.7	5.1
D4	713148	5213101	7.8	5.2
D5	713306	5212963	8.0	5.5
D6	713394	5212847	8.1	5.8
D7	713504	5212710	8.3	6.0
D8	713548	5212586	8.2	6.1
D9	713612	5212471	8.0	5.9
D10	713782	5212299	8.1	5.9

Notes
1 Co-ordinate system is NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production – continued.

Turbine	Easting[1] [m]	Northing[1] [m]	Mean hub-height wind speed[2] [m/s]	Energy output[3] [GWh/annum]
D11	713797	5212123	8.2	5.7
D12	713804	5211967	8.2	5.7
D13	713825	5211808	8.4	5.8
D14	713923	5211651	8.5	6.0
D15	714110	5211480	8.6	6.0
D16	714140	5211343	8.8	6.2
D17	714221	5211203	8.8	6.2
D18	714256	5211079	8.7	6.3
D19	714389	5210919	8.1	6.1
D20	714431	5210790	8.0	6.1
D21	714483	5210670	7.8	6.0
D22	714548	5210546	7.7	5.8
D23	714617	5210412	7.9	6.0
D24	714706	5210239	7.8	5.7
D25	714770	5210115	7.8	5.6
D26	714808	5209968	8.1	5.7
D27	714859	5209842	8.2	5.8
D28	715048	5209688	8.2	5.9
D29	715111	5209565	8.2	5.9
D30	715439	5209397	8.3	6.0
D31	715497	5209279	8.5	6.1
D32	715540	5209153	8.5	6.2
D33	715902	5208995	7.6	5.7
D34	715978	5208872	7.8	5.8
D35	716054	5208760	8.0	5.8
D36	716107	5208627	8.1	5.9
D37	716249	5208493	7.8	5.8
E1B	711733	5213874	7.2	5.0
E2B	711787	5213749	7.4	5.4
E3B	711840	5213624	7.6	5.4
E4B	711891	5213496	7.5	5.2
E5B	711938	5213368	7.4	4.7
E6B	712006	5213240	7.5	4.6
E7B	712079	5213117	7.5	4.7
E8B	712226	5212981	7.7	4.8
E9B	712441	5212828	7.7	5.0
E10B	712579	5212692	7.6	5.2
F1	712831	5214477	7.8	5.4

Notes
1 Co-ordinate system is NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production – continued.

Turbine	Easting [1] [m]	Northing [1] [m]	Mean hub-height wind speed [2] [m/s]	Energy output [3] [GWh/annum]
F2	712848	5214328	7.8	5.4
F3	712863	5214181	7.7	5.5
F4	712908	5214054	7.7	5.4
F5	712952	5213932	7.6	5.2
G1	713683	5214487	8.0	5.5
G2	713726	5214310	7.8	5.3
G3	713748	5214150	7.7	5.1
G4	713692	5213903	7.7	5.1
G5	713746	5213777	7.8	5.3
G6	713790	5213656	7.8	5.3
G7	713843	5213526	7.7	5.1
H1	714479	5214366	7.3	4.8
H2	714522	5214185	7.2	4.7
H3	714524	5214028	7.1	4.5
I1	714496	5213729	7.3	4.7
I2	714544	5213572	7.3	4.7
J1A	714304	5212766	7.8	5.3
J2A	714363	5212648	7.9	5.3
J3A	714424	5212527	7.8	5.3
J4B	714484	5212407	7.6	5.4
K1	711576	5212148	7.4	5.5
K2	711629	5212018	7.5	5.5
K3	711676	5211891	7.5	5.5
K4	711726	5211771	7.3	5.4
K5	711808	5211648	7.2	5.2
K6	711870	5211522	7.2	5.1
L1	712979	5211535	7.4	5.0
L2	713091	5211392	7.6	5.4
L3	713205	5211265	7.6	5.4
L4	713271	5211142	7.4	5.3
M1	711222	5213427	7.3	5.4
M2	711261	5213296	7.4	5.4
M3	711297	5213167	7.4	5.4
M4	711337	5213038	7.5	5.4
M5	711374	5212905	7.6	5.5
M6	711421	5212782	7.6	5.6
N1	711674	5214775	7.4	5.5
N2	711717	5214648	7.6	5.7

Notes
1 Co-ordinate system is NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production – continued.

Turbine	Easting[1] [m]	Northing[1] [m]	Mean hub-height wind speed[2] [m/s]	Energy output[3] [GWh/annum]
N3	711781	5214521	7.7	5.6
N4	711808	5214406	7.7	5.3
O1	711026	5214382	7.2	5.3
O2	711064	5214252	7.3	5.4
O3	711104	5214124	7.4	5.4
O4	711134	5213983	7.2	5.3
P1	712627	5211952	7.4	4.6
P2	712662	5211813	7.4	4.6
Q1	712406	5209590	7.3	5.2
Q2	712390	5209358	7.3	5.2
Q3	712441	5209186	7.2	5.2
Q4	712489	5209018	7.1	5.2
Q5	712565	5208881	7.0	5.0

Notes
1 Co-ordinate system is NAD27
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.3 Turbine layout with predicted individual turbine wind speed and energy production – concluded.

Direction sector [degrees]	Number of records	Correlation ratio
345 – 15	53	1.17
15 – 45	346	1.11
45 – 75	278	1.01
75 – 105	71	0.98
105 – 135	16	1.09
135 – 165	14	1.10
165 – 195	20	1.18
195 – 225	64	1.17
225 – 255	357	1.07
255 – 285	1463	1.11
285 – 315	297	1.08
315 – 345	33	1.11

Table 6.1 Directional correlation ratios betweenMasts 309 at 49 m and 312 at 49 m.

Target mast	Reference mast	Correlation	Period
301	304	304 at 49 m – 301 at 50 m	13 Dec 02 to 01 Apr 03 22 Dec 03 to 31 Jul 05
302	306	306 at 49 m – 302 at 60 m	14 Dec 02 to 08 Apr 03
305	304	304 at 49 m – 305 at 49 m	13 Dec 02 to 09 Oct 03
306	306	306 at 49 m S – 306 at 49 m W	20 Jun 04 to 02 Jun 05
307	306	306 at 49 m – 307 at 49 m	12 Jun 04 to 31 Jul 05
309	306	306 at 49 m – 309 at 49 m	11 Jun 04 to 31 Jul 05
310	304	304 at 49 m – 310 at 49 m	13 Dec 02 to 11 Oct 03 01 Jul 05 to 31 Jul 05
310	310	310 at 49 m W – 310 at 49 m S	11 Oct 03 to 02 May 04
311	306	306 at 30 m – 311 at 30 m	14 Dec 02 to 08 Oct 03
312	309	309 at 49 m – 312 at 49 m	17 Dec 02 to 21 Nov 03
313	308	308 at 49 m – 313 at 49 m	19 Dec 02 to 12 Jun 04
314	308	308 at 49 m – 314 at 49 m	19 Dec 02 to 07 Apr 03
314	302	302 at 50 m – 314 at 49 m	08 Apr 03 to 12 Jun 04

Table 6.2 Synthesis steps to predict the long-term mean wind speed at each mast location.

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	8.2	1403	1427
February	6.4	1746	1754
March	9.2	2153	2153
April	7.6	2148	2140
May	7.8	2232	2232
June	7.9	2160	2160
July	7.9	2232	2232
August	7.2	1488	1488
September	8.4	1440	1440
October	9.2	1488	1488
November	8.4	1423	1423
December	8.1	1380	1339
Mean of means	**8.1**		

Table 6.3 Predicted monthly and annual mean wind speeds at Mast 301 at 50m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.5	1283	1283
February	6.1	1861	1861
March	8.7	2214	2214
April	6.8	2160	2160
May	7.3	2232	2232
June	7.3	2160	2160
July	7.4	2232	2232
August	6.7	1488	1488
September	7.7	1438	1438
October	8.4	1488	1488
November	7.7	1409	1409
December	7.5	1387	1387
Mean of means	**7.4**		

Table 6.4 Predicted monthly and annual mean wind speeds at Mast 302 at 60m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	8.2	1403	1427
February	6.4	1746	1754
March	9.4	2153	2153
April	7.5	2140	2140
May	7.9	2232	2232
June	8.1	2160	2160
July	8.1	2232	2232
August	7.4	1488	1488
September	8.5	1440	1440
October	9.1	1488	1488
November	8.4	1423	1423
December	8.1	1339	1339
Mean of means	**8.1**		

Table 6.5 Predicted monthly and annual mean wind speeds at Mast 304 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.6	1550	1550
February	6.3	1789	1789
March	9.3	2171	2171
April	7.5	2152	2152
May	8.1	2232	2232
June	8.3	2160	2160
July	8.4	2232	2232
August	7.6	1488	1488
September	8.6	1440	1440
October	8.8	1488	1488
November	7.8	1440	1440
December	7.8	1308	1308
Mean of means	**8.0**		

Table 6.6 Predicted monthly and annual mean wind speeds at Mast 305 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	8.2	1287	1287
February	6.6	1854	1854
March	9.7	2232	2232
April	7.4	2152	2152
May	8.0	2232	2232
June	8.1	2160	2160
July	8.2	2232	2232
August	7.5	1488	1488
September	8.4	1440	1440
October	8.9	1488	1488
November	8.0	1440	1440
December	7.7	1393	1393
Mean of means	**8.1**		

Table 6.7 Predicted monthly and annual mean wind speeds at Mast 306 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	8.5	1336	1336
February	6.8	1893	1893
March	10.3	2232	2232
April	7.7	2152	2152
May	8.6	2232	2232
June	8.6	2160	2160
July	8.8	2232	2232
August	7.9	1488	1488
September	9.0	1440	1440
October	9.3	1488	1488
November	8.4	1440	1440
December	8.3	1483	1483
Mean of means	**8.6**		

Table 6.8 Predicted monthly and annual mean wind speeds at Mast 307 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.3	1430	1430
February	5.9	1967	1967
March	9.2	2221	2221
April	7.0	2150	2150
May	7.6	2232	2232
June	7.6	2160	2160
July	7.7	2232	2232
August	7.1	1488	1488
September	8.0	1440	1440
October	8.8	1091	1091
November	7.5	1440	1440
December	7.1	1396	1396
Mean of means	**7.6**		

Table 6.9 **Predicted monthly and annual mean wind speeds at Mast 308 at 49m (Dec 2002 to Jul 2005).**

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.2	1474	1474
February	6.0	1940	1962
March	9.3	2232	2232
April	7.1	2152	2152
May	7.8	2232	2232
June	7.9	2160	2160
July	8.1	2232	2232
August	7.3	1488	1488
September	8.2	1440	1440
October	8.4	1488	1488
November	7.5	1440	1440
December	7.3	1553	1552
Mean of means	**7.7**		

Table 6.10 **Predicted monthly and annual mean wind speeds at Mast 309 at 49m (Dec 2002 to Jul 2005).**

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.1	1624	1633
February	6.1	1793	1793
March	8.7	2179	2179
April	7.0	2150	2150
May	7.6	2063	2063
June	7.5	2160	2160
July	7.6	2232	2232
August	6.8	1488	1488
September	8.0	1440	1440
October	8.5	1488	1488
November	7.5	1440	1440
December	7.1	1426	1426
Mean of means	**7.5**		

Table 6.11 Predicted monthly and annual mean wind speeds at Mast 310 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.7	1463	1462
February	6.5	1937	1961
March	10.2	2232	2232
April	7.7	2151	2151
May	8.5	2232	2232
June	8.7	2160	2160
July	8.9	2232	2232
August	8.1	1488	1488
September	9.0	1440	1440
October	9.1	1488	1488
November	7.9	1440	1440
December	7.9	1411	1411
Mean of means	**8.4**		

Table 6.12 Predicted monthly and annual mean wind speeds at Mast 312 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	6.9	1452	1452
February	5.7	1979	1979
March	8.5	2221	2221
April	6.6	2160	2160
May	7.1	2232	2232
June	7.1	2160	2160
July	7.2	2232	2232
August	6.5	1488	1488
September	7.5	1440	1440
October	8.0	1488	1488
November	7.2	1440	1440
December	6.9	1419	1419
Mean of means	**7.5**		

Table 6.13 Predicted monthly and annual mean wind speeds at Mast 313 at 49m (Dec 2002 to Jul 2005).

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	7.0	1372	1372
February	5.8	1828	1828
March	8.4	2189	2189
April	6.6	2151	2151
May	7.0	2232	2232
June	7.1	1492	1492
July	7.0	1488	1488
August	6.5	1488	1488
September	7.5	1440	1440
October	8.0	1488	1488
November	7.3	1427	1427
December	6.9	1294	1294
Mean of means	**7.1**		

Table 6.14 Predicted monthly and annual mean wind speeds at Mast 314 at 49m (Dec 2002 to Jul 2005).

Site: Mast 304 at 67 m **Period:** Annual (Dec 2002 to Jul 2005)

Wind Speed (m/s)	Wind Direction (degrees)												No Direction	Total (%)
	0	30	60	90	120	150	180	210	240	270	300	330		
0	0.04	0.01	0.03	0.02	0.05	0.02	0.04	0.05	0.06	0.07	0.05	0.03		0.47
1	0.18	0.29	0.28	0.30	0.28	0.25	0.23	0.25	0.37	0.35	0.17	0.18		3.14
2	0.32	0.67	0.70	0.63	0.34	0.36	0.42	0.58	0.66	0.39	0.29	0.25		5.59
3	0.39	1.02	1.14	1.00	0.58	0.45	0.62	0.77	1.03	0.59	0.30	0.23		8.11
4	0.32	1.35	1.04	0.79	0.51	0.35	0.45	0.82	1.57	1.14	0.36	0.18		8.87
5	0.24	1.27	0.83	0.31	0.21	0.21	0.32	0.65	1.85	1.73	0.51	0.16		8.29
6	0.15	1.45	0.64	0.09	0.06	0.15	0.28	0.58	1.93	2.19	0.62	0.13		8.25
7	0.13	1.55	0.60	0.02	0.02	0.08	0.14	0.42	1.56	2.36	0.67	0.05		7.61
8	0.14	1.50	0.40	0.01	0.01	0.02	0.09	0.30	1.32	2.23	0.67	0.02		6.72
9	0.08	1.31	0.23	0.01		0.01	0.04	0.25	1.02	2.24	0.74	0.01		5.95
10	0.04	1.13	0.16	+		0.01	0.01	0.24	0.76	2.10	1.18	0.02		5.66
11	0.02	0.84	0.09			0.01	0.02	0.17	0.50	1.96	1.39	0.01		5.02
12	0.01	0.54	0.07			0.02	0.01	0.14	0.32	1.85	1.61	+		4.58
13	0.01	0.44	0.06			+	+	0.09	0.24	1.67	1.76			4.28
14	0.01	0.40	0.06					0.10	0.18	1.48	1.63			3.86
15	0.01	0.33	0.05					0.08	0.10	1.31	1.56			3.45
16		0.29	0.03					0.05	0.06	1.11	1.36			2.90
17		0.24	0.01					0.04	0.06	0.86	1.10			2.31
18		0.17	+					0.03	0.05	0.64	0.80			1.70
19		0.13						0.02	0.03	0.45	0.48			1.12
20		0.08	+					0.01	0.03	0.30	0.29			0.72
21		0.03	+					0.01	0.04	0.19	0.17			0.45
22		0.02						0.01	0.04	0.14	0.13			0.33
23		0.01						+	0.02	0.12	0.05			0.20
24		+						+	+	0.07	0.05			0.13
25								0.01	+	0.04	0.03			0.09
26								+		0.05	0.03			0.08
27								+		0.02	0.03			0.06
28								+		0.01	+			0.02
29														
30										+				+
31										0.02				0.02
32														
33														
34														
35														
36														
37														
38														
39 - 44														
45 and over														
Total (%)	2.09	15.08	6.43	3.18	2.07	1.94	2.68	5.71	13.81	27.67	18.03	1.29		100
Av.Speed (m/s)	4.49	7.99	5.21	3.19	3.09	3.59	3.97	6.15	6.75	10.27	12.34	3.65	0.00	8.4

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

Table 6.15 Predicted wind speed and direction frequency distribution at Mast 304 at 67 m.

Mast	Wind speed measurement heights [m]	Long-term mean wind speed at highest measurement height [m/s]	Power law shear exponent 'a' from measurement	Estimated long-term mean wind speed at 67 m [m/s]
301	50, 30	8.1	0.07	8.2
302	60, 30	7.4	0.08	7.5
304	49, 30	8.1	0.10	8.4
305	49, 30	8.0	0.07	8.3
306	49, 30	8.1	0.07	8.3
307	49, 30	8.6	0.04	8.7
308	49, 30	7.6	0.08	7.8
309	49, 30	7.7	0.07	7.9
310	49, 30	7.5	0.07	7.6
312	49, 30	8.4	0.03	8.4
313	49, 30	7.5	0.08	7.7
314	49, 30	7.1	0.12	7.4

Table 6.16 Predictions of the wind speeds at the site masts.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.25		
Period rep. of long-term	3.8%	0.32		
Correlation	1.1%	0.09		
Shear to 67 m	1.5%	0.12		
Overall historical wind speed		**0.43**		**0.8**
Substation Metering accuracy			0.3%	0.0
Wake and Topographic error			5.0%	0.5
Future wind variability (1 year)	6.0%	0.49		0.9
Future wind variability (10 years)	1.9%	0.16		0.3
Overall energy uncertainty (1 year)				**1.3**
Overall energy uncertainty (10 years)				**1.0**

Note: Sensitivity of net production to wind speed is calculated to be 1.88 GWh/annum. (m/s)

Table 6.17 Uncertainty in projected energy output of Turbines A1 to A2 based on Mast 301.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.23		
Period rep. of long-term	3.8%	0.29		
Correlation	0.1%	0.01		
Shear to 67 m	0.5%	0.04		
Overall historical wind speed		**0.37**		**11.2**
Substation Metering accuracy			0.3%	0.4
Wake and Topographic error			7.0%	9.9
Future wind variability (1 year)	6.0%	0.45		13.7
Future wind variability (10 years)	1.9%	0.14		4.3
Overall energy uncertainty (1 year)				**20.3**
Overall energy uncertainty (10 years)				**15.6**

Note: Sensitivity of net production to wind speed is calculated to be 30.46 GWh/annum. (m/s)

Table 6.18 Uncertainty in projected energy output of Turbines D1 to D2, E1B to E10B, K1 to K6, L1 to L4, M1 to M6 and P1 to P2 based on Mast 302.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.25		
Period rep. of long-term	3.9%	0.32		
Correlation	0.0%	0.00		
Shear to 67 m	1.5%	0.13		
Overall historical wind speed		**0.43**		**2.8**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			6.0%	2.8
Future wind variability (1 year)	6.0%	0.50		3.3
Future wind variability (10 years)	1.9%	0.16		1.1
Overall energy uncertainty (1 year)				**5.2**
Overall energy uncertainty (10 years)				**4.1**

Note: Sensitivity of net production to wind speed is calculated to be 6.64 GWh/annum. (m/s)

Table 6.19 Uncertainty in projected energy output of Turbines C1 to C8 based on Mast 304.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.25		
Period rep. of long-term	3.8%	0.31		
Correlation	0.5%	0.04		
Shear to 67 m	1.5%	0.12		
Overall historical wind speed		**0.42**		**3.6**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			6.0%	3.5
Future wind variability (1 year)	6.0%	0.49		4.2
Future wind variability (10 years)	1.9%	0.16		1.3
Overall energy uncertainty (1 year)				**6.6**
Overall energy uncertainty (10 years)				**5.2**

Note: Sensitivity of net production to wind speed is calculated to be 8.58 GWh/annum. (m/s)

Table 6.20 Uncertainty in projected energy output of Turbines C9 to C18 based on Mast 305.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.25		
Period rep. of long-term	3.8%	0.32		
Correlation	0.1%	0.01		
Shear to 67 m	1.5%	0.12		
Overall historical wind speed		**0.42**		**4.0**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			7.0%	3.9
Future wind variability (1 year)	6.0%	0.49		4.7
Future wind variability (10 years)	1.9%	0.16		1.5
Overall energy uncertainty (1 year)				**7.8**
Overall energy uncertainty (10 years)				**5.8**

Note: Sensitivity of net production to wind speed is calculated to be 9.44 GWh/annum. (m/s)

Table 6.21 Uncertainty in projected energy output of Turbines D3 to D9 and J1A to J4B based on Mast 306.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.26		
Period rep. of long-term	3.8%	0.33		
Correlation	0.3%	0.02		
Shear to 67 m	1.5%	0.13		
Overall historical wind speed		**0.44**		**2.7**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			6.0%	2.9
Future wind variability (1 year)	6.0%	0.52		3.2
Future wind variability (10 years)	1.9%	0.16		1.0
Overall energy uncertainty (1 year)				**5.2**
Overall energy uncertainty (10 years)				**4.1**

Note: Sensitivity of net production to wind speed is calculated to be 6.20 GWh/annum. (m/s)

Table 6.22 Uncertainty in projected energy output of Turbines D10 to D18 based on Mast 307.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.23		
Period rep. of long-term	3.9%	0.30		
Correlation	0.0%	0.00		
Shear to 67 m	1.5%	0.12		
Overall historical wind speed		**0.40**		**3.4**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			7.0%	3.3
Future wind variability (1 year)	6.0%	0.47		4.0
Future wind variability (10 years)	1.9%	0.15		1.3
Overall energy uncertainty (1 year)				**6.2**
Overall energy uncertainty (10 years)				**4.9**

Note: Sensitivity of net production to wind speed is calculated to be 8.62 GWh/annum. (m/s)

Table 6.23 Uncertainty in projected energy output of Turbines F2 to F5, G4 to G7 and I1 to I2 based on Mast 308.

Source of uncertainty	Wind speed		Energy output[1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.24		
Period rep. of long-term	3.8%	0.30		
Correlation	0.3%	0.03		
Shear to 67 m	1.5%	0.12		
Overall historical wind speed		**0.40**		**1.7**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			4.0%	1.1
Future wind variability (1 year)	6.0%	0.47		2.0
Future wind variability (10 years)	1.9%	0.15		0.6
Overall energy uncertainty (1 year)				**2.8**
Overall energy uncertainty (10 years)				**2.1**

Note: Sensitivity of net production to wind speed is calculated to be 4.19 GWh/annum. (m/s)

Table 6.24 Uncertainty in projected energy output of Turbines D19 to D23 based on Mast 309.

Source of uncertainty	Wind speed		Energy output[1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.23		
Period rep. of long-term	3.8%	0.29		
Correlation	0.5%	0.03		
Shear to 67 m	1.5%	0.11		
Overall historical wind speed		**0.39**		**4.7**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			7.0%	4.5
Future wind variability (1 year)	6.0%	0.46		5.5
Future wind variability (10 years)	1.9%	0.14		1.7
Overall energy uncertainty (1 year)				**8.5**
Overall energy uncertainty (10 years)				**6.7**

Note: Sensitivity of net production to wind speed is calculated to be 11.98 GWh/annum. (m/s)

Table 6.25 Uncertainty in projected energy output of Turbines A3 to A8, B1 to B2 and Q1 to Q5 based on Mast 310.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.25		
Period rep. of long-term	3.8%	0.32		
Correlation	0.7%	0.06		
Shear to 67 m	1.5%	0.13		
Overall historical wind speed		**0.43**		**4.2**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			6.0%	4.5
Future wind variability (1 year)	6.0%	0.51		4.9
Future wind variability (10 years)	1.9%	0.16		1.6
Overall energy uncertainty (1 year)				**7.9**
Overall energy uncertainty (10 years)				**6.3**

Note: Sensitivity of net production to wind speed is calculated to be 9.71 GWh/annum. (m/s)

Table 6.26 Uncertainty in projected energy output of Turbines D24 to D37 based on Mast 312.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.23		
Period rep. of long-term	3.8%	0.30		
Correlation	0.4%	0.03		
Shear to 67 m	1.5%	0.12		
Overall historical wind speed		**0.39**		**2.3**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			7.0%	2.3
Future wind variability (1 year)	6.0%	0.46		2.8
Future wind variability (10 years)	1.9%	0.15		0.9
Overall energy uncertainty (1 year)				**4.3**
Overall energy uncertainty (10 years)				**3.4**

Note: Sensitivity of net production to wind speed is calculated to be 5.94 GWh/annum. (m/s)

Table 6.27 Uncertainty in projected energy output of Turbines F1, G1 to G3 and H1 to H3 based on Mast 313.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer	3.0%	0.22		
Period rep. of long-term	3.8%	0.28		
Correlation	0.4%	0.03		
Shear to 67 m	1.5%	0.11		
Overall historical wind speed		**0.38**		**2.9**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			6.0%	2.4
Future wind variability (1 year)	6.0%	0.44		3.5
Future wind variability (10 years)	1.9%	0.14		1.1
Overall energy uncertainty (1 year)				**5.1**
Overall energy uncertainty (10 years)				**3.9**

Note: Sensitivity of net production to wind speed is calculated to be 7.82 GWh/annum. (m/s)

Table 6.28 Uncertainty in projected energy output of Turbines N1 to N4 and O1 to O4 based on Mast 314.

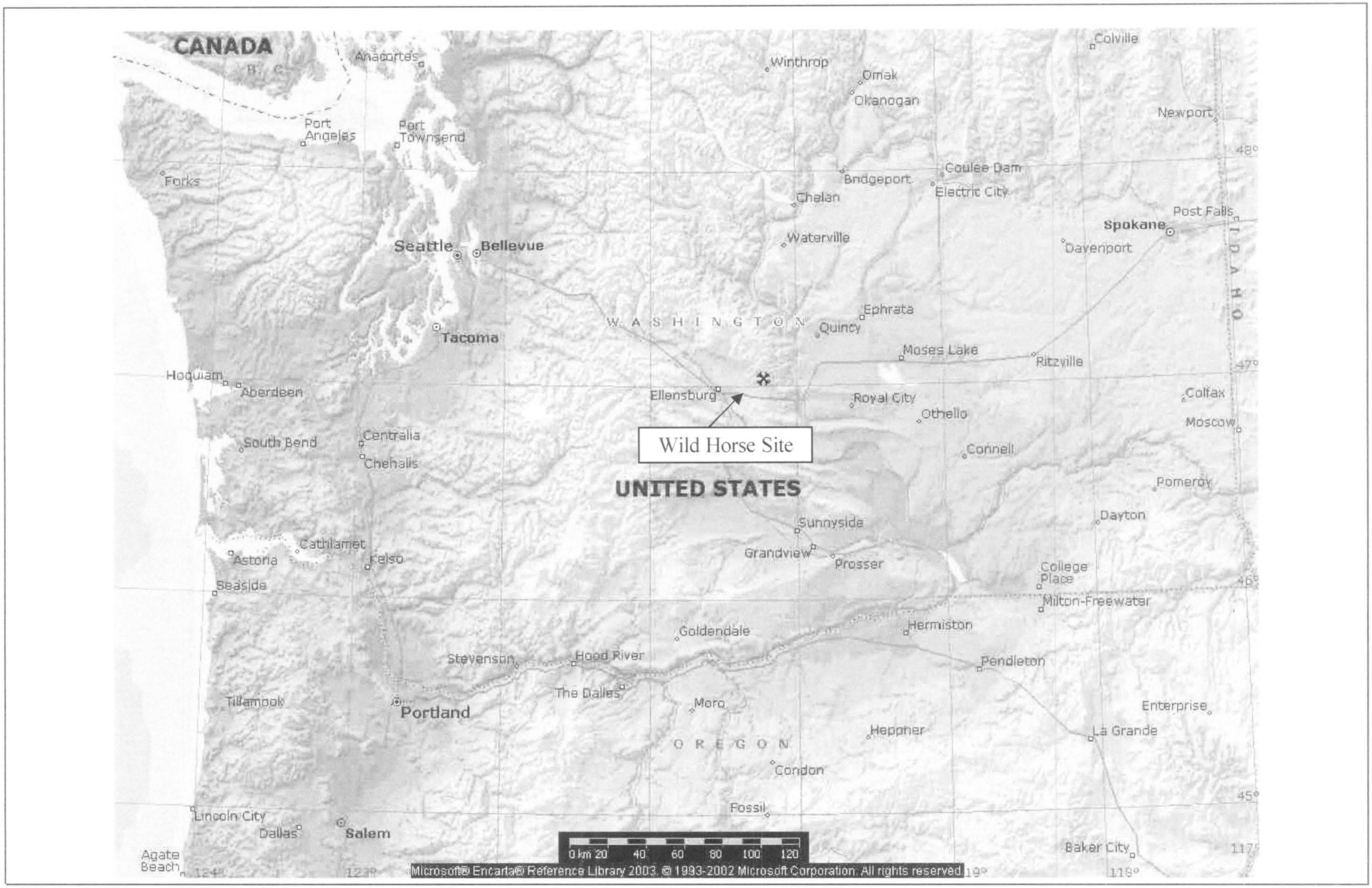


Figure 2.1 **Location of the Wild Horse site.**

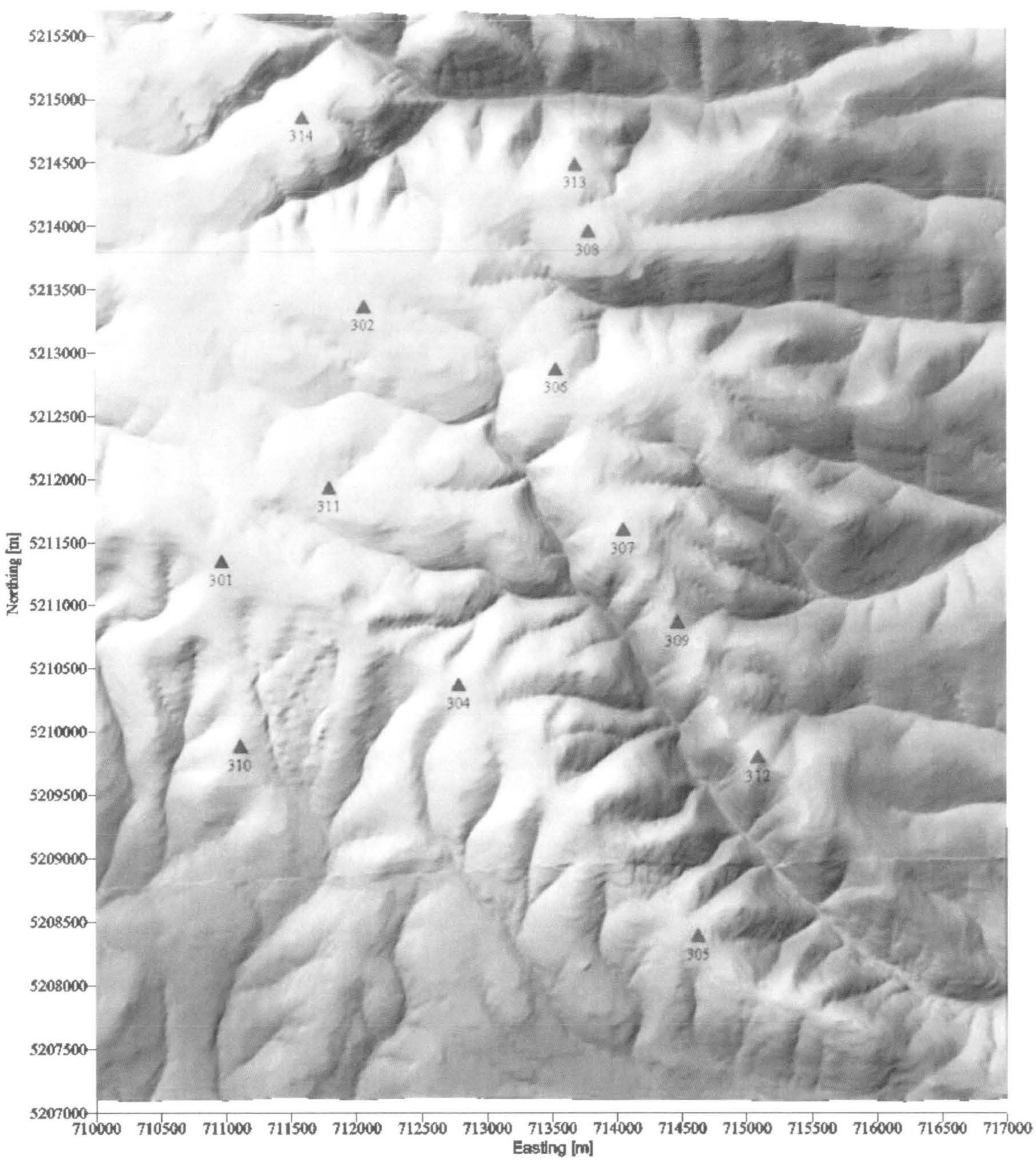


Figure 2.2 Location of the Wild Horse meteorological masts.

Figure 2.3 View of the Wild Horse site from Mast 309 looking east.

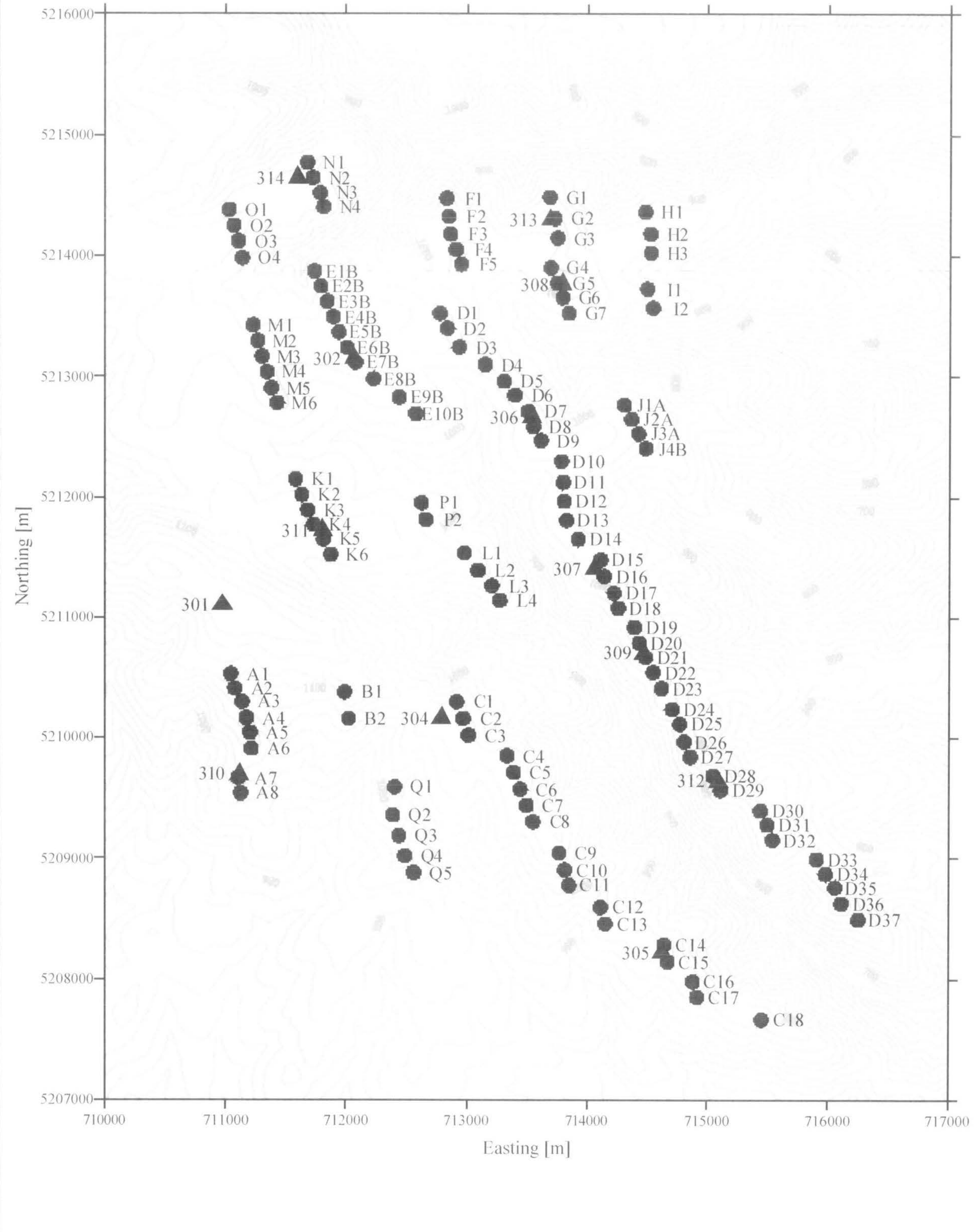


Figure 5.1 Wild Horse Wind Farm proposed turbine layout.

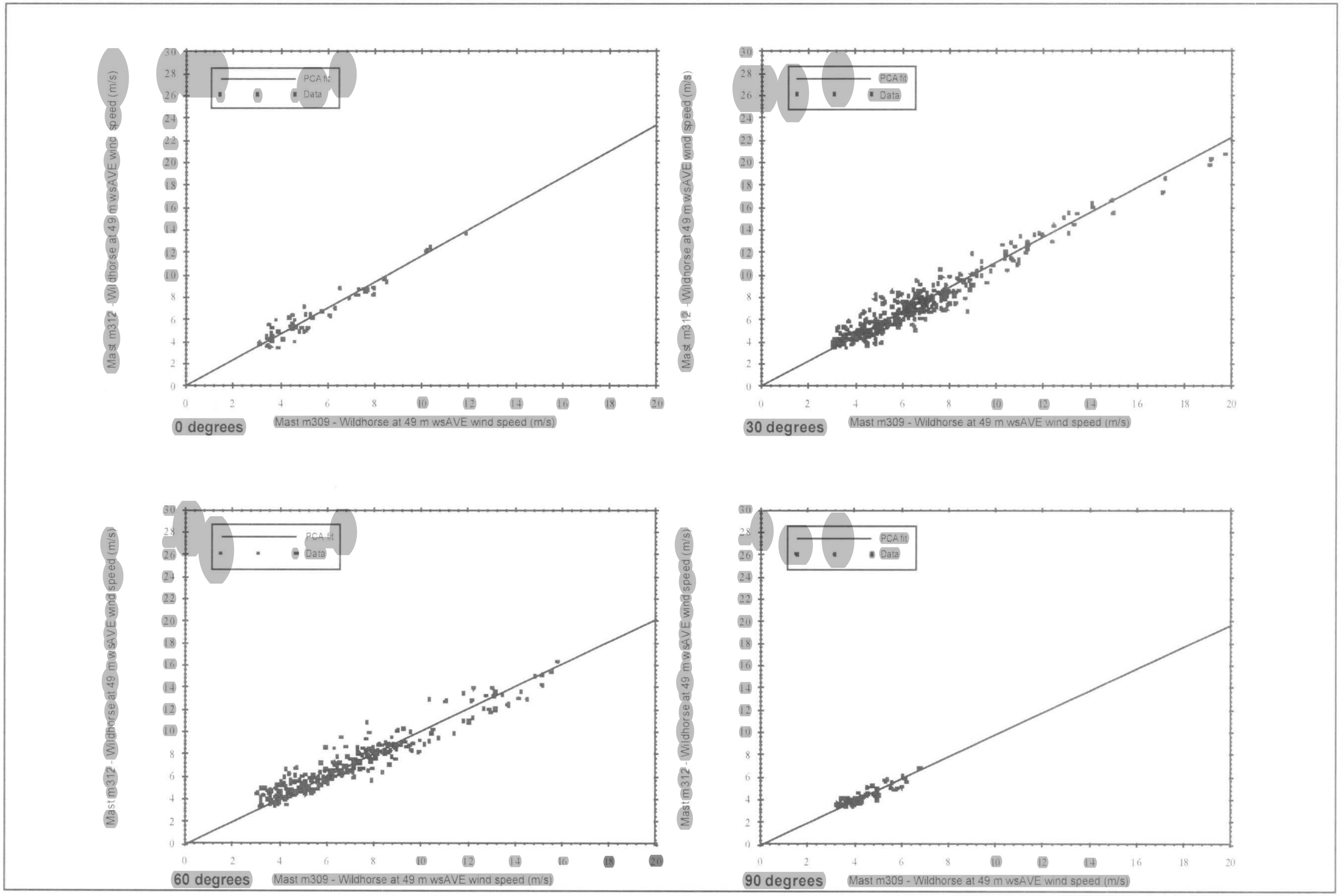


Figure 6.1 Correlation of hourly mean wind speed at Mast 309 at 49m and Mast 312 at 49m.

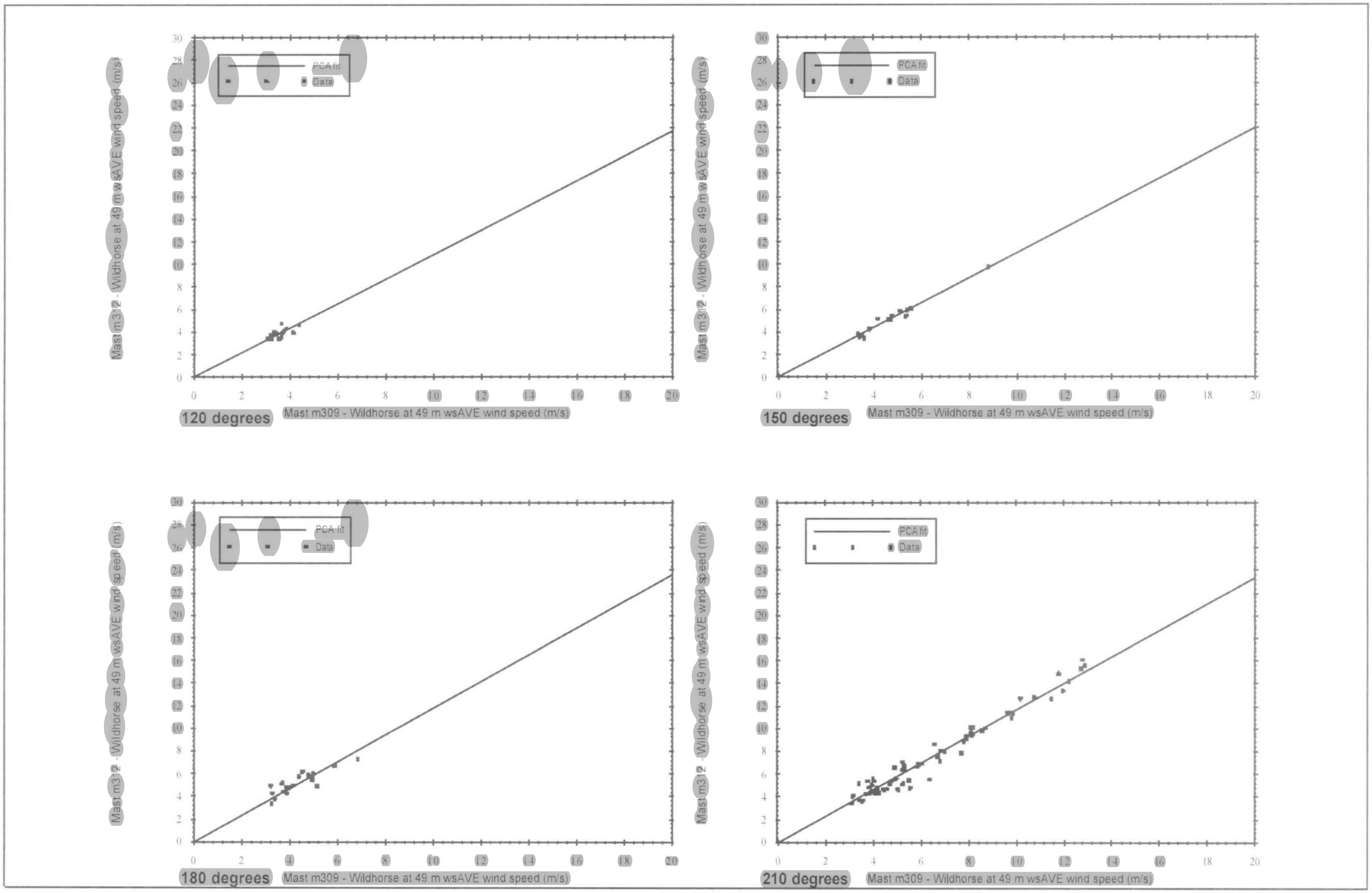


Figure 6.1 Correlation of hourly mean wind speed at Mast 309 at 49m and Mast 312 at 49m. -continued

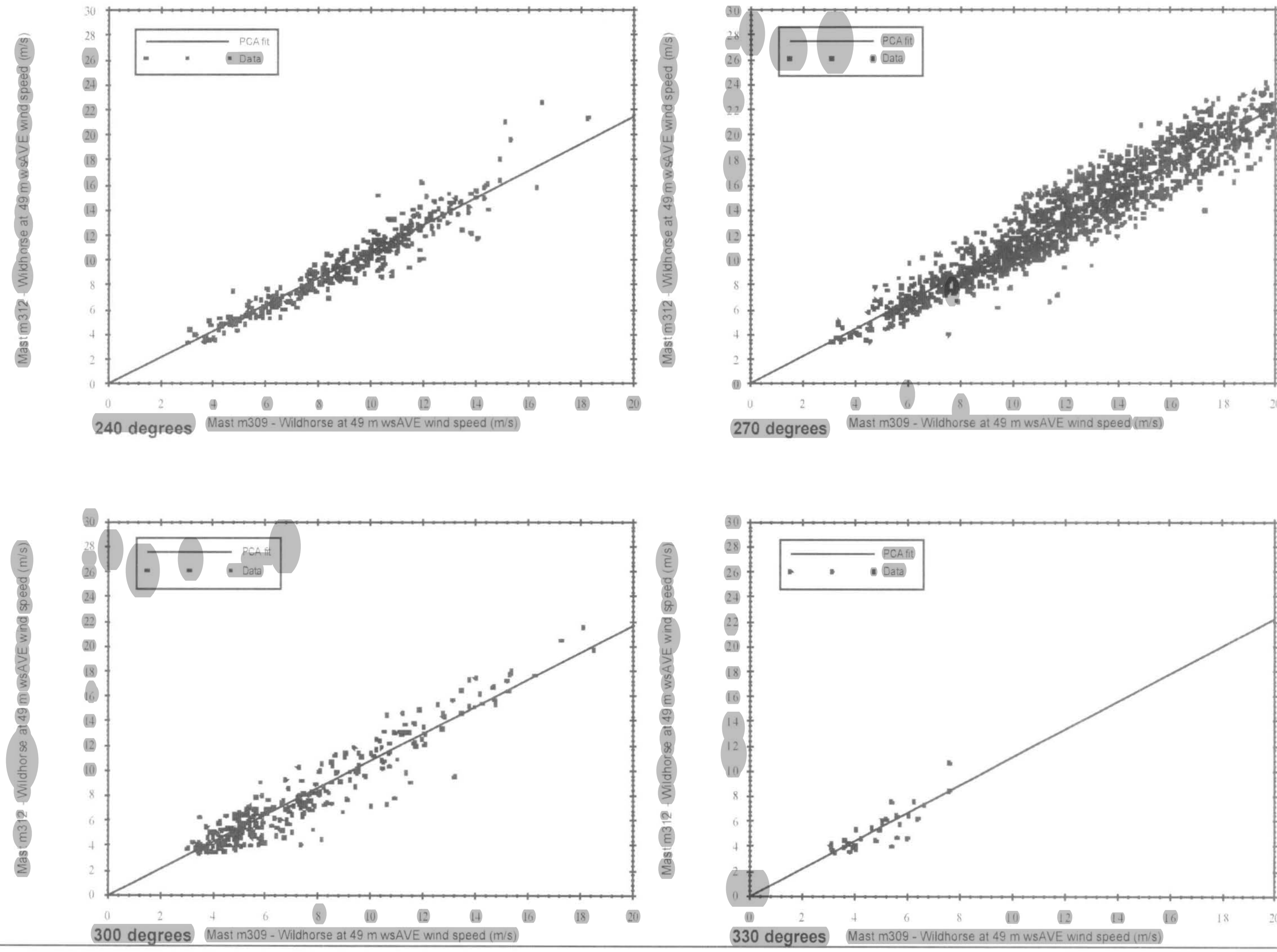


Figure 6.1 Correlation of hourly mean wind speed at Mast 309 at 49m and Mast 312 at 49m. -concluded

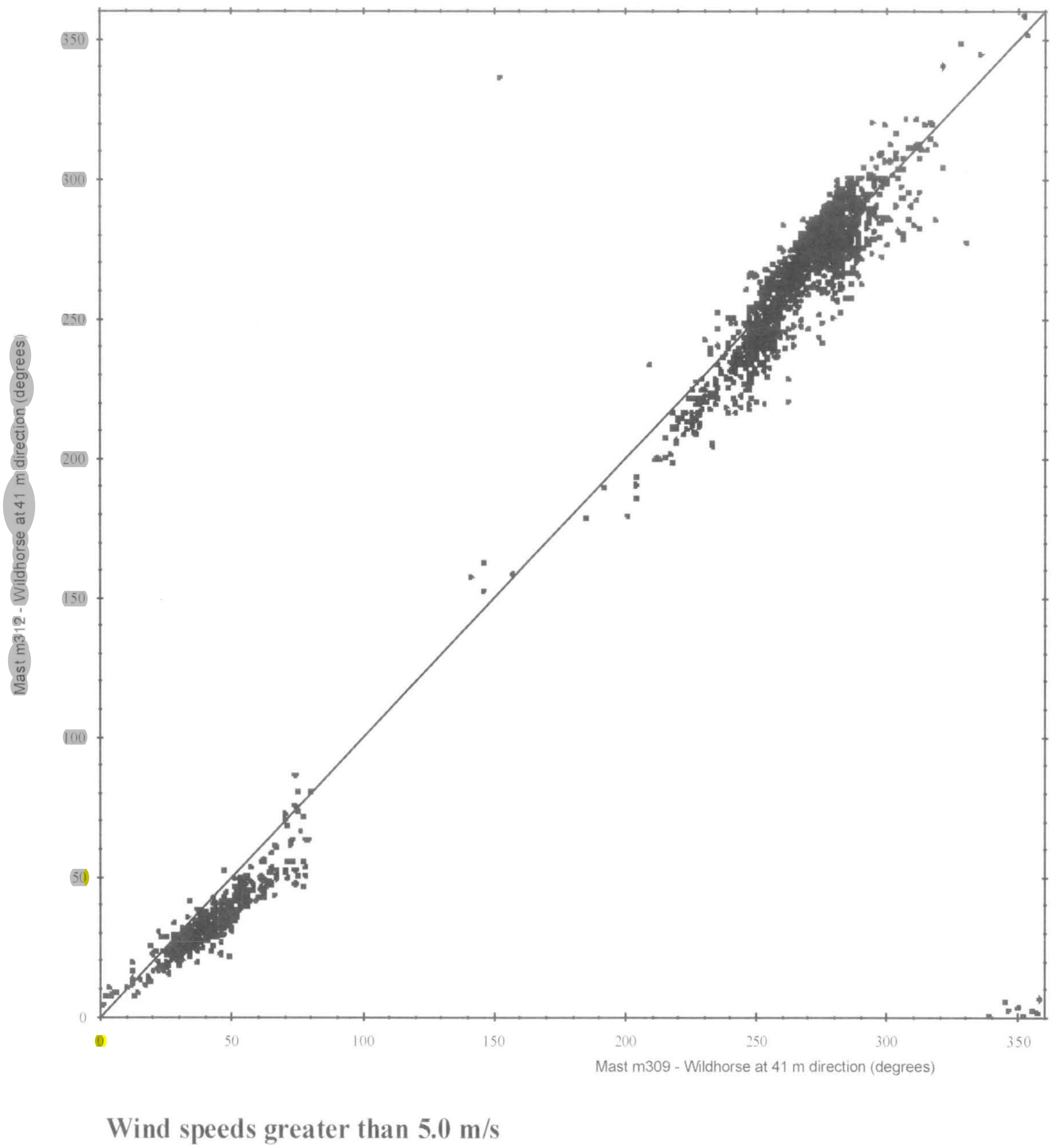


Figure 6.2 Correlation of hourly mean wind direction at Mast 309 and Mast 312.

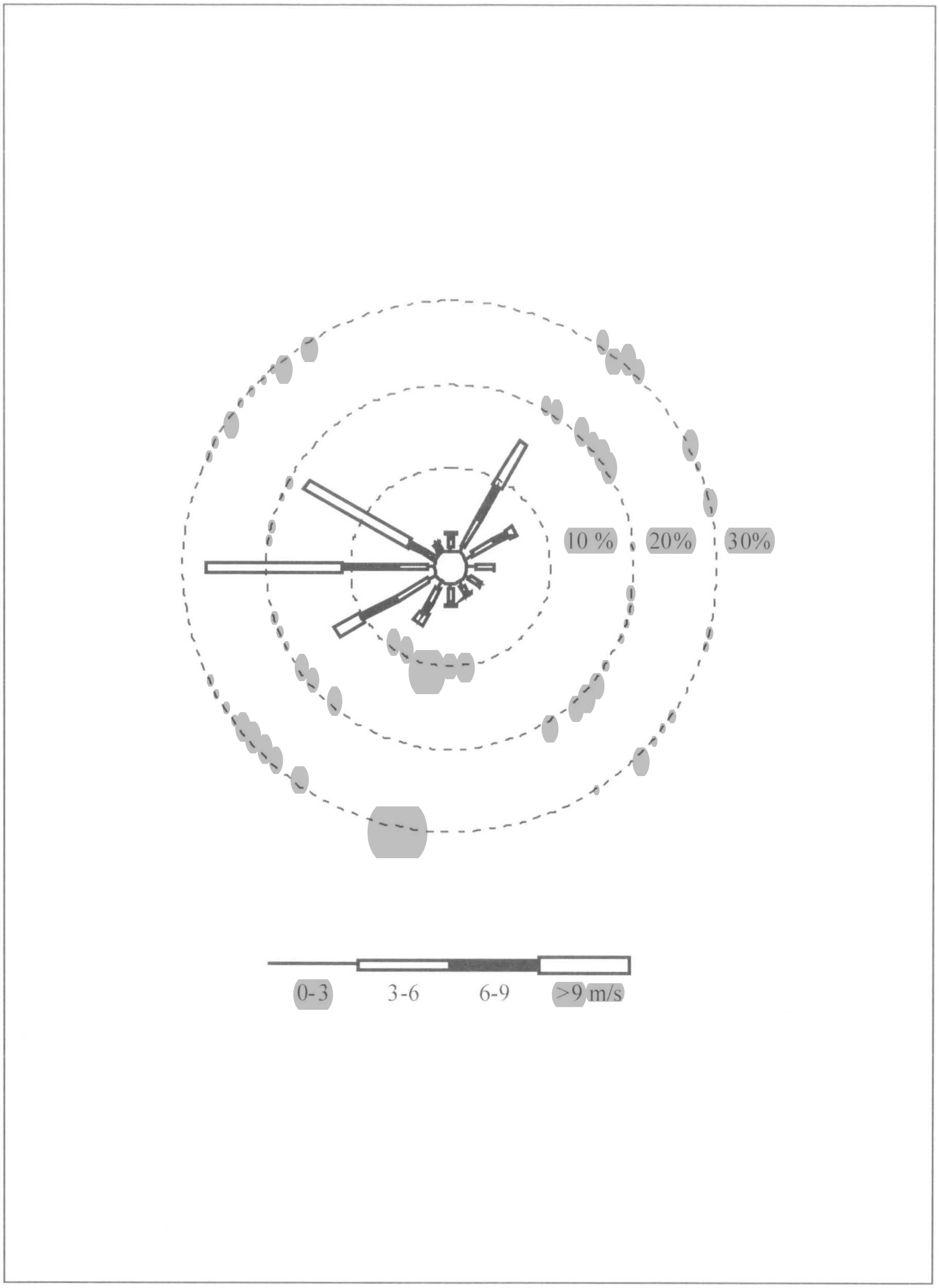


Figure 6.3 Annual wind rose from Mast 304 at 67 m.

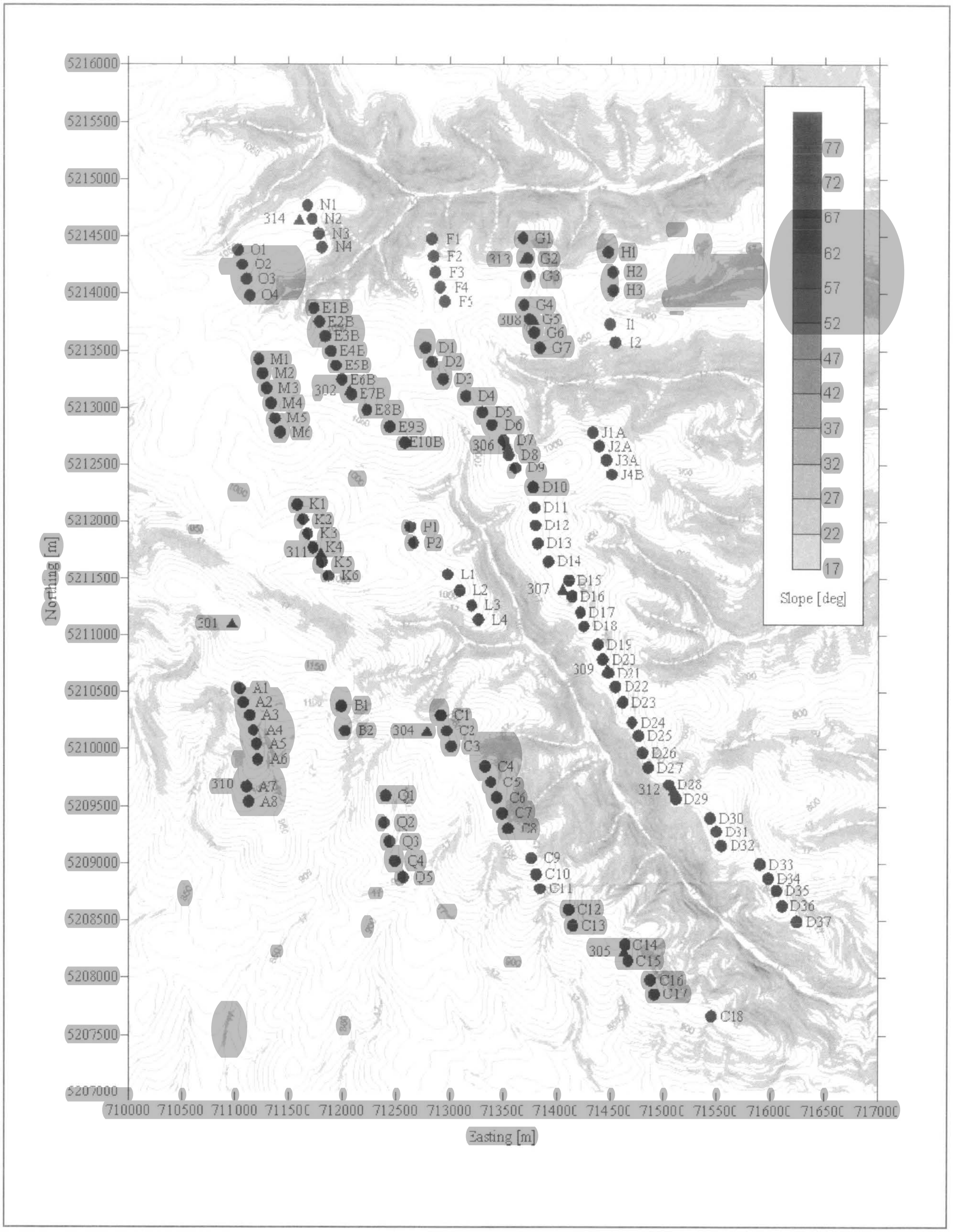


Figure 6.4 **Areas of steep slopes on the Wild Horse site.**

APPENDIX 1

Data analysis procedure

1. Correlation of wind speed and direction across the site.
2. Site wind speed variations.
3. Projected energy production
4. Confidence analysis
5. References

1 Correlation of wind speed and direction across the site

The method used to determine the long-term mean wind speed for a "target" site from a "reference" site is based on the Measure-Correlate-Predict approach, which is outlined below.

The first stage in the approach is to measure, over a period of about one year, concurrent wind data from both the "target" site and the nearby "reference" site for which well established long-term wind records are available. The short-term measured wind data are then used to establish the correlation between the winds at the two locations. Finally, the correlation is used to adjust the long-term historical data recorded at the "reference" site to calculate the long-term mean wind speed at the site.

The concurrent data are correlated by comparing wind speeds at the two locations for each of twelve 30 degree direction sectors, based on the wind direction recorded at the "reference" site. 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. Only those records with speeds in excess of 5 m/s at both locations are used.

- Wind speed ratios are determined for each of the direction sectors using a principal component analysis with the solution forced through the origin. This method is equivalent to a linear least-squared regression forced through the origin minimising the orthogonal offset.

In order to minimize the influence of localized winds on the wind speed ratio, the data are screened to reject records where the speed recorded at the "reference" site falls below 3 m/s or a slightly different level at the "target" site. The average wind speed ratio is used to adjust the 3 m/s wind speed level for the "reference" site to obtain the higher level for the "target" site, to ensure unbiased exclusion of data. The wind speed at which this level is set is a balance between excluding low winds from the analysis and still having sufficient data for the analysis. The level used excludes only winds below the cut-in wind speed of a wind turbine which do not contribute to the energy production.

The result of the analysis described above is a table of wind speed ratios, each corresponding to one of twelve direction sectors. These ratios are used to factor the wind data measured at the "reference" site over the historical reference period, to obtain the long-term mean wind speed at the "target" site.

2 Site wind speed variations

To calculate the variation of mean 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 [1].

The inputs to the model are a digitized map of the topography and surface roughness length of the terrain for the site and surrounding area. A digitized map of an area surrounding the site of 28 km x 28 km was derived from 1:24,000 USGS scale maps. Although this domain size is much larger than the area of the site itself, such an area is necessary since the flow at any point is dictated by the terrain several kilometres upwind.

Wind flow is affected by the roughness of the ground. The surface roughness length of the site and surrounding area has been estimated, as detailed in the main text.

The wind flow calculations were carried out for 30 degree steps in wind direction corresponding to the measured wind rose and results were produced as speed-up factors relative to the mast location for a grid encompassing the site area.

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

3 Projected energy production

The components of the derivation of the wind farm net energy output prediction are listed and described below:

Ideal energy output

The ideal energy production is the theoretical output of the wind farm with the hub height wind speeds at the appropriate mast location applied for all associated turbines. Any density adjustment required due to a difference between the air density at hub height at the reference mast location and that assumed for the turbine power curve is applied as discussed in the main body of the report and included in the ideal energy output.

Topographic and wake effect calculations

The first step in modelling flow through an array of wind turbines is the calculation of the flow in the wake of a single machine. Immediately downstream of the rotor, there is a momentum deficit with respect to free stream conditions, which is equal to the thrust force on the machine. As the flow proceeds downstream, there is a spreading of the wake and recovery to free stream conditions. Turbulent momentum transfer is important in this process.

The model used here, WindFarmer, has been developed by GH and validated using measurements on both full-scale machines and on wind-tunnel models [2, 3, 4].

The model is employed in a scheme which, taking each wind speed and direction in turn calculates the power production of the wind farm. The important parameters used in this process are:

- array layout
- upstream mean wind speed
- ambient turbulence
- wind turbine thrust characteristic
- wind turbine power characteristic
- rotor speed
- topographical speed-up factors from site wind flow calculations

It is noted that due to the relatively tight spacing of the turbines in the prevailing wind directions, an additional pragmatic margin has been included in the array loss to account for the likely reduced rate of wake recovery compared to that modelled.

Topographical effects are accounted for in the model using the speed-up factors calculated by the wind flow model described above. Any air density adjustments required due to differences between the hub height air density at the turbine locations and that at the reference mast location is applied as discussed in the main body of the report and included in the topographic effect. The array model is used to calculate the wind speed in the turbine wakes, assuming the terrain is flat, and the wind speed is adjusted by the speed-up factor when the wake reaches a downstream turbine.

Electrical transmission efficiency

A figure of 97.9 % has been included for the electrical efficiency of the wind farm as provided by Zilkha [6.2]. Neither a review of the Zilkha figure nor a detailed analysis of the electrical system has been undertaken by GH. It is recommended that this figure be reviewed once such an analysis has been performed.

Turbine availability

A figure of 97 % has been assumed for turbine availability based on data from modern operational wind farms. However, availability may be a matter of warranty between the owner and the turbine supplier and the assumed figure should be reviewed when the terms of that warranty are clear.

Blade degradation and fouling

The turbine production may be affected by the build up of insects, dirt or ice on the blades. This build up will change the characteristics of the blade and therefore affect the performance of the blades and the turbine output.

An adjustment has been included to allow for lost production due to blade fouling. A figure of 98.0 % has been assumed to be appropriate for these pitch regulated turbines.

High wind hysteresis

This is caused by the turbine cut in and cut out control criteria for high wind speeds. The magnitude of this loss is influenced by three factors.

1. The turbine will cut out when the maximum mean wind speed is exceeded and it will not cut in again until this mean wind speed is below a mean wind speed level lower than the cut out mean wind speed.
2. The turbine will cut out if the instantaneous gust wind speed exceeds a maximum level and the turbine will not cut in until the wind speed drops to a lower value.
3. The accuracy of the calibration of the instruments that are determining the wind characteristics at the turbine.

These three effects will cause the turbine to possibly lose production for some proportion of high mean wind speed occurrences. The magnitude of this lost production has been estimated by GH by repeating the analysis using a power curve with the cut out wind speed reduced by 2.5 m/s.

Substation maintenance

Net wind farm production may be reduced due to the electrical output not being transferred to the grid network while the substation is shutdown for maintenance. A typical figure of 99.8% is assumed in this analysis to represent one day per year of planned maintenance. This is included as scheduled maintenance can not generally be accurately planned to occur on a day with low wind speeds.

Utility downtime

Net wind farm production will be reduced if the grid is not available for the wind farm to output electricity to it. This type of loss must be considered on a site specific basis. It has not been considered in this analysis.

Wind sector manageme nt

If wind turbine spacing is close the site conditions may exceed the wind conditions within the wind turbine certification criteria. In these circumstances it may be necessary to shut down some turbines which are closely spaced when the wind direction is parallel to the line of turbines. Details of a WSM strategy for the final V80 layout to be employed have been provided and the effect included in this assessment.

4 Confidence analysis

There are 5 categories of uncertainty associated with the site wind speed prediction at the proposed site:

1. There is an uncertainty associated with the measurement accuracy of the anemometers. The instruments used have not been individually calibrated. In addition the mounting arrangement of the instruments is not to recommended standards. A figure of 3.0 % is assumed here to account for these and other second order effects such as over-speeding, degradation, air density variations and additional turbulence effects.

2. The long-term mean wind speed at each mast was derived from correlation analyses, using other site masts as a long-term reference. The uncertainty associated with correlating and extrapolating between masts is evaluated from the statistical scatter in the correlation plots.

3. There is an uncertainty associated with the assumption made here that the historical period at the meteorological site is representative of the climate over longer periods. A study of historical wind records indicates a typical variability of 6 % in the annual mean wind speed [5]. This figure is used to define the uncertainty in assuming the long-term mean wind speed is defined by a period approximately 2.5 years in length.

4. There is uncertainty associated with the derivation of the wind shear between heights on the mast and the assumption that this is representative of the wind flow at heights up to hub height. A figure of either 0.5 or 1.5 % has been assumed here to account for this uncertainty dependent upon the extent of extrapolation.

5. Additionally, even if the long-term mean wind speed were perfectly defined there will be variability in future mean wind speeds observed at the wind farm site. The variability in future mean wind speeds is dependant on the period considered. Performance over one and ten years of operation are therefore included in the uncertainty analysis. Account is taken of the future variability of wind speed in the energy confidence analysis but not the wind speed confidence analysis.

It is assumed that the time series of wind speed is random with no systematic trends. Care was taken to ensure that consistency of the reference measurement system and exposure has been maintained over the historical period and no allowance is made for uncertainties arising due to changes in either.

Uncertainties type 1 to 4 from above are added as independent errors on a root-sum-square basis to give the total uncertainty in the site wind speed prediction for the historical period considered.

It is considered here that there are 5 categories of uncertainty in the energy output projection:

1. Long-term mean wind speed dependent uncertainty is derived from the total wind speed uncertainty (types 1 to 4 above) using a factor for the sensitivity of the annual energy output to changes in annual mean wind speed. This sensitivity is derived by a perturbation analysis about the central estimate.

2. Wake and topographic modelling uncertainties. Validation tests of the methods used here, based on full-scale wind farm measurements made at small wind farms have shown that the methods are accurate to 2 % in most cases. For this development an uncertainty in the wake and topographic modelling of 4 % to 7 % is assumed due to complex terrain and close turbine spacing.

3. Future wind speed-dependent uncertainties described in '5' above have been derived using the factor for the sensitivity of the annual energy output to changes in annual mean wind speed.

4. Accuracy of the fiscal substation energy meter. An uncertainty of 0.3 % is assumed here based on typical utility meter accuracy.

5. Turbine uncertainties are generally the subject of contract between the developer and turbine supplier and we have therefore made no allowance for them in this work.

Again those uncertainties which are considered are added as independent errors on a root-sum-square basis to give the total uncertainty in the projected energy output.

5 References

1. I Troen and E L Petersen, "European Wind Atlas", Risø National Laboratory, Denmark, 1989.

2. U Hassan, A G Glendinning and C A Morgan, "A Wind Tunnel Investigation of the wake structure and machine loads within small wind turbine farms", Proc of the 12th BWEA Wind Energy Conference, IMechE, 1990.

3. J Højstrup, "Turbulence measurements in a windfarm", Proc. EWEA Wind Energy Conference, Madrid, 1990.

4. J G Warren et al. "Performance of wind farms in complex terrain", Proc. Of the 17th BWEA Wind Energy Conference, 1995.

5. P Raftery, A J Tindal and A D Garrad, "Understanding the risks of financing windfarms", Proc. EWEA Wind Energy Conference, Dublin, 1997.

DRAFT

Wind Resource and Energy Assessment Wild Horse Expansion Wind Power Project

EARP0030

CONFIDENTIAL

October 7, 2008

Prepared for:

Puget Sound Energy
PO Box 97034 PSE-11N
Bellevue, WA 98009-9734

DNV Global Energy Concepts Inc.
1809 7th Avenue, Suite 900
Seattle, Washington 98101
Phone: (206) 387-4200
Fax: (206) 387-4201
www.globalenergyconcepts.com
www.dnv.com

MANAGING RISK

NOTICE

The information contained in this document has been prepared exclusively for the client named on the cover and no other. This document is intended to be strictly for the use of this client only and is not intended to be, and may not be, relied upon by third parties without the specific written consent of DNV Global Energy Concepts Inc. (DNV-GEC). While this report has been prepared pursuant to generally accepted practices in the industry, it is possible that actual results may vary from those predicted herein. The contract under which this report was created and compiled contains restrictions on liability between the parties, and any permissive use by a third party shall be subject to those liability limits. In no event does DNV-GEC warrant this product, except for the specific purpose for which it was created. DNV-GEC accepts no liability for any indirect or consequential damages, or any damages of that type, unless it specifically consents thereto in writing. This report relies on data and information provided by the client and others, for which DNV-GEC assumes no responsibility. The information contained in this report is applicable to the equipment tested or reviewed and may not be applicable to other pieces of equipment of the same make and model or different equipment, or equipment manufactured by other entities.

Questions or concerns related to this report or any of the information contained herein should be directed to the author of the report or an officer of DNV-GEC.

Approvals

Prepared by Date

Prepared by Date

Reviewed by Date

Version Block

Version	Release Date	Summary of Changes
DRAFT		

Table of Contents

EXECUTIVE SUMMARY 1
BACKGROUND AND PROJECT DESCRIPTION 2
SITE DESCRIPTION AND WIND RESOURCE MEASUREMENTS 4
WIND ANALYSIS METHODOLOGY 9
WIND ANALYSIS RESULTS 11
WIND SHEAR 11
TURBULENCE 14
WIND ROSE 17
MONTHLY AND LONG-TERM WIND SPEEDS 19
Long-Term Reference Stations Consulted 21
HUB-HEIGHT WIND SPEEDS 23
TURBINE LAYOUT AND GROSS ENERGY ESTIMATES 25
LOSSES, UNCERTAINTIES, AND NET ENERGY CALCULATIONS 29
LOSSES 29
Routine Maintenance Downtime 29
Fault Downtime 29
Minor Component Failure Downtime 30
Major Component Failures 30
Balance-of-Plant Downtime 31
Turbine Wake/Array 31
Electrical Line 31
Blade Soiling 32
Weather 32
Turbulence and Controls 33
Blade Degradation 33
Power Performance 33
Wind Sector Management 33
UNCERTAINTIES 33
Anemometer Accuracy 34
Tower Effects on Measurements 34
Data Capture/QC/Validation 34
Representativeness of Period of Data 34
Reference Site Relationships/Consistency of Long-Term References 34
Wind Shear 35
Topographic Effects/On-Site Correlations 35
Wind Frequency Distribution 35
Wind Speeds over Project Life Relative to Long-Term Average 35
Changes in Long-Term Average Wind Speed 35
Effect of Asymmetric Uncertainties 36
NET ENERGY 36
APPENDIX A – SITE PHOTOS
APPENDIX B – MET TOWER COMMISSIONING SHEETS

List of Figures

Figure 1. Location of the Proposed Wild Horse Expansion Wind Power Project 3
Figure 2. Project Meteorological Tower Locations 4
Figure 3. Diurnal Shear Exponents by Month for Met 319 11
Figure 4. Diurnal Shear Exponents by Month for Met 320 12
Figure 5. Directional Shear Exponents by Met Tower 12
Figure 6. Turbulence Intensity by Wind Speed at 67-m Hub Height 17
Figure 7. Met 319 Wind Rose at 50 m 18
Figure 8. Met 320 Wind Rose at 50 m 18
Figure 9. Location of Wild Horse Expansion and Long-term Reference Stations 22
Figure 10. Turbine and Met Tower Locations 25

List of Tables

Table 1. Wild Horse Expansion Executive Summary 1
Table 2. Proposed Wind Turbine Specifications 3
Table 3. Met Tower Summary 5
Table 4. Percent Valid Data 6
Table 5. Average Shear Exponents by Hour 13
Table 6. Average Shear Exponents by Direction 14
Table 7. Mean Turbulence Intensity by Direction Sector (%) 15
Table 8. Mean Turbulence Intensity by Wind Speed (%) 16
Table 9. Summary Statistics of Correlations from Met 303 to Met 319 19
Table 10. Monthly Average Wind Speeds (m/s) 20
Table 11. Correlation Parameters for Met 319 and Met 320 to Long-Term Stations 23
Table 12. Annual Average Hub Height Wind Speeds 24
Table 13. Hub-Height Average Wind Speed Frequency Distributions and Power Curves at 1.10 kg/m^3 Air Density 26
Table 14. Gross Energy and Gross Capacity Factor for Vestas V80 at 67 m 27
Table 15. Location, Average Wind Speed, Gross Energy Estimate, and Wake Loss for Vestas V80 Turbines at 67-m Hub-Height 28
Table 16. Summary of Net Average Energy Production for the Vestas V80 2.0 MW Turbine with a 67-m Hub Height 36
Table 17. Summary of P50 Long-Term Average Losses for Vestas V80 2.0 MW at 67-m Hub Height 37
Table 18. Average Net Energy Estimate for Each Turbine for Vestas V80 2.0MW at 67-m Hub Height 38
Table 19. 12-Month by 24-Hour Percent of Energy Production (%) for Vestas V80 2.0 MW Turbines at 67-m Hub Height 39

Executive Summary

DNV Global Energy Concepts Inc. (DNV-GEC) has been retained by Puget Sound Energy (PSE) to complete an energy assessment for the proposed Wild Horse Expansion wind power project, located approximately 16 km (25 miles) east of Ellensburg, Washington. Table 1 presents a summary of the key features of the project site, wind resource and estimated energy production. Full details of DNV-GEC's methodology and analysis results are included in the main body of the report.

Table 1. Wild Horse Expansion Executive Summary

Project Summary		
Project Name	Wild Horse Expansion	
Location	Kittitas County	
Turbine Type	Vestas V80 2.0MW	
Turbine Hub Height (m)	67	
Number of Turbines	22	
Installed Capacity (MW)	44.0	
Wind Resource Summary		
Mean Air Density (kg/m^3)	1.10	
Average Met Tower Shear	0.08	
Average Turbulence Intensity	10%	
Average Long-Term Adjustment	0%	
Average Long-Term Hub-Height Wind Speed (m/s)	Met 319	7.1
	Met 320	7.4
Average Turbine Hub-Height Wind Speed (m/s)		6.9
Energy Assessment Summary		
Gross Energy (GWh/year)	106.9	
Total Losses	16.4%	
P50 Net Energy (GWh/year)	89.3	
P50 Net Capacity Factor	23.2%	
P5 Net Energy (GWh/year)	103.2	
P5 Net Capacity Factor	26.8%	
P95 Net Energy (GWh/year)	75.5	
P95 Net Capacity Factor	19.6%	

Background and Project Description

DNV Global Energy Concepts Inc. (DNV-GEC) has been retained by Puget Sound Energy (PSE) to complete an energy assessment for the proposed Wild Horse Expansion wind power project, located approximately 16 km (25 miles) east of Ellensburg, Washington. The location of the project is displayed in Figure 1. This report presents an energy assessment for a 22-turbine layout consisting of Vestas V80 2.0 MW wind turbines installed a 67-m hub height.

The total installed project capacity for the Vestas V80 turbines is 44.0 MW. The principal features of the proposed turbines are shown in Table 2.

In addition to the energy assessment presented here, DNV-GEC has prepared several other estimates for the Wild Horse Expansion project at different phases of the development process. In January 2008 DNV-GEC reviewed an energy assessment report prepared by RAM Associates (RAM) for a 22-turbine layout that differs from the current layout under consideration. Based on that review, DNV-GEC made preliminary energy estimates based on RAM's met tower wind speeds and wind distribution while applying DNV-GEC adjustments for topography and technical losses. In that analysis, DNV-GEC estimated net P50 energy for the 22-turbine layout for the Gamesa G87 and Vestas V80 1.8 MW wind turbines at a hub height of 67 m. The net P50 capacity factor estimates for the two turbine types were 25.7% and 24.9%, respectively.

In May 2008 DNV-GEC issued a draft energy assessment for the same 22-turbine layout evaluated in the RAM report based on DNV-GEC's independent processing and review of the met tower data measured on site. Energy estimates for three configurations listed below were presented:

- Vestas V80 1.8 MW wind turbine with a 67-m hub height
- Vestas V80 1.8 MW wind turbine with an 80-m hub height
- Vestas V90 1.8 MW turbine with an 80-m hub height

The P50 net capacity factor estimates for the three configurations evaluated in the May 2008 draft energy assessment were 24.8%, 25.4%, and 28.8% respectively.

Since issuing the draft energy assessment in May 2008, DNV-GEC has performed several high level analyses of project variations ranging in size from 22 to 28 turbines. On May 16, 2008, estimates for the same three configurations listed above were supplied for a layout consisting of 27 turbines. The net capacity factors were within 0.1% of the estimates for the 22 turbines reported in the May draft.

On August 15, 2008, DNV-GEC supplied energy estimates for 22- and 26-turbine layout variants based on the Vestas V80 2.0 MW turbine. The net capacity factor estimates were 23.0% and 23.3% respectively.

This current report focuses on a revised 22-turbine layout and the Vestas V80 2.0 MW turbine.

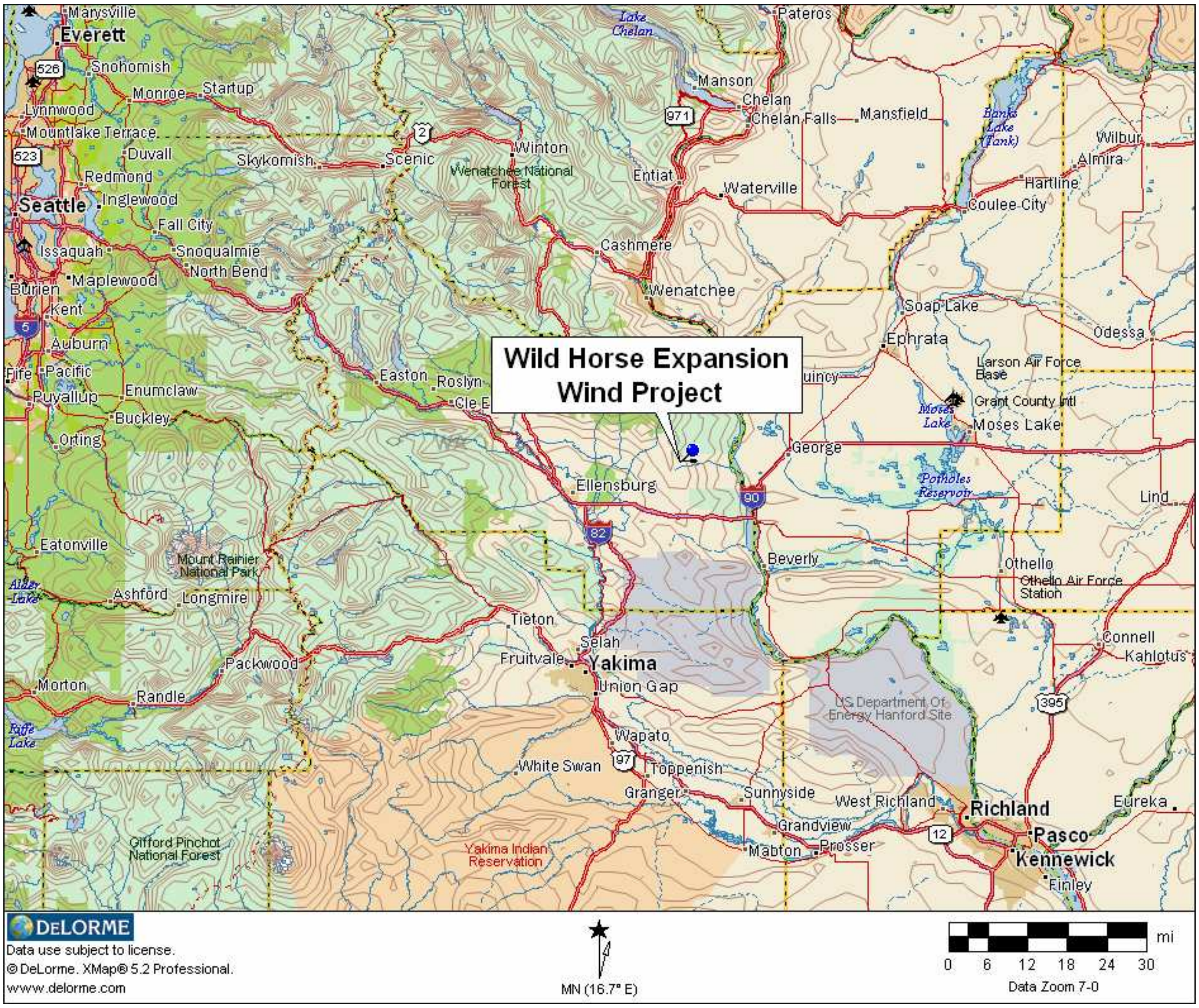


Figure 1. Location of the Proposed Wild Horse Expansion Wind Power Project

Table 2. Proposed Wind Turbine Specifications

Turbine Model	Vestas V80
Hub Height, m	67
Rotor Diameter, m	80
Rotor Speed, rpm	9.0 to 19.0
Rated Power, kW	2000
Climate Package	Standard (-20ºC to +40ºC)

Site Description and Wind Resource Measurements

DNV-GEC conducted a site visit to the proposed Wild Horse Expansion wind power project region on March 12, 2008. Information obtained from this visit was incorporated into this analysis. The project is adjacent to the operating Wild Horse wind power project owned by PSE. The area is characterized by rolling hills and fingers that run west and east from a broad ridge oriented north to south. The mean proposed turbine elevation is 1,086 meters above sea level (masl) and these locations cover a 67-m range in elevation between the lowest and highest turbine locations. There are well maintained roads through the Wild Horse project, but these roads do not extend into the Wild Horse Expansion area. Dirt roads through the Wild Horse Expansion area provide access to the meteorological (met) towers.

Wind data examined for this analysis were collected at five met towers associated with the project. All of the met towers are located within close range of the proposed turbine locations. A map of the project site showing the met tower locations is presented in Figure 2.

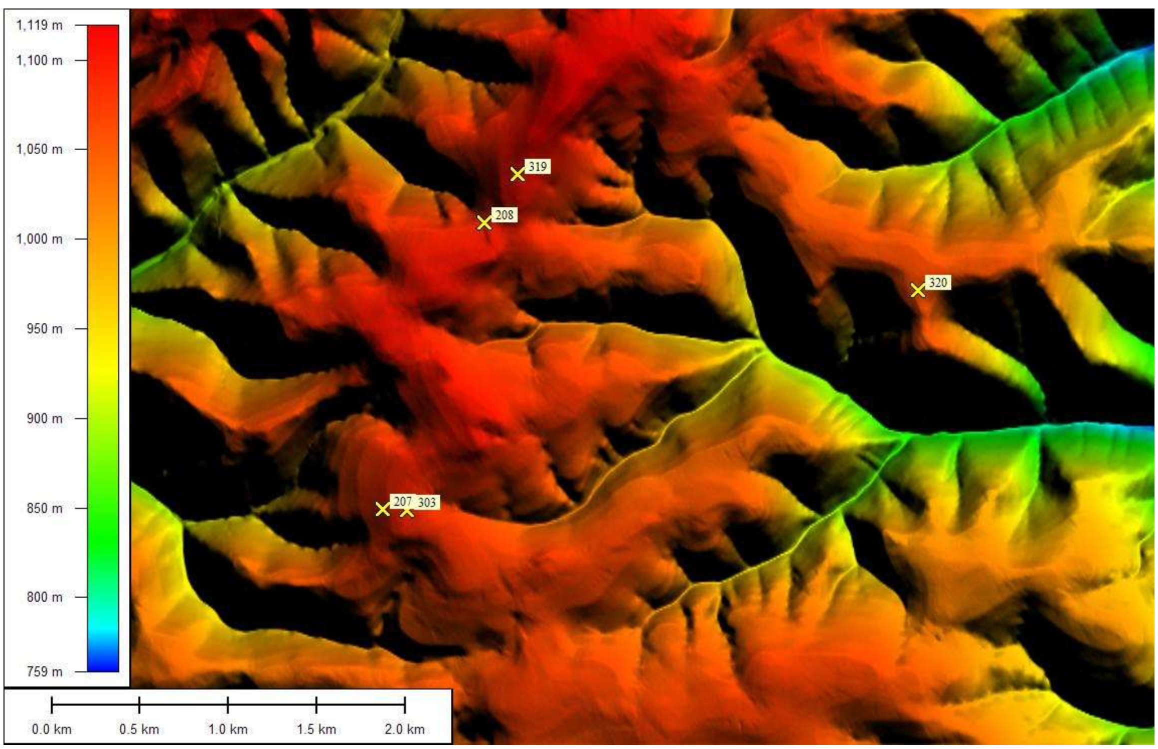


Figure 2. Project Meteorological Tower Locations

All five met towers are NRG Systems, Inc., tubular pole-type towers erected specifically for wind resource measurements. Table 3 summarizes the met tower data used in this analysis including the data start and end dates, measurement levels and sensor orientations. DNV-GEC compiled, validated, and incorporated into this analysis all available on-site tower data.

Table 3. Met Tower Summary

Met	Ground Elevation (masl)	Period of Record	Nominal Wind Speed Collection Heights (m)[1]	Anemometer Orientations (º)	Sampling Rate[2]
207	1084	6/9/2001 – 3/13/2003	50, 30, 15	287	mixed
208	1088	6/1/2001 – 3/13/2003	50, 30, 10	287	mixed
303	1087	3/30/2003 – 2/29/2008	15(2)	270 (180)	10-minute
319	1104	6/25/2005 – 3/14/2008	50(2), 30(2), 10	270 (180)	mixed
320	1058	6/16/2005 – 3/17/2008	50(2), 30(2), 10	270 (180)	10-minute

1. (2) indicates that two wind speed sensors are mounted at or very near that level.

2. A “mixed” sampling rate indicates that data were collected at an hourly rate and a 10-minute rate for different data periods.

Representative photos of the met towers are presented in Appendix A. The commissioning sheets for Met 319 and Met 320 are included in Appendix B.

Met 207, Met 208, and Met 319 used NRG 9300 data loggers. Met 303 and Met 320 used NRG Symphonie data loggers.

When two sensors are mounted at or very near the same measurement level, DNV-GEC designates a primary and secondary anemometer orientation based on the tower configuration and the prevailing winds at the site. For the met towers in the Wild Horse Expansion area, DNV-GEC designated the west-oriented anemometers as primary and the south-oriented anemometers as secondary. Wind speeds from the primary anemometers are used in this analysis except when the data are invalid, in which case the secondary sensor data are used, if valid.

Data from all met towers were evaluated; however, the energy assessment is primarily based on the data collected at Met 319 and Met 320. Met 303 data were used to extend the period of record at Met 319 and to evaluate the long-term representativeness of the period of record at Met 320. The shear exponent could not be calculated from Met 303 data because it is not instrumented with sensors at multiple measurement levels and the tower height is too short to extrapolate to hub height with confidence. For this reason, the data from Met 303 were not used to characterize hub-height wind speeds or to estimate energy production for the project. Met 207 and Met 208 were not used directly in the energy estimate. Data from these met towers could not be adjusted to represent the long-term wind speeds for the site because these data sets do not have concurrent periods of record with Met 303, the tower with the longest period of record, and do not correlate well to nearby long-term reference stations. The inability to extend these towers’ records resulted in periods of record inconsistent with Met 319 and Met 320. While not used directly in the assessment, Met 207 and Met 208 were used to confirm on-site wind characteristics indicated by the other on-site measurements.

The percent of valid data per month is presented in Table 4. A valid data record is defined as a record for which both a valid upper level wind speed and a direction measurement are available. Some reasons for invalid records include missing data, tower shadow of anemometers and icing. The data recovery rates for this site are fair. The lower data recovery in the winter months is primarily due to the icing of the measurement sensors. Overall recovery values for the met towers represent the annual average recovery excluding months of partial data collection at the beginning and end of the period of record.

For Met 319, data are missing from July 16, 2005, to July 23, 2005, and from October 22, 2005, to October 26, 2005. No data were collected from late November 2005, when the tower collapsed, to June 20, 2006, when the tower was replaced. From June 20, 2006 forward, the ratio of the wind speeds measured by the sensors at the 50-m level indicate a gradual decline of the wind speed measurement from the secondary sensor. This trend continued until a complete malfunction of that sensor in June 2007. At the time of the site visit, a broken cup on this anemometer was observed. The data from this sensor were removed from the analysis beginning in June 2006, resulting in a lower recovery rate because there is no secondary measurement available when the primary sensor is shadowed by the tower.

Data are missing for Met 319 between October 27, 2006, and February 2, 2007, when an Anabat rope became tangled with the tower. The tower was lowered to remove the rope and the secondary 30-m sensor was replaced. Data are also missing from October 22, 2007, to October 26, 2007, for Met 319. The overall recovery value listed in Table 4 for Met 319 includes the periods of missing data in the average.

Recovery for Met 207 and 208 is lower than the other towers because there is no secondary sensor on the tower that would provide a valid measurement when the primary sensor is waked by the tower.

Table 4. Percent Valid Data

Month	Met 207	Met 208	Met 303	Met 319	Met 320
2001 June	62%	70%	N/A	N/A	N/A
July	93%	92%	N/A	N/A	N/A
August	83%	86%	N/A	N/A	N/A
September	80%	85%	N/A	N/A	N/A
October	85%	90%	N/A	N/A	N/A
November	78%	87%	N/A	N/A	N/A
December	46%	54%	N/A	N/A	N/A
2002 January	74%	81%	N/A	N/A	N/A
February	81%	86%	N/A	N/A	N/A
March	95%	95%	N/A	N/A	N/A
April	91%	87%	N/A	N/A	N/A
May	95%	91%	N/A	N/A	N/A
June	98%	87%	N/A	N/A	N/A
July	98%	86%	N/A	N/A	N/A
August	97%	87%	N/A	N/A	N/A
September	98%	87%	N/A	N/A	N/A
October	93%	81%	N/A	N/A	N/A
November	94%	82%	N/A	N/A	N/A
December	43%	46%	N/A	N/A	N/A

Month		Met 207	Met 208	Met 303	Met 319	Met 320
2003	January	53%	52%	N/A	N/A	N/A
	February	90%	82%	N/A	N/A	N/A
	March	32%	32%	5%	N/A	N/A
	April	N/A	N/A	99%	N/A	N/A
	May	N/A	N/A	100%	N/A	N/A
	June	N/A	N/A	100%	N/A	N/A
	July	N/A	N/A	100%	N/A	N/A
	August	N/A	N/A	100%	N/A	N/A
	September	N/A	N/A	100%	N/A	N/A
	October	N/A	N/A	100%	N/A	N/A
	November	N/A	N/A	98%	N/A	N/A
	December	N/A	N/A	56%	N/A	N/A
2004	January	N/A	N/A	54%	N/A	N/A
	February	N/A	N/A	78%	N/A	N/A
	March	N/A	N/A	98%	N/A	N/A
	April	N/A	N/A	95%	N/A	N/A
	May	N/A	N/A	100%	N/A	N/A
	June	N/A	N/A	100%	N/A	N/A
	July	N/A	N/A	100%	N/A	N/A
	August	N/A	N/A	100%	N/A	N/A
	September	N/A	N/A	100%	N/A	N/A
	October	N/A	N/A	100%	N/A	N/A
	November	N/A	N/A	99%	N/A	N/A
	December	N/A	N/A	75%	N/A	N/A
2005	January	N/A	N/A	78%	N/A	N/A
	February	N/A	N/A	97%	N/A	N/A
	March	N/A	N/A	96%	N/A	N/A
	April	N/A	N/A	98%	N/A	N/A
	May	N/A	N/A	100%	N/A	N/A
	June	N/A	N/A	100%	19%	49%
	July	N/A	N/A	100%	77%	100%
	August	N/A	N/A	100%	100%	100%
	September	N/A	N/A	100%	100%	100%
	October	N/A	N/A	100%	69%	100%
	November	N/A	N/A	70%	17%	75%
	December	N/A	N/A	70%	0%	76%
2006	January	N/A	N/A	81%	0%	93%
	February	N/A	N/A	94%	0%	98%
	March	N/A	N/A	96%	0%	98%
	April	N/A	N/A	97%	0%	100%
	May	N/A	N/A	99%	0%	100%

Month	Met 207	Met 208	Met 303	Met 319	Met 320
June	N/A	N/A	100%	26%	100%
July	N/A	N/A	100%	88%	100%
August	N/A	N/A	100%	86%	100%
September	N/A	N/A	100%	81%	100%
October	N/A	N/A	98%	77%	99%
November	N/A	N/A	84%	0%	93%
December	N/A	N/A	68%	0%	88%
2007 January	N/A	N/A	77%	0%	83%
February	N/A	N/A	84%	68%	81%
March	N/A	N/A	91%	91%	98%
April	N/A	N/A	94%	87%	100%
May	N/A	N/A	99%	85%	100%
June	N/A	N/A	100%	85%	100%
July	N/A	N/A	100%	87%	100%
August	N/A	N/A	100%	87%	100%
September	N/A	N/A	100%	91%	100%
October	N/A	N/A	98%	80%	100%
November	N/A	N/A	80%	77%	83%
December	N/A	N/A	75%	69%	81%
2008 January	N/A	N/A	84%	80%	89%
February	N/A	N/A	98%	88%	100%
March	N/A	N/A	N/A	43%	52%
Overall*	**83%**	**81%**	**93%**	**56%**	**95%**

*Excludes partial months at beginning and end of the period of record or due to periods of missing data.

Wind Analysis Methodology

This section presents an overview of the methodology used to process the data. Details of the analysis and results are provided in following sections.

All wind speed sensors used at the site were uncalibrated NRG #40 anemometers. Raw data from the site met towers were processed using the consensus transfer function for these sensors: wind speed (m/s) = 0.765 x Hz + 0.35.

DNV-GEC followed a standard validation process to identify and remove erroneous data (e.g., due to icing or tower shadow). Wind speed data were considered invalid due to icing if the temperature was near or below freezing and an additional criterion was met, such as the wind vane or anemometer standard deviation equaling zero for consecutive records or the 10-minute/hourly average wind speed being lower than expected, relative to the wind speeds at other levels. Data were also considered invalid when the tower shadowed the sensors (waked data). This occurs when the wind comes from directions that place the tower between the wind and a sensor. For example, an anemometer mounted to the east of the tower will record invalid wind speed data when the winds are from the west. All invalid data are removed from the data set. For NRG tubular towers, the significant tower wake influence is approximately 50° wide. Wind direction for each data record was determined using the upper level wind vane. The vane at a lower level was used when data from the upper level vane were unavailable for a given record.

Hub-height wind speeds were estimated using the monthly diurnal wind shear pattern measured at the site. DNV-GEC computed shear from wind speed sensors on booms with the same orientation.

Long-term reference stations were consulted for the purpose of adjusting on-site data to reflect the long-term mean wind speed. Due to poor correlations with the off-site long-term reference stations DNV-GEC chose not to make a long-term adjustment to the on-site data. The considerations and methodology for this decision are discussed in *Monthly and Long-Term Wind Speeds* section of this report.

The wind speeds were normalized to 8,760 hours so that hub-height annual frequency distributions could be created. To normalize the data set to 8,760 hours, DNV-GEC developed a monthly record-length correction factor by counting the number of records with valid upper sensor wind speed and wind direction observations available in each month. The data were then categorized by wind direction sector (30° sectors centered on 0°, 30°, etc.) and wind speed bin (intervals of 0.5 m/s centered on 0.5 m/s, 1.0 m/s, etc.) in order to generate hub-height annual frequency distributions showing the number of observations in each wind speed bin and for each wind direction sector.

DNV-GEC also calculated the turbulence intensity (TI) for each measurement level at each met tower. TI was calculated as the standard deviation of the wind speed observation divided by the mean wind speed observation within the 10-minute interval. Only 10-minute data were used in calculation of TI. TI at 67-m was estimated by using the standard deviation of the upper level sensor with the hub-height estimated wind speed, which results in somewhat lower TI than actually measured at the upper level sensor and is consistent with the expected decrease in TI with increased height.

Wind Analysis Results

Evaluation of the data, including a discussion of the wind shear, wind speed correlations, turbulence, and a presentation of the wind roses, is included in this section. Because data from the met towers had varying degrees of influence on the energy assessment, only the results from the primary met towers, Met 319 and Met 320, are provided below. Analysis results for Met 207, Met 208 and Met 303 are discussed when relevant to the energy assessment.

Wind Shear

DNV-GEC calculated the wind shear exponent[1] between a lower and an upper anemometer for sensors located on booms with the same orientation. Only wind speeds greater than 4 m/s were included in the calculation. Primary sensors were used except for cases where the primary sensor was waked by the tower, iced or malfunctioning, in which case the shear was calculated between the secondary sensors if available.

Shear at Met 319 and Met 320 was calculated between the 50-m and 30-m sensors and is shown in Figure 3 and Figure 4, respectively. Directional shear is shown in Figure 5.

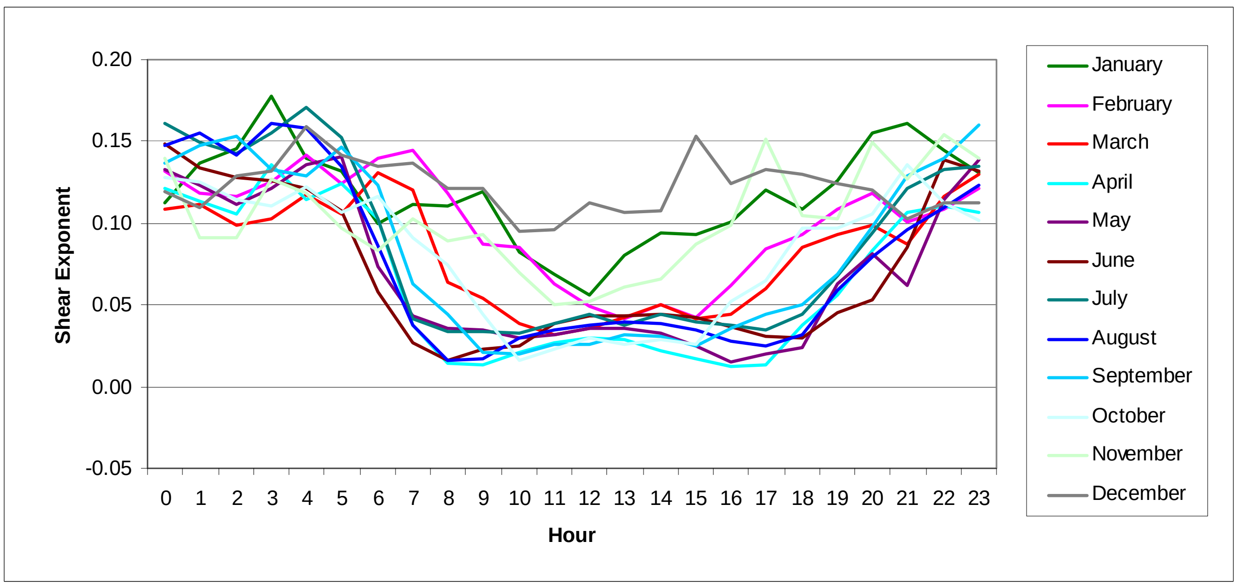


Figure 3. Diurnal Shear Exponents by Month for Met 319

[1] Wind shear describes the typical increase in wind speed at greater heights above the ground. The wind shear exponent (alpha or α) is one method of describing the extent to which wind speeds vary with increasing height above ground level. The equation that uses the exponent is $(V_1 / V_2) = (H_1 / H_2)^{\alpha}$, where V_1 and V_2 are wind speeds at heights H_1 and H_2, respectively (measured from the ground level), and α is the dimensionless wind shear exponent.

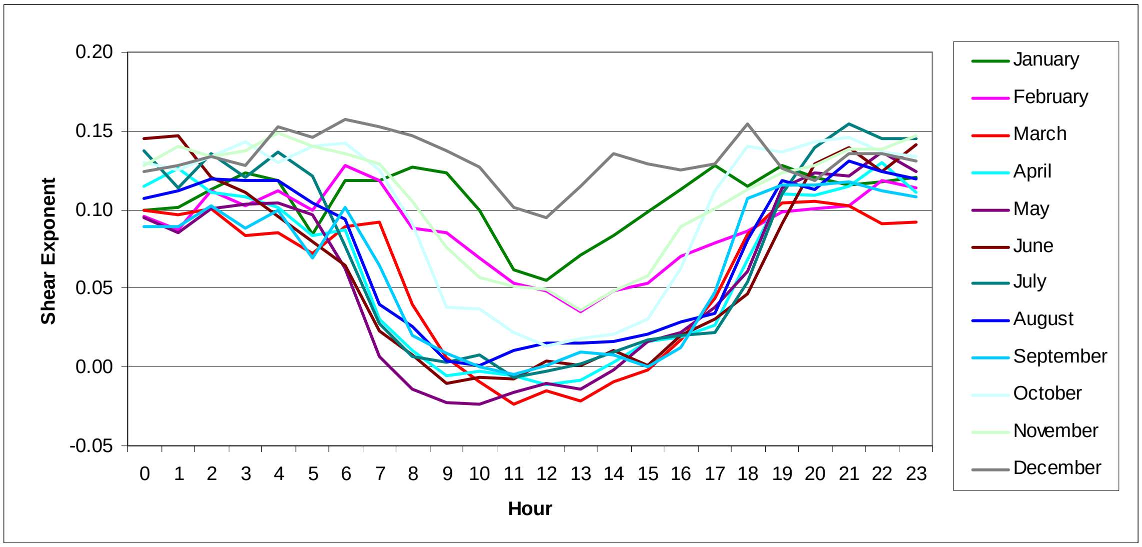


Figure 4. Diurnal Shear Exponents by Month for Met 320

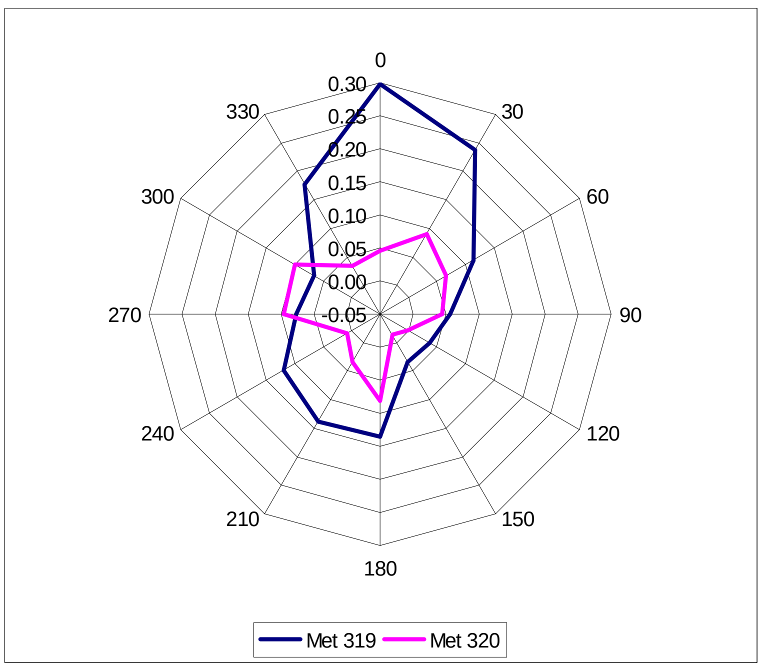


Figure 5. Directional Shear Exponents by Met Tower

Note: Shear values from 0º and 330º are based on less than 34 hours of measurement for Met 319 and less than 66 hours for Met 320.

Resulting overall average shear exponents for each met tower are listed in Table 5 by hour and in Table 6 by direction. Average annual shear exponents are 0.09 and 0.08 for Met 319 and Met 320, respectively. Shear could not be calculated at Met 303 because there are not sensors at multiple measurement levels. Met 207 confirms the shear pattern measured at Met 319 and Met 320 with an average annual shear exponent 0.09. The shear exponent calculated from Met 208 data, however, indicates a higher value of 0.15. The calculated shear exponent can vary from met tower to met tower due to different terrain and vegetation surrounding each met tower and the distance between sites. Inaccurate reporting of the wind speed measurement heights on a tower can also affect the calculated shear exponent.

Shear calculated at Met 319 and Met 320 was applied to measurement-height wind speeds on a monthly and diurnal basis to estimate hub-height wind speeds.

Table 5. Average Shear Exponents by Hour

Hour	Met 319	Met 320
0	0.13	0.11
1	0.13	0.11
2	0.12	0.12
3	0.13	0.11
4	0.14	0.12
5	0.13	0.10
6	0.10	0.10
7	0.08	0.08
8	0.06	0.05
9	0.06	0.04
10	0.05	0.03
11	0.04	0.02
12	0.05	0.02
13	0.05	0.02
14	0.05	0.03
15	0.05	0.04
16	0.05	0.05
17	0.06	0.07
18	0.07	0.09
19	0.08	0.11
20	0.10	0.12
21	0.11	0.13
22	0.12	0.13
23	0.13	0.12
Average	**0.09**	**0.08**

Table 6. Average Shear Exponents by Direction

Direction Sector (º)	Met 319	Met 320
0	0.30	0.05
30	0.24	0.09
60	0.11	0.07
90	0.06	0.04
120	0.04	0.00
150	0.03	-0.02
180	0.14	0.08
210	0.14	0.03
240	0.12	0.01
270	0.08	0.10
300	0.07	0.10
330	0.18	0.03
Overall	**0.09**	**0.08**

Note: Shear values from 0º and 330º are based on less than 34 hours of measurement for Met 319 and less than 66 hours for Met 320.

Turbulence

Turbulence intensity (TI) was calculated as the ratio of the wind speed standard deviation to the wind speed. Average TI was calculated for all wind speeds, and average TI at wind speeds greater than 4 m/s was calculated by direction. Turbulence decreases with height above ground level; consequently, TI at the upper measurement levels on each tower were extrapolated to the 67-m turbine hub heights by applying wind shear to calculate a hub-height wind speed while keeping the standard deviation constant. This method has been shown to reliably predict the decrease in turbulence with height across measurement levels on towers, and should produce reasonable predictions of the hub-height turbulence.

The estimated TI at 67-m and the average measured TI by direction at the upper measurement level (50-m) are presented in Table 7, for Met 319 and Met 320. TI values are shown by wind speed in Table 8 for upper measurement level and hub height. TI versus wind speed at the 67-m hub height is plotted in Figure 6. Excluding TI from wind speeds less than 4 m/s, overall turbulence levels are low to moderate for Met 319 and Met 320 with weighted averages of 10% and 11%, respectively, at the 67-m hub height. Met 207 and Met 208 data confirm the TI pattern at Met 319 and Met 320 with an overall turbulence level of 11% calculated at both towers for the 67-m hub height.

Table 7. Mean Turbulence Intensity by Direction Sector (%)

Direction Sector (°)	Met 319		Met 320	
	50 m	67 m	50 m	67 m
0	17	16	13	13
30	13	12	11	10
60	10	9	10	10
90	10	10	17	18
120	18	18	21	22
150	20	19	19	19
180	17	16	16	16
210	15	14	15	14
240	14	14	12	12
270	9	9	11	11
300	8	8	8	8
330	13	11	17	17
Average (>4m/s)	**12**	**10**	**11**	**11**

Table 8. Mean Turbulence Intensity by Wind Speed (%)

Wind Speed (m/s)	Met 319		Met 320	
	50 m	67 m	50 m	67 m
1	44	46	44	46
2	25	25	23	24
3	17	16	18	18
4	13	13	16	16
5	11	11	13	13
6	10	10	12	12
7	10	9	11	11
8	9	9	11	10
9	9	9	10	10
10	9	9	10	10
11	9	9	10	9
12	8	8	10	10
13	8	8	10	10
14	8	8	10	10
15	**8**	**8**	**10**	**9**
16	8	7	9	9
17	8	8	9	9
18	8	8	9	9
19	7	7	9	9
20	7	7	9	9
21	8	8	8	8
22	8	8	8	8
23	8	7	8	8
24	7	7	8	8
25	6	6	8	8
Average (>4m/s)	**12**	**10**	**11**	**11**

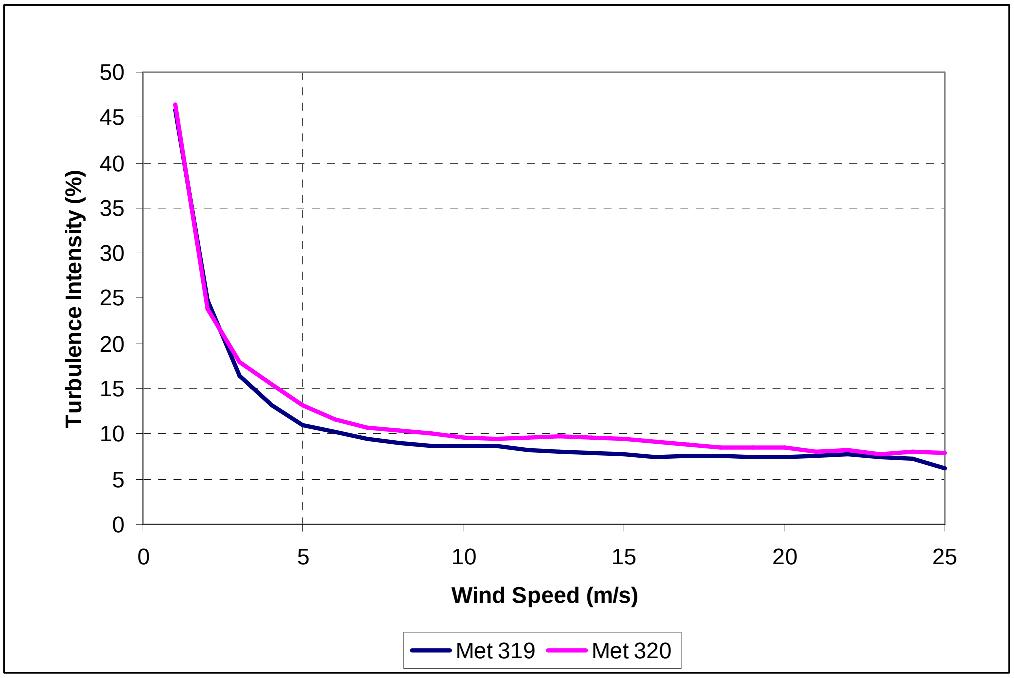


Figure 6. Turbulence Intensity by Wind Speed at 67-m Hub Height

Wind Rose

A wind rose depicts the frequency and energy content of wind by direction. Annualized wind roses estimated at 50 m for Met 319 and Met 320 are presented in Figure 7 and Figure 8, respectively. As shown in the figures, the wind roses show a similar pattern, with significant energy-producing winds coming from the west.

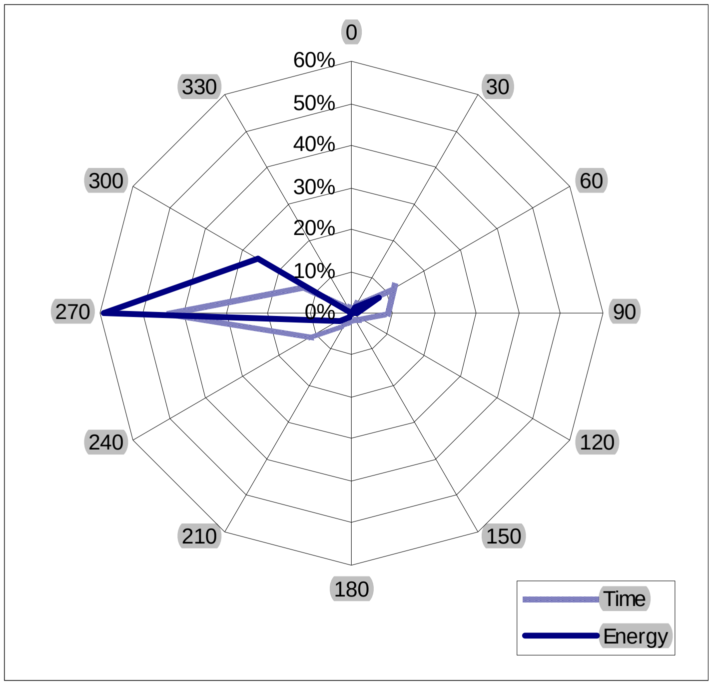


Figure 7. Met 319 Wind Rose at 50 m

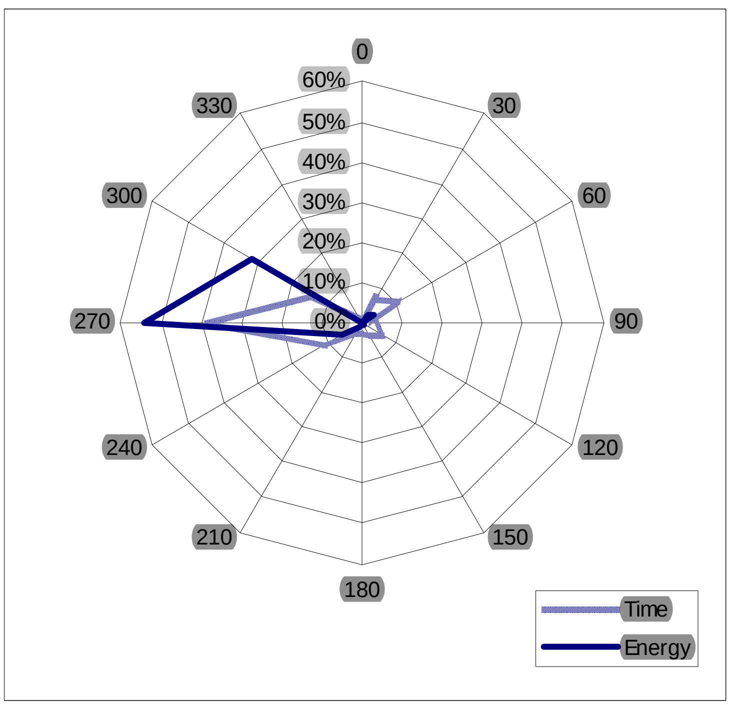


Figure 8. Met 320 Wind Rose at 50 m

Monthly and Long-Term Wind Speeds

To extend the period of record to better represent the long-term wind speeds at the site, long-term adjustments based on on-site met towers and nearby reference stations were considered.

Data were synthesized at Met 319 from data measured at Met 303 to extend the period of record and to fill in periods of missing data. The data were synthesized based on linear regressions between Met 319 and Met 303 derived over concurrent measurement periods. These regressions were generated using hourly average wind speeds greater than 3 m/s, and were established on a directional basis using 30° wind direction sectors, in order to capture potential differences in relationships resulting from variations in the terrain surrounding the towers. These comparisons were made between the upper measurement levels on each tower. The overall R-squared value including all data was 0.90 indicating a good relationship. Summary statistics describing the observed relationships by direction are presented in Table 9. The slopes and intercepts shown in this table were applied to the measured 15-m wind speeds at Met 303 to synthesize upper level data at Met 319. Data were only synthesized for periods where no measured data were available.

Table 9. Summary Statistics of Correlations from Met 303 to Met 319

Direction Sector (º)	Slope	Intercept	R^2	Number of Data Points
0*	0.69	2.82	0.21	26
30	1.01	0.99	0.84	195
60	0.93	0.72	0.91	803
90	0.91	0.55	0.81	627
120*	0.86	0.87	0.50	166
150*	0.97	0.53	0.58	85
180	1.01	0.57	0.74	68
210	0.96	0.60	0.90	203
240	1.04	0.50	0.84	1231
270	1.05	0.87	0.88	5302
300	1.09	1.10	0.92	840
330*	0.79	1.62	0.06	14
Overall	**1.09**	**0.39**	**0.90**	**9560**

*Slope and intercept values for sectors where the correlation coefficient was low were replaced with the overall slope and intercept value.

Data were not synthesized at Met 320 because the hourly correlation between Met 320 and Met 303 was poor with an overall R-squared value of 0.64. As an alternative method, monthly adjustment factors were developed based on the 5-year record at Met 303 as possible means for adjusting the measurements at Met 320 to reflect a longer-term wind speed for the site. Monthly adjustment factors indicated the region's winds during the period of on-site record were 0.3% lower than the long-term average. Due to the small correction indicated by the data, DNV-GEC chose not to adjust the data at Met 320. Although an adjustment was not made to the measured data from Met 320, the estimated wind speeds were treated as equivalent to the length of record at Met 303.

Monthly averages of upper level measured and synthesized wind speeds for each met tower are presented in Table 10. The monthly averages are based on the data available during that month and may not be representative of the full month. The overall averages are annualized.

Table 10. Monthly Average Wind Speeds (m/s)

Month		Met 303 (15-m)	Met 319* (50-m)	Met 320 (50-m)
2003	March	11.3	***12.9***	N/A
	April	5.7	***6.5***	N/A
	May	5.7	***6.7***	N/A
	June	6.0	***7.0***	N/A
	July	5.6	***6.5***	N/A
	August	5.0	***5.9***	N/A
	September	6.3	***7.2***	N/A
	October	7.3	***8.1***	N/A
	November	7.5	***8.4***	N/A
	December	5.6	***6.4***	N/A
2004	January	6.8	***7.7***	N/A
	February	4.6	***5.2***	N/A
	March	7.6	***8.6***	N/A
	April	4.9	***5.7***	N/A
	May	6.5	***7.6***	N/A
	June	5.6	***6.4***	N/A
	July	5.9	***6.8***	N/A
	August	5.1	***6.0***	N/A
	September	6.0	***7.0***	N/A
	October	6.6	***7.6***	N/A
	November	4.7	***5.7***	N/A
	December	6.0	***6.8***	N/A
2005	January	5.6	***6.4***	N/A
	February	5.1	***5.9***	N/A
	March	6.5	***7.4***	N/A
	April	6.3	***7.1***	N/A
	May	5.4	***6.1***	N/A
	June	5.9	***6.8***	6.1
	July	6.0	***6.9***	7.4
	August	5.2	5.9	6.4
	September	5.2	6.1	6.6
	October	5.3	***6.3***	6.5
	November	5.6	***6.5***	7.9
	December	5.5	***6.2***	7.1
2006	January	6.1	***7.2***	8.9
	February	8.0	***8.8***	9.1
	March	5.9	***6.6***	6.8
	April	6.4	***7.3***	7.6
	May	6.0	***6.9***	7.0
	June	5.3	***6.3***	6.6

Month	Met 303 (15-m)	Met 319* (50-m)	Met 320 (50-m)
July	5.8	6.7	7.2
August	5.1	6.0	6.3
September	4.9	5.9	5.9
October	5.8	***7.0***	7.3
November	6.8	***7.8***	8.8
December	5.1	***5.9***	5.9
2007 January	6.0	***7.0***	8.3
February	5.8	***7.6***	7.3
March	6.9	8.1	8.2
April	6.8	7.9	7.5
May	5.7	6.6	6.5
June	6.4	7.7	7.4
July	5.2	6.2	6.4
August	5.6	6.8	6.8
September	5.7	6.8	6.9
October	5.9	**6.9**	7.1
November	5.3	7.4	7.4
December	5.7	7.3	7.9
2008 January	6.0	7.3	7.8
February	7.1	7.8	8.6
March	N/A	7.0	7.4
Average Wind Speed (m/s)	**5.9**	**6.9**	**7.3**

*Data in Bold Italics include synthesized based on the relationship to Met 303

Long-Term Reference Stations Consulted

Various long-term reference stations were consulted for correlation to on-site data for the purpose of adjusting the on-site data to reflect the long-term mean wind speed. The reference stations and the site are shown together in Figure 9. On-site data were correlated to regional long-term meteorological data from Automated Surface Observing System (ASOS) stations and a radiosonde observation station. On-site data were also correlated to modeled data from the U.S. National Centers for Environmental Prediction/National Center for Atmospheric Research Reanalysis Project (Reanalysis data). After analysis of the reference data, DNV-GEC chose not to make a long-term adjustment to the on-site wind speeds based on the reference stations due to poor correlations. The considerations and methodology for this decision are discussed below.

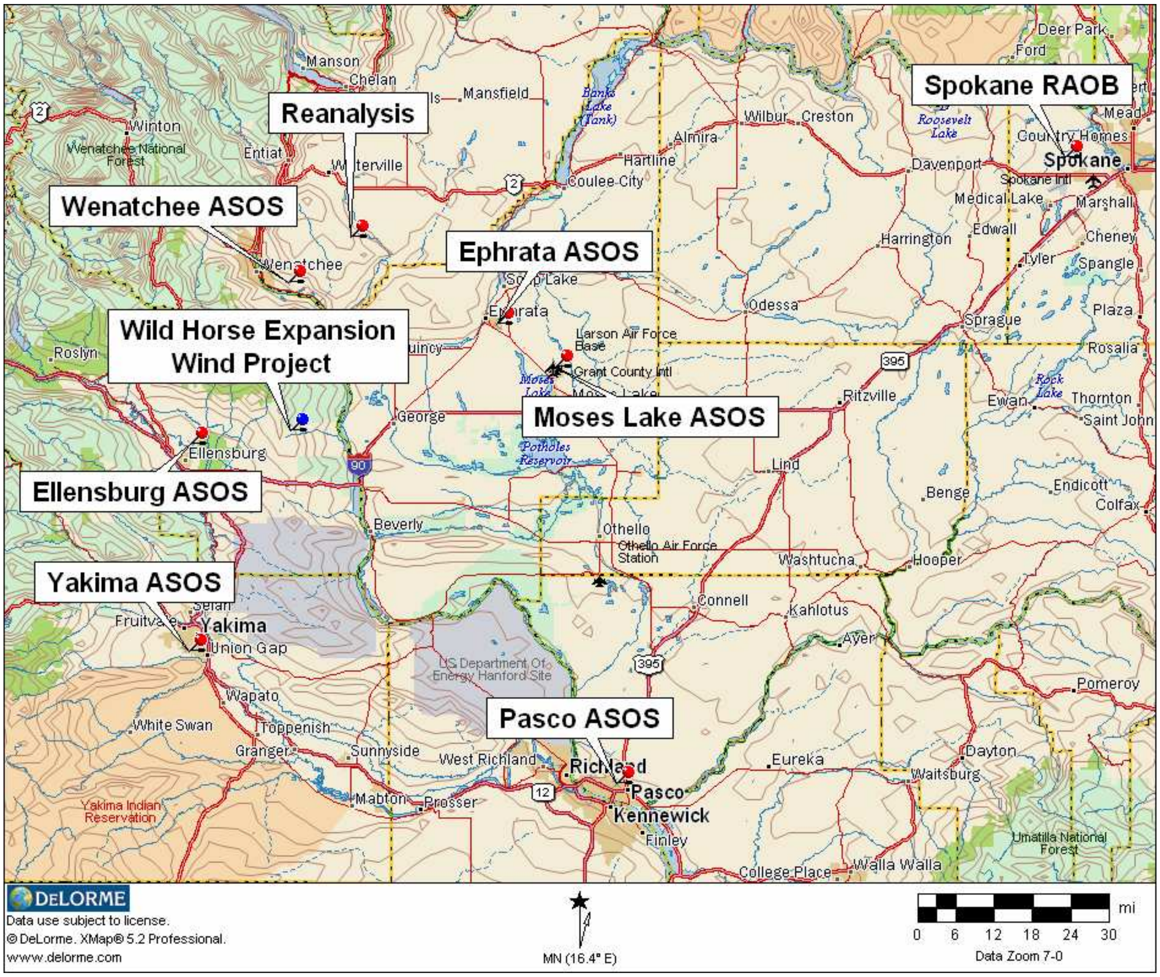


Figure 9. Location of Wild Horse Expansion and Long-term Reference Stations

Wind data from the Automated Surface Observing System (ASOS) stations near Ellensburg, Wenatchee, Yakima, Ephrata, Moses Lake, and Pasco were consulted. Monthly averages have a poor correlation to on-site monthly averages; with the greatest R-squared value being 0.39. Over the past few years, the National Weather Service and Federal Aviation Administration have been converting ASOS station anemometry to sonic sensors. This type of instrumentation change can affect the long-term consistency of the data. All ASOS stations consulted report a sensor change during the on-site period of record. Due to this sensor change and poor correlations to site data, the ASOS stations were not considered further as potential long-term references.

Wind data from the Spokane radiosonde observation station (Spokane RAOB) were consulted. The Spokane RAOB is located approximately 200 km (125 miles) east of the project. Data were investigated at the 1000 m height. The Spokane RAOB data demonstrated a fair correlation to on-site data, with a monthly R-squared value of 0.62 when correlated to Met 320. The data were examined over the period October 1995 to March 2008. The Spokane RAOB data indicated the region's winds during the period of on-site record were 1.7% higher than the long-term average. The Spokane RAOB data were found to be consistent over the entire period with no indications of upward or downward trends; however, long-term adjustments from this station were not pursued further due to relatively poor correlations with site data.

DNV-GEC also evaluated Reanalysis data. The Reanalysis model is a global climate model that assimilates a network of meteorological observations to simulate past weather. The output includes wind speed and wind direction on a 2.5º latitude by 2.5º longitude grid, four times daily, at 28 vertical levels. DNV-GEC evaluated the grid point 47.5º N and 120º W, at pressure levels of 925 millibars (mb) and 850 mb, corresponding to approximately 750 m and 1500 m above sea level, respectively. The Reanalysis grid point examined is located approximately 50 km (30 miles) northeast of the project. The Reanalysis data demonstrated a poor correlation to on-site data, with a monthly R-squared value of 0.28 observed at the 850-mb level when correlated to Met 320.

Correlation parameters derived from the relationship between the on-site and reference station monthly average wind speeds are shown in Table 11.

Table 11. Correlation Parameters for Met 319 and Met 320 to Long-Term Stations

Reference Station	Quality of Correlation (R^2 Value) with Met 319	Quality of Correlation (R^2 Value) with Met 320
Ellensburg ASOS	0.22	0.15
Wenatchee ASOS	0.25	0.19
Yakima ASOS	0.15	0.05
Ephrata ASOS	0.02	0.00
Moses Lake ASOS	0.04	0.07
Pasco ASOS	0.36	0.39
Spokane RAOB	0.54	0.62
Reanalysis 47.5º N, 120º W (850 mb)	0.22	0.28

As shown in Table 11, the correlation between the data measured on site and at the local reference stations is poor; therefore, DNV-GEC chose not to use the reference station data to adjust on-site wind speeds as it would not reduce the uncertainty on the long-term average wind speed.

Hub-Height Wind Speeds

Based on the estimated met tower wind speeds and wind shear, DNV-GEC developed a wind speed frequency distribution representing the hub-height (67-m) wind speeds and wind direction at each met tower location. Shear conditions observed between a lower and upper level sensor at each tower were assumed to continue up to hub height.

Data from each tower over their entire period of record were binned into annual distributions and normalized to represent 8,760 hours per year. Wind speed frequency distributions were generated for each tower from this data set. Annual hub-height wind speeds computed from the frequency distributions are presented in Table 12.

Table 12. Annual Average Hub Height Wind Speeds

Met Tower	Wind Speed (m/s) at 67-m Hub-Height
319	7.1
320	7.4

Turbine Layout and Gross Energy Estimates

Turbine locations for the project layout are presented in Figure 10. Turbine coordinates are listed in Appendix C. DNV-GEC estimated individual turbine hub-height wind speeds based on hub-height met tower wind speeds, the MS-Micro/3 software package wind flow model results, relative vegetation, elevation, exposure, production data from the Wild Horse project, and DNV-GEC's judgment about wind flow across the terrain. The methodology for the energy estimates is presented below.

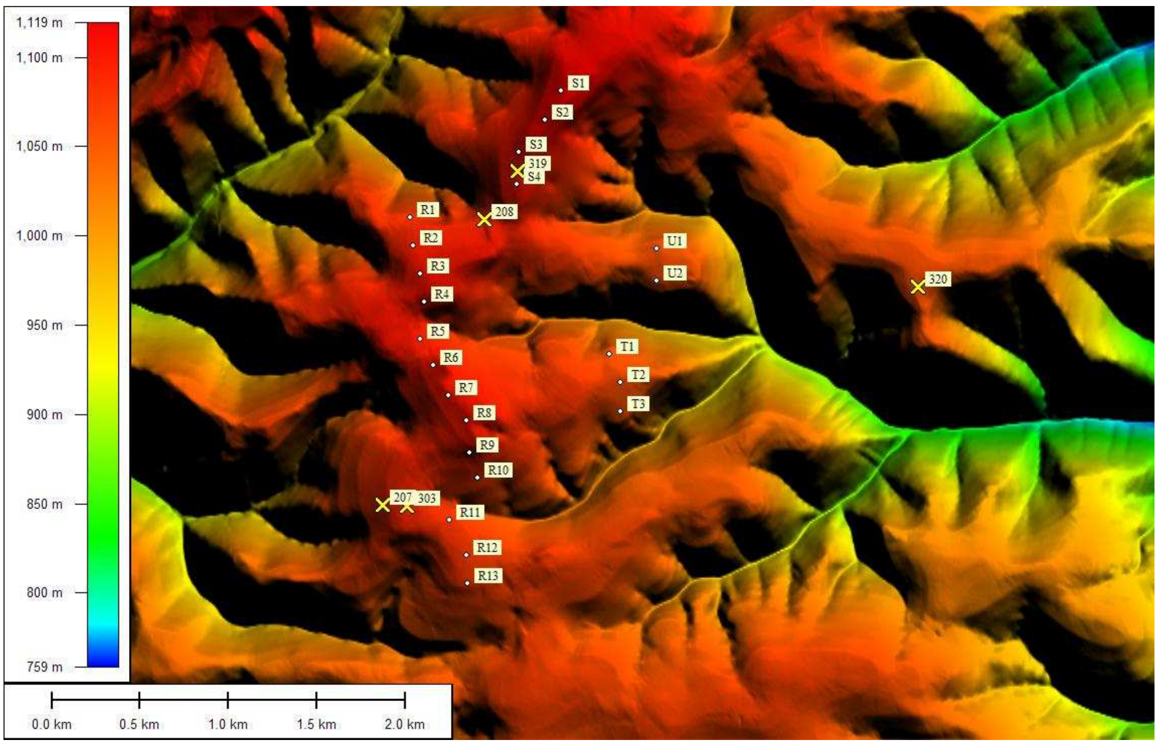


Figure 10. Turbine and Met Tower Locations

DNV-GEC estimated the average air density for the site to be 1.10 kg/m^3 based on measured temperature data (an average of approximately 7ºC) from the on-site met towers and the average turbine hub-height elevation (1153 m). Density-specific power curves at 1.10 kg/m^3 for the Vestas V80 turbine was used to calculate energy production.

The power curve and wind speed distributions from the met towers were used to estimate annual gross energy for each turbine location. Table 13 presents the long-term annual frequency at the met tower locations and the power curve for the Vestas V80. The gross energy and gross capacity factor at the met tower locations for the proposed turbine type and hub height are listed in Table 14.

Table 13. Hub-Height Average Wind Speed Frequency Distributions and Power Curves at 1.10 kg/m^3 Air Density

Wind Speed (m/s)	Vestas V80 Power (kW)	Met 319 at 67 m (hours)	Met 320 at 67 m (hours)
0.0	0	0	0
0.5	0	57	236
1.0	0	146	190
1.5	0	219	247
2.0	0	267	331
2.5	0	371	408
3.0	0	460	453
3.5	0	543	471
4.0	57	586	454
4.5	96	580	423
5.0	135	560	397
5.5	191	497	374
6.0	249	443	348
6.5	328	402	330
7.0	408	360	303
7.5	512	329	280
8.0	617	285	275
8.5	746	254	268
9.0	875	227	249
9.5	1017	211	242
10.0	1160	182	229
10.5	1303	165	221
11.0	1445	146	195
11.5	1571	141	178
12.0	1693	130	169
12.5	1780	126	159
13.0	1862	113	144
13.5	1907	109	134
14.0	1949	102	122
14.5	1967	92	114
15.0	1984	82	106
15.5	1990	78	92
16.0	1995	71	80
16.5	1997	64	73
17.0	1999	55	66
17.5	2000	48	56
18.0	2000	42	50
18.5	2000	36	42
19.0	2000	31	37
19.5	2000	25	31
20.0	2000	21	28
20.5	2000	19	19
21.0	2000	14	21

Wind Speed (m/s)	Vestas V80 Power (kW)	Met 319 at 67 m (hours)	Met 320 at 67 m (hours)
21.5	2000	11	17
22.0	2000	9	15
22.5	2000	7	14
23.0	2000	6	10
23.5	2000	6	10
24.0	2000	6	9
24.5	2000	3	6
25.0	2000	3	5
>25.0	0	21	28
Average Wind Speed (m/s)		**7.1**	**7.4**

Table 14. Gross Energy and Gross Capacity Factor for Vestas V80 at 67 m

	Met 319	Met 320
Gross energy per turbine (MWh/yr)	4966	5729
Gross capacity factor[1]	28.3%	32.7%

1. Capacity factors are based on a turbine rating of 2000 kW for the Vestas V80 2.0MW.

Estimated wake losses have been calculated using the WindFarm software package. The contribution of the existing Wild Horse project turbines to wake losses at Wild Horse Expansion was included in the calculation. Annual wake losses were estimated using four calculation methods. The four methods utilize combinations of two wake models (Ainslie and Park) that predict the deficit behind single turbines and two wake combination models (square root of the sum of squares of velocity deficit, and energy balance) that combine the single wakes when they overlap. Detailed investigations have shown wake model performance to be sensitive to terrain type, atmospheric stability, turbulence intensity, and inter-turbine spacing.

The performance of each model is not completely understood; therefore, DNV-GEC took the average of the four models as a best approximation of the expected wake losses. The spread of the four model results was also used to quantify the expected uncertainty of the calculations.

To incorporate the different measured wind distributions into the wake analysis, wake calculations were made using distributions from Met 319 and Met 320. Individual wake loss calculations were then averaged based on the squared-distance between each turbine and each met tower.

Estimates of wind speed, gross energy, and wake loss for each of the turbines in the project are presented in Table 15.

Table 15. Location, Average Wind Speed, Gross Energy Estimate, and Wake Loss for Vestas V80 Turbines at 67-m Hub-Height

Turbine ID	WGS84 UTM10		Assigned 67-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy Minus Wakes (MWh/yr)
	Easting (m)	Northing (m)				
R1	709798	5216270	6.5	4347	-3.8	4183
R2	709817	5216107	6.8	4671	-3.0	4532
R3	709855	5215951	6.9	4786	-1.9	4696
R4	709880	5215789	6.9	4775	-1.5	4703
R5	709858	5215583	6.9	4799	-1.9	4708
R6	709929	5215433	7.0	4909	-2.4	4792
R7	710017	5215264	7.0	4886	-2.7	4756
R8	710117	5215120	6.9	4842	-3.9	4652
R9	710136	5214939	6.9	4757	-3.4	4594
R10	710179	5214795	6.8	4726	-3.6	4557
R11	710021	5214558	6.9	4754	-3.9	4567
R12	710118	5214359	6.9	4796	-3.0	4654
R13	710123	5214199	6.9	4776	-3.1	4627
S1	710650	5216986	7.1	5041	-1.6	4963
S2	710559	5216819	7.1	5034	-3.4	4863
S3	710411	5216639	7.0	4923	-3.7	4741
S4	710404	5216457	7.1	4992	-3.9	4796
T1	710923	5215497	6.9	4977	-10.6	4447
T2	710986	5215335	7.0	5112	-11.0	4551
T3	710990	5215172	7.0	5072	-11.5	4488
U1	711193	5216094	6.8	4842	-7.7	4471
U2	711195	5215908	7.0	5052	-8.8	4610
		Average	**6.9**	**4858**	**-4.6**	**4634**

Losses, Uncertainties, and Net Energy Calculations

Based on the gross annual energy estimated above, DNV-GEC estimated net energy production using a stochastic model to evaluate each source of loss or uncertainty identified for the project. Distributions appropriate for each loss or uncertainty were determined and a probabilistic description of the annual net energy was built, integrating each source. The model was then run in 10,000 iterations with each parameter changed randomly and independently to describe the distribution of potential net energy. These results were then summarized to determine the probability of exceedance of various levels. A summary of the model inputs and resulting energy projections follows.

Note that many of the losses and uncertainties are estimated based on DNV-GEC's current knowledge of the project and DNV-GEC's experiences with other wind farms. For example, the mechanical availability assumptions used are based on DNV-GEC's experiences monitoring performance of modern megawatt-scale wind turbines of similar design, but the availability at this particular site may be higher or lower for a variety of reasons. To some extent, low availability or performance may be mitigated through turbine warranties, insurance, or other factors; these issues are not considered explicitly in this analysis.

Losses

The following losses were estimated for the project. For the purpose of uncertainty modeling, the following losses are normally distributed with uncertainty values listed at one standard deviation, unless otherwise noted.

Routine Maintenance Downtime

This item includes energy lost during periods of routine maintenance of the wind turbines. Time spent for maintenance of typical modern megawatt-scale wind turbines is approximately 40 to 120 hours per year. The magnitude can vary depending on turbine complexity, cleaning requirements, and frequency of larger tasks such as gear oil changes.

DNV-GEC estimated routine maintenance downtime of 60 hours per year (or 0.7% of the year). In general, operators seek to schedule maintenance for low-wind times. However, with a large number of turbines requiring maintenance and with the schedule constraints of the maintenance crews who perform maintenance, there is only limited flexibility to avoid windy periods, so the energy loss cannot be eliminated entirely. The relationship between time spent on routine maintenance and energy loss was also modeled as an uncertainty, with a best estimate of a multiplier of 0.6 of energy per unit time and an uncertainty of 0.1 around this estimate. Consequently, the P50 case represents an energy loss of approximately 0.4%.

Fault Downtime

Some downtime will be incurred associated with turbine faults. The P50-case fault downtime values estimated by DNV-GEC were approximately 1.5% for Year 1, and approximately 1.1% (or 100 hours per year) thereafter. Based on DNV-GEC's experience with other projects using pitch-regulated turbines, this downtime is heavily weighted towards high-wind periods.

Consequently, the relationship between faults and energy loss was also modeled as an uncertainty, with a best estimate of a multiplier of 1.7 of energy per unit time and an uncertainty of 0.2 around this estimate. DNV-GEC estimated the resulting P50 average energy loss as approximately 1.9%.

Minor Component Failure Downtime

Some downtime will be incurred associated with failures of smaller components such as motors, relays, valves, power electronics, sensors, controllers, and bushings; and other small malfunctions normally experienced by modern megawatt-scale wind turbines. As the equipment ages, failure of minor components with design lives less than 20 years is expected to increase.

Based on experience, DNV-GEC estimated the minor component failure downtime values to be 0.6% over Years 1 through 5, 1.3% over Years 6 through 10, 1.7% over Years 11 through 15, and 1.9% thereafter. The majority of the components evaluated are expected to have mean lives of approximately 10 years, so the replacement rate tends to level off later in the project life. DNV-GEC's expectation based on experience with operating wind projects is that component failures will be slightly weighted towards high-wind periods; consequently, the relationship between minor component failures and energy loss was also modeled as an uncertainty, with a best estimate of a multiplier of 1.2 of energy per unit time and an uncertainty of 0.1 around this estimate. DNV-GEC estimated the resulting P50 average energy loss as approximately 1.7%.

Major Component Failures

Some downtime will be associated with major systems in the turbines. Examples of such events include gearbox, generator, or blade replacements, yaw system failures, turbine fires, or similar problems. These issues affect individual turbines but may cause those turbines to be off line for an extended period of time. While a typical year may have relatively limited downtime associated with major failures relative to the project life average, the infrequent events can result in significant lost energy. These losses are also expected to increase over time, as turbine systems wear out and more gearboxes and other components fail. DNV-GEC estimates that the frequency of failure of major components is expected to begin increasing in Years 6 through 10 of the turbine's life and continue to increase for the remainder of the turbine design life. The increasing failure rate will be offset somewhat by increased efficiency as experience is gained in replacing major components. However, as the number of major component failures increases, the total time required for component replacement will also increase, which will adversely impact turbine availability.

The modeled failure rate and associated downtime for major components was based on experience with similar projects. The P50-case major component failure downtime values estimated by DNV-GEC were 0.5% for Years 1 through 5, 1% for Years 6 through 10, 1.5% for Years 11 through 15, and 2% for Years 16 through 20. The losses associated with major failures were modeled as an asymmetrical distribution with a long tail, representing small possibilities of significant downtime; however, the majority of losses are expected to be at or less than the mean. DNV-GEC's expectation based on experience with operating wind projects is that component failures will be slightly weighted towards high-wind periods. Consequently, the relationship between major component failures and energy loss was also modeled as an uncertainty, with a best estimate of a multiplier of 1.2 of energy per unit time and an uncertainty of 0.1 around this estimate. DNV-GEC estimated the resulting P50 average energy loss as approximately 1.5%.

Balance-of-Plant Downtime

Approximately 10 to 20 hours of downtime are associated with annual maintenance on project infrastructure (such as the project substation, pad mount transformers, etc.). These activities are typically planned events that coincide with low-wind months and/or days. Unplanned failures and repairs associated with the balance of plant, such as substation transformer failures, electrical collection system or communication system problems, or transmission outages are uncommon; however, their impact on lost production could be considerable if the failures impact the whole project or large groups of turbines. The mean loss related to both planned and unplanned balance-of-plant events has been estimated to be 0.5% and is not expected to increase over time.

The losses associated with balance-of-plant failures were modeled as an asymmetrical distribution with a long tail, representing small possibilities of significant downtime; however, the majority of losses are expected to be at or less than the mean.

Turbine Wake/Array

DNV-GEC modeled wake losses using the site layout and estimated the losses for each turbine. The estimated wake loss was calculated at 4.6% for the 22 Vestas V80 2.0 MW turbines at a 67-m hub height. These losses include wake effects from the existing Wild Horse project which consists of 127 Vestas V80 1.8 MW turbines at a 67-m hub height. There are two sources of uncertainty on this estimate: uncertainty on the accuracy of the wake loss model, and uncertainty on the model input.

DNV-GEC estimated the uncertainty on the model accuracy by evaluating results predicted by different combinations of wake loss models and wake combination methods available within the WindFarm software package; these included axisymmetric wake and WAsP/Park wake velocity deficit models, and sum of squares of wakes and energy balance combination methods. The average of these results was used as the base case, with the highest of the four models predicting a 5.3% loss and the lowest predicting a 3.8% loss for the Vestas V80 at 67 m hub height case. The spread of the model results for the other two project configurations is comparable. The average of the model outcomes is a reasonable approximation of wake losses on most projects. The resulting estimated wake losses for each turbine are shown in Table 15.

In addition to uncertainty associated with the loss model, DNV-GEC considered uncertainty on the model inputs, including turbulence at hub height and wind direction distribution. Based on the results of the various tests of model combinations and consideration of these other issues, DNV-GEC estimated a combined wake loss uncertainty of 1.0% of energy.

Electrical Line

DNV-GEC assumed 2.0% for line losses and in-project parasitic consumption. This estimate is based on information provided to DNV-GEC by PSE including actual electrical line losses at the existing Wild Horse project and simplified estimates of line losses for the Wild Horse Expansion project. This value is within the typical range for a modern wind project. These losses represent the difference between energy measured at each wind turbine and energy measured at the project substation. Actual losses will depend on the efficiency of the transformers used at the facility, collection wire sizing, and internal parasitic consumption "behind the meter" in very low wind conditions. A standard deviation of 0.5% was assumed and the range of possible losses ranged between 1.0% and 3.0%.

Blade Soiling

Turbine performance may be reduced as dust or insects on the blades. DNV-GEC estimated losses for this issue at 0.5%, with a range of possible losses from 0% to 1%.

Weather

Weather losses encompass a range of issues that result in lost production, including but not limited to the following:

- High- or low-temperature shutdowns
- Lightning damage to turbines
- Grid outages or communications failures caused by lightning
- Hail damage to blades or facility shutdowns to prevent such damage
- Turbines shut down due to ice-related faults
- Reduced power performance due to ice build-up on blades
- Reduced site access due to inclement weather
- Other weather-related turbine faults that are classified as the owner's responsibility

Based on a review of the meteorological data and DNV-GEC's experiences with other wind projects in the area, DNV-GEC estimated a typical case loss of 2.0% for weather conditions, with a range of potential weather losses from 0.5% to 4.5%. It should be noted that this value represents energy loss and not percentage of time lost, as weather downtime frequently occurs during higher-than-average wind conditions.

Based on the technical specifications for the Vestas V80 turbine, the range of operating temperatures is -20°C to +40°C. The available on-site temperature data did not indicate any occurrences of temperature below -20ºC or above +40°C.

The upper NRG sensors were iced on average 3.5% of the time. There is no industry standard for estimating the impact of icing on turbines relative to its impact on the NRG anemometer. DNV-GEC estimates that approximately half of the time lost to icing of an unheated NRG 40 anemometer the turbines may be adversely affected by icing. The estimate of weather related energy losses considers the fact that the icing occurs in the relatively high-wind winter months (although potentially during lower wind periods) and will likely impact both turbine performance and availability.

DNV-GEC's experience with operating projects in similar climates indicates that the weather-related losses are highly variable from site to site, and from year to year. For example, the frequency and duration of icing events can vary substantially, with most years having little ice while others experience events where sites are frozen for days at a time with little or no turbine production. Similarly, lightning damage to turbines occurs in infrequent, intermittent events, but can produce significant periods of downtime. Note that some such events may be covered by business interruption insurance that may compensate the project owner for lost revenue; such insurance is not considered in this energy analysis. The overall loss estimate is typical as an approximate overall average based on a variety of operating projects monitored by DNV-GEC.

Turbulence and Controls

This topic includes potential differences in turbine performance, relative to the reference power curve, due to conditions such as high turbulence, variable winds creating significant off-yaw operations, and high-wind hysteresis. DNV-GEC estimated losses for these issues at 1%, with a range from 0% to 2%.

Blade Degradation

Typically, turbine performance decreases somewhat over the life of a project. Degradation of the blade surface is the largest factor that can produce such a change. The turbine blade performance will gradually degrade over time. A small annual decrease in performance was included in the model, with a most likely case loss averaging approximately 0.4% over 20 years (beginning with zero losses and slowly increasing following an exponential decay curve to 1% by Year 20).

Power Performance

There is a probability that the turbines will perform at a level different from the reference power curve for reasons other than those counted in other losses (such as blade soiling and degradation, turbulence, etc.). This is modeled as a distribution of possible outcomes with a most likely value of 0%, a small potential for up to 3% higher performance and a small potential for 5% lower performance. The P50 case is equivalent to a 0.2% reduction in power averaged over the life of the project.

Wind Sector Management

PSE provided DNV-GEC with a preliminary wind sector management strategy proposed by Vestas. Based on the proposed wind sector management strategy, DNV-GEC estimates losses associated with the wind sector management will be on the order of 0.05%.

Uncertainties

The following uncertainties were estimated as percentages of the mean wind speed for the site. Based on the wind frequency distribution for the project, there is an approximate relationship of a 1.4% uncertainty on energy for each 1% uncertainty on wind speed for the Vestas V80 turbine. This relationship varies with speed because the power curve flattens at high wind speeds; there is a smaller increase in energy when wind speeds increase relative to the magnitude of the decrease in energy as wind speeds decrease. This is reflected in the uncertainty model by shifting the wind speed frequency distribution up or down as the mean wind speed changes and recalculating the gross energy as a ratio of the best-estimate case. Except as noted below, all uncertainties on wind speed shown are assumed to be normally distributed; uncertainty values listed are at one standard deviation. However, because of the non-linear relationship of wind speed to energy, the resulting energy uncertainties are not normally distributed.

Anemometer Accuracy

This parameter represents the variability in measurement of wind by individual anemometers. An uncertainty of approximately 1.5% on wind speed was assumed based on the typical error on measurements found in testing of a large number of NRG 40 anemometers[2] used as the primary sensor at the site. This uncertainty is reduced based on the number of independent measurements; consequently, DNV-GEC estimates the overall project uncertainty associated with anemometer accuracy at 1.1% on wind speed, based on the 1.5% uncertainty on a single measurement divided by the square root of two, representing the two met towers used in this analysis.

Tower Effects on Measurements

Some uncertainty is associated with the mounting effects of anemometers on towers; even when mounted according to industry-standard procedures, small speed-up and slow-down effects are seen on measurements on tubular tilt-up towers. Larger effects are observed on lattice towers, particularly where the boom lengths are short relative to the tower face width. At each of the towers at the site, pairs of anemometers are present at the upper measurement level, allowing for selection of unwaked wind speeds and minimization of measurement effects. Based on the site visit, a review of the documentation of the mounting arrangements on the towers and a review of the data, DNV-GEC estimated an overall site-wide average wind speed uncertainty of 2.0% for this issue. The uncertainty in this category is relatively high because the sensors are oriented directly into and perpendicular to the predominant wind direction. Both of these orientations lead to higher tower effects than the preferred orientation of 45° off predominant wind direction.

Data Capture/QC/Validation

Several periods of data were missing or removed from each tower because of icing, sensor malfunction and other issues. DNV-GEC estimated an uncertainty of 1.0% on wind speed for this issue, based on the amount of missing or invalid data and other factors informing a potential influence of icing.

Representativeness of Period of Data

Data from local long-term meteorological stations, radiosonde data and a nearby Reanalysis grid point were investigated to determine the interannual wind conditions for the region. The interannual variability was estimated at approximately 5.5% of the mean. This degree of variability is consistent with the expected wind variability in the region. Based on these values, the uncertainty associated with the representativeness of the period of record equals 5.5% divided by the square root of 4.8 years, or 2.5% on wind speed.

Reference Site Relationships/Consistency of Long-Term References

This uncertainty represents the uncertainty on the relationship to the long-term reference station used to adjust the observed site wind speeds to long-term conditions, and also on the consistency of the long-term data sets used to describe the wind conditions between tower locations. DNV-GEC did not make a long-term adjustment based on a reference station so there is no uncertainty associated with this category.

[2] Lockhart, Thomas J. and Bailey, Bruce H., *The NRG Maximum Type 40 Anemometer Calibration Project*. National Renewable Energy Laboratory, March 1998.

Wind Shear

There is some uncertainty on whether the wind shear exponents measured over the period at the tower locations are representative of the long term. Shear can also vary based on the exposure at a met tower relative to turbine locations, seasonal variation, and other effects; DNV-GEC estimated the overall shear uncertainty based on a combination of these issues. The effective aggregate uncertainty associated with shear was estimated at approximately 1.5% on wind speed, based on the consistency of shear between the towers, knowledge of the tower configurations and with DNV-GEC's expectations based on other sites in similar terrain, and considering the different measurement heights and available shear data at each tower.

Topographic Effects/On-Site Correlations

This uncertainty represents the potential difference in wind speed between the met tower locations and the wind turbine locations, as well as the uncertainty on the correlations used to describe the wind conditions between the tower locations. The site terrain varies, resulting in complex wind flow. Based on a review of topographic maps and information from the site visit, DNV-GEC would expect some variation in wind speeds between each met tower. The data suggest a wide range of wind speeds on-site with a difference of 0.4 m/s between the highest and lowest annualized met tower wind speeds. Due to the difference in wind speeds at the met towers, size of the project area and complexity of the terrain, DNV-GEC estimated the uncertainty at 4.5%.

Wind Frequency Distribution

The uncertainty on the wind frequency distribution represents the possibility that for a given wind speed the energy production may be higher or lower than expected due to a more or less favorable distribution of winds. For example, the frequency of high-wind cutouts; a year with several intense storms may record substantial time at wind speeds above the 25 m/s turbine cutout speed, thereby increasing the overall average wind speed but not increasing the energy production. There are two aspects to this uncertainty: the first represents the uncertainty on the distribution measured over the period of measurement at the site towers, and the second represents the year-to-year variability in the wind speed distribution. DNV-GEC estimated an annual variability of 3.0% on energy related to differences in wind distribution. This variability applies to both uncertainties on distribution: the uncertainty on the past distribution over the on-site data collection period (4.8 years) which is equal to 3.0% divided by the square root 4.8, or 1.4%. The 3.0% variability applies to the uncertainty on the future distribution, which is allowed to vary year by year.

Wind Speeds over Project Life Relative to Long-Term Average

Uncertainty exists regarding whether the true long-term mean wind speed will occur over the project life. Given an assumed 20-year project lifespan and a 5.5% interannual variability, this uncertainty is calculated as 5.5% divided by the square root of 20 or 1.2% on wind speed. For the 1-year energy analysis, this parameter was set to 5.5% on wind speed.

Changes in Long-Term Average Wind Speed

Changes to local or global climate patterns may produce changes in site wind conditions over the life of the project; there is uncertainty as to whether such changes are occurring, and if so, to what extent. DNV-GEC assumed a 1.0% uncertainty on wind speed to account for this issue.

Effect of Asymmetric Uncertainties

Some of the loss factors described earlier are "lopsided" or asymmetric in nature. To the extent loss factors are asymmetric, the effect of the asymmetry is captured in the spread of the P1-P99 values in Table 16 as well as the P50 loss values described above and in Table 17. Although the uncertainties described above are symmetric, their effect on energy is asymmetric because of the non-linear relationship of wind speed to energy. That is, small increases in average winds result in proportionally smaller changes in energy compared to small decreases in average winds. The effect of this asymmetric energy uncertainty distribution is small compared to other losses, but it does result in a small energy loss factor that is included as the "effect of asymmetric uncertainties" entry in Table 17.

Net Energy

Based on the model inputs described above, Table 16 shows the probabilities of various levels of annual energy production, for long-term and one-year periods. P50 losses are presented in Table 17 and Table 18 presents the net energy for each turbine. Percent of production on a 12-month by 24-hour basis is presented in Table 19.

Table 16. Summary of Net Average Energy Production for the Vestas V80 2.0 MW Turbine with a 67-m Hub Height

Probability of Exceedance	20-Year Average	10-Year Average (First Ten Years)	One-Year (Entire Project Life)	One-Year (During First Ten Years)
Net Annual Energy Production (GWh/yr)				
1%	108.4	110.8	116.7	118.0
5%	103.2	105.0	108.6	109.9
10%	100.3	101.9	104.4	105.7
25%	95.2	96.6	97.3	98.5
50%	**89.3**	**90.6**	**89.3**	**90.6**
75%	83.7	84.7	81.6	82.8
90%	78.5	79.4	74.7	75.8
95%	75.5	76.1	70.6	71.7
99%	70.0	70.4	63.3	64.2
Net Annual Capacity Factor[1]				
1%	28.1%	28.7%	30.3%	30.6%
5%	26.8%	27.3%	28.2%	28.5%
10%	26.0%	26.4%	27.1%	27.4%
25%	24.7%	25.1%	25.2%	25.6%
50%	**23.2%**	**23.5%**	**23.2%**	**23.5%**
75%	21.7%	22.0%	21.2%	21.5%
90%	20.4%	20.6%	19.4%	19.7%
95%	19.6%	19.8%	18.3%	18.6%
99%	18.2%	18.3%	16.4%	16.7%

1. Capacity factors are based on the turbine rating of 2000 kW for the Vestas V80 2.0MW.

Table 17. Summary of P50 Long-Term Average Losses for Vestas V80 2.0 MW at 67-m Hub Height

Gross Energy (GWh/year)	**106.9**
Losses	**Long-Term P50 Losses, % of Energy**
Routine maintenance	0.4%
Faults	1.9%
Minor components (1)	1.7%
Major components (1)	1.5%
Balance of plant	0.5%
Wake	4.7%
Electrical line	2.0%
Blade soiling	0.5%
Weather, including icing, lightning, hail	2.3%
Turbulence and controls	1.0%
Blade degradation (1)	0.4%
Power performance	0.2%
Effect of asymmetric uncertainties	0.6%
Wind Sector Management	0.1%
Total Losses	**16.4%**
Net Energy (GWh/year)	**89.3**
Net Capacity Factor[2]	**23.2%**

1. Values are long-term averages over a 20-year project life and are lower in initial years of operation.

2. Capacity factors are based on the turbine rating of 2000 kW for the Vestas V80 2.0MW.

Table 18. Average Net Energy Estimate for Each Turbine for Vestas V80 2.0MW at 67-m Hub Height

Turbine ID	Net Energy (MWh/yr)
R1	3.7
R2	4.0
R3	4.1
R4	4.1
R5	4.1
R6	4.2
R7	4.2
R8	4.1
R9	4.0
R10	4.0
R11	4.0
R12	4.1
R13	4.1
S1	4.3
S2	4.3
S3	4.2
S4	4.2
T1	3.9
T2	4.0
T3	3.9
U1	3.9
U2	4.0
Total (GWh/yr)	**89.3**

Table 19. 12-Month by 24-Hour Percent of Energy Production (%) for Vestas V80 2.0 MW Turbines at 67-m Hub Height

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.39	0.35	0.40	0.33	0.28	0.30	0.31	0.23	0.28	0.39	0.32	0.39
1	0.39	0.32	0.39	0.32	0.27	0.28	0.28	0.23	0.27	0.40	0.33	0.39
2	0.38	0.32	0.37	0.32	0.26	0.28	0.27	0.23	0.26	0.40	0.34	0.37
3	0.38	0.33	0.36	0.31	0.26	0.25	0.26	0.23	0.25	0.39	0.34	0.34
4	0.35	0.33	0.36	0.30	0.26	0.24	0.25	0.21	0.27	0.38	0.35	0.36
5	0.37	0.34	0.36	0.30	0.25	0.24	0.22	0.20	0.27	0.37	0.36	0.33
6	0.35	0.34	0.37	0.30	0.23	0.24	0.23	0.17	0.27	0.35	0.37	0.33
7	0.31	0.34	0.37	0.30	0.26	0.25	0.22	0.16	0.28	0.33	0.37	0.33
8	0.31	0.33	0.37	0.32	0.29	0.26	0.24	0.18	0.30	0.35	0.36	0.31
9	0.34	0.33	0.39	0.34	0.30	0.27	0.24	0.22	0.33	0.37	0.37	0.29
10	0.33	0.33	0.42	0.36	0.30	0.29	0.26	0.23	0.34	0.38	0.39	0.30
11	0.34	0.34	0.44	0.36	0.33	0.33	0.29	0.25	0.34	0.39	0.39	0.33
12	0.36	0.35	0.45	0.36	0.35	0.35	0.33	0.28	0.36	0.39	0.40	0.34
13	0.38	0.35	0.48	0.38	0.38	0.38	0.38	0.31	0.37	0.38	0.41	0.36
14	0.39	0.35	0.50	0.40	0.42	0.41	0.41	0.37	0.39	0.39	0.41	0.34
15	0.38	0.36	0.51	0.42	0.48	0.47	0.46	0.42	0.43	0.39	0.39	0.31
16	0.38	0.35	0.50	0.44	0.50	0.52	0.51	0.47	0.44	0.39	0.40	0.30
17	0.38	0.34	0.49	0.42	0.51	0.55	0.54	0.49	0.42	0.38	0.40	0.31
18	0.35	0.35	0.47	0.38	0.46	0.53	0.51	0.43	0.35	0.39	0.38	0.32
19	0.34	0.37	0.44	0.33	0.41	0.44	0.42	0.32	0.33	0.40	0.35	0.33
20	0.34	0.37	0.45	0.32	0.37	0.38	0.34	0.26	0.30	0.40	0.35	0.30
21	0.36	0.37	0.43	0.33	0.34	0.33	0.32	0.25	0.29	0.39	0.34	0.32
22	0.35	0.37	0.41	0.33	0.33	0.32	0.32	0.24	0.29	0.39	0.35	0.35
23	0.39	0.38	0.39	0.32	0.32	0.29	0.31	0.22	0.29	0.40	0.33	0.37

Note that this matrix is an estimate of the pattern of average energy production. The energy production in any given hour or month may deviate significantly from this pattern.

Appendix A – Site Photos

Photo 1. View from Met 319 facing North

Photo 2. View from Met 319 facing East

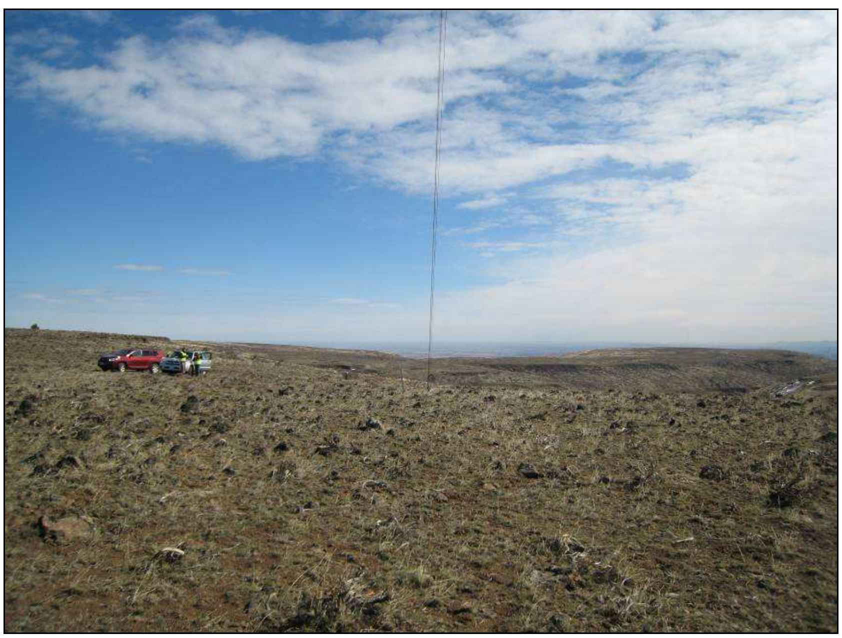


Photo 3. View from Met 319 facing South

Photo 4. View from Met 319 facing West

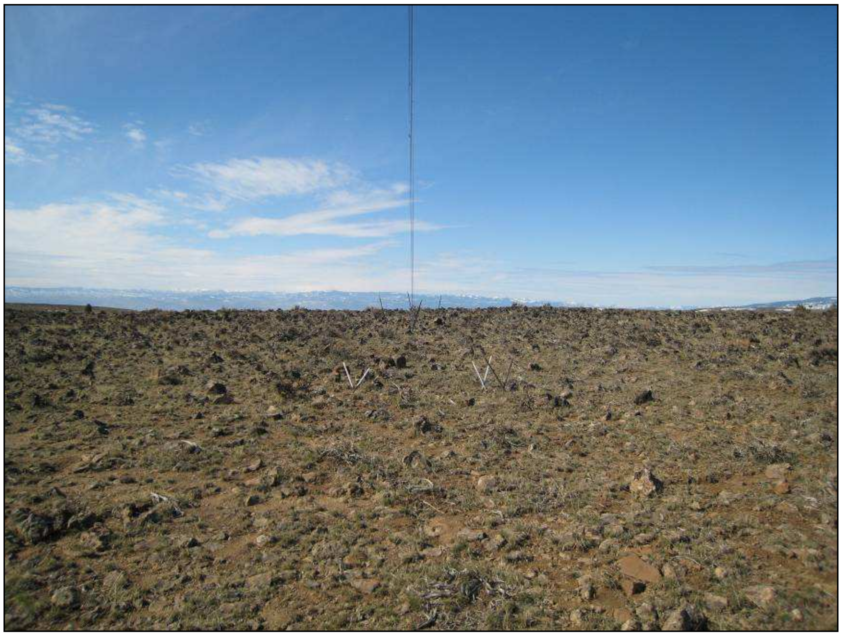


Photo 5. View from Met 320 facing North

Photo 6. View from Met 320 facing East

Photo 7. View from Met 320 facing South

Photo 8. View from Met 320 facing West

Appendix B – Met Tower Commissioning Sheets

MET TOWER COMMISSIONING SHEET

Site: 0319

State:	Washington	Tower Type:	50m Tall Tower	Date Installed:	6/20/2006
Township/County:	Kittitas Valley	Cell Provider:	Verizon	Installed By:	Wind Rivers
Project Name:	Wild Horse	Logger Cell #:	406.223.1779	Data Retrieval By:	GEC
Logger Type & S/N	Symphonie 30909019	Calling To #:	1-800-290-4375	Tel #:	206-378-4200
ESN:	214-00067550	Tower Lat/Long:	N 47*04.139/ W 120*13*686	Local Contact:	Dana Peck
Landowner(s):		Map Datum:	NAD 27	Tel #:	503-962-1122
Tel #:		Elevation:	3637ft	Lock Combination:	na

Instrument Type (ch# / sensor)	Instrument Height (measured)	Instrument Orientation (deg from True N)	NOTES (slope/offset, etc.)	Sensor Replacement (date/time, height/orientation, ect.)
1 ANE	49m	270		
2 ANE	49m	180		
3 ANE	30m	270		
4 ANE	30m	180		
5 ANE	10m	270		
7 VANE	42m	0		
8 VANE	10m	0		

Lead Technician: Joel Hewit Date: 6/20/2006

MET TOWER COMMISSIONING SHEET

Site: 0320

State:	Washington	Tower Type:	NRG 50m Tall Tower	Date Installed:	6/15/2005
Township/County:	Kittitas	Cell Provider:	Verizon	Installed By:	Met Tower Services Inc.
Project Name:	Wild Horse	Logger Cell #:	406.223.2326	Data Retrieval By:	GEC
Logger Type & S/N	Symphonie 35262531	Calling To #:	GEC	Tel #:	425-822-9008
ESN:		Tower Lat/Long:	N47 03.738 W120 11.888	Local Contact:	Andrew Young
Landowner(s):	State of WA-Wildlife	Map Datum:	NAD 27	Tel #:	(503)-222-9400 x 102
Tel #:		Elevation:	3490ft.	Lock Combination:	

Instrument Type (ch# / sensor)	Instrument Height (measured)	Instrument Orientation (deg from True N)	NOTES (slope/offset, etc.)	Sensor Replacement (date/time, height/orientation, ect.)
1.#40 Anemometer	50m	250		
2.#40 Anemometer	50m	160		
3.#40 Anemometer	30m	250		
4.#40 Anemometer	30m	160		
5.#40 Anemometer	10m	250		
1. #200 Vane	41m	340	Boom is off the south side but oriented North.	
2. #200 Vane	10m	340	Boom is off the south side but oriented North.	
1. Temperature	2m		North Side of Tower	
			20 degrees for declination. Instrumentation orientation is clock-wise from Magnetic north.	
			Latitude, Longitude, and elevation measured on the data installed with a Garmin GPS III Plus.	
			Anchor Positions: N=340, E=70, S=160, W=250. Lightning rod is off the east side	
			All anchors are rebar drilled into the rock.	

Lead Technician: Chris Sailor Date: 6/15/2005 a DNV company

DRAFT

Wind Resource and Energy Assessment Lower Snake River Phase I Wind Power Project

EARP0091

CONFIDENTIAL

March 3, 2010

Prepared for:

Puget Sound Energy
10885 NE 4th Street
Bellevue, WA 98004

DNV Global Energy Concepts Inc.
1809 7th Avenue, Suite 900
Seattle, Washington 98101 USA
Phone: (206) 387-4200
Fax: (206) 387-4201
www.globalenergyconcepts.com
www.dnv.com

MANAGING RISK

NOTICE

The information contained in this document has been prepared exclusively for the client named on the cover and no other. This document is intended to be strictly for the use of this client only and is not intended to be, and may not be, relied upon by third parties without the specific written consent of DNV Global Energy Concepts Inc., (DNV-GEC). While this report has been prepared pursuant to generally accepted practices in the industry, it is possible that actual results may vary from those predicted herein. The contract under which this report was created and compiled contains restrictions on liability between the parties, and any permissive use by a third party shall be subject to those liability limits. In no event does DNV-GEC warrant this product, except for the specific purpose for which it was created. DNV-GEC accepts no liability for any indirect or consequential damages, or any damages of that type, unless it specifically consents thereto in writing. This report relies on data and information provided by the client and others, for which DNV-GEC assumes no responsibility. The information contained in this report is applicable to the equipment tested or reviewed and may not be applicable to other pieces of equipment of the same make and model or different equipment, or equipment manufactured by other entities.

Questions or concerns related to this report or any of the information contained herein should be directed to the author of the report or an officer of DNV-GEC.

Approvals

Prepared by Date

Reviewed by Date

Version Block

Version	Release Date	Summary of Changes
DRAFT		

Table of Contents

EXECUTIVE SUMMARY 1

BACKGROUND AND PROJECT DESCRIPTION 3

WIND RESOURCE AND ENERGY ASSESSMENT OVERVIEW 8

WIND RESOURCE MEASUREMENTS 10

METEOROLOGICAL TOWER CONFIGURATIONS 10
DATA VALIDATION 11
DATA RECOVERY 12

WIND ANALYSIS RESULTS 14

ON-SITE CORRELATIONS AND MONTHLY WIND SPEEDS 14
WIND SHEAR 18
TURBULENCE 24
LONG-TERM ADJUSTMENTS 26
LONG-TERM HUB-HEIGHT WIND SPEEDS 31
WIND ROSE 31

GROSS ENERGY ESTIMATES AND WAKE EFFECTS 33

GROSS ENERGY ESTIMATES 33
WAKE EFFECTS 36

LOSSES AND UNCERTAINTIES 39

LOSSES 39
Availability 39
Wake Effect Losses 41
Turbine Performance 41
Electrical 42
Environmental 42
Curtailment 44
Other 44
UNCERTAINTIES 44
Interannual Variability of the Wind 44
Anemometer Accuracy 45
Tower Effects on Measurements 45
Data Capture/Quality Control/Validation 45
Representativeness of Period of Data 45
Reference Site Relationships/Consistency of Long-Term References 45
Wind Shear 45
Topographic Effects/On-Site Correlations 46
Wind Frequency Distribution 46
Wind Speeds over Project Life Relative to Long-Term Average 46
Changes in Long-Term Average Wind Speed 46

NET ENERGY ESTIMATE 47

APPENDIX A – TURBINE AND MET TOWER COORDINATES

APPENDIX B – SITE PHOTOS

APPENDIX C – MET TOWER COMMISSIONING SHEETS

APPENDIX D – WIND SPEED, GROSS ENERGY ESTIMATE, AND WAKE LOSS FOR EACH TURBINE

APPENDIX E – NET TURBINE ENERGY FOR FOUR WAKE LOSS SCENARIOS

List of Figures

Figure 1. Location of the LSR Phase I Wind Power Project 4
Figure 2. LSR Phase I Meteorological Towers and Proposed Turbine Locations.......... 6
Figure 3. LSR Phase II Project Region 7
Figure 4. Wind Resource and Energy Assessment Process Overview 9
Figure 5. Diurnal Shear Exponents by Month for Met M252.......... 18
Figure 6. Diurnal Shear Exponents by Month for Met M370.......... 19
Figure 7 Diurnal Shear Exponents by Month for Met M371.......... 19
Figure 8. Diurnal Shear Exponents by Month for Met M399.......... 20
Figure 9. Diurnal Shear Exponents by Month for Met M437.......... 20
Figure 10. Diurnal Shear Exponents by Month for Met M438.......... 21
Figure 11. Diurnal Shear Exponents by Month for Met M440.......... 21
Figure 12. Directional Shear Exponents by Met Tower 22
Figure 13. Turbulence Intensity by Hub-Height Wind Speed 26
Figure 14. Location of Lower Snake River Phase I and Long-Term Reference Stations 27
Figure 15. Comparison of Daily Average Wind Speed at Kennewick BPA and Met M252 29
Figure 16. Comparison of Daily Average Wind Speed at Kennewick BPA and Met M370 30
Figure 17. Met M370 Annual Wind Rose at 80 m 32

List of Tables

Table 1. Lower Snake River Phase I Project Executive Summary.......... 1
Table 2. Lower Snake River Phase I Energy Production Executive Summary 2
Table 3. Proposed Wind Turbine Specifications 4
Table 4. Met Tower Summary.......... 10
Table 5. Valid Data Recovery.......... 12
Table 6. Summary of Correlation Statistics between Met M399 and Met M370.......... 15
Table 7. Summary of Correlation Statistics between Met M437 and Met M370.......... 15
Table 8. Summary of Correlation Statistics between Met M438 and Met M370.......... 16
Table 9. Summary of Correlation Statistics between Met M440 and Met M370.......... 16
Table 10. Monthly Average Wind Speeds (m/s) 16
Table 11. Average Shear Exponents by Hour.......... 23
Table 12. Average Shear Exponents by Direction.......... 23
Table 13. Average Turbulence Intensity at for Wind Speeds > 4 m/s (%).......... 24
Table 14. Average Turbulence Intensity by Direction Sector (%) 25
Table 15. Investigated Long-Term Reference Station Summary 27

Table 16. Correlation Parameters for Met M252 and Met M370 to Kennewick BPA Reference Data 28
Table 17. Monthly Long-Term Adjustment Factors 30
Table 18. Annual Average Long-Term Adjusted 80-m Wind Speeds 31
Table 19. Long-Term Hub-Height Average Wind Speed Frequency Distributions and SWT-2.3-101 Power Curve at 1.15 kg/m^3 Air Density 34
Table 20. 12-Month by 24-Hour Gross Energy Production 38
Table 21. Summary of Wake Loss Scenarios 41
Table 22. Summary of Project Net Average Energy Production Including Impact of Phase I Wakes Only 47
Table 23. Summary of Project Net Average Energy Production Including Impact of Phase II Wakes 48
Table 24. Summary of Project Net Average Energy Production Including Impact of Phase III Wakes 49
Table 25. Summary of Project Net Average Energy Production Including Impact of Phase II and III Wakes 50
Table 26. Summary of Long-Term P50 Losses 51

Executive Summary

DNV Global Energy Concepts Inc. (DNV-GEC) has been retained by Puget Sound Energy to complete an energy assessment for the proposed Lower Snake River Phase I Wind Power Project located approximately 11 km (7 miles) northeast of Dayton, Washington. Table 1 presents a summary of the key features of the Project site and wind resource. Table 2 presents a summary of the estimated energy production. DNV-GEC's methodology, assumptions, analysis, uncertainties, and results are described in the main body of the report.

Table 1. Lower Snake River Phase I Project Executive Summary

Project Summary	
Project Name	Lower Snake River Phase I
Location	Garfield County, Washington
Turbine Type	Siemens SWT-2.3-101
Turbine Hub Height (m)	80
Turbine Rated Power (kW)	2300
Number of Turbines	149
Installed Capacity (MW)	342.7
Wind Resource Summary	
Average Air Density (kg/m^3)	1.15
Average Met Tower Shear Exponent	0.10
Average Hub-Height Turbulence Intensity, Wind Speeds > 4 m/s	11%
Average Long-Term Adjustment	-2.4%
Average Long-Term Hub-Height Wind Speed (m/s)	
Met M252	7.1
Met M370	7.2
Met M371	7.2
Met M399	6.9
Met M437	7.3
Met M438	6.8
Met M440	6.9
Average Turbine Hub-Height Wind Speed (m/s)	7.0

Table 2. Lower Snake River Phase I Energy Production Executive Summary

Energy Assessment Summary, 20-Year Values				
Wake Loss Scenario	**Phase I Only**	**Phase I & II**	**Phase I & III**	**Phase I, II & III**
P50 Losses				
- Availability Loss	5.8%	5.8%	5.8%	5.8%
- Wake Effects Loss	7.9%	13.8%	8.8%	14.4%
- Turbine Performance Loss	1.2%	1.2%	1.2%	1.2%
- Electrical Loss	1.3%	1.3%	1.3%	1.3%
- Environmental Loss	2.9%	2.9%	2.9%	2.9%
- Curtailment Loss	Not Considered	Not Considered	Not Considered	Not Considered
- Other Loss	0.8%	0.9%	0.8%	0.8%
Estimated Gross Energy (GWh/year)	1103	1103	1103	1103
Estimated Total Losses	18.5%	23.8%	19.3%	24.4%
P5 Net Energy (GWh/year)	1017	985	1012	985
P5 Net Capacity Factor	33.9%	32.8%	33.7%	32.8%
P95 Net Energy (GWh/year)	782	702	769	690
P95 Net Capacity Factor	26.0%	23.4%	25.6%	23.0%
P50 Net Energy (GWh/year)	**899**	**840**	**890**	**834**
P50 Net Capacity Factor	**29.9%**	**28.0%**	**29.6%**	**27.8%**

Background and Project Description

DNV Global Energy Concepts Inc. (DNV-GEC) has been retained by Puget Sound Energy (PSE) to complete an energy assessment for the proposed Lower Snake River (LSR) Phase I Wind Power Project, located approximately 11 km (7 miles) northeast of Dayton, Washington. This report presents the methodology, assumptions, analysis, uncertainties, and results of the assessment. It first provides an overview of the wind resource and energy assessment process. It then discusses wind resource measurements and wind analysis results. Gross energy production is estimated based on wind speed frequency distributions and wind flow across the terrain. Finally, losses and uncertainties are considered to arrive at net energy estimates for the project with associated probability levels.

The location of the LSR Phase I Project is displayed in Figure 1. The LSR Phase I Project is planned to consist of 149 Siemens SWT-2.3-101 2.3 megawatt (MW) wind turbines installed at an 80-m hub height for a total installed project capacity of 342.7 MW. The principal features of the proposed turbine are shown in Table 3.

Analysis of the suitability of the proposed turbine model for the LSR Phase I Site is outside the scope of this assessment. Site suitability is commonly evaluated by wind turbine manufacturers or consultants and should be conducted as part of the project development process to confirm that site climatic conditions and the proposed turbine layout are within the design criteria of the turbine.

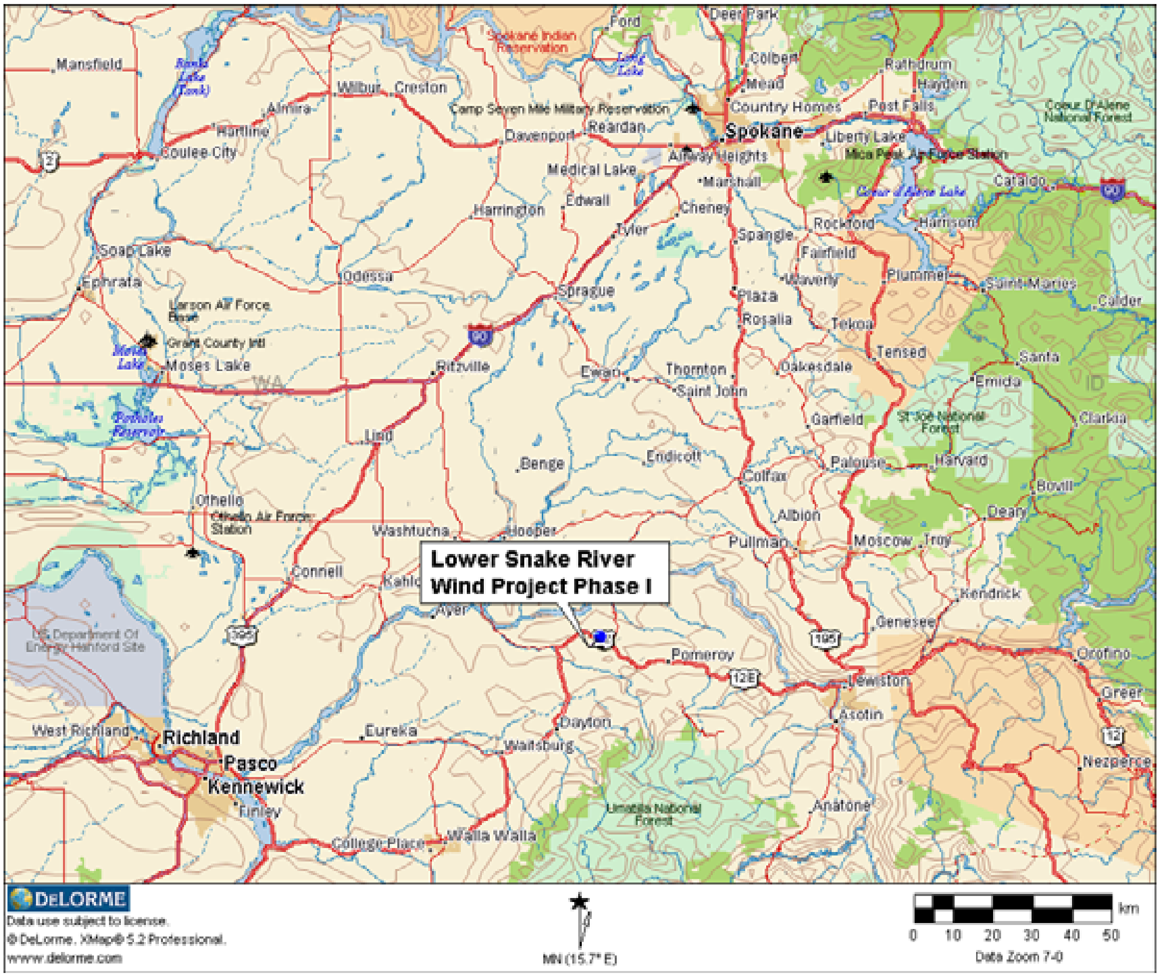


Figure 1. Location of the LSR Phase I Wind Power Project

Table 3. Proposed Wind Turbine Specifications

Turbine Model	Siemens SWT-2.3-101
Hub Height, m	80
Rotor Diameter, m	101
Rotor Speed, rpm	6 – 16
Rated Power, kW	2300
Operating Wind Speed Range (m/s)	4.0 – 25.0
Climate Package(1)	Cold Weather

1. Ambient operating temperature -25°C to +35°C

PSE provided the LSR Phase I Project layout. Wind data were collected at 21 meteorological (met) towers associated with the Project. Seven met towers are located within the LSR Phase I Project boundary; however, three of these towers (Met M540, Met M541, and Met M542) were installed in July 2009 and do not have a sufficient data record for inclusion in this analysis. Data from these towers were used qualitatively to estimate the changes in wind speed over the Project area. Four longer-term Phase I met towers (Met M370, Met M437, Met M440, Met M438) make up the primary data set used in this analysis. Three nearby met towers (Met M252, Met M371 and Met M399) were also evaluated but do not significantly impact the results. LSR Phase I Project met tower and turbine locations are presented in Figure 2. The turbine and met tower coordinates are given in Appendix A. Figure 3 presents the proposed turbine locations for all phases of the LSR Project and the existing turbine locations of the Hopkins Ridge and Marengo wind power projects.

The energy assessment provides the net energy estimates for only the LSR Phase I wind turbines. However, the assessment includes four wake loss scenarios that estimate the impact of the Phase II and II turbines on the Phase I energy production. The four scenarios:

1. Phase I without the impact of later development
2. Impact of Phase II
3. Impact of Phase III
4. Impact of both Phase II and III

DNV-GEC conducted a site visit to the LSR Phase I Project region on September 15, 2009. Information obtained from this visit was incorporated into the analysis. The LSR Project is sited in a large agricultural area in rural Washington. The terrain consists of multiple ridges that are aligned east to west or northwest to southeast. The average proposed turbine elevation is 543 meters above sea level (masl) and the proposed turbine locations cover a 290-m range in elevation. There are roads and off-road-vehicle trails throughout the Project area; however, not all turbine locations are currently accessible by vehicle.

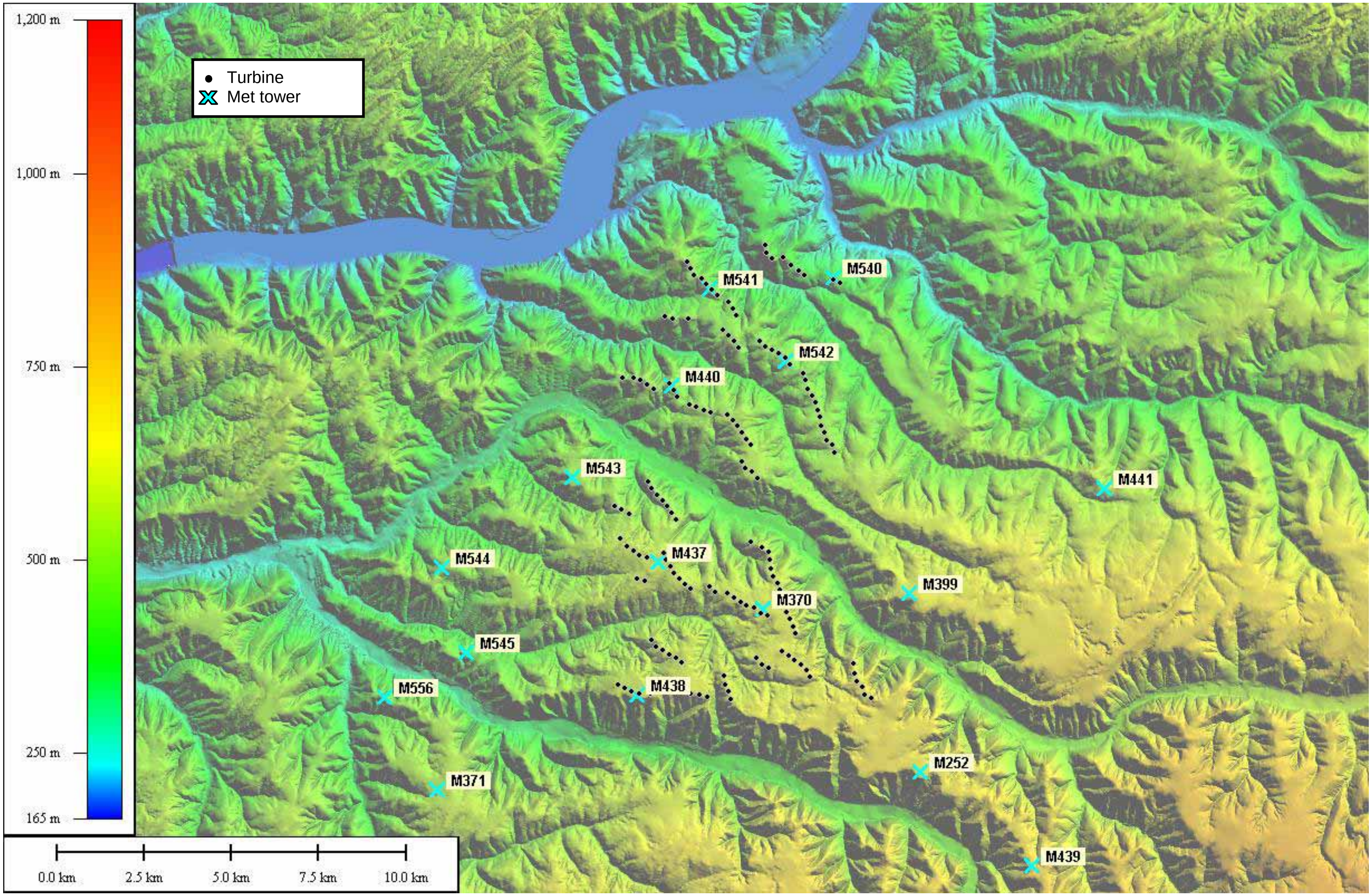


Figure 2. LSR Phase I Meteorological Towers and Proposed Turbine Locations

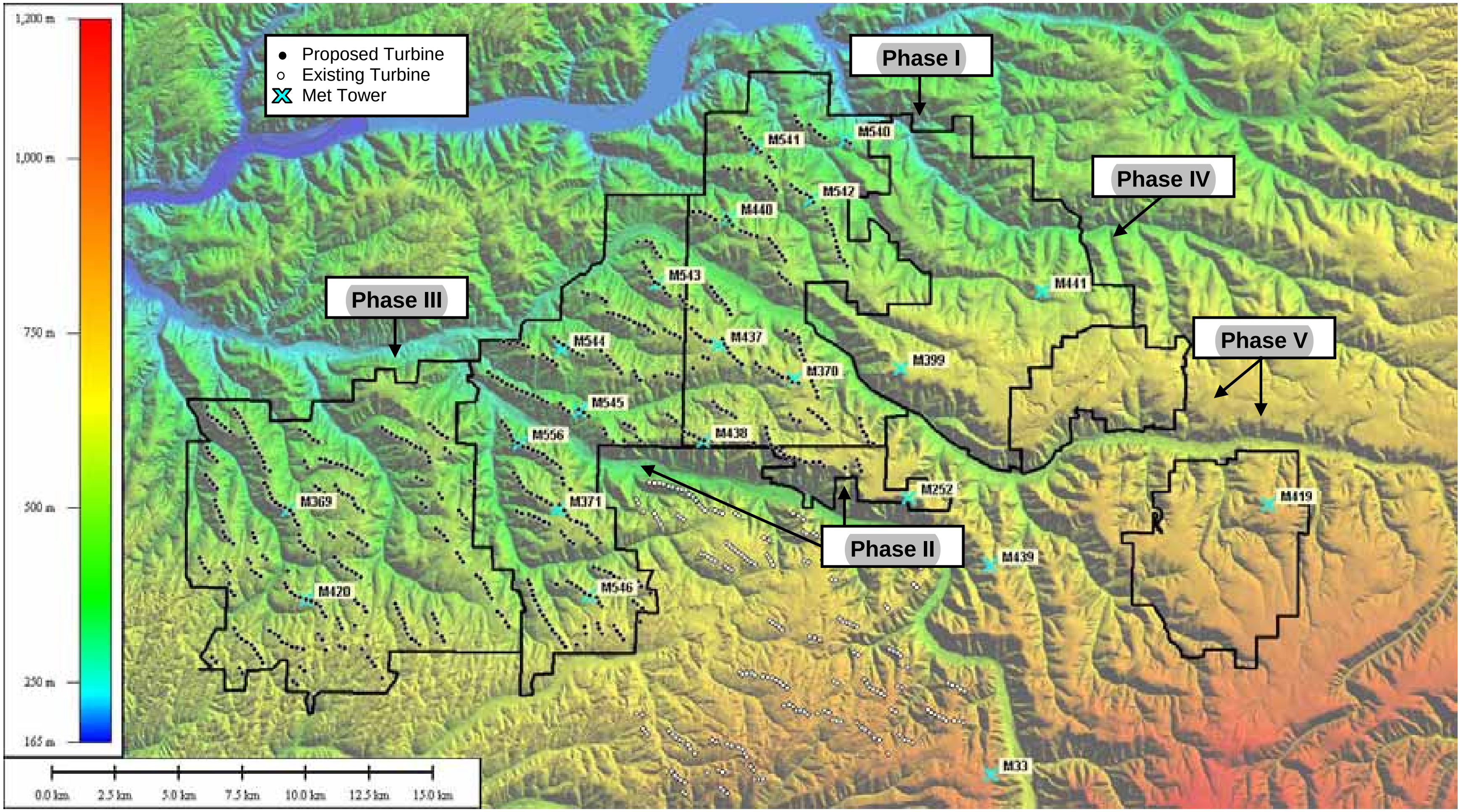


Figure 3. LSR Phase II Project Region

Wind Resource and Energy Assessment Overview

This section presents an overview of the methodology used to process the data, evaluate the wind characteristics, and estimate energy production. A schematic of the wind resource and energy assessment process is shown in Figure 4. Details of the analysis and results are provided in following sections.

DNV-GEC processed raw data from seven met towers were processed and removed any invalid data. Wind speeds measured by anemometers at different heights were used to calculate the wind shear, which is a measure of how the wind speed changes according to height. The shear calculations were used to extrapolate wind speeds at the measurement heights to the turbine hub height. DNV-GEC consulted nearby long-term reference stations to determine how well the on-site data represent the long-term average wind speeds. DNV-GEC adjusted the on-site wind speeds to reflect the long-term average based on the reference data. The long-term hub-height wind speeds were normalized to one year (8,760 hours) so that annual wind speed frequency distributions could be created representing the met tower locations. DNV-GEC calculated the turbulence intensity (TI) for each measurement level at each met tower. TI is used in modeling turbine wake effects.

DNV-GEC estimated individual turbine hub-height wind speeds based on long-term adjusted hub-height met tower wind speeds, wind-flow modeling results, elevation and exposure, and our professional judgment regarding wind flow across the terrain. DNV-GEC estimated the annual gross energy production for each turbine location using the annual wind speed frequency distributions from the met towers, the estimated turbine wind speeds, and the turbine power curve. We estimated the Project's net energy based on the gross annual energy and the technical losses and uncertainties estimated for the Project.

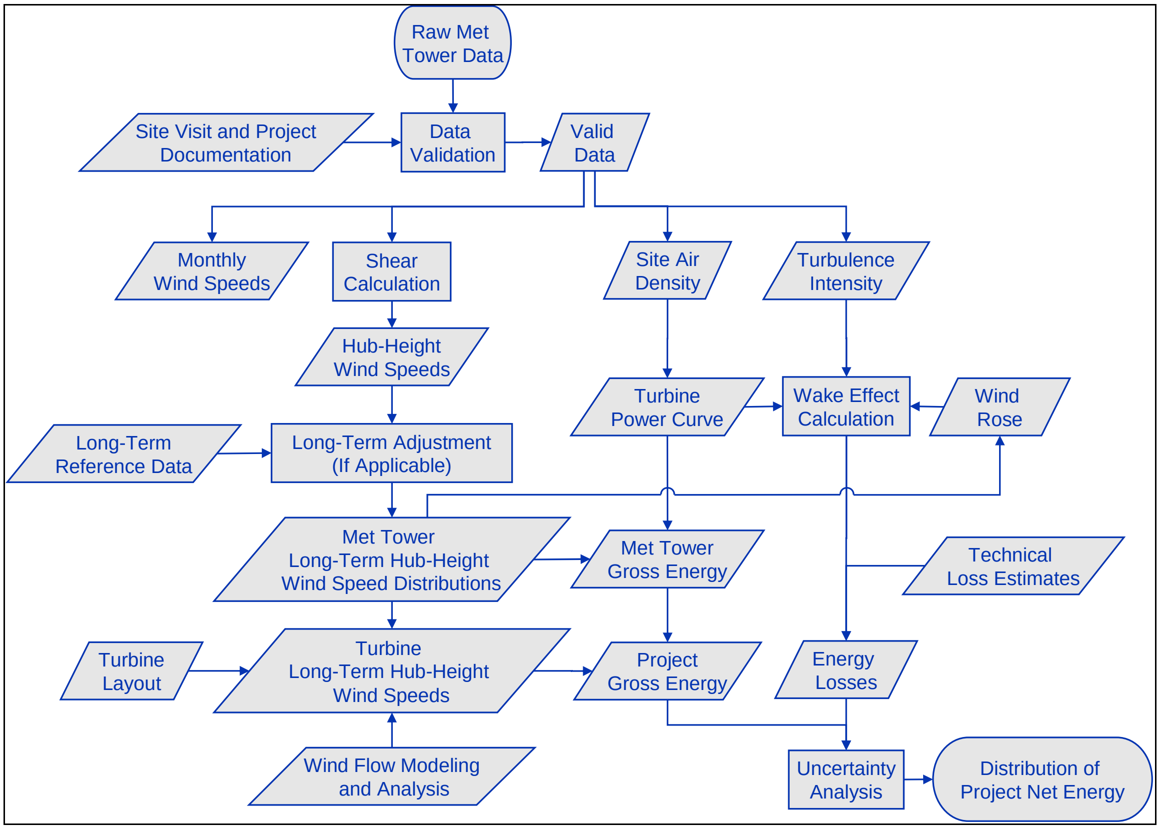


Figure 4. Wind Resource and Energy Assessment Process Overview

Wind Resource Measurements

DNV-GEC evaluated data from four on-site met towers and three nearby met towers. These towers were erected specifically for wind resource measurements. Three other met towers have been installed in and around the LSR Phase I Project area, but these met towers do not have a sufficient data record to be included in this analysis. Data from these three towers were only used qualitatively to estimate the changes in wind speed over the Project area. This section describes the met tower configurations, the data validation process, and the data recovery.

Meteorological Tower Configurations

A summary of the met tower configurations is presented in Table 4, including data start and end dates, anemometer heights and orientations, and data sampling rate. The anemometer heights were provided with the tower documentation. DNV-GEC confirmed these heights during the site visit using a Laser Technology Inc. TruPulse 200 Laser Rangefinder with an accuracy of approximately 1 m. All anemometer heights measured during the site visit were within 1 m of the documented height. Representative photos of the met towers are presented in Appendix B. The commissioning sheets for all seven met towers are included in Appendix C.

Table 4. Met Tower Summary

Met Tower	Tower Type	Ground Elevation (masl)	Period of Record	Years of Data	Anemometer Heights (m) [1]	Anemometer Orientations (º)
M252	Rohn 25G	687	03/08/05 – 08/31/09	4.2	56.3, 35.3	288
M370	Rohn 25G	612	05/03/07 – 08/31/09	2.3	60.4, 56.1, 35.1	135
M371	Rohn 25G	547	05/03/07 – 08/31/09	2.3	60.4, 56.1, 35.1	135, 131[2]
M399	Sabre 1200 TLWD	634	09/11/07 – 08/31/09	2.0	60.2, 58.0, 35.1	151
M437	Sabre 1800 TLWD	595	06/16/08 – 08/31/09	1.2	58.1 (2), 53.1, 38.2, 23.1	138, 320
M438	Sabre 1800 TLWD	598	06/17/08 – 08/31/09	1.2	58.1 (2), 53.1, 38.5, 23.1	130, 300
M440	Sabre 1800 TLWD	509	06/16/08 – 08/31/09	1.2	58.1 (2), 53.1, 38.2, 23.1	139, 319

1. (2) indicates that two anemometers are mounted at or very near that level.
2. The top anemometer is oriented to 135º and the lower anemometers are oriented to 131º

For all sites, measurements were recorded every 10 minutes throughout the collection period. All met towers are lattice towers and utilize Campbell Scientific Data Loggers. The side-mounted anemometers are mounted on booms at least 2.0 m long. With the exception of M252, the top anemometer(s) on each tower met tower are on goalpost-type booms and elevated above the top of the tower. All anemometers at the site are A1002L cup anemometers manufactured by Vector Instruments and calibrated by Svend Ole Hansen ApS. PSE provided calibration certificates for each anemometer to DNV-GEC. Raw wind speed data were processed using the respective calibration transfer parameters for each sensor.

According to the maintenance records provided by PSE, the Met M252 logger was replaced on September 5, 2008. The 35.3-m anemometer on Met M252 was replaced on April 11, 2007, due to a malfunction. Both wind vanes on Met M252 were replaced on July 17, 2009. For Met M370 and Met M371, the boom length of the side-mounted anemometers was changed from 2.87 m to 2.23 m on July 13, 2007.

Met M252, Met M371, and Met M399 are not located in the immediate project area, but were included in this analysis to increase the overall data-collection period and provide additional information about the wind speed variability across the site.

Data Validation

The available met tower data were compiled, validated, and incorporated into the analysis. DNV-GEC followed a standard validation process to identify and remove erroneous data (e.g., due to icing or tower shadow).

In cases where there are two anemometers at the same level, DNV-GEC designated one primary anemometer and one secondary anemometer. Wind speeds from the primary anemometer are used in this analysis except when the data are invalid, in which case valid data from the secondary anemometer are used. Met M437, Met M438, and M440 are the only met towers that have two anemometers at the same level. For these anemometers, DNV-GEC designated the southeast-oriented anemometers as primary and the northeast-oriented anemometers as secondary. Wind shear is only calculated from anemometers that share the same orientation.

Wind speed data were considered erroneous due to icing if the temperature was near or below freezing and an additional criterion was met, such as the wind vane or anemometer standard deviation equaling zero for consecutive records or the average wind speed being lower than expected, relative to the wind speeds at other levels. Wind vane data were considered erroneous due to icing if the standard deviation was zero for several consecutive records when temperatures were near or below freezing.

Data were also considered erroneous when the anemometers were affected by tower shadow (waked data). Tower shadow occurs when the wind direction is opposite to the anemometer orientation and places the tower between the wind and anemometer. For example, an anemometer oriented south of the tower will record invalid wind speed data when the winds are from the north. Data corresponding to the tower-waked sector (50º wide) were removed for all anemometers except those mounted on goalpost booms. We determined the wind direction for each data record using the upper-level wind vane whenever possible; otherwise the lower-level wind vane was used.

Met M370, Met M437, and Met M438 had malfunctioning wind vanes at the 54.6-m, 49.6-m, and 49.6-m levels, respectively. In all cases, the malfunction was reported to be caused by a manufacturing defect. The malfunctioning wind vanes were replaced on January 24, 2009. Analysis of the data from these wind vanes showed occasional deviation from the actual wind direction (as recorded by the other wind vanes at the Project site). For Met M370, we primarily used the upper-level wind vane (at 60.1 m) in this analysis so the malfunction of the 54.6-m wind vane had little effect on the analysis. For Met M437, there was no significant deviation between the direction data of the two wind vanes, so we used data from the 49.6-m wind vane in the analysis. For M438, data from the 49.6-m wind vane deviated from the other wind vane on that tower and on other towers. During that time, we used the direction data from the lower-level wind vane.

The lower anemometer of Met M252 (35.3 m) measured intermittently erroneous data from April 2005 to April 2007, when it was replaced. Data from this time period were removed from the analysis so that the wind shear calculation would not be affected.

Data Recovery

Data recovery rates indicating the percent of data records with valid upper wind speed and direction measurements are presented by month and year in Table 5. The low data recovery rates for the winter months were due to anemometer and wind vane icing. Lower recovery rates for Met M252 are due to the removal of tower-waked data. There is no secondary anemometer at the upper level to replace the tower-waked data. There is a missing period of data at Met M252, from June 1, 2006, to July 31, 2006. Additionally, low data recovery for Met M252 in November 2006 and December 2006 is due to incomplete data transmittals. For the other towers, the data recovery is sufficient and data from the top-mounted anemometer were not affected by tower shadow because these anemometers are mounted above the tower top on goalpost booms.

Table 5. Valid Data Recovery

Month	Met M252	Met M370	Met M371	Met M399	Met M437	Met M438	Met M440
2005 March	71%	N/A	N/A	N/A	N/A	N/A	N/A
2005 April	86%	N/A	N/A	N/A	N/A	N/A	N/A
2005 May	92%	N/A	N/A	N/A	N/A	N/A	N/A
2005 June	96%	N/A	N/A	N/A	N/A	N/A	N/A
2005 July	98%	N/A	N/A	N/A	N/A	N/A	N/A
2005 August	98%	N/A	N/A	N/A	N/A	N/A	N/A
2005 September	98%	N/A	N/A	N/A	N/A	N/A	N/A
2005 October	95%	N/A	N/A	N/A	N/A	N/A	N/A
2005 November	74%	N/A	N/A	N/A	N/A	N/A	N/A
2005 December	84%	N/A	N/A	N/A	N/A	N/A	N/A
2006 January	96%	N/A	N/A	N/A	N/A	N/A	N/A
2006 February	91%	N/A	N/A	N/A	N/A	N/A	N/A
2006 March	87%	N/A	N/A	N/A	N/A	N/A	N/A
2006 April	90%	N/A	N/A	N/A	N/A	N/A	N/A
2006 May	92%	N/A	N/A	N/A	N/A	N/A	N/A
2006 June	2%	N/A	N/A	N/A	N/A	N/A	N/A
2006 July	1%	N/A	N/A	N/A	N/A	N/A	N/A
2006 August	96%	N/A	N/A	N/A	N/A	N/A	N/A
2006 September	93%	N/A	N/A	N/A	N/A	N/A	N/A

Month	Met M252	Met M370	Met M371	Met M399	Met M437	Met M438	Met M440
2006 October	95%	N/A	N/A	N/A	N/A	N/A	N/A
2006 November	46%	N/A	N/A	N/A	N/A	N/A	N/A
2006 December	37%	N/A	N/A	N/A	N/A	N/A	N/A
2007 January	72%	N/A	N/A	N/A	N/A	N/A	N/A
2007 February	84%	N/A	N/A	N/A	N/A	N/A	N/A
2007 March	94%	N/A	N/A	N/A	N/A	N/A	N/A
2007 April	95%	N/A	N/A	N/A	N/A	N/A	N/A
2007 May	95%	92%	92%	N/A	N/A	N/A	N/A
2007 June	95%	100%	100%	N/A	N/A	N/A	N/A
2007 July	98%	100%	100%	N/A	N/A	N/A	N/A
2007 August	97%	100%	100%	N/A	N/A	N/A	N/A
2007 September	98%	100%	100%	65%	N/A	N/A	N/A
2007 October	93%	100%	100%	100%	N/A	N/A	N/A
2007 November	88%	98%	95%	100%	N/A	N/A	N/A
2007 December	78%	81%	88%	84%	N/A	N/A	N/A
2008 January	89%	96%	99%	99%	N/A	N/A	N/A
2008 February	92%	100%	100%	100%	N/A	N/A	N/A
2008 March	97%	100%	100%	100%	N/A	N/A	N/A
2008 April	98%	100%	100%	100%	N/A	N/A	N/A
2008 May	93%	100%	100%	100%	N/A	N/A	N/A
2008 June	96%	100%	100%	100%	48%	45%	48%
2008 July	96%	100%	100%	100%	100%	100%	100%
2008 August	94%	100%	100%	100%	100%	100%	100%
2008 September	92%	100%	100%	100%	100%	100%	100%
2008 October	92%	100%	100%	100%	100%	100%	100%
2008 November	88%	100%	100%	99%	98%	100%	100%
2008 December	92%	99%	100%	99%	100%	100%	100%
2009 January	57%	59%	59%	59%	66%	62%	61%
2009 February	81%	93%	94%	93%	92%	94%	94%
2009 March	96%	100%	100%	100%	100%	100%	100%
2009 April	95%	98%	100%	100%	100%	100%	100%
2009 May	94%	100%	100%	100%	100%	100%	100%
2009 June	94%	100%	100%	100%	100%	100%	100%
2009 July	93%	100%	100%	100%	100%	100%	100%
2009 August	96%	100%	100%	100%	100%	100%	100%
Overall(1)	**86%**	**97%**	**98%**	**97%**	**97%**	**97%**	**97%**

1. Excludes partial months at beginning of the period of record.

Wind Analysis Results

This section discusses our evaluation of the wind data, including on-site wind speed correlations, monthly wind speeds, wind shear, turbulence, long-term wind speeds, and wind rose.

On-Site Correlations and Monthly Wind Speeds

In order to bring the met towers to a consistent period of record, DNV-GEC synthesized data at Met M399, Met M437, Met M438 and Met M440 from Met M370. We used the Variance Measure-Correlate-Predict (MCP) method[1] to establish a statistical relationship between Met M370 and the other met towers over simultaneous periods at each. We generated slope and intercept parameters using hourly average wind speeds greater than 3 m/s. We established the directional basis using 30° wind direction sectors to capture potential differences in relationships resulting from variations in the terrain surrounding the towers. These comparisons were made between the upper-measurement levels on each tower.

DNV-GEC evaluated the strength of the linear associations between the on-site met towers and found no apparent problems with the relationships between the data sets. The overall R-squared values associated with the linear relationships between Met M252 and the other met towers exceeded 0.80. When correlated to Met M370, the overall R-squared values exceeded 0.88, indicating a stronger correlation. Because of the stronger relationship, the Met M370 data set was used to synthesize data at Met M399, Met M437, Met M438 and Met M440.

DNV-GEC used directional correlation parameters based on 30º direction sectors to synthesize the data. For direction sectors with low average wind speeds or low data counts the correlation was often poor, with R-squared values between 0.42 and 0.70. In these cases, we used the non-directional relationship rather than the directional relationship. Summary statistics describing the observed relationships by direction are presented in Table 6 through Table 9. The slopes and intercepts shown in these tables were applied to the measured upper-level wind speeds at Met M370 to synthesize upper-level data at the other met towers. Data were only synthesized for periods when no measured data were available.

Monthly averages of upper-level measured and synthesized wind speeds for each met tower are presented in Table 10. The annual averages are listed at the bottom of the table.

[1] The Variance MCP model determines the slope and offset of a linear fit based on the standard deviations of the data from each tower and on the mean wind speeds at each tower over the period of concurrent data collection. This model is described in this reference: Rogers, A. L., Rogers, J. W., Manwell, J. F., Comparison of the Performance of Four Measure-Correlate-Predict Algorithms, Journal of Wind Engineering and Industrial Aerodynamics, Vol. 93/3, pp. 243-264, 2005.

Table 6. Summary of Correlation Statistics between Met M399 and Met M370

Direction Sector (º)	Slope	Intercept (m/s)	R^2	# of Data Points
0	1.13	-0.33	0.70	179
30	1.14	-0.52	0.76	319
60	1.10	-0.33	0.73	395
90	1.29	-1.27	0.82	641
120	0.99	0.45	0.71	405
150	0.88	1.11	0.76	348
180	1.09	-0.44	0.91	578
210	1.12	-1.77	0.92	6457
240	1.03	-0.79	0.94	2484
270	1.03	-0.39	0.91	390
300	1.02	-0.09	0.88	101
330*	1.04	-0.64	0.92	77

*Due to poor correlation or low data count the slope and offset for this sector were taken from the overall relationship.

Table 7. Summary of Correlation Statistics between Met M437 and Met M370

Direction Sector (º)	Slope	Intercept (m/s)	R^2	# of Data Points
0	1.17	-0.59	0.77	137
30	1.06	-0.22	0.78	254
60	0.98	0.18	0.78	303
90	1.15	-1.08	0.76	433
120	1.28	-1.80	0.78	211
150*	0.98	0.22	0.95	133
180	1.07	-0.30	0.87	276
210	0.94	0.82	0.95	3754
240	0.95	0.25	0.95	1757
270	1.01	-0.07	0.93	317
300*	0.98	0.22	0.95	78
330*	0.98	0.22	0.95	63

*Due to poor correlation or low data count the slope and offset for this sector were taken from the overall relationship.

Table 8. Summary of Correlation Statistics between Met M438 and Met M370

Direction Sector (º)	Slope	Intercept (m/s)	R^2	# of Data Points
0	1.26	-0.67	0.71	130
30	1.24	-0.63	0.74	250
60	1.16	-0.42	0.72	273
90*	1.09	-1.05	0.91	421
120*	1.09	-1.05	0.91	208
150*	1.09	-1.05	0.91	123
180	1.24	-1.80	0.83	234
210	1.18	-2.13	0.92	3529
240	1.02	-0.69	0.91	1669
270	1.02	-0.21	0.87	307
300*	1.09	-1.05	0.91	75
330*	1.09	-1.05	0.91	54

*Due to poor correlation or low data count the slope and offset for this sector were taken from the overall relationship.

Table 9. Summary of Correlation Statistics between Met M440 and Met M370

Direction Sector (º)	Slope	Intercept (m/s)	R^2	# of Data Points
0*	1.04	-0.52	0.88	119
30*	1.04	-0.52	0.88	239
60*	1.04	-0.52	0.88	271
90*	1.04	-0.52	0.88	384
120*	1.04	-0.52	0.88	198
150*	1.04	-0.52	0.88	133
180*	1.04	-0.52	0.88	218
210	1.07	-0.85	0.87	3511
240	0.97	-0.20	0.87	1624
270	1.02	-0.07	0.89	291
300*	1.04	-0.52	0.88	75
330*	1.04	-0.52	0.88	49

*Due to poor correlation or low data count the slope and offset for this sector were taken from the overall relationship.

Table 10. Monthly Average Wind Speeds (m/s)

Month	Met M252	Met M370	Met M371	Met M399	Met M437	Met M438	Met M440
2005 March	8.7	N/A	N/A	N/A	N/A	N/A	N/A
2005 April	6.8	N/A	N/A	N/A	N/A	N/A	N/A
2005 May	6.2	N/A	N/A	N/A	N/A	N/A	N/A
2005 June	8.0	N/A	N/A	N/A	N/A	N/A	N/A
2005 July	6.4	N/A	N/A	N/A	N/A	N/A	N/A
2005 August	6.6	N/A	N/A	N/A	N/A	N/A	N/A
2005 September	6.3	N/A	N/A	N/A	N/A	N/A	N/A
2005 October	6.2	N/A	N/A	N/A	N/A	N/A	N/A
2005 November	8.2	N/A	N/A	N/A	N/A	N/A	N/A

Month	Met M252	Met M370	Met M371	Met M399	Met M437	Met M438	Met M440
2005 December	5.7	N/A	N/A	N/A	N/A	N/A	N/A
2006 January	9.8	N/A	N/A	N/A	N/A	N/A	N/A
2006 February	8.4	N/A	N/A	N/A	N/A	N/A	N/A
2006 March	7.0	N/A	N/A	N/A	N/A	N/A	N/A
2006 April	7.0	N/A	N/A	N/A	N/A	N/A	N/A
2006 May	6.9	N/A	N/A	N/A	N/A	N/A	N/A
2006 June	2.7	N/A	N/A	N/A	N/A	N/A	N/A
2006 July	4.2	N/A	N/A	N/A	N/A	N/A	N/A
2006 August	6.1	N/A	N/A	N/A	N/A	N/A	N/A
2006 September	5.9	N/A	N/A	N/A	N/A	N/A	N/A
2006 October	6.3	N/A	N/A	N/A	N/A	N/A	N/A
2006 November	8.3	N/A	N/A	N/A	N/A	N/A	N/A
2006 December	4.8	N/A	N/A	N/A	N/A	N/A	N/A
2007 January	7.1	N/A	N/A	N/A	N/A	N/A	N/A
2007 February	7.7	N/A	N/A	N/A	N/A	N/A	N/A
2007 March	7.3	N/A	N/A	N/A	N/A	N/A	N/A
2007 April	7.3	N/A	N/A	N/A	N/A	N/A	N/A
2007 May	6.9	7.0	6.9	***6.7***	***7.0***	***6.6***	***6.7***
2007 June	7.3	7.5	7.4	***7.0***	***7.5***	***7.0***	***7.2***
2007 July	5.4	6.1	6.1	***5.6***	***6.1***	***5.5***	***5.7***
2007 August	6.3	6.6	6.6	***6.2***	***6.7***	***6.2***	***6.4***
2007 September	6.4	6.9	6.8	***6.4***	***7.0***	***6.4***	***6.6***
2007 October	6.5	6.6	6.5	6.4	***6.6***	***6.1***	***6.3***
2007 November	5.6	5.5	5.6	5.3	***5.6***	***5.0***	***5.2***
2007 December	9.9	10.0	9.3	9.9	***10.1***	***10.0***	***9.9***
2008 January	8.0	7.5	7.6	7.5	***7.5***	***7.3***	***7.3***
2008 February	8.8	8.1	7.8	8.0	***8.0***	***7.9***	***7.9***
2008 March	8.7	8.7	8.7	8.6	***8.8***	***8.4***	***8.5***
2008 April	8.4	8.5	8.5	8.2	***8.5***	***8.2***	***8.3***
2008 May	7.1	7.3	7.2	6.9	***7.3***	***6.9***	***7.0***
2008 June	8.4	8.8	8.6	8.4	***8.8***	***8.5***	***8.6***
2008 July	6.3	7.1	7.1	6.4	7.1	6.5	6.9
2008 August	6.5	6.9	6.8	6.5	7.0	6.6	6.7
2008 September	5.1	5.3	5.1	4.9	5.4	4.9	5.0
2008 October	5.5	5.7	5.6	5.5	5.7	5.5	5.4
2008 November	6.4	6.1	5.8	5.9	6.0	5.9	5.5
2008 December	6.9	6.8	6.6	6.6	6.8	6.4	6.0
2009 January	11.4	11.0	10.8	10.6	9.8	11.0	9.8
2009 February	4.5	4.7	4.3	4.5	4.7	4.3	4.5
2009 March	8.1	8.1	8.2	7.9	8.2	8.0	8.1
2009 April	6.9	7.1	7.2	6.7	7.3	6.9	7.1
2009 May	7.2	7.4	7.2	7.1	7.4	7.2	7.1
2009 June	6.2	6.8	6.8	6.4	6.9	6.5	6.7
2009 July	5.7	5.9	5.8	5.7	5.9	5.7	5.6
2009 August	6.1	6.7	6.8	6.1	6.8	6.2	6.6
Annual Average Wind Speed (m/s)	**7.0**	**7.2**	**7.1**	**6.9**	**7.2**	**6.9**	**6.9**

Note: Data in ***Bold Italics*** include synthesized values.

Wind Shear

Vertical wind shear (shear) is the change of wind speed with height above ground level. DNV-GEC estimated the hub-height wind speeds at the met tower locations by applying the monthly diurnal wind shear pattern measured at the site to the wind data from the upper measurement level. DNV-GEC calculated the wind shear exponent[2] between a lower-level and an upper-level anemometer that share the same orientation. Only wind speeds greater than 4 m/s were included in the calculation. Only primary anemometers were used because no secondary anemometers are mounted at a lower level.

DNV-GEC calculated wind shear at each met tower between the lowest and uppermost side-mounted (non-goalpost-mounted) anemometers. We also evaluated shear from the goalpost-mounted and a lower-level anemometer; however, due to the different mounting (and therefore different tower effects in the measurements), DNV-GEC did not calculate shear using the goalpost-mounted anemometers. Shear values derived from different anemometer heights on the same tower did not vary significantly.

The monthly diurnal wind shear pattern for each met tower is shown in Figure 5 through Figure 11. Due to low recovery of wind speeds greater than 4 m/s during February 2009, the shear values for that month at Met M437, Met M438, and Met M440 are an average of the shear values from January 2009 to March 2009 data. The directional shear pattern, based on 30º direction sectors is shown in Figure 12.

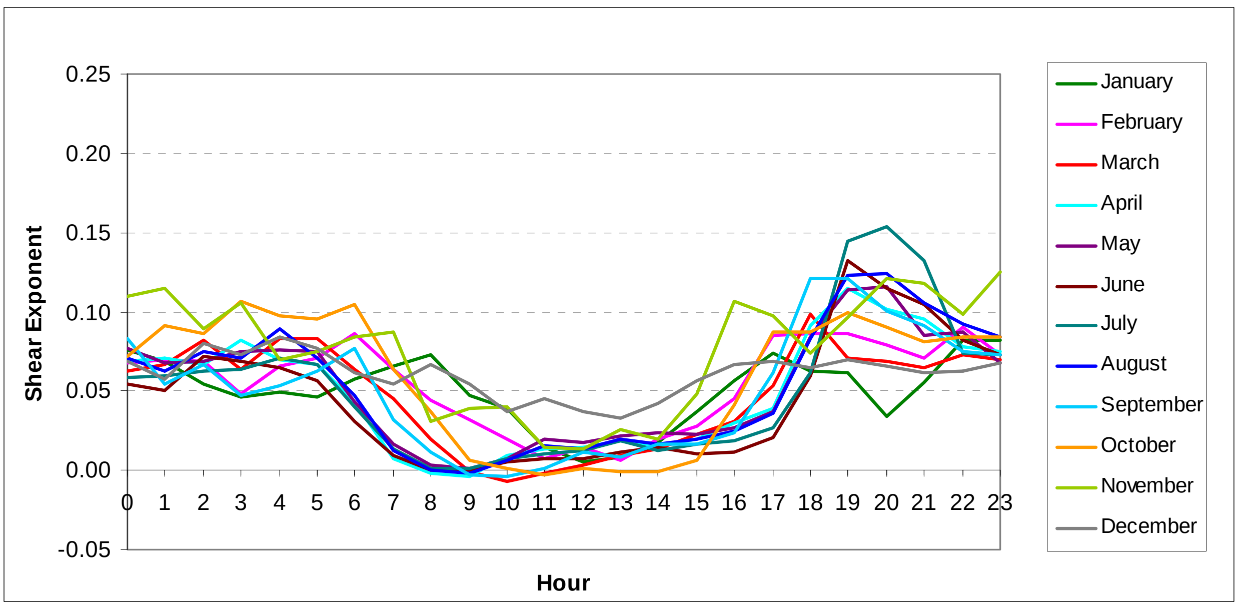


Figure 5. Diurnal Shear Exponents by Month for Met M252

[2] Wind shear describes the typical increase in wind speed at greater heights above the ground. The wind shear exponent (alpha or α) is one method of describing the extent to which wind speeds vary with increasing height above ground level. The equation that uses the exponent is $(V_1 / V_2) = (H_1 / H_2)^{\alpha}$, where V_1 and V_2 are wind speeds at heights H_1 and H_2, respectively (measured from the ground level), and α is the dimensionless wind shear exponent.

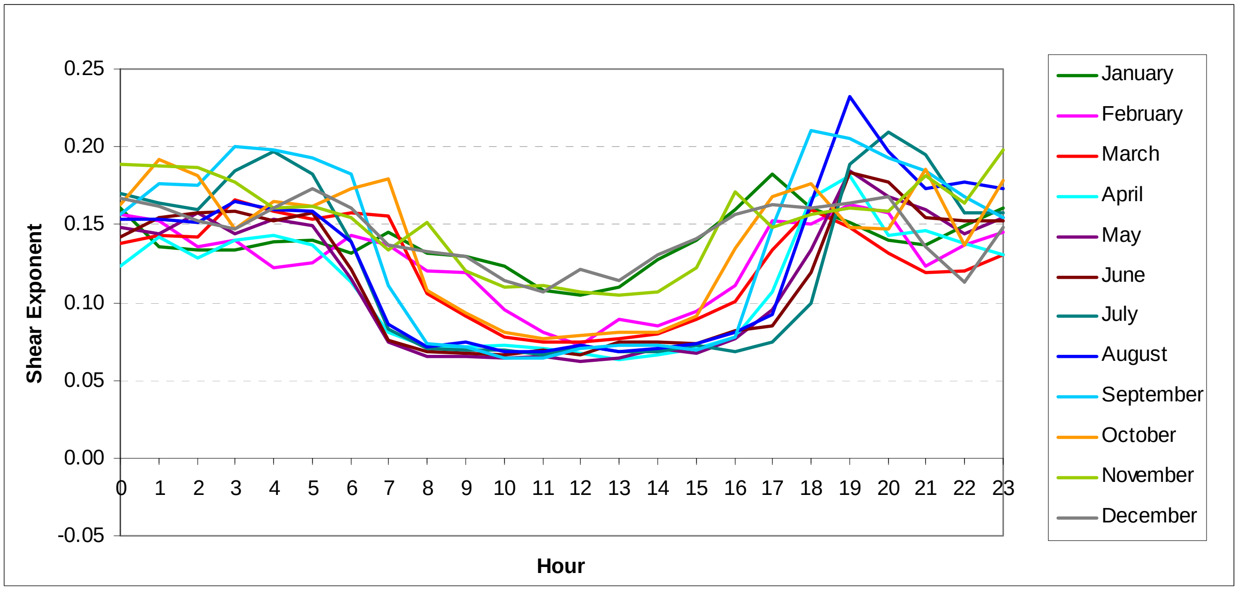


Figure 6. Diurnal Shear Exponents by Month for Met M370

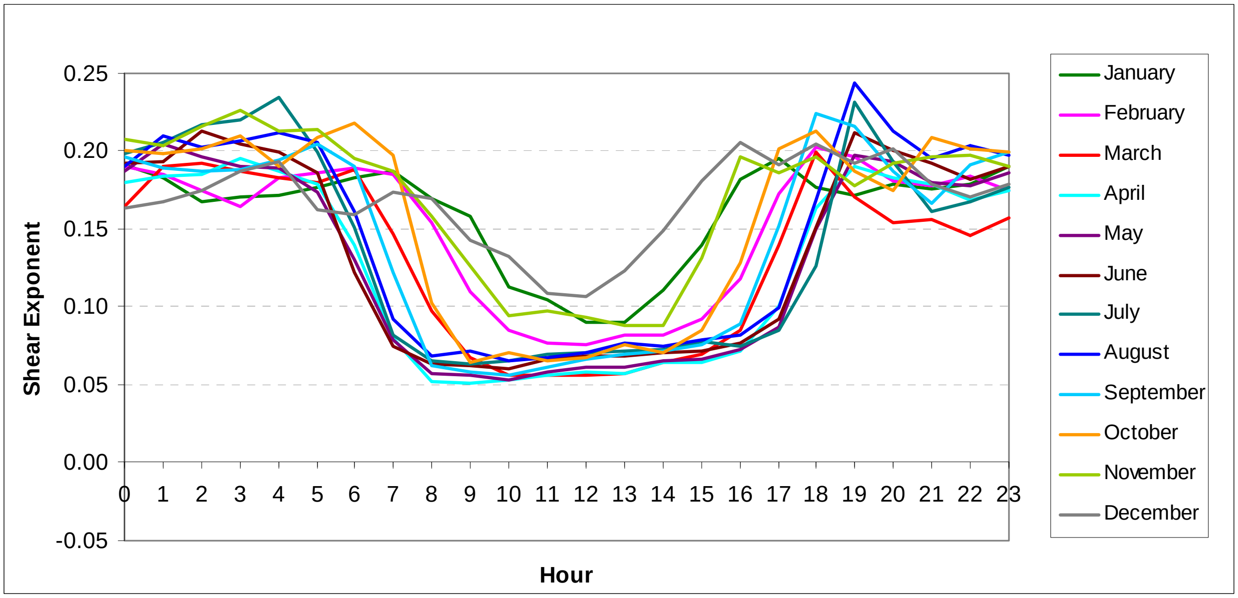


Figure 7 Diurnal Shear Exponents by Month for Met M371

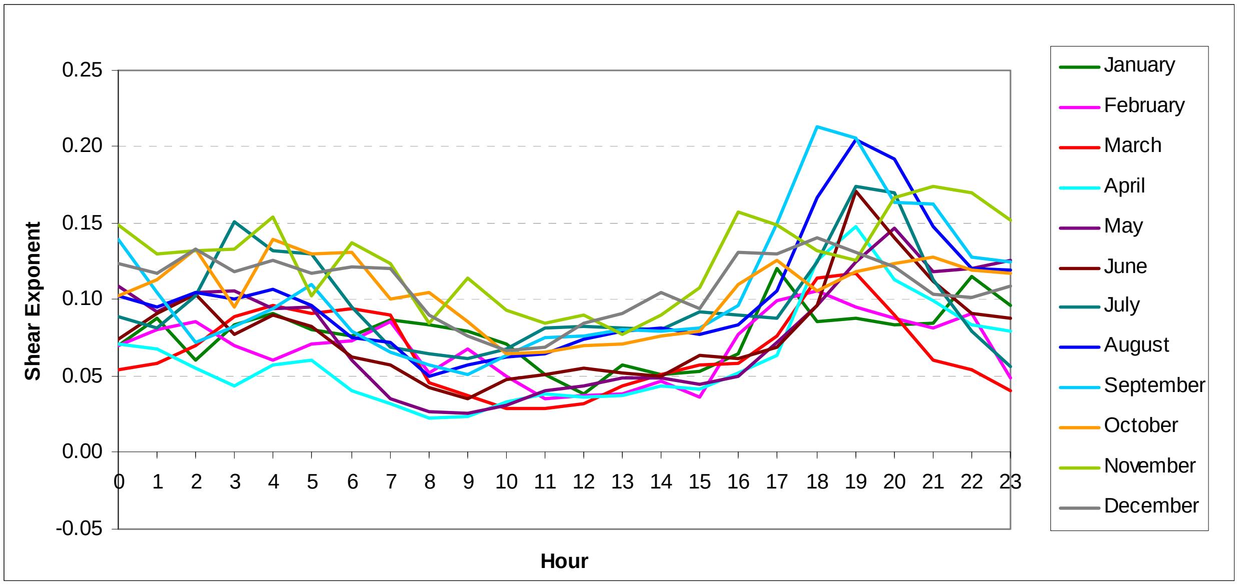


Figure 8. Diurnal Shear Exponents by Month for Met M399

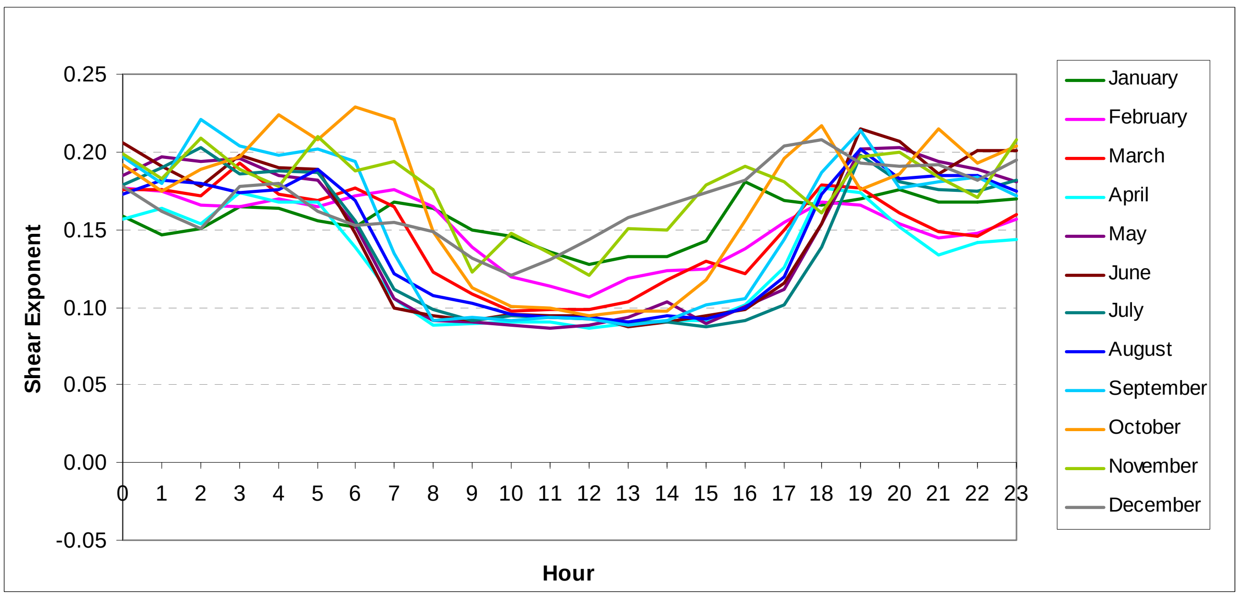


Figure 9. Diurnal Shear Exponents by Month for Met M437

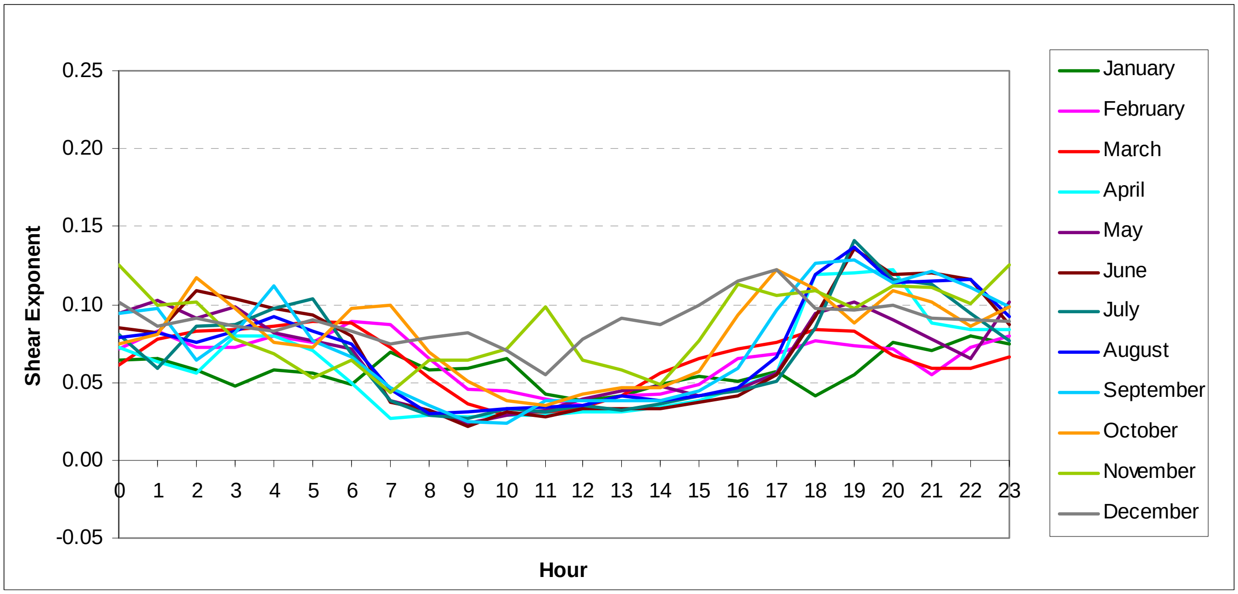


Figure 10. Diurnal Shear Exponents by Month for Met M438

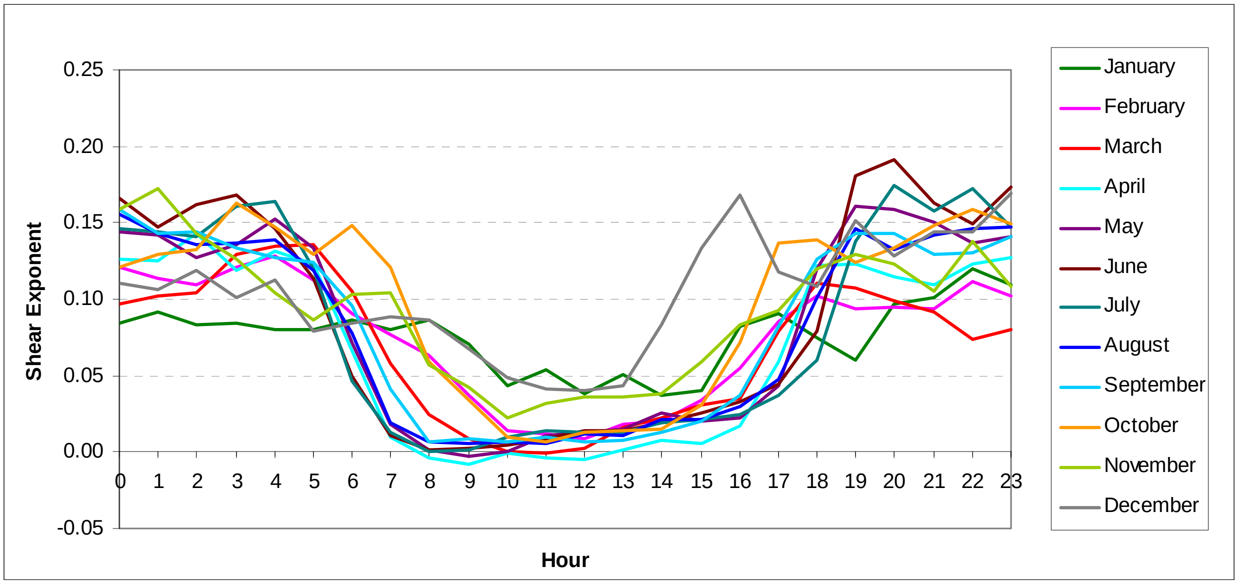
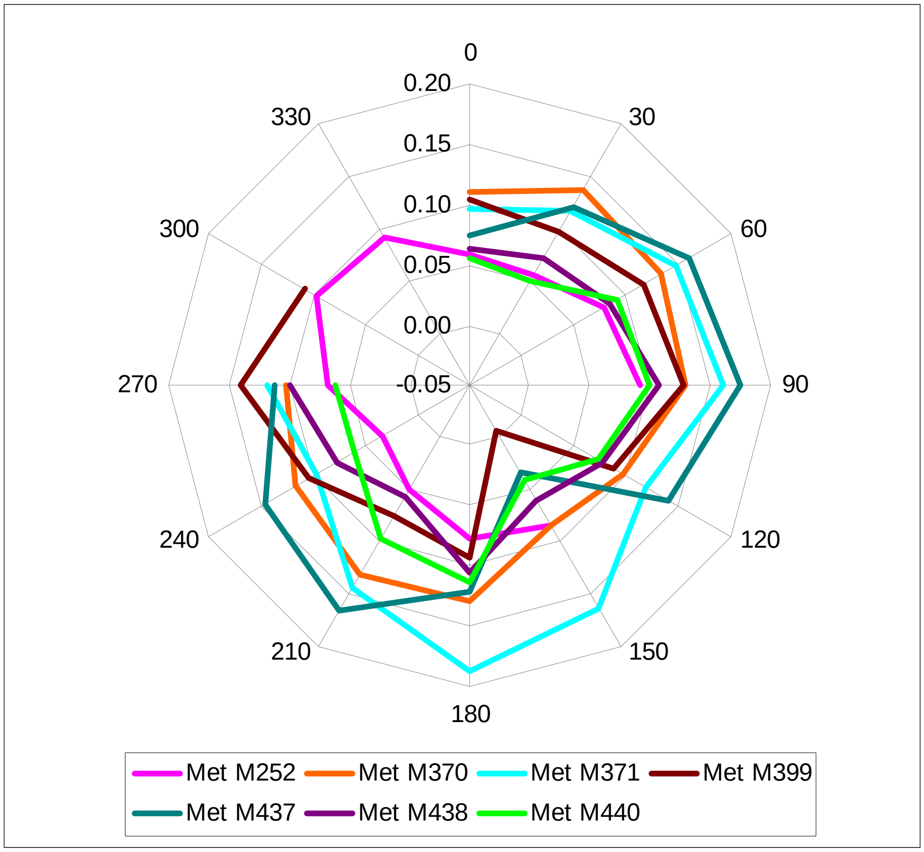


Figure 11. Diurnal Shear Exponents by Month for Met M440



Note: Shear averages corresponding to tower-waked direction sectors were removed from this figure due to the low number of valid shear values in that sector.

Figure 12. Directional Shear Exponents by Met Tower

Resulting overall average shear exponents for each met tower are listed in Table 11 by hour and in Table 12 by direction. Average annual shear exponents vary significantly between the towers. This is reasonable based on DNV-GEC's experience with similar sites, the terrain at each met tower and the distance between sites. The directional distribution of shear also varies from tower to tower. Differences are significant, and are likely due to local effects of the terrain at each met tower location.

Table 11. Average Shear Exponents by Hour

Hour	Met M252	Met M370	Met M371	Met M399	Met M437	Met M438	Met M440
0	0.07	0.16	0.19	0.10	0.18	0.08	0.13
1	0.07	0.16	0.19	0.09	0.18	0.08	0.13
2	0.07	0.16	0.19	0.10	0.18	0.08	0.13
3	0.07	0.16	0.20	0.10	0.18	0.08	0.13
4	0.07	0.16	0.20	0.10	0.18	0.08	0.13
5	0.07	0.16	0.19	0.10	0.18	0.08	0.11
6	0.06	0.14	0.17	0.09	0.17	0.07	0.09
7	0.04	0.12	0.13	0.08	0.15	0.06	0.05
8	0.02	0.10	0.10	0.06	0.12	0.05	0.03
9	0.01	0.09	0.09	0.06	0.11	0.04	0.02
10	0.01	0.08	0.08	0.06	0.11	0.04	0.01
11	0.01	0.08	0.07	0.06	0.11	0.04	0.02
12	0.01	0.08	0.07	0.06	0.10	0.04	0.02
13	0.02	0.08	0.08	0.06	0.11	0.05	0.02
14	0.02	0.09	0.08	0.07	0.11	0.05	0.03
15	0.03	0.09	0.09	0.07	0.12	0.05	0.04
16	0.04	0.11	0.12	0.09	0.13	0.07	0.06
17	0.06	0.13	0.14	0.10	0.15	0.08	0.08
18	0.08	0.15	0.18	0.13	0.17	0.10	0.11
19	0.10	0.18	0.20	0.14	0.19	0.10	0.13
20	0.10	0.17	0.19	0.13	0.18	0.10	0.13
21	0.09	0.16	0.18	0.12	0.18	0.09	0.13
22	0.08	0.15	0.18	0.11	0.17	0.09	0.13
23	0.08	0.16	0.18	0.10	0.18	0.09	0.13
Average (>4m/s)	**0.05**	**0.13**	**0.15**	**0.09**	**0.15**	**0.07**	**0.08**

Table 12. Average Shear Exponents by Direction

Direction Sector (°)	Met M252	Met M370	Met M371	Met M399	Met M437	Met M438	Met M440
0	0.06	0.11	0.10	0.10	0.07	0.06	0.06
30	0.06	0.14	0.12	0.10	0.12	0.07	0.05
60	0.08	0.13	0.15	0.12	0.16	0.08	0.09
90	0.09	0.13	0.16	0.13	0.17	0.11	0.10
120	N/A	0.10	0.12	0.09	0.14	0.08	0.07
150	0.08	0.09	0.16	-0.01	0.03	0.06	0.04
180	0.08	0.13	0.19	0.09	0.12	0.11	0.11
210	0.05	0.13	0.14	0.08	0.17	0.06	0.10
240	0.03	0.12	0.10	0.10	0.15	0.08	0.06
270	0.07	0.10	0.12	0.14	0.11	0.10	0.06
300	0.10	N/A	N/A	0.11	N/A	N/A	N/A
330	0.09	N/A	N/A	N/A	N/A	N/A	N/A

Note: Shear averages corresponding to tower-waked direction sectors were removed from this table due to the low number of valid shear values in that sector.

Turbulence

DNV-GEC calculated turbulence intensity (TI) as the ratio of the wind speed standard deviation to the wind speed. TI is used in modeling wake losses and can be used to inform turbine site-suitability studies. Average TI was calculated for all wind speeds, and TI at wind speeds greater than 4 m/s was calculated by direction. Turbulence decreases with height above ground level; consequently, TI at the upper measurement levels on each tower was extrapolated to the 80-m turbine hub height by applying wind shear to calculate a hub-height wind speed while keeping the standard deviation constant.

The measured TI at all heights and estimated TI at hub height (80 m) are presented in Table 13 for all met towers. The average measured TI by direction at the upper measurement level and the extrapolated TI at hub height are presented in Table 14. These hub-height directional TI values are inputs for the Project wake effect modeling, discussed in the Gross Energy Estimates and Wake Effects section of this report. Overall turbulence levels are moderate for all met towers, with annual weighted averages for wind speeds greater than 4 m/s between 10% and 13% at hub height. This is consistent with DNV-GEC's expectations based on experience with similar sites and knowledge of the region. Figure 13 illustrates TI by wind speed for each met tower.

Table 13. Average Turbulence Intensity at for Wind Speeds > 4 m/s (%)

Met Tower	Nominal Measurement Height							Extrapolated Height
	23-m	35-m	38-m	53-m	56-m	58-m	60-m	80-m
Met M252	N/A	13	N/A	N/A	13	N/A	N/A	12
Met M370	N/A	11	N/A	N/A	11	N/A	11	10
Met M371	N/A	12	N/A	N/A	11	N/A	11	10
Met M399	N/A	12	N/A	N/A	N/A	12	12	11
Met M437	12	N/A	11	10	N/A	10	N/A	10
Met M438	14	N/A	14	13	N/A	13	N/A	13
Met M440	12	N/A	11	10	N/A	10	N/A	10

Table 14. Average Turbulence Intensity by Direction Sector (%)

Direction Sector (°)	Met M252		Met M370		Met M371		Met M399		Met M437		Met M438		Met M440	
	56-m	80-m	60-m	80-m	60-m	80-m	60-m	80-m	58-m	80-m	58-m	80-m	58-m	80-m
0	15	14	14	14	16	16	15	15	19	19	16	16	17	17
20	14	14	14	14	15	14	14	14	15	15	14	14	15	15
40	14	14	14	13	13	13	13	13	15	14	12	12	13	12
60	12	11	11	11	10	9	11	11	12	11	10	10	10	10
80	10	10	9	9	9	9	9	9	9	9	9	9	8	8
100	N/A	N/A	7	7	9	9	8	8	8	8	8	8	8	8
120	N/A	N/A	8	7	11	10	8	8	7	7	8	7	9	9
140	12	11	7	7	10	10	7	7	7	7	12	11	11	11
160	9	9	8	8	10	9	10	9	9	9	16	15	9	9
180	12	12	9	9	9	8	12	12	10	9	15	14	11	10
200	14	13	10	9	9	9	13	12	9	8	16	16	10	10
220	12	12	10	10	11	11	11	11	9	8	13	13	9	9
240	13	13	12	12	14	13	13	13	10	10	15	14	11	11
260	16	16	15	15	16	15	15	15	13	13	15	15	14	13
280	16	16	15	14	15	14	16	15	15	14	14	14	14	14
300	13	13	14	14	16	16	15	15	14	14	15	15	15	15
320	13	13	17	17	18	18	19	18	17	16	15	14	19	18
340	15	15	17	17	18	17	17	17	18	18	18	18	18	18
Average (>4m/s)	**13**	**12**	**11**	**10**	**11**	**10**	**12**	**11**	**10**	**10**	**13**	**13**	**10**	**10**

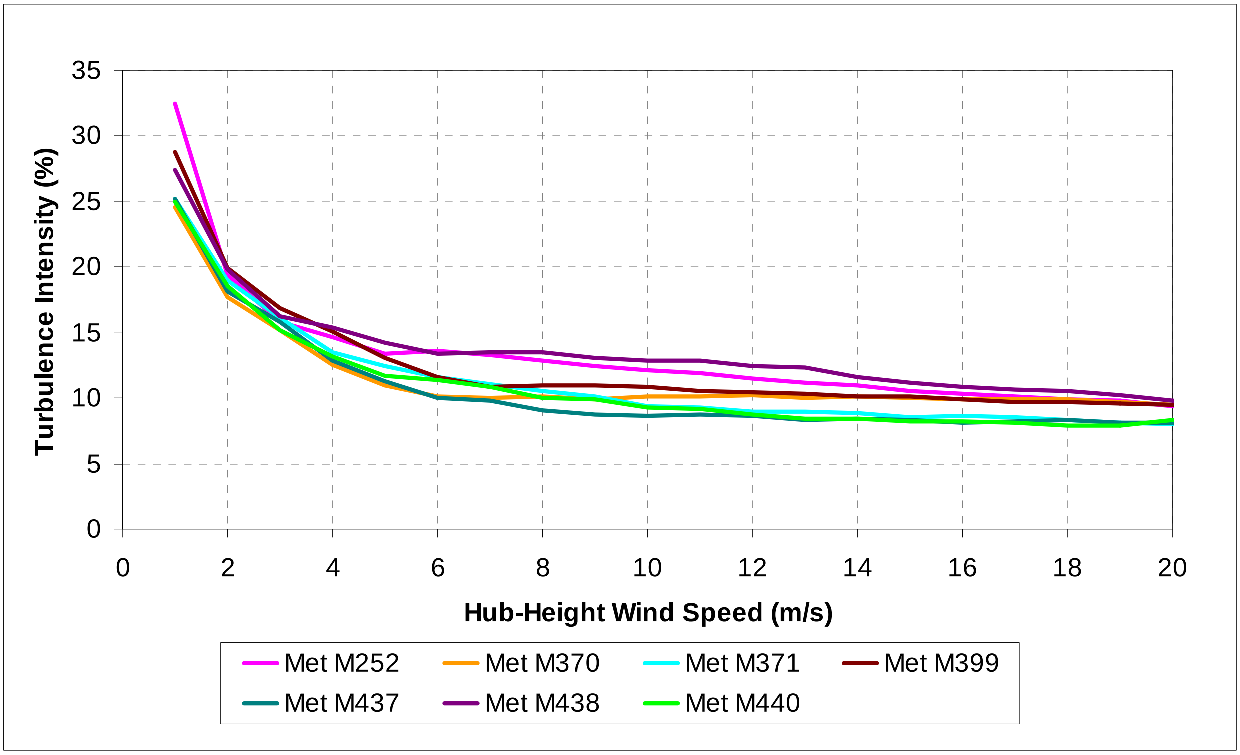


Figure 13. Turbulence Intensity by Hub-Height Wind Speed

Long-Term Adjustments

DNV-GEC consulted various long-term reference stations for correlation to on-site data in order to adjust the data to reflect the long-term average wind speed. The stations and the site are shown together in Figure 14. After analyzing the reference data, DNV-GEC chose to make an aggregate long-term downward adjustment of 1.5% on wind speed to Met M252 and an approximately 2.5% downward adjustment to the other met towers based on the Kennewick Bonneville Power Administration (BPA) data. The considerations and methodology for these adjustments are discussed below.

DNV-GEC correlated on-site data to long-term data from Met M33, a 56.3-m met tower owned by RES Americas, and from a 26-m BPA met tower located in Kennewick, Washington. We also investigated correlations between the on-site data and the Spokane radiosonde observation station (RAOB); however, the data from this station correlated poorly to the on-site data. None of the Automated Surface Observing System (ASOS) stations within 150 km of the Project areas were suitable to serve as the primary long-term reference station because of recent conversion to sonic anemometry and/or low recorded wind speeds. Consequently, these stations were not pursued as potential long-term reference candidates.

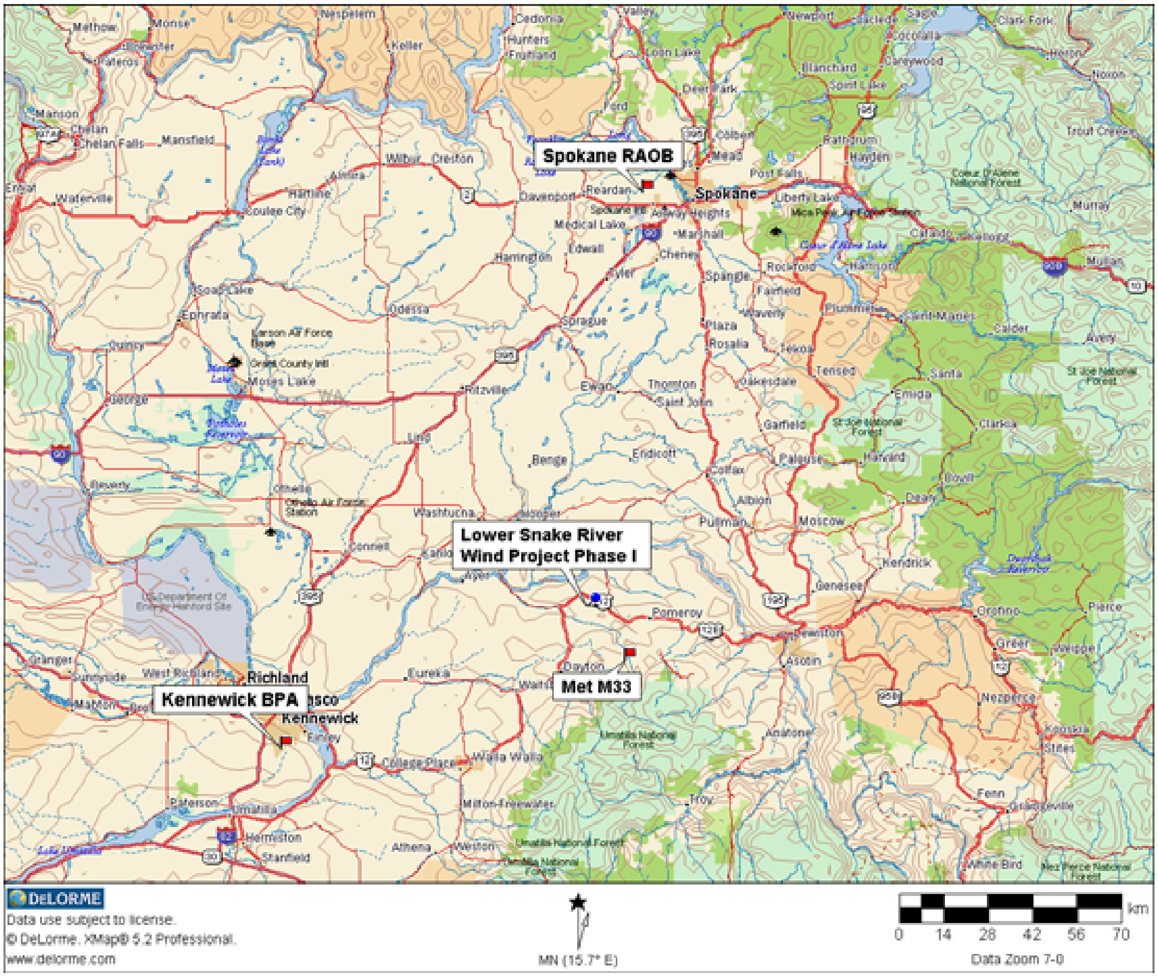


Figure 14. Location of Lower Snake River Phase I and Long-Term Reference Stations

Details of the correlation between average monthly wind speeds at the site and each long-term station considered are shown in Table 15. The table also presents other considerations for determining the suitability of the long-term reference stations. With the exception of Met M33 and the Kennewick BPA station, the stations in Table 15 were not used quantitatively in calculating the long-term adjustment at the site.

Table 15. Investigated Long-Term Reference Station Summary

Reference Station	Sensor Height (m)	R-Squared Correlation to On-Site Data (Monthly)	Period of Record	Distance from Site (km)	Notes
Met M33	56	0.74	2001-2009	22	Poor data recovery
Kennewick BPA	26	0.68	1994-2009	111	
Spokane RAOB	1050	0.44	1995-2009	120	Poor correlation

Met M33 is located approximately 22 km (14 mi) southeast of the Project area and was installed in July 2001. The tower is instrumented with Vector A100L2 cup anemometers and DNV-GEC performed the data validation. Correlation parameters were developed for two seasons, based on the distinct seasonal relationship apparent in the on-site and reference data sets. Daily averages from Met M33 correlate well to Met M370 with an R-squared value of 0.94 for the summer months (March through September) and 0.88 for the winter months (October through February). Using the data from Met M33 would result in a 6.4% downward adjustment to 4.2-year data set at Met M252 and a 5.1% downward adjustment to 2.3-year data set at Met M370. Long-term adjustments of this magnitude are highly unlikely considering that the estimated inter-annual variability in this region is approximately 5%. The missing data and low data-recovery rate in the winter months at Met M33 due to iced anemometers appears to bias the long-term adjustment. For this reason, the Met M33 data were not used to adjust the on-site met tower data.

DNV-GEC also analyzed data from the Kennewick BPA tower. The Kennewick BPA tower is located approximately 111 km (69 mi) southwest of the Project area. The tower is instrumented with RM Young Wind Monitor prop vane anemometers and the data were validated and provided by the Oregon State University Energy Resources Research Laboratory. The data record starts in 1976; however, due to changes in the instrumentation, only data from August 1994 to August 2009 were used in this analysis. Correlations based on daily averages from the Kennewick BPA tower to the site are fair and are presented in Table 16. Figure 15 and Figure 16 illustrate the seasonal relationship between the Kennewick BPA met tower and Met M252 and M370.

Table 16. Correlation Parameters for Met M252 and Met M370 to Kennewick BPA Reference Data

Met Tower	Season	Slope	Intercept (m/s)	Quality of Correlation (R^2 Value)
Met M252	March through September	0.88	-0.05	0.62
Met M252	October through February	0.92	-1.13	0.81
Met M370	March through September	0.79	0.59	0.64
Met M370	October through February	0.75	-0.21	0.77

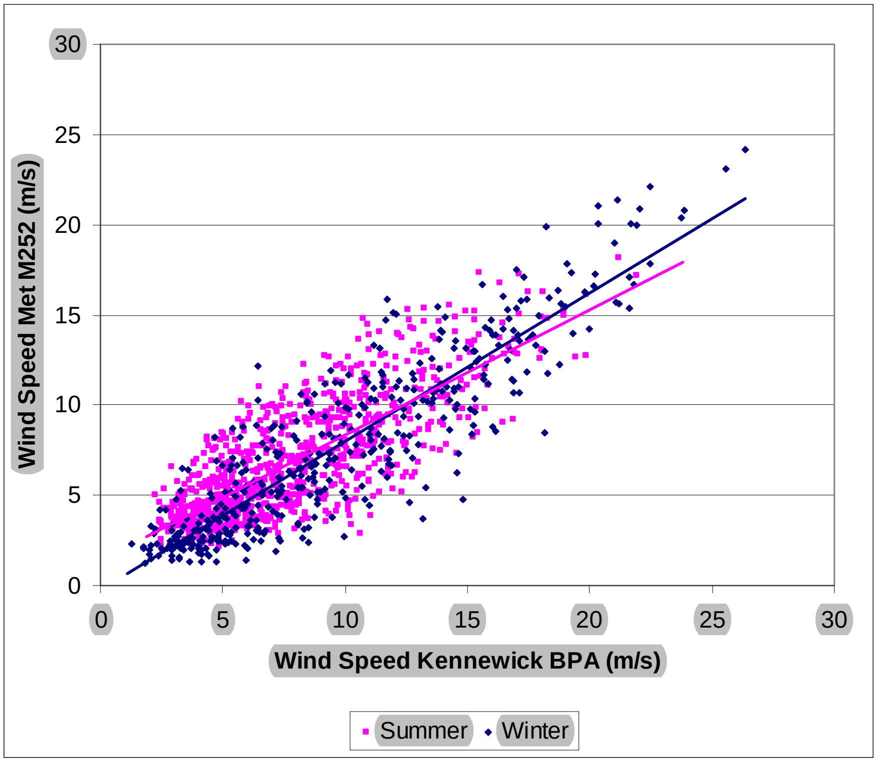


Figure 15. Comparison of Daily Average Wind Speed at Kennewick BPA and Met M252

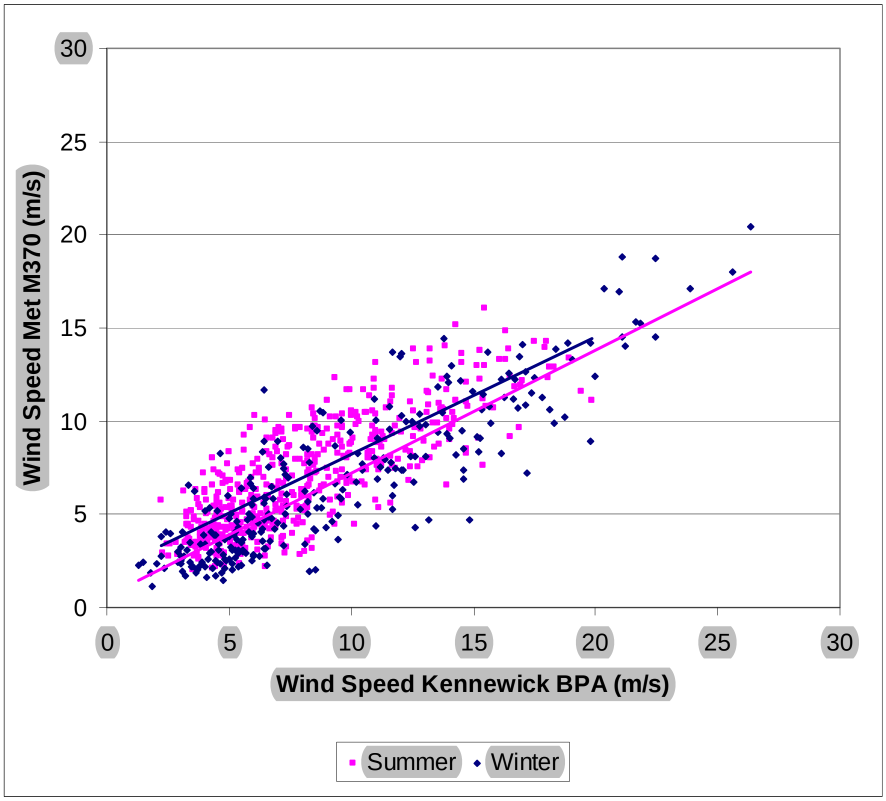


Figure 16. Comparison of Daily Average Wind Speed at Kennewick BPA and Met M370

DNV-GEC adjusted the 4.2 years of on-site data at Met M252 and the 2.3 years at the other towers on a monthly basis using long-term monthly adjustment factors derived from the Kennewick BPA data set. These adjustment factors, presented in Table 17, represent the ratio between the reference site's long-term average wind speed for each month, and the reference site's monthly average wind speed during the period of record. For example, the February adjustment factor for Met M252 in Table 17 (0.91) indicates that the long-term average wind speed during February of each year is 9% higher than the average wind speed measured during February of each year at Met M252. The adjustment factor is multiplied by the hub-height wind speed on a per-record basis to produce a long-term hub-height wind speed. In our example, all of the Met M252 hub-height wind speed records in February are multiplied by 0.91.

Table 17. Monthly Long-Term Adjustment Factors

Met Tower	Month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Met M252	0.85	0.91	0.98	0.99	1.03	0.93	1.07	1.02	1.04	1.01	1.06	1.01
Met M370	0.86	0.99	0.93	0.97	1.03	0.96	1.04	0.97	1.03	0.98	1.21	0.85

Long-Term Hub-Height Wind Speeds

Based on the estimated met tower wind speeds and the diurnal monthly wind shear pattern at each met tower, DNV-GEC developed a wind speed frequency distribution representing the long-term, hub-height (80-m) wind speed and wind direction at each met tower location. To generate frequency distributions, data from each tower over its entire period of record were binned by wind speed and direction. To normalize the data set to 8,760 hours, DNV-GEC developed a monthly record-length correction factor by counting the number of records with valid upper-level sensor wind speed and wind direction observations available in each month. We then categorized data according to wind direction sector (20° sectors centered on 0°, 20°, etc.) and wind speed bin (intervals of 0.5 m/s centered on 0.5 m/s, 1.0 m/s, etc.) to generate the hub-height annual frequency distribution showing the number of observations in each wind speed bin and for each wind direction sector. Wind speed frequency distributions were generated for each tower from this data set. Annual long-term hub-height (80-m) wind speeds computed from the frequency distributions are presented in Table 18.

Table 18. Annual Average Long-Term Adjusted 80-m Wind Speeds

Met Tower	Wind Speed (m/s)
Met M252	7.1
Met M370	7.2
Met M371	7.2
Met M399	6.9
Met M437	7.3
Met M438	6.8
Met M440	6.9

Wind Rose

A wind rose depicts the frequency and energy content of wind by direction. An annualized wind rose estimated at 80 m for Met M370 is presented in Figure 17. The other met towers show a similar wind direction distribution, with significant energy-producing winds coming from the southwest.

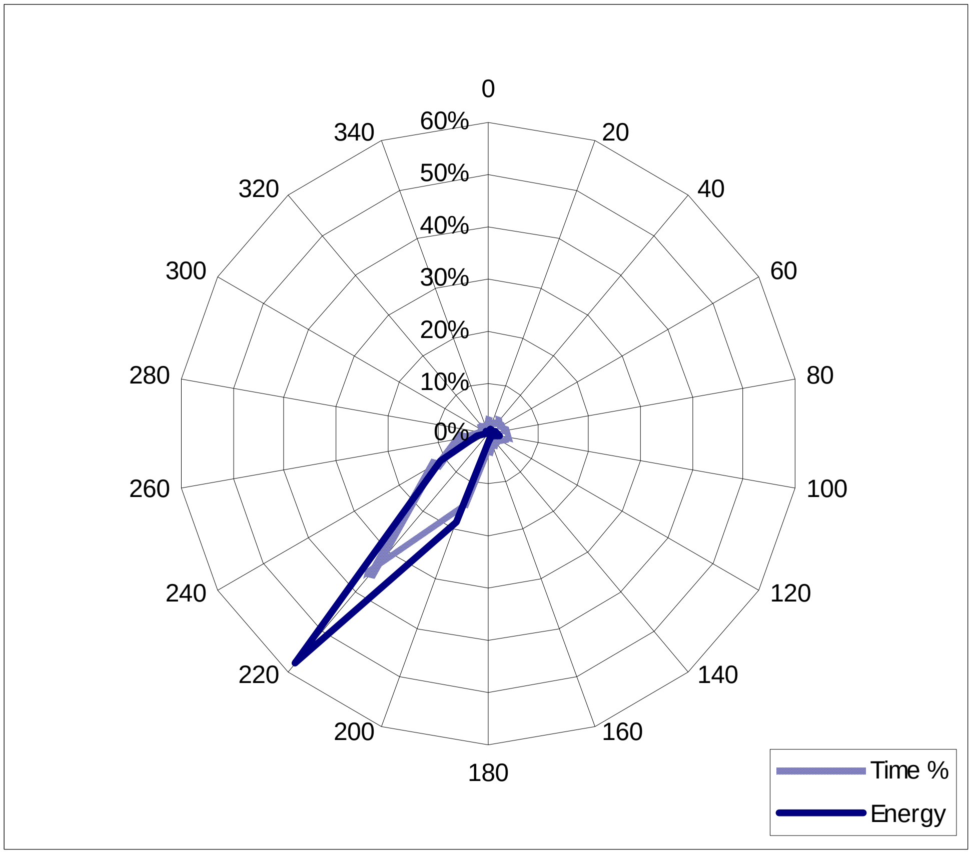


Figure 17. Met M370 Annual Wind Rose at 80 m

Gross Energy Estimates and Wake Effects

The turbine power curve, met tower wind speed distributions and the estimated turbine hub-height wind speeds used to determine the Project gross energy production are presented below. The methodology for estimating the Project gross energy production and wake effects is also discussed.

Gross Energy Estimates

DNV-GEC estimated the average air density of 1.15 kg/m^3 for the Project based on measured temperature data (an annual average of approximately 11.7ºC) from Met M33 and the average turbine hub-height elevation (623 m). PSE provided a density-specific power curve for the SWT-2.3-101 turbine at 1.16 kg/m^3. DNV-GEC adjusted the power curve to the site density (1.15 kg/m^3) and used it to calculate energy production.

The power curve and wind speed distributions from the met towers were used to estimate annual gross energy production for each turbine location. Table 19 presents the long-term annual wind speed frequency distributions, the power curve, and the gross energy production for a single SWT-2.3-101 turbine at the met tower locations.

Table 19. Long-Term Hub-Height Average Wind Speed Frequency Distributions and SWT-2.3-101 Power Curve at 1.15 kg/m^3 Air Density

Wind Speed (m/s)	SWT-2.3-101 Power (kW)	Met M252 (hours/yr)	Met M370 (hours/yr)	Met M371 (hours/yr)	Met M399 (hours/yr)	Met M437 (hours/yr)	Met M438 (hours/yr)	Met M440 (hours/yr)
0.0	0	8	1	2	18	35	152	44
0.5	0	122	99	157	137	102	190	156
1.0	0	199	225	340	279	220	298	309
1.5	0	326	327	424	382	311	395	431
2.0	0	428	415	468	475	408	473	509
2.5	0	529	479	476	526	449	526	524
3.0	0	586	486	463	533	463	553	511
3.5	0	589	467	417	529	454	492	466
4.0	105	541	451	387	479	425	442	424
4.5	165	495	422	360	430	400	400	379
5.0	223	433	389	346	383	376	356	366
5.5	317	356	371	324	345	361	319	340
6.0	411	298	335	293	304	328	295	308
6.5	543	259	311	276	273	307	260	290
7.0	676	237	288	260	256	292	251	266
7.5	851	222	264	249	246	279	233	253
8.0	1028	214	260	241	230	258	222	231
8.5	1251	203	240	230	222	240	220	233
9.0	1476	206	229	223	212	245	196	213
9.5	1710	192	221	232	202	228	195	196
10.0	1944	187	215	226	201	228	187	182
10.5	2082	178	208	217	194	211	175	180
11.0	2214	167	202	211	195	202	176	180
11.5	2255	165	199	207	191	204	177	177
12.0	2289	158	192	203	175	205	161	173
12.5	2295	145	182	199	172	191	155	170
13.0	2299	141	176	187	159	184	158	164
13.5	2299	131	158	166	141	167	143	148

Wind Speed (m/s)	SWT-2.3-101 Power (kW)	Met M252 (hours/yr)	Met M370 (hours/yr)	Met M371 (hours/yr)	Met M399 (hours/yr)	Met M437 (hours/yr)	Met M438 (hours/yr)	Met M440 (hours/yr)
14.0	2300	119	141	152	125	154	124	134
14.5	2300	112	128	134	109	132	111	121
15.0	2300	97	112	120	97	115	101	107
15.5	2300	91	97	101	83	105	95	94
16.0	2300	84	79	88	73	86	78	78
16.5	2300	73	69	65	65	73	69	70
17.0	2300	63	57	62	56	60	61	57
17.5	2300	57	49	51	49	52	51	49
18.0	2300	54	42	41	41	43	47	42
18.5	2300	43	31	33	31	33	39	33
19.0	2300	39	26	23	27	23	32	27
19.5	2300	36	21	21	19	20	23	22
20.0	2300	31	15	15	15	14	21	16
20.5	2300	23	11	10	13	12	16	13
21.0	2300	21	11	10	10	10	13	12
21.5	2300	19	8	6	8	8	9	10
22.0	2300	16	5	6	8	5	8	6
22.5	2300	14	5	4	6	6	8	6
23.0	2300	11	5	5	5	5	6	6
23.5	2300	9	4	4	3	4	5	5
24.0	2300	7	5	3	2	3	6	3
24.5	2300	6	4	3	3	3	5	3
25.0	2300	4	3	3	3	3	4	3
>25.0	0	18	18	16	18	17	27	19
Average Wind Speed (m/s)		**7.1**	**7.2**	**7.2**	**6.9**	**7.3**	**6.8**	**6.9**
Gross Energy for a Single Turbine (MWh/yr)		**7226**	**7839**	**7967**	**7246**	**8099**	**7128**	**7293**
Gross Capacity Factor		**35.9%**	**38.9%**	**39.5%**	**36.0%**	**40.2%**	**35.4%**	**36.2%**

DNV-GEC estimated individual turbine average hub-height wind speeds based on hub-height met tower wind speeds, the MS-Micro/3 software package wind flow model results, turbine distance from met towers, elevation and exposure, and DNV-GEC's judgment about wind flow across the terrain. DNV-GEC also considered the relative wind speeds at Met M540, Met M541, and Met M542 and Met M440 from July through September 2009 when estimating the wind speeds in the northern section of the LSR Phase I Project area. We calculated the individual turbine gross energy based on the assigned turbine wind speeds and the wind speed to energy relationship derived from the met tower frequency distribution and the power curve. The assigned turbine wind speeds and estimated gross energy are presented in Table 19.

Wake Effects

When a turbine extracts energy from the wind it causes an energy deficit in the form of lower wind speeds behind the turbine. The wake effect category accounts for the corresponding reduction in energy production at downwind turbines due to this phenomenon. DNV-GEC estimated this wake effect using four calculation methods in the WindFarm software package. The four methods utilize combinations of two wake models (Ainslie and Park) that predict the deficit behind single turbines and two wake combination models (square root of the sum of squares of velocity deficit, and energy balance) that combine the single wakes when they overlap. Detailed investigations have shown wake model performance is sensitive to terrain type, atmospheric stability, turbulence intensity, and inter-turbine spacing. DNV-GEC took the average of the four models as a best approximation of the expected wake losses. The spread of the four model results was also used to quantify the expected uncertainty of the calculations.

The proposed Phase II and Phase III projects are upwind (southwest) of the Phase I Project area as shown in Figure 3. Four wake loss scenarios were estimated for the Phase I project:

1. The wake loss of the Phase I project assuming no further development
2. The wake loss impact of Phase II
3. The impact of Phase III
4. The impact of Phase II and III combined.

The Hopkins Ridge Wind Project is located south of the proposed LSR Phase I Project area and will cause wake-induced energy loss at some turbines downwind. However, the Hopkins Ridge Project was constructed and online by November 2005[3], so the period of record at the met towers captures the wake effects of the Project. Consequently, the Hopkins Ridge turbines were not added to the wake analysis. The potential difference in wake effects at the turbine locations relative to the met tower locations was not assessed in this analysis.

The neighboring Marengo I and Marengo II projects are located to the southeast of the proposed Phase I Project area. Both projects were constructed and online in 2008, after data collection had commenced at the Phase I met towers. The Marengo I and Marengo II Projects are not located directly upwind of the proposed LSR Phase I Project area, and DNV-GEC expects that wake

[3] Puget Sound Energy webpage.
http://www.pse.com/energyEnvironment/energysupply/pages/EnergySupply_ElectricityWind.aspx?tab=2&chapter= Accessed December 2009.

effects on the collected data are minimal. DNV-GEC also expects that the wake effects on the proposed LSR Phase I turbine locations will be similarly minimal. Consequently, for this analysis, the Marengo turbines were not included in the wake analysis.

To incorporate the differences between the measured wind speed and direction distributions into the wake analysis, DNV-GEC created wake calculations using distributions from all met towers. The distributions are based on 20º direction sectors, in order to have sufficient directional resolution for this unidirectional site.

DNV-GEC's estimates of wind speed, energy, and wake effects (for each of the four wake loss scenarios) for each of the turbines in the project is included in Appendix D.

A 12-month by 24-hour percent of gross energy production matrix is presented in Table 20. The energy production matrix is an estimate of the long-term pattern of average gross energy production by month and by hour. The energy production in any given hour or month of a specific year may deviate significantly from the pattern presented in the matrix.

Table 20. 12-Month by 24-Hour Gross Energy Production

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.41%	0.31%	0.44%	0.43%	0.47%	0.47%	0.40%	0.39%	0.32%	0.29%	0.25%	0.40%
1	0.41%	0.30%	0.46%	0.43%	0.49%	0.49%	0.42%	0.42%	0.32%	0.28%	0.26%	0.39%
2	0.43%	0.28%	0.45%	0.44%	0.48%	0.52%	0.44%	0.43%	0.32%	0.27%	0.29%	0.38%
3	0.42%	0.27%	0.43%	0.44%	0.46%	0.53%	0.43%	0.41%	0.33%	0.28%	0.28%	0.37%
4	0.42%	0.27%	0.42%	0.46%	0.45%	0.52%	0.41%	0.41%	0.33%	0.26%	0.27%	0.39%
5	0.42%	0.27%	0.44%	0.47%	0.43%	0.48%	0.39%	0.38%	0.30%	0.27%	0.26%	0.42%
6	0.42%	0.28%	0.43%	0.46%	0.41%	0.46%	0.35%	0.35%	0.28%	0.28%	0.29%	0.41%
7	0.42%	0.26%	0.44%	0.46%	0.42%	0.45%	0.36%	0.36%	0.26%	0.29%	0.29%	0.39%
8	0.41%	0.27%	0.46%	0.47%	0.42%	0.42%	0.35%	0.37%	0.28%	0.28%	0.28%	0.38%
9	0.40%	0.27%	0.50%	0.48%	0.41%	0.39%	0.34%	0.36%	0.31%	0.30%	0.27%	0.37%
10	0.42%	0.26%	0.53%	0.47%	0.40%	0.34%	0.33%	0.35%	0.31%	0.32%	0.27%	0.37%
11	0.45%	0.28%	0.55%	0.44%	0.39%	0.32%	0.29%	0.33%	0.30%	0.32%	0.28%	0.38%
12	0.48%	0.27%	0.52%	0.42%	0.35%	0.31%	0.26%	0.30%	0.28%	0.33%	0.30%	0.39%
13	0.47%	0.28%	0.48%	0.40%	0.33%	0.31%	0.25%	0.28%	0.28%	0.34%	0.31%	0.36%
14	0.43%	0.26%	0.44%	0.38%	0.33%	0.31%	0.25%	0.28%	0.28%	0.32%	0.34%	0.35%
15	0.41%	0.25%	0.41%	0.37%	0.30%	0.29%	0.26%	0.28%	0.27%	0.32%	0.32%	0.31%
16	0.40%	0.24%	0.41%	0.33%	0.29%	0.28%	0.26%	0.28%	0.28%	0.28%	0.31%	0.30%
17	0.38%	0.26%	0.40%	0.27%	0.31%	0.28%	0.25%	0.26%	0.28%	0.27%	0.27%	0.35%
18	0.41%	0.26%	0.34%	0.27%	0.30%	0.28%	0.23%	0.26%	0.25%	0.26%	0.25%	0.38%
19	0.41%	0.25%	0.35%	0.28%	0.30%	0.27%	0.23%	0.25%	0.23%	0.25%	0.25%	0.39%
20	0.41%	0.26%	0.37%	0.32%	0.33%	0.28%	0.20%	0.24%	0.25%	0.27%	0.24%	0.40%
21	0.41%	0.28%	0.40%	0.35%	0.35%	0.34%	0.23%	0.27%	0.26%	0.27%	0.22%	0.42%
22	0.42%	0.26%	0.42%	0.38%	0.39%	0.37%	0.29%	0.31%	0.27%	0.30%	0.23%	0.40%
23	0.42%	0.28%	0.43%	0.39%	0.41%	0.42%	0.35%	0.36%	0.29%	0.31%	0.24%	0.41%

Losses and Uncertainties

Based on the gross annual energy estimated above, DNV-GEC generated a probability distribution for 20-year annual project net energy production using the following procedure:

- Probability distributions were assigned to each loss and uncertainty category.
- The distributions were parameterized using project-specific data.
- The loss and uncertainty model was then run in 100,000 iterations with each parameter changed randomly and independently to describe the distribution of potential net energy production. The individual results were combined to generate a distribution of net energy outcomes at several probability levels.

The results of these simulations are summarized in Table 21, which provides the net average energy production; and Table 22 which provides a summary of the long-term P50 losses.

Note that many of the losses and uncertainties are estimated based on DNV-GEC's current knowledge of the project and experiences with other wind projects. For example, the mechanical availability assumptions used are based on DNV-GEC's experiences monitoring performance of modern megawatt-scale wind turbines of similar design, but the availability at this particular site may be higher or lower for a variety of reasons. To some extent, low availability or performance may be mitigated through turbine warranties, insurance, or other factors; these issues are not considered explicitly in this analysis.

Losses

DNV-GEC estimated losses for the Project. For the purpose of uncertainty modeling, the following losses are normally distributed with uncertainty values listed at one standard deviation, unless otherwise noted. The P50 project losses are summarized by category in Table 26.

Availability

The availability loss category includes events that cause the turbine or any balance of plant component to be unavailable for power production. This category is subdivided into turbine availability and balance of plant. Weather-related events are addressed separately.

Turbine Availability

Turbine availability is lost energy production associated with:

- Routine maintenance downtime
- Fault downtime
- Minor component failures
- Major component failures

Routine maintenance downtime includes energy lost during periods of routine maintenance of the wind turbines. Time spent for maintenance of typical modern megawatt-scale wind turbines is approximately 40 to 120 hours per year. The magnitude can vary depending on turbine complexity, number of personnel assigned to the task, cleaning requirements, and frequency of larger tasks such as gear oil changes. In general, operators seek to schedule maintenance during periods of low wind speeds. However, with a large number of turbines requiring maintenance and the schedule constraints of the maintenance crews, there is limited flexibility to avoid periods of high wind speeds, so the energy loss cannot be eliminated entirely.

Some downtime will be incurred due to turbine faults. Based on DNV-GEC's experience with other projects using pitch-regulated turbines, this downtime is heavily weighted towards high-wind periods. Consequently, the loss due to faults is modeled to occur more frequently during high wind periods.

Some downtime will be incurred associated with failures of smaller components such as motors, relays, valves, power electronics, sensors, controllers, and bushings; and other small malfunctions normally experienced by modern megawatt-scale wind turbines. Based on experience, DNV-GEC estimated the minor component failure downtime values to increase with the age of the project as components with design lives less than 20 years wear out. The majority of the components evaluated are expected to have average lives of approximately 10 years, so the replacement rate tends to level off later in the project life. DNV-GEC's expects that component failures will be slightly weighted towards high-wind periods; consequently, the energy loss associated with minor component failures is modeled to occur more frequently in high wind periods.

Some downtime will be associated with major systems in the turbines. Examples of such events include gearbox, generator, or blade replacements, yaw system failures, turbine fires, or similar problems. These issues affect individual turbines but may cause those turbines to be off line for an extended period of time. While a typical year may have relatively limited downtime associated with major failures relative to the project life average, the infrequent events can result in significant lost energy. These losses are also expected to increase over time, as turbine systems wear out and more gearboxes and other components fail. The increasing failure rate will be offset somewhat by increased efficiency as experience is gained in replacing major components. However, as the number of major component failures increases, the total time required for component replacement will also increase, which will adversely impact turbine availability. DNV-GEC's expectation based on experience with operating wind projects is that component failures will be slightly weighted towards high-wind periods.

DNV-GEC estimated the turbine availability loss to be 5.4%.

Balance-of-Plant Downtime

Approximately 10 to 20 hours of downtime are associated with annual maintenance on project infrastructure (such as the project substation, pad-mount transformers, etc.). These activities are typically planned events that coincide with low-wind months and/or days. Unplanned failures and repairs associated with the balance of plant, such as substation transformer failures, electrical collection system or communication system problems, or transmission outages are uncommon;

however, their impact on lost production could be considerable if the failures impact the whole project or large groups of turbines. The mean loss related to both planned and unplanned balance-of-plant events has been estimated to be 0.5% and is not expected to increase over time.

The losses associated with balance-of-plant failures were modeled as an asymmetrical distribution with a long tail, representing small possibilities of significant downtime; however, the majority of losses are expected to be at or less than the mean.

Wake Effect Losses

DNV-GEC modeled wake losses using the site layout and estimated the losses for each turbine. The estimated project wake loss was calculated for four scenarios that consider the impact of the proposed LSR Phase II and Phase III Projects. The result of the four scenarios is presented in Table 21.

Table 21. Summary of Wake Loss Scenarios

Wake Loss Scenario	Internal Wake Loss	Future Wake Loss	Total Wake Loss	Wake Loss Uncertainty
Phase I only	7.9%	0.0%	7.9%	2.9%
Phase I and II	7.9%	5.6%	13.5%	6.4%
Phase I and III	7.9%	0.9%	8.7%	3.6%
Phase I, II, and III	7.9%	6.2%	14.0%	7.1%

The impact from the existing Hopkins Ridge Project is not included in this calculation because the measured wind speed data were collected after the Hopkins Ridge Project was operational. As noted earlier, the Marengo projects are not directly upwind of the LSR Phase I project and are therefore not modeled here.

There are two sources of uncertainty on this estimate: uncertainty on the accuracy of the wake loss model, and uncertainty on the model input. DNV-GEC estimated the uncertainty on the model accuracy by evaluating results predicted by different combinations of wake loss models and wake combination methods available within the WindFarm software package; these included axisymmetric wake and WAsP/Park wake velocity deficit models, and sum of squares of wakes and energy balance combination methods. The average of the model outcomes is a reasonable approximation of wake losses on most projects. The resulting estimated wake losses for each turbine are shown in Appendix D.

In addition to uncertainty associated with the accuracy of the loss models, DNV-GEC considered uncertainty on the model inputs, including turbulence intensity at hub height and the wind speed and direction distributions. DNV-GEC estimated the combined uncertainty of the accuracy of the wake loss models and the wake loss model inputs as shown in Table 21.

Turbine Performance

The turbine performance loss category reconciles the differences between the theoretical energy production of a wind turbine and the energy production that is practically achieved. Subcategories of issues identified as affecting turbine performance are as follows:

Power Performance

Turbines may perform at a level different from the reference power curve for reasons other than those counted in other losses (such as blade soiling and degradation, turbulence, etc.). This is modeled as a distribution of possible outcomes with a most likely value of 0%, a small potential for up to 3% higher performance and a small potential for 5% lower performance. This results in a P50 power performance loss estimate of 0.2%.

Turbulence and Controls

This topic includes potential differences in turbine performance, relative to the reference power curve, due to conditions such as high turbulence, variable winds creating significant off-yaw operations, and high-wind hysteresis. DNV-GEC estimated losses for these issues at 1%, with a range from 0% to 2%.

The loss associated with high or low wind hysteresis was not specifically calculated for this project. A specific calculation would require more information about the cut-in and cut-out controls of the SWT-2.3-101.

Electrical

Electrical losses represent the difference between energy measured at each wind turbine and energy measured at the utility meter. This loss accounts for the inefficiencies of the electrical system and the internal parasitic consumption (behind the meter) in very low wind conditions. The electrical loss estimate is partially based on an electrical line loss study that was provided to DNV-GEC by PSE. The line loss estimate was prepared by Burns & McDonnell and described in the memo titled: *Task Number 6.1: Collector System Loss Analysis Lower Snake River Wind Farm Development Project*, dated December 10, 2009. DNV-GEC reviewed the loss calculation methodology described in the memo, but did not independently verify the electrical line loss calculation. The Burns & McDonnell annual line loss estimate of 0.8% includes electrical losses between the turbines and the 230 kV side of the Center Ferry BPA substation, but does not account for parasitic consumption. The line loss calculation was made using the lumped system equivalent model and the electrical specifications of the collection system. DNV-GEC believes this model is an appropriate method for calculating electrical losses of a wind project. Based on DNV-GEC's experience with modern wind projects, a loss of 0.8% is reasonable; however, higher electrical line losses (approximately 2%) are more common.

For the LSR Phase I project DNV-GEC assumed a best estimate of 1.3% for line losses and in-project parasitic consumption. A standard deviation of 0.3% was assumed and possible losses ranged between 0.8% and 1.8%. This estimate is specific to the electrical specifications used in the Burns and McDonnell analysis. Substituting collection system components with equipment of different electrical specifications or altering the wire sizing could significantly change the electrical loss of the project.

Environmental

Several issues related to the environment where the proposed wind power project is located will affect energy production. Subcategories of typical environmental losses are as follows:

Blade Soiling

Turbine performance may be reduced as dust or insects build up on the blades. DNV-GEC estimated losses for this issue at 0.5%, with a range of possible losses from 0% to 1%.

Blade Degradation

Typically, turbine performance decreases somewhat over the life of a project. Degradation of the blade surface is the largest factor that can produce such a change. The turbine blade performance will gradually degrade over time. A small annual decrease in performance was included in the model, with a most likely case loss averaging approximately 0.4% over 20 years (beginning with zero losses and slowly increasing following an exponential decay curve to 1% by Year 20).

Weather

Weather losses encompass a range of issues that result in lost production, including but not limited to the following:

- High- or low-temperature shutdowns
- Lightning damage to turbines
- Grid outages or communications failures caused by lightning
- Hail damage to blades or facility shutdowns to prevent such damage
- Turbines shut down due to ice-related faults
- Reduced power performance due to ice build-up on blades
- Reduced site access due to inclement weather

Based on a review of the meteorological data and DNV-GEC's experience with other wind projects in the area, DNV-GEC estimated a typical case loss of 2.0% for weather conditions, with a range of potential weather losses from 0.5% to 3.0%. It should be noted that this value represents energy loss and not percentage of time lost, as weather downtime frequently occurs during higher-than-average wind conditions. This estimate includes an evaluation of the wind speeds during ambient temperatures outside the operating temperature range for the turbine and a review of anemometer icing as an indicator of icing conditions at the project site, a portion of which will likely impact both turbine performance and availability.

DNV-GEC's experience with operating projects in similar climates indicates that the weather-related losses are highly variable from site to site, and from year to year. For example, the frequency and duration of icing events can vary substantially, with most years having little ice while others experience events where sites are frozen for days at a time with little or no turbine production. Similarly, lightning damage to turbines occurs in infrequent, intermittent events, but can produce significant periods of downtime. Note that some such events may be covered by business interruption insurance that may compensate the project owner for lost revenue; such insurance is not considered in this energy analysis. The overall loss estimate is typical as an approximate overall average based on a variety of operating projects monitored by DNV-GEC.

Project Site Vegetation

This topic includes the potential for vegetation around the project site, particularly trees, to grow and negatively affect the localized wind resource. In areas of dense forest, any increase in canopy height is fundamentally a decrease in turbine hub height. There is minimal potential for significant vegetation growth on the project site. As a result, the vegetation loss for this project is estimated to be 0.0%.

Curtailment

No effects of curtailment requirements or strategies have been evaluated in this analysis. Potential reasons for project curtailment include but are not limited to sound impact mitigation, avian (birds, bats) impact mitigation, turbine load mitigation, and power transmission constraints.

Other

Effect of Asymmetric Uncertainties

Some of the loss factors described above are “lopsided” or asymmetric in nature. To the extent loss factors are asymmetric, the effect of the asymmetry is captured in the spread of the P1-P99 values in Table 22 through Table 25 as well as the P50 loss values described above and in Table 26. Although the uncertainties described below are symmetric, their effect on energy is asymmetric because of the non-linear relationship of wind speed to energy. That is, small increases in average winds result in proportionally smaller changes in energy compared to small decreases in average winds. The effect of this asymmetric energy uncertainty distribution is small compared to other losses, but it does result in a small energy loss factor that is included as the “effect of asymmetric uncertainties” entry in Table 26.

Uncertainties

The following uncertainties were estimated as percentages of the mean wind speed for the site. Based on the wind frequency distribution for the project, there is an approximate relationship of an uncertainty of 1.2% on energy for each 1% uncertainty on wind speed. An uncertainty based on wind speed is not equal to an uncertainty on energy because of the shape of the power curve. 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. This is reflected in the uncertainty model by shifting the wind speed frequency distribution up or down simulating a change in the wind speed and recalculating the gross energy as a ratio of the best-estimate case. Except as noted below, all uncertainties on wind speed shown are assumed to be normally distributed; uncertainty values listed are at one standard deviation. However, because of the non-linear relationship of wind speed to energy, the resulting energy uncertainties are not normally distributed.

Interannual Variability of the Wind

The interannual variability is an input to several of the uncertainty categories. It represents the expected range of variation in annual average wind speed from year to year. Data from three long-term meteorological stations were investigated to determine the interannual wind conditions for the region. The average interannual variability in the region was estimated to be 5.0% per year.

Anemometer Accuracy

This parameter represents the variability in measurement of wind by individual anemometers. An uncertainty of approximately 1.0% on wind speed was assumed based on the typical error on Vector Instruments V100L2 anemometers. This uncertainty is reduced based on the number of independent measurements; consequently, DNV-GEC estimates the overall project uncertainty associated with anemometer accuracy at 0.4% on wind speed, based on the 1.0% uncertainty on a single measurement divided by the square root of five, representing the number of met towers used significantly in this analysis.

Tower Effects on Measurements

Some uncertainty is associated with the effects of mounting anemometers on towers; even when mounted according to industry-standard procedures, small speed-up and slow-down effects are seen on measurements on tubular tilt-up towers and lattice towers. With the exception of Met M252, the top anemometer was mounted above the tower and a goalpost mast, reducing the effects of the towers on the wind speed measurements. Based on the site visit, a review of the documentation of the mounting arrangements on the towers and a review of the data, DNV-GEC estimated an overall site-wide average wind speed uncertainty of 0.8% for this issue. This estimate is low relative to other tower configurations that do not use a goalpost mast.

Data Capture/Quality Control/Validation

Several periods of data were missing or removed from each tower because of icing, equipment malfunction and other issues. DNV-GEC estimated an uncertainty of 1.5% on wind speed for this issue, based on the amount of missing or invalid data.

Representativeness of Period of Data

There is a 14.1-year period of record at the reference site that was used in this analysis. The uncertainty associated with the representativeness of the period of record equals the interannual variability divided by the square root of the period of record (14.1 years), or 1.3% on wind speed.

Reference Site Relationships/Consistency of Long-Term References

This uncertainty represents the uncertainty on the relationship to the long-term reference station used to adjust the observed site wind speeds to long-term conditions, and also on the consistency of the long-term data sets used to describe the wind conditions between tower locations. DNV-GEC expects the uncertainty on the relationship to be moderate. There is a weak correlation to site wind speeds; however, there is long period of data available from the Kennewick BPA reference tower. DNV-GEC estimated an uncertainty of 2.0% for this category.

Wind Shear

There is some uncertainty on whether the shear values measured over the period at the tower locations are representative of the long term. Shear can vary based on the exposure at a met tower relative to turbine locations, seasonal variation, and other effects. It is also unknown whether the shear at the measurements heights extends up through hub-height. DNV-GEC estimated the overall shear uncertainty based on a combination of these issues. The effective aggregate uncertainty associated with shear was estimated at approximately 1.7% on wind speed, based on the consistency of shear between the towers, knowledge of the tower configurations, DNV-GEC's experience from other sites in similar terrain, and considering the available shear data at each tower.

Topographic Effects/On-Site Correlations

This uncertainty represents the potential difference in wind speed between the met tower locations and the wind turbine locations, as well as the uncertainty on the correlations used to describe the wind conditions between the tower locations. The site consists of variable terrain, resulting in wind flow complexity. Based on a review of topographic maps and information from the site visit, DNV-GEC would expect variation in wind speeds at each met tower. The met tower data suggest a range of on-site wind speeds that differ by 0.5 m/s between the highest and lowest annualized met tower wind speeds. However, met towers are situated in locations representative of only a small percentage of total turbine locations. Due the complexity of the terrain, the total size of the project and the quantity and location of the met towers, DNV-GEC estimated the uncertainty at 4.5%.

Wind Frequency Distribution

The uncertainty on the wind frequency distribution represents the possibility that for a given annual mean wind speed the energy production may be higher or lower than expected due to a more or less favorable distribution of wind speeds. For example, the frequency of high-wind cutouts; a year with several intense storms may record substantial time at wind speeds above the 25 m/s turbine cutout speed, thereby increasing the overall average wind speed but not increasing the energy production. There are two aspects to this uncertainty: the first represents the uncertainty on the distribution measured over the period of measurement at the site towers, and the second represents the year-to-year variability in the wind speed distribution. DNV-GEC estimated an annual variability of 3.0% on energy related to differences in wind distribution. This variability applies to both uncertainties on distribution: the uncertainty on the past distribution over the on-site data collection period (2.3 years) is equal to 3.0% divided by the square root of 2.3, or 2.0%. The 3.0% variability applies to the uncertainty on the future distribution, which is allowed to vary year by year.

Wind Speeds over Project Life Relative to Long-Term Average

Uncertainty exists regarding whether the true long-term mean wind speed will occur over the project life. Given an assumed 20-year project lifespan, this uncertainty is calculated as the interannual variability divided by the square root of 20 or 1.1% on wind speed.

Changes in Long-Term Average Wind Speed

Changes to local or global climate patterns may produce changes in site wind conditions over the life of the project; there is uncertainty as to whether such changes are occurring, and if so, to what extent. DNV-GEC assumed a 1.0% uncertainty on wind speed to account for this issue.

Net Energy Estimate

Based on the estimated gross annual energy, DNV-GEC estimated net energy production using a stochastic model to evaluate each source of loss or uncertainty identified above. Distributions appropriate for each loss or uncertainty were determined and a probabilistic description of the annual net energy was built, integrating each source. The model was then run in 100,000 iterations with each parameter changed randomly and independently to describe the distribution of potential net energy production. Table 22, Table 23, Table 24 and Table 25 summarize the results showing the probability of exceedance of various levels of annual energy production for each of the four wake loss scenarios. A summary of the long-term P50 losses are presented in Table 26 for each of the wake loss scenarios. The estimated net annual energy production for each turbine for each of the wake loss scenarios is presented in Appendix E.

Table 22. Summary of Project Net Average Energy Production Including Impact of Phase I Wakes Only

Probability of Exceedance	20-Year Average	10-Year Average (First 10 Years)	1-Year (Entire Project Life)	1-Year (During First 10 Years)
Net Annual Energy Production (GWh/yr)				
1%	1067	1085	1119	1131
5%	1017	1033	1054	1066
10%	992	1007	1019	1032
25%	947	961	962	975
50%	**899**	**911**	**899**	**911**
75%	851	862	835	848
90%	807	817	779	791
95%	782	790	745	757
99%	733	739	682	693
Net Annual Capacity Factor				
1%	35.5%	36.1%	37.3%	37.7%
5%	33.9%	34.4%	35.1%	35.5%
10%	33.0%	33.5%	34.0%	34.4%
25%	31.6%	32.0%	32.1%	32.5%
50%	**29.9%**	**30.3%**	**29.9%**	**30.3%**
75%	28.3%	28.7%	27.8%	28.2%
90%	26.9%	27.2%	26.0%	26.3%
95%	26.0%	26.3%	24.8%	25.2%
99%	24.4%	24.6%	22.7%	23.1%

Table 23. Summary of Project Net Average Energy Production Including Impact of Phase II Wakes

Probability of Exceedance	20-Year Average	10-Year Average (First 10 Years)	1-Year (Entire Project Life)	1-Year (During First 10 Years)
Net Annual Energy Production (GWh/yr)				
1%	1043	1060	1088	1101
5%	985	1000	1015	1027
10%	953	968	976	988
25%	900	913	911	923
50%	**840**	**852**	**840**	**852**
75%	783	792	771	782
90%	731	740	710	721
95%	702	710	675	686
99%	647	653	611	621
Net Annual Capacity Factor				
1%	34.7%	35.3%	36.2%	36.7%
5%	32.8%	33.3%	33.8%	34.2%
10%	31.8%	32.2%	32.5%	32.9%
25%	30.0%	30.4%	30.3%	30.7%
50%	**28.0%**	**28.4%**	**28.0%**	**28.4%**
75%	26.1%	26.4%	25.7%	26.0%
90%	24.4%	24.7%	23.7%	24.0%
95%	23.4%	23.7%	22.5%	22.8%
99%	21.6%	21.8%	20.4%	20.7%

Table 24. Summary of Project Net Average Energy Production Including Impact of Phase III Wakes

Probability of Exceedance	20-Year Average	10-Year Average (First 10 Years)	1-Year (Entire Project Life)	1-Year (During First 10 Years)
Net Annual Energy Production (GWh/yr)				
1%	1063	1080	1114	1127
5%	1012	1027	1048	1060
10%	985	1000	1013	1025
25%	940	954	954	967
50%	**890**	**902**	**890**	**902**
75%	840	850	825	837
90%	795	805	768	780
95%	769	777	734	746
99%	719	726	671	682
Net Annual Capacity Factor				
1%	35.4%	36.0%	37.1%	37.5%
5%	33.7%	34.2%	34.9%	35.3%
10%	32.8%	33.3%	33.7%	34.1%
25%	31.3%	31.8%	31.8%	32.2%
50%	**29.6%**	**30.0%**	**29.6%**	**30.0%**
75%	28.0%	28.3%	27.5%	27.9%
90%	26.5%	26.8%	25.6%	26.0%
95%	25.6%	25.9%	24.4%	24.8%
99%	24.0%	24.2%	22.4%	22.7%

Table 25. Summary of Project Net Average Energy Production Including Impact of Phase II and III Wakes

Probability of Exceedance	20-Year Average	10-Year Average (First 10 Years)	1-Year (Entire Project Life)	1-Year (During First 10 Years)
Net Annual Energy Production (GWh/yr)				
1%	1045	1061	1088	1101
5%	985	999	1013	1025
10%	951	965	973	985
25%	896	908	906	918
50%	**834**	**845**	**834**	**845**
75%	773	783	762	773
90%	720	729	700	711
95%	690	698	664	675
99%	633	641	599	609
Net Annual Capacity Factor				
1%	34.8%	35.3%	36.3%	36.7%
5%	32.8%	33.3%	33.7%	34.1%
10%	31.7%	32.2%	32.4%	32.8%
25%	29.8%	30.3%	30.2%	30.6%
50%	**27.8%**	**28.2%**	**27.8%**	**28.2%**
75%	25.8%	26.1%	25.4%	25.7%
90%	24.0%	24.3%	23.3%	23.7%
95%	23.0%	23.3%	22.1%	22.5%
99%	21.1%	21.3%	20.0%	20.3%

Table 26. Summary of Long-Term P50 Losses

Wake Loss Scenario	Phase I Only	Phases I & II	Phases I & III	Phases I, II & III
Gross Energy (GWh/year)	**1103**	**1103**	**1103**	**1103**
LOSSES				
Availability	**5.8%**	**5.8%**	**5.8%**	**5.8%**
Turbine (1)	5.4%	5.4%	5.4%	5.4%
Balance of plant	0.5%	0.5%	0.5%	0.5%
Wake Effects	**7.9%**	**13.8%**	**8.8%**	**14.4%**
Internal wake effects	7.9%	7.9%	7.9%	7.9%
External wake effects	0.0%	0.0%	0.0%	0.0%
Future wake effects	0.0%	5.6%	0.9%	6.2%
Turbine Performance	**1.2%**	**1.2%**	**1.2%**	**1.2%**
Power performance	0.2%	0.2%	0.2%	0.2%
Turbulence and controls	1.0%	1.0%	1.0%	1.0%
Electrical	**1.3%**	**1.3%**	**1.3%**	**1.3%**
Environmental	**2.9%**	**2.9%**	**2.9%**	**2.9%**
Blade soiling	0.5%	0.5%	0.5%	0.5%
Blade degradation (1)	0.4%	0.4%	0.4%	0.4%
Weather, including icing, lightning, hail	2.0%	2.0%	2.0%	2.0%
Vegetation (1)	0.0%	0.0%	0.0%	0.0%
Curtailment	Not Considered	Not Considered	Not Considered	Not Considered
Other	**0.8%**	**0.9%**	**0.8%**	**0.8%**
Effect of asymmetric uncertainties	0.8%	0.9%	0.8%	0.8%
Total Losses	**18.5%**	**23.8%**	**19.3%**	**24.4%**
Net Energy (GWh/year)	**899**	**840**	**890**	**834**
Net Capacity Factor	**29.9%**	**28.0%**	**29.6%**	**27.8%**

1. Values are long-term averages over a 20-year project life and are lower in initial years of operation.

PSE provided information[4] regarding the Siemens availability warranty of 96% (a 4% loss). This availability loss is a percentage of downtime and therefore is not directly comparable to our availability loss estimate of 5.8% which is a percentage of the energy. Additionally, Siemens availability warranty excludes balance-of-plant outages, which are included in our estimate, as well as any force majeure losses, which DNV-GEC includes separately as weather losses.

In order to provide an approximation of the Siemens availability warranty as a percent of energy lost due to unavailability, DNV-GEC applied a time-to-energy multiplier of 1.3 to the 4% downtime. Based on DNV-GEC's experience with operating projects, downtime due to turbine

[4] Siemens Turbine Supply Agreement, Exhibit R1, Availability Test Procedure, Document ID: PG-R4-40-0000-0014-05, September 1, 2009.

faults and minor and major component failures is usually disproportionately weighted towards high-wind periods. For this reason, the time-to-energy multiplier of 1.3 was used. Including a balance-of-plant energy loss estimate of 0.5%, DNV-GEC approximates the Siemens' warranted availability to be an energy loss of 5.8%, the same as DNV-GEC's P50 case. Note that the Siemens availability warranty of 96% is a contractual value, and not necessarily intended as a loss estimate. Also, the Siemens warranty applies for only the first five years of project life where DNV-GEC's value is for a 20-year project life.

Appendix A – Turbine and Met Tower Coordinates

ID	WGS84 UTM11 Easting (m)	WGS84 UTM11 Northing (m)
M252	442623	5144729
M370	438151	5149376
M371	428836	5144242
M399	442322	5149830
M437	435163	5150736
M438	434557	5146946
M440	435537	5155756
A-01	438197	5159775
A-02	438254	5159562
A-03	438402	5159400
A-04	438732	5159418
A-05	438956	5159200
A-06	439152	5159043
A-07	439325	5158908
A-08	440153	5158797
A-09	440342	5158675
B-01	435980	5159299
B-02	436061	5159095
B-03	436173	5158906
B-04	436378	5158815
B-05	436520	5158648
B-06	436681	5158498
B-07	436831	5158335
B-08	435358	5157733
B-09	435568	5157660
B-10	436009	5157672
C-01	437152	5158138
C-02	437272	5157954
C-03	437373	5157760
C-04	437012	5157337
C-05	437174	5157188
C-06	437319	5157024
C-07	437435	5156838
C-08	438037	5157021
C-09	438208	5156884
D-01	438395	5156768
D-02	438600	5156690
D-03	438772	5156554
D-04	438902	5156377
D-05	439297	5156115
D-06	439365	5155906
D-07	439419	5155658
D-08	439558	5155483
D-09	439652	5155285
E-01	439710	5155073
E-02	439772	5154863
E-03	439811	5154624
E-04	439883	5154417
E-05	439948	5154208
E-06	440107	5154056
E-07	440192	5153833
F-01	434146	5155980
F-02	434443	5155980
F-03	434653	5155914
F-04	434840	5155799
F-05	435019	5155673
F-06	435484	5155809
F-07	435604	5155626
F-08	435696	5155426
F-09	436038	5155225
G-01	436247	5155158
G-02	436446	5155066
G-03	436655	5155000
G-04	437129	5154936
G-05	437277	5154774
G-06	437412	5154601
G-07	437534	5154419
H-01	437661	5154240
H-02	437791	5154063
H-03	437540	5153581
H-04	437651	5153393
H-05	437840	5153297
H-06	437998	5153125
I-01	434860	5153010

ID	WGS84 UTM11	
	Easting (m)	Northing (m)
I-02	434974	5152813
I-03	435118	5152648
I-04	435264	5152484
I-05	435413	5152323
I-06	435531	5152132
I-07	435647	5151946
I-08	435315	5150990
I-09	435381	5150781
J-01	435513	5150606
J-02	435610	5150409
J-03	435753	5150242
J-04	435903	5150083
J-05	436087	5149963
J-06	436632	5150027
J-07	436787	5149872
J-08	437128	5149829
J-09	437305	5149700
K-01	437495	5149591
K-02	437681	5149474
K-03	437897	5149411
K-04	438071	5149273
K-05	438280	5149207
K-06	437965	5147972
K-07	438103	5147801
K-08	438320	5147713
L-01	437807	5151293
L-02	438118	5151148
L-03	438293	5151015
L-04	438347	5150800
L-05	438372	5150529
L-06	438446	5150323
L-07	438549	5150129
L-08	438624	5149923
L-09	438697	5149716
M-01	438761	5149506
M-02	438828	5149297
M-03	438909	5149093
M-04	439000	5148892
M-05	439064	5148682
M-06	438700	5148192
M-07	438874	5148059

ID	WGS84 UTM11	
	Easting (m)	Northing (m)
M-08	439048	5147925
M-09	439222	5147792
N-01	439387	5147647
N-02	439485	5147451
N-03	440722	5147813
N-04	440758	5147550
N-05	440834	5147323
N-06	440989	5147157
N-07	441042	5146929
N-08	441238	5146831
O-01	434969	5148510
O-02	435099	5148317
O-03	435266	5148199
O-04	435460	5148096
O-05	435658	5148002
O-06	435832	5147869
O-07	435709	5147190
O-08	435878	5147049
O-09	436086	5146979
P-01	435448	5147185
P-02	434924	5146955
P-03	434602	5146968
P-04	434395	5147041
P-05	434198	5147138
P-06	433997	5147226
Q-01	436345	5146949
Q-02	436553	5146879
Q-03	437027	5147483
Q-04	437074	5147232
Q-05	437152	5147023
Q-06	437221	5146798
R-01	433896	5152321
R-02	434107	5152226
R-03	434309	5152095
R-04	434060	5151386
R-05	434259	5151160
R-06	434444	5151043
R-07	434622	5150914
R-08	434829	5150840
R-09	434557	5150249
R-10	434771	5150199

Appendix B – Site Photos

Photo 1. View of Met M252 facing Northeast

Photo 2. View of Met M370 facing Northeast

Photo 3. View of Met M371 facing Northeast

Photo 4. View of Met M399 facing Northeast

Photo 5. View of Met M3437 facing Northeast

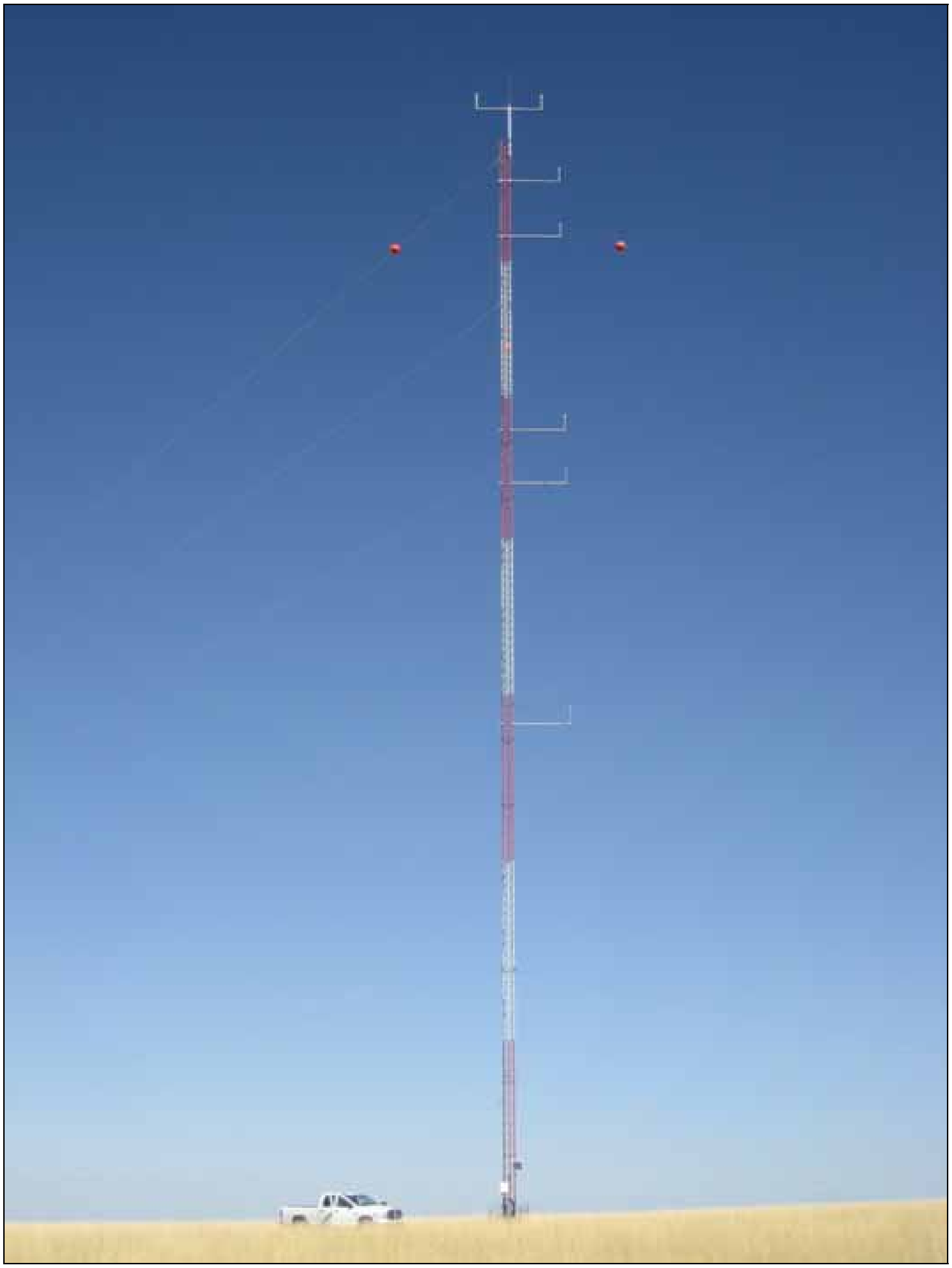


Photo 6. View of Met M438 facing Northeast

Photo 7. View of Met M440 facing Northeast

Appendix C – Met Tower Commissioning Sheets

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	**PROJECT:**	Task 31 Lower Snake River Data Svcs	**TASK:**	PSE.31.001	**GEC TOWER/SITE NUMBER:**	**1252 (M252)**

CONTACT INFORMATION — Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 20, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	March 8, 2005
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Marshall Feehan	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	509-489-1855	GPS latitude:	46.4536905
Nearest town:	Marengo	Landowner e-mail:	--	GPS longitude:	-117.7471298
Direction to town:	S			GPS elevation:	2254 feet 687 meters
Distance to town:	1 miles 2 kilometers	Property manager name:	--	Magnetic declination:	16.3° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	--		
Direction to airport:	N	Manager e-mail:	--		
Distance to airport:	5.09671709 miles 8 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower	Surface roughness within 1 mile/1.6 km	North	East	South	West	at Tower	Environment		Corresponding Maps:
Ridge (>500 ft/>150 m):			X			Snow or open water:						Desert:		
Rolling hills (50-500 ft/15-150 m):	X	X		X		Soil/small rocks:						Agricultural:		
Flat (<50 ft/<15 m):					X	Large rock/boulder:						Grassland:	X	
Valley (>500 ft/>150 m):						Plants (1-12 in./1-25 cm):						Shrubs:		
Shoreline:						Brush (1-3 ft/25-100 cm):	X	X	X	X	X	Forest:		
						Trees (>3 ft/>1 m):						Shoreline:		
						Trees/buildings(>10 ft/>3 m):						Open water:		
						Trees/buildings(>30 ft/>10 m):								

Access Requirements

Road Conditions:		**Obstacles:**		**Suggested Transportation:**	spring	summer	fall	winter
Paved:		Gate:						
Gravel:	X	Locked gate:		Automobile:				
Dirt:		Seasonal locks:		4x4 vehicle:	X	X	X	X
Path:		Fence:		Quad/motorbike:				
None:		Electric fence:		Snowmobile:				
Distance units:		Railroad:		Boat:				
Miles:		Agricultural:		Aircraft:				
Kilometers:		Animals:		Walking:				

Specific Access Instructions:

From the intersection of Marjorie Rd and W. Oliphant Ridge Road go west on W. Oliphant Ridge (a gravel road) for about 0.25 miles. Access site via large open gate and gp 60m south to the tower.

Tower Lowering Obstacles		**Tower Markings/ Fencing**	
Large rocks:		Fencing:	
Fences:		Guy guards:	
Trees/shrubs:		Marker balls:	
Anchor locations:		Winch anchor flag:	
Overhead electrical wires:		Bat detection:	
		Bird diverters:	
		Tower paint:	X

METEOROLOGY STATION Page 2 of 3

Tower Lock Combination	Gate Combination
007	--

Tubular/Lattice?	Vendor name	Model	Tower height				Tower width at base				Grounding system description
lattice	Radian	25G 60m Lattice	189.9606302	feet	57.9	meters	12	inches	30.48	cm	copper wire embedded in ground

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time: 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	12380	1252	-8 (PST)	3/8/2005		X		English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven XT	09609058849	0915414274	--	512-673-6827	166.155.147.249	12:00 PM	1 Day(s)	Verizon

Communications device:	IMSI	IMEI	MSISDN/C	SIM	Power Supply	Power Supply Description
	--	--	--	--	Solar	Campbell SP10 10 watt PV panel (serial #: 1525816)

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	7517, H5B	1		1	184.71	feet	56.3	meters	78.74	inches	200.00	cm	288	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	6845, S1V	1		1	115.81	feet	35.3	meters	78.74	inches	200.00	cm	288	--	--
Ch.	V1	vane	Vector	W200P Vane	9919, 919	0.071	0	1	176.51	feet	53.8	meters	78.74	inches	200.00	cm	288	--	--
Ch.	V2	vane	NRG	#200P Vane		0.071	0	1	109.25	feet	33.3	meters	59.06	inches	150.00	cm	288	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer		1		1	4.92	feet	1.5	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature		1		1	9.84	feet	3	meters	--	inches	--	cm	90	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed)						Page 3 of 3
No.	**Date**	**Company**	**Technician**	**Company Phone**	**On-site Client Representative**	**Incident Description/Work Performed**
1	3/8/2005	RES				Tower installation
2	7/17/2009	RES				Replacement of 53.8-m and 33.3-m vanes, logger program update, and replacement of satellite modem with CDMA
3	9/17/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	**PROJECT:**	Task 31 Lower Snake River Data Svcs	**TASK:**	PSE.31.001	**GEC TOWER/SITE NUMBER:**	**1370 (M370)**

CONTACT INFORMATION Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 20, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	May 3, 2007
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Kenny Price	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	509-843-3350	GPS latitude:	46.4951146
Nearest town:	Chard	Landowner e-mail:	--	GPS longitude:	-117.8059652
Direction to town:	NW			GPS elevation:	2008 feet 612 meters
Distance to town:	4 miles 6 kilometers	Property manager name:	--	Magnetic declination:	15.9833° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	--		
Direction to airport:	SW	Manager e-mail:	--		
Distance to airport:	2.89813325 miles 5 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower
Ridge (>500 ft/>150 m):					
Rolling hills (50-500 ft/15-150 m):	X	X	X	X	
Flat (<50 ft/<15 m):					X
Valley (>500 ft/>150 m):					
Shoreline:					

Surface roughness within 1 mile/1.6 km	North	East	South	West	at Tower
Snow or open water:					
Soil/small rocks:					
Large rock/boulder:					
Plants (1-12 in./1-25 cm):	X	X	X	X	X
Brush (1-3 ft/25-100 cm):					
Trees (>3 ft/>1 m):					
Trees/buildings(>10 ft/>3 m):					
Trees/buildings(>30 ft/>10 m):					

Environment	
Desert:	
Agricultural:	X
Grassland:	X
Shrubs:	
Forest:	
Shoreline:	
Open water:	

Corresponding Maps:

Access Requirements

Road Conditions:		Obstacles:		Suggested Transportation:	spring	summer	fall	winter
Paved:		Gate:						
Gravel:		Locked gate:		Automobile:				
Dirt:		Seasonal locks:		4x4 vehicle:	X	X	X	X
Path:		Fence:		Quad/motorbike:				
None:	X	Electric fence:		Snowmobile:				
Distance units:		Railroad:		Boat:				
Miles:		Agricultural:	X	Aircraft:				
Kilometers:		Animals:		Walking:				

Specific Access Instructions:

From Owens Rd and W Oliphant Rd head east on W Oliphant Rd. Follow past old farm to 46.49330750° N, 117.80033690° W. Enter field from east drive 500yds to tower. Hayfield- hike in if wheat is high.

Tower Lowering Obstacles	
Large rocks:	
Fences:	
Trees/shrubs:	
Anchor locations:	
Overhead electrical wires:	

Tower Markings/ Fencing	
Fencing:	Cattle panel
Guy guards:	X
Marker balls:	
Winch anchor flag:	
Bat detection:	
Bird diverters:	
Tower paint:	X

METEOROLOGY STATION Page 2 of 3

Tower Lock Combination	Gate Combination
007	--

Tubular/Lattice?	Vendor name	Model	Tower height				Tower width at base				Grounding system description
lattice	Radian	25G 60m Lattice	183.7270344	feet	56	meters	12	inches	30.48	cm	Two Grounding Rods, logger and tower ground connect to separate rods

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time: 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	79541	1370	-8 (PST)	5/3/2007			X	English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven XT	09609058844	0915414627	--	512-673-2513	166.159.34.190	12:30 PM	1 Day(s)	Verizon
	IMSI	IMEI	MSISDN/C	SIM	Power Supply	Power Supply Description				
	--	--	--	--	Solar	PV panel				

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	9951, FAV	1		1	198.16	feet	60.4	meters	68.90	inches	175.00	cm	135	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	9968. FCX	1		1	184.06	feet	56.1	meters	112.99	inches	287.00	cm	135	--	--
Ch.	A3	anemometer	Vector	A100L2/R30 Rotor	9881, EUB	1		1	115.16	feet	35.1	meters	112.99	inches	287.00	cm	135	--	--
Ch.	V1	vane	Vector	W200P Vane	50521, V21	0.071	0	1	197.18	feet	60.1	meters	112.99	inches	287.00	cm	315	--	--
Ch.	V2	vane	Vector	W200P Vane	13007, 007	0.071	0	1	179.13	feet	54.6	meters	112.99	inches	287.00	cm	135	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer		1		1	--	feet	--	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature	TP001	1		1	32.81	feet	10	meters	--	inches	--	cm	0	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed) Page 3 of 3

No.	Date	Company	Technician	Company Phone	On-site Client Representative	Incident Description/Work Performed
1	5/3/2007	RES				Tower installation
2	6/17/2009	RES				Logger program update and replacement of satellite modem with CDMA
3	9/17/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	PROJECT:	Task 31 Lower Snake River Data Svcs	TASK:	PSE.31.001	GEC TOWER/SITE NUMBER:	1371

CONTACT INFORMATION — Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 20, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	May 3, 2007
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Randy James	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	509-382-2760	GPS latitude:	46.4480003
Nearest town:	Tucannon	Landowner e-mail:	--	GPS longitude:	-117.9265531
Direction to town:	N			GPS elevation:	1795 feet 547 meters
Distance to town:	3 miles 5 kilometers	Property manager name:	--	Magnetic declination:	16.0° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	--		
Direction to airport:	NE	Manager e-mail:	--		
Distance to airport:	9.61380753 miles 15 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower
Ridge (>500 ft/>150 m):					
Rolling hills (50-500 ft/15-150 m):	X	X	X	X	
Flat (<50 ft/<15 m):					X
Valley (>500 ft/>150 m):					
Shoreline:					

Surface roughness within 1 mile/1.6 km	North	East	South	West	at Tower
Snow or open water:					
Soil/small rocks:					
Large rock/boulder:					
Plants (1-12 in./1-25 cm):					
Brush (1-3 ft/25-100 cm):	X	X	X	X	X
Trees (>3 ft/>1 m):					
Trees/buildings(>10 ft/>3 m):					
Trees/buildings(>30 ft/>10 m):					

Environment	
Desert:	
Agricultural:	X
Grassland:	
Shrubs:	
Forest:	
Shoreline:	
Open water:	

Corresponding Maps:

Access Requirements

Road Conditions:		Obstacles:	
Paved:		Gate:	
Gravel:	X	Locked gate:	
Dirt:		Seasonal locks:	
Path:		Fence:	
None:	X	Electric fence:	
Distance units:		Railroad:	
Miles:		Agricultural:	X
Kilometers:		Animals:	

Suggested Transportation:	spring	summer	fall	winter
Automobile:				
4x4 vehicle:	X	X	X	X
Quad/motorbike:				
Snowmobile:				
Boat:				
Aircraft:				
Walking:				

Specific Access Instructions:

At intersection of Kellogg Hollow Rd, Willow Creek Rd and Brines Road, head North on Brines Rd (gravel road) for about 2.5 mi. Brines road makes a 90° turn, when it does that enter the field and access the tower from the north.

Tower Lowering Obstacles	
Large rocks:	
Fences:	
Trees/shrubs:	
Anchor locations:	
Overhead electrical wires:	

Tower Markings/ Fencing	
Fencing:	Cattle panel
Guy guards:	X
Marker balls:	
Winch anchor flag:	
Bat detection:	
Bird diverters:	
Tower paint:	X

METEOROLOGY STATION Page 2 of 3

Tower Lock Combination	Gate Combination
007	

Tubular/Lattice?	Vendor name	Model	Tower height				Tower width at base				Grounding system description
lattice	Radian	25G 60m Lattice	188.9763782	feet	57.6	meters	12	inches	30.48	cm	Two grounding rods, logger and tower ground connect to separate rods about 5ft apart

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time: 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	7956	1371	-8 (PST)	3/5/2007		X		English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven XT	09609002263	0911413688	--	512-673-6528	166.155.147.252	12:00 PM	1 Day(s)	Verizon
	IMSI	IMEI	MSISDN/C		SIM		Power Supply	Power Supply Description		
	--	--	--		--		Solar	PV panel		

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	9962, CFCR	1		1	198.16	feet	60.4	meters	68.90	inches	175.00	cm	135	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	9970-FCZ	1		1	184.06	feet	56.1	meters	112.99	inches	287.00	cm	131	--	--
Ch.	A3	anemometer	Vector	A100L2/R30 Rotor	9886, CEUG	1		1	115.16	feet	35.1	meters	112.99	inches	287.00	cm	131	--	--
Ch.	V1	vane	Vector	W200P Vane		0.071	0	1	197.18	feet	60.1	meters	68.90	inches	175.00	cm	315	--	--
Ch.	V2	vane	Vector	W200P Vane	CU11	0.071	0	1	179.13	feet	54.6	meters	112.99	inches	287.00	cm	135	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer		1		1	--	feet	--	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature		1		1	9.84	feet	3	meters	--	inches	--	cm	0	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed)						Page 3 of 3
No.	**Date**	**Company**	**Technician**	**Company Phone**	**On-site Client Representative**	**Incident Description/Work Performed**
1	5/3/2007	RES				Tower installation
2	6/17/2009	RES				Logger program update and replacement of satellite modem with CDMA
3	9/15/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	**PROJECT:**	Task 31 Lower Snake River Data Svcs	**TASK:**	PSE.31.001	**GEC TOWER/SITE NUMBER:**	**1399**

CONTACT INFORMATION Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 20, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	September 11, 2007
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Bob Biachi	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	--	GPS latitude:	46.4995703
Nearest town:	Pomeroy	Landowner e-mail:	--	GPS longitude:	-117.751673
Direction to town:	E			GPS elevation:	2080 feet 634 meters
Distance to town:	8 miles 12 kilometers	Property manager name:	Dan Ledgerwood	Magnetic declination:	15.91667° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	509-780-8569		
Direction to airport:	NW	Manager e-mail:	--		
Distance to airport:	2.23855809 miles 4 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower
Ridge (>500 ft/>150 m):	X		X		
Rolling hills (50-500 ft/15-150 m):		X		X	
Flat (<50 ft/<15 m):					X
Valley (>500 ft/>150 m):					
Shoreline:					

Surface roughness within 1 mile/1.6 km	North	East	South	West	at Tower
Snow or open water:					
Soil/small rocks:					
Large rock/boulder:					
Plants (1-12 in./1-25 cm):					
Brush (1-3 ft/25-100 cm):	X	X	X	X	X
Trees (>3 ft/>1 m):					
Trees/buildings(>10 ft/>3 m):					
Trees/buildings(>30 ft/>10 m):					

Environment	
Desert:	
Agricultural:	X
Grassland:	
Shrubs:	
Forest:	
Shoreline:	
Open water:	

Corresponding Maps:

Access Requirements

Road Conditions:		**Obstacles:**		**Suggested Transportation:**	spring	summer	fall	winter
Paved:		Gate:	X					
Gravel:		Locked gate:		Automobile:				
Dirt:		Seasonal locks:		4x4 vehicle:	X	X	X	X
Path:	X	Fence:		Quad/motorbike:				
None:	X	Electric fence:		Snowmobile:				
Distance units:		Railroad:		Boat:				
Miles:		Agricultural:	X	Aircraft:				
Kilometers:		Animals:		Walking:				

Specific Access Instructions:

On Highway 12 west of mile post 394 across the street from an abandoned grain silo enter a gate and head N (0.1 mi) to a field, cross the field (0.25 mi), then drive up the hill (0.25 mi) to a gate at 46.49842840° N, 117.76206870° W. Enter gate and follow edge of the wheat field (0.5 mi) to the met tower.

Tower Lowering Obstacles	
Large rocks:	
Fences:	
Trees/shrubs:	
Anchor locations:	
Overhead electrical wires:	

Tower Markings/ Fencing	
Fencing:	Cattle panel
Guy guards:	X
Marker balls:	
Winch anchor flag:	
Bat detection:	
Bird diverters:	
Tower paint:	

METEOROLOGY STATION Page 2 of 3

Tower Lock Combination	Gate Combination
007	--

Tubular/Lattice?	Vendor name	Model	Tower height				Tower width at base				Grounding system description
lattice	Sabre	60m 1200 TLWD	189.9606302	feet	57.9	meters	12.5	inches	31.75	cm	Two grounding rods, logger and tower ground connect to separate rods

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time: 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	10936	1399	-8 (PST)	9/11/2007		X		English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven XT	09609012971	0911414796	--	512-673-6587	166.155.147.251	12:50 PM	1 Day(s)	Verizon

Communications device:	IMSI	IMEI	MSISDN/C	SIM	Power Supply	Power Supply Description
	--	--	--	--	Solar	20 Watt PV panel

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	10281, GRR	1		1	197.51	feet	60.2	meters	68.11	inches	173.00	cm	151	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	10353, HCM	1		1	190.29	feet	58	meters	68.11	inches	173.00	cm	151	--	--
Ch.	A3	anemometer	Vector	A100L2/R30 Rotor	5667, CGS	1		1	115.16	feet	35.1	meters	68.11	inches	173.00	cm	151	--	--
Ch.	V1	vane	Vector	W200P Vane	50831, V31	0.071	0	1	195.87	feet	59.7	meters	68.11	inches	173.00	cm	331	--	--
Ch.	V2	vane	Vector	W200P Vane	50651, VSI	0.071	0	1	164.04	feet	50	meters	68.11	inches	173.00	cm	151	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer	C2750065	1		1	9.84	feet	3	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature	TP001	1		1	9.84	feet	3	meters	--	inches	--	cm	45	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed)						Page 3 of 3
No.	**Date**	**Company**	**Technician**	**Company Phone**	**On-site Client Representative**	**Incident Description/Work Performed**
1	9/11/2007	RES				Tower installation
2	6/17/2009	RES				Update logger program
3	9/18/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	PROJECT:	Task 31 Lower Snake River Data Svcs	TASK:	PSE.31.001	GEC TOWER/SITE NUMBER:	1437 (M437)

CONTACT INFORMATION Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 21, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	June 16, 2008
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Bob Cox	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	509-843-1750	GPS latitude:	46.50707
Nearest town:	Dodge	Landowner e-mail:	--	GPS longitude:	-117.8450905
Direction to town:	NE			GPS elevation:	1952 feet 595 meters
Distance to town:	2 miles 2 kilometers	Property manager name:	--	Magnetic declination:	15.8167° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	--		
Direction to airport:	E	Manager e-mail:	--		
Distance to airport:	3.91747667 miles 6 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower
Ridge (>500 ft/>150 m):					
Rolling hills (50-500 ft/15-150 m):	X	X	X	X	
Flat (<50 ft/<15 m):					X
Valley (>500 ft/>150 m):					
Shoreline:					

Surface roughness within 1 mile/1.6 km	North	East	South	West	at Tower
Snow or open water:					
Soil/small rocks:					
Large rock/boulder:					
Plants (1-12 in./1-25 cm):					
Brush (1-3 ft/25-100 cm):	X	X	X	X	X
Trees (>3 ft/>1 m):					
Trees/buildings(>10 ft/>3 m):					
Trees/buildings(>30 ft/>10 m):					

Environment	
Desert:	
Agricultural:	
Grassland:	X
Shrubs:	
Forest:	
Shoreline:	
Open water:	

Corresponding Maps:

Access Requirements

Road Conditions:		Obstacles:		Suggested Transportation:	spring	summer	fall	winter
Paved:		Gate:						
Gravel:		Locked gate:		Automobile:				
Dirt:		Seasonal locks:		4x4 vehicle:	X	X	X	X
Path:	X	Fence:		Quad/motorbike:				
None:		Electric fence:		Snowmobile:				
Distance units:		Railroad:		Boat:				
Miles:		Agricultural:		Aircraft:				
Kilometers:		Animals:		Walking:				

Specific Access Instructions:

From the intersection ofHighway 12 and Highway 127 head south on Owens Rd to W Oliphant Rd intersects Owens road. Turn west on to a path and proceed 0.5 miles, when path splits at 46.50067520° N, 117.83283880° W vear to the right (northwest) and follow the path to the tower 0.75 miles to the tower.

Tower Lowering Obstacles	
Large rocks:	
Fences:	
Trees/shrubs:	
Anchor locations:	
Overhead electrical wires:	

Tower Markings/ Fencing	
Fencing:	Cattle panel
Guy guards:	X
Marker balls:	X
Winch anchor flag:	
Bat detection:	
Bird diverters:	
Tower paint:	X

METEOROLOGY STATION							Page 2 of 3
Tower Lock Combination	**Gate Combination**						
007	--						Grounding system description
Tubular/Lattice?	Vendor name	Model	Tower height		Tower width at base		Two grounding rods, logger and tower ground connect to separate rods
lattice	Sabre	60m 1800 TLWD	180.0000003 feet	54.864 meters	18 inches	45.72 cm	

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time: 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	6029	1437	-8 (PST)	6/16/2008		X		English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven XT	09609058880	0915414268	--	512-673-7964	166.155.147.246	1:20 PM	1 Day(s)	Verizon
	IMSI	IMEI	MSISDN/C		SIM		Power Supply	Power Supply Description		
	--	--	--		--		Solar	Campbell SP20 20 Watt PV panel, serial number: 5432103		

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	7403, X5G	1		1	190.62	feet	58.1	meters	79.92	inches	203.00	cm	138	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	10680, IXw	1		1	190.62	feet	58.1	meters	79.92	inches	203.00	cm	320	--	--
Ch.	A3	anemometer	Vector	A100L2/R30 Rotor	10269, GRD	1		1	174.21	feet	53.1	meters	103.15	inches	262.00	cm	138	--	--
Ch.	A4	anemometer	Vector	A100L2/R30 Rotor	6741, 9EI	1		1	125.33	feet	38.2	meters	103.15	inches	262.00	cm	138	--	--
Ch.	A5	anemometer	Vector	A100L2/R30 Rotor	10068, FLX	1		1	75.79	feet	23.1	meters	103.15	inches	262.00	cm	135	--	--
Ch.	V1	vane	Vector	W200P Vane	14223, 223	0.071	0	1	162.73	feet	49.6	meters	103.15	inches	262.00	cm	137	--	--
Ch.	V2	vane	Vector	W200P Vane	14352, 252	0.071	0	1	115.81	feet	35.3	meters	103.15	inches	262.00	cm	138	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer	C1250020	1		1	5.25	feet	1.6	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature		1		1	8.53	feet	2.6	meters	--	inches	--	cm	0	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed)						Page 3 of 3
No.	**Date**	**Company**	**Technician**	**Company Phone**	**On-site Client Representative**	**Incident Description/Work Performed**
1	6/16/2008	RES				Tower installation
2	6/16/2009	RES				Logger program update and replacement of satellite modem with CDMA
3	9/17/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	PROJECT:	Task 31 Lower Snake River Data Svcs	TASK:	PSE.31.001	GEC TOWER/SITE NUMBER:	**1438 (M438)**

CONTACT INFORMATION Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 21, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	June 17, 2008
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Ole Klegseth	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	702-387-5349	GPS latitude:	46.4729047
Nearest town:	Dodge	Landowner e-mail:	--	GPS longitude:	-117.8524516
Direction to town:	NE			GPS elevation:	1962 feet 598 meters
Distance to town:	4 miles 6 kilometers	Property manager name:	Bo Blachley	Magnetic declination:	15.8° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	509-843-1394 (Work)		
Direction to airport:	NE	Manager e-mail:	509-751-7782 (Cell)		
Distance to airport:	5.6863373 miles 9 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower	**Surface roughness** within 1 mile/1.6 km	North	East	South	West	at Tower	**Environment**		**Corresponding Maps:**
Ridge (>500 ft/>150 m):						Snow or open water:						Desert:		
Rolling hills (50-500 ft/15-150 m):	X	X	X	X	X	Soil/small rocks:	X	X	X	X	X	Agricultural:		
Flat (<50 ft/<15 m):						Large rock/boulder:						Grassland:	X	
Valley (>500 ft/>150 m):						Plants (1-12 in./1-25 cm):						Shrubs:		
Shoreline:						Brush (1-3 ft/25-100 cm):						Forest:		
						Trees (>3 ft/>1 m):						Shoreline:		
						Trees/buildings(>10 ft/>3 m):						Open water:		
						Trees/buildings(>30 ft/>10 m):								

Access Requirements

Road Conditions:		**Obstacles:**		**Suggested Transportation:**	spring	summer	fall	winter
Paved:		Gate:						
Gravel:		Locked gate:		Automobile:				
Dirt:		Seasonal locks:		4x4 vehicle:	X	X	X	X
Path:		Fence:		Quad/motorbike:				
None:		Electric fence:		Snowmobile:				
Distance units:		Railroad:		Boat:				
Miles:		Agricultural:		Aircraft:				
Kilometers:		Animals:		Walking:				

Specific Access Instructions:

Contact PSE for proper route to the tower,

Tower Lowering Obstacles	
Large rocks:	
Fences:	
Trees/shrubs:	
Anchor locations:	
Overhead electrical wires:	

Tower Markings/ Fencing	
Fencing:	Cattle panel
Guy guards:	X
Marker balls:	X
Winch anchor flag:	
Bat detection:	
Bird diverters:	
Tower paint:	X

METEOROLOGY STATION							Page 2 of 3
Tower Lock Combination	Gate Combination						
007	--						Grounding system description
Tubular/Lattice?	Vendor name	Model	Tower height		Tower width at base		Two grounding rods, logger and tower ground connect to separate rods
lattice	Sabre	60m 1800 TLWD	179.9868769 feet	54.86 meters	18 inches	45.72 cm	

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	10153	1438	-8 (PST)	6/17/2008		X		English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven XT	09609058503	0915414605	--	512-673-6634	166.155.147.248:12345	1:30 PM	1 Day(s)	Verizon
	IMSI	IMEI	MSISDN/C		SIM		Power Supply	Power Supply Description		
	--	--	--		--		Solar	Campbell SP20 20 Watt PV		

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	8593, W5N	1		1	190.62	feet	58.1	meters	79.92	inches	203.00	cm	130	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	9040, BPL	1		1	190.62	feet	58.1	meters	79.92	inches	203.00	cm	300	--	--
Ch.	A3	anemometer	Vector	A100L2/R30 Rotor	7324, F3V	1		1	174.21	feet	53.1	meters	103.15	inches	262.00	cm	130	--	--
Ch.	A4	anemometer	Vector	A100L2/R30 Rotor	7390, F8B	1		1	126.31	feet	38.5	meters	103.15	inches	262.00	cm	130	--	--
Ch.	A5	anemometer	Vector	A100L2/R30 Rotor	10001, FFF	1		1	75.79	feet	23.1	meters	103.15	inches	262.00	cm	130	--	--
Ch.	V1	vane	Vector	W200P Vane	14227, 227	1		1	162.73	feet	49.6	meters	103.15	inches	262.00	cm	130	--	--
Ch.	V2	vane	Vector	W200P Vane	14079, 079	1		1	115.81	feet	35.3	meters	103.15	inches	262.00	cm	130	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer		1		1	5.25	feet	1.6	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature	TP001	1		1	7.87	feet	2.4	meters	--	inches	--	cm	0	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed)						Page 3 of 3
No.	**Date**	**Company**	**Technician**	**Company Phone**	**On-site Client Representative**	**Incident Description/Work Performed**
1	6/17/2008	RES				Tower installation
2	6/17/2009	RES				Logger program update and replacement of satellite modem with CDMA
3	9/17/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

METEOROLOGY TOWER INFORMATION SHEET - Rev6.05.16.2008

CLIENT:	Puget Sound Energy	**PROJECT:**	Task 31 Lower Snake River Data Svcs	**TASK:**	PSE.31.001	**GEC TOWER/SITE NUMBER:**	**1440 (M440)**

CONTACT INFORMATION Page 1 of 3

Installation company:	Unknown	Client contact:	Heather Dohan	Site name:	Lower Snake River
Install company phone:	--	Client phone:	425-457-5877	Time zones from GMT:	(GMT-08:00)
Install company email:	--	Client email:	Heather.Dohan@pse.com		
Data mgmt company:	DNV Global Energy Concepts Inc.	Meteorologist:	Heather Dohan	Current date:	October 21, 2009
Data mgmt phone:	206-387-4200	Meteorologist phone:	425-457-5877	Date tower operational:	June 16, 2008
Data mgmt email:	metdata@globalenergyconcepts.com	Meteorologist email:	Heather.Dohan@pse.com	Date tower decommissioned:	

LOCATION

Country:	United States	Landowner:	Dodge Heirs	GPS map datum:	WGS84
State/Province/Territory:	Washington	Landowner phone:	--	GPS latitude:	46.5522766
Nearest town:	Chard	Landowner e-mail:	--	GPS longitude:	-117.84091
Direction to town:	SW			GPS elevation:	1670 feet 509 meters
Distance to town:	1 miles 2 kilometers	Property manager name:	Harmon Smith	Magnetic declination:	15.8166° E
Nearest airport name:	Scott Seed Farm Airport FAA code 85WA	Manager phone:	509-549-3368		
Direction to airport:	SE	Manager e-mail:	--		
Distance to airport:	3.95745092 miles 6 kilometers				

Topography within 1 mile/1.6 km	North	East	South	West	at Tower
Ridge (>500 ft/>150 m):	X	X	X	X	
Rolling hills (50-500 ft/15-150 m):					X
Flat (<50 ft/<15 m):					
Valley (>500 ft/>150 m):					
Shoreline:					

Surface roughness within 1 mile/1.6 km	North	East	South	West	at Tower
Snow or open water:					
Soil/small rocks:					
Large rock/boulder:					
Plants (1-12 in./1-25 cm):					
Brush (1-3 ft/25-100 cm):	X	X	X	X	X
Trees (>3 ft/>1 m):					
Trees/buildings(>10 ft/>3 m):					
Trees/buildings(>30 ft/>10 m):					

Environment	
Desert:	
Agricultural:	
Grassland:	X
Shrubs:	
Forest:	
Shoreline:	
Open water:	

Corresponding Maps:

Access Requirements

Road Conditions:		**Obstacles:**		**Suggested Transportation:**	spring	summer	fall	winter
Paved:		Gate:						
Gravel:	X	Locked gate:		Automobile:				
Dirt:		Seasonal locks:		4x4 vehicle:	X	X	X	X
Path:	X	Fence:		Quad/motorbike:				
None:		Electric fence:		Snowmobile:				
Distance units:		Railroad:		Boat:				
Miles:		Agricultural:		Aircraft:				
Kilometers:		Animals:		Walking:				

Specific Access Instructions:

From Dodge Junction (Intersection of Highway 12 and 127) go north on 127 at the top of the hill turn left onto Hagen Rd. Go about 1 mile through the canyon and turn left at 46.54833330° N, 117.80040740° W near no trespassing signs. Go about 2 miles on a faint 2 wheeled track long the ridge to the met tower.

Tower Lowering Obstacles	
Large rocks:	
Fences:	
Trees/shrubs:	
Anchor locations:	
Overhead electrical wires:	

Tower Markings/ Fencing	
Fencing:	Cattle panel
Guy guards:	
Marker balls:	
Winch anchor flag:	
Bat detection:	
Bird diverters:	
Tower paint:	X

METEOROLOGY STATION Page 2 of 3

Tower Lock Combination	Gate Combination
007	--

Tubular/Lattice?	Vendor name	Model	Tower height				Tower width at base				Grounding system description
lattice	Sabre	60m 1800 TLWD	179.9868769	feet	54.86	meters	18	inches	45.72	cm	Two grounding rods, logger and tower ground connect to separate rods

Data Logger:	Vendor name	Model	Board revision	Serial number	Station identification	Logger time zone	Logger date	Averaging time: 1 hour	10 min	other	Logger data units				Lightning protection			
Data logger 1:	Campbell	CR1000	1000_SA_6-A	4711	1440	-8 (PST)	6/16/2008		X		English		Metric	X	yes	X	no	
Data logger 2:											English		Metric		yes		no	

Telecommunications/ Manual Collection:	Vendor name	Model	ESN	Serial Number	MIN	MDN	IP Address	Call Schedule Time	Site Calls Every	Service Provider
Communications device:	Airlink	Raven CDMA	09609058898	0915414616	--	512-673-6243	166.155.147.29	1:50 PM	1 Day(s)	Verizon
	IMSI	IMEI	MSISDN/C		SIM		Power Supply	Power Supply Description		
	--	--	--		--		Solar	Campbell SP20 20 Watt PV		

Sensors:		Type	Vendor Name	Model number	Serial number	Slope	Offset	Data logger 1 or 2	Sensor mounting height				Boom length				Boom Direction	Calibration Date	Calibration Agency
Ch.	A1	anemometer	Vector	A100L2/R30 Rotor	8112, W5K	1		1	190.62	feet	58.1	meters	79.92	inches	203.00	cm	139	--	--
Ch.	A2	anemometer	Vector	A100L2/R30 Rotor	9682, JTP	1		1	190.62	feet	58.1	meters	79.53	inches	202.00	cm	319	--	--
Ch.	A3	anemometer	Vector	A100L2/R30 Rotor	9863, ERG	1		1	174.21	feet	53.1	meters	103.15	inches	262.00	cm	138	--	--
Ch.	A4	anemometer	Vector	A100L2/R30 Rotor	10648, IUW	1		1	125.33	feet	38.2	meters	103.15	inches	262.00	cm	138	--	--
Ch.	A5	anemometer	Vector	A100L2/R30 Rotor	10071, FMA	1		1	75.79	feet	23.1	meters	103.15	inches	262.00	cm	138	--	--
Ch.	V1	vane	Vector	W200P Vane	14232, 232	0.071	0	1	162.40	feet	49.5	meters	103.15	inches	262.00	cm	138	--	--
Ch.	V2	vane	Vector	W200P Vane	14226, 226	0.071	0	1	115.81	feet	35.3	meters	103.15	inches	262.00	cm	138	--	--
Ch.	B1	barometer	Vaisala	PTB101B Barometer	B4520009	1		1	6.23	feet	1.9	meters	--	inches	--	cm	--	--	--
Ch.	T1	thermometer	Campbell	107L Temperature	TP001	1		1	7.55	feet	2.3	meters	--	inches	--	cm	0	--	--
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			
Ch.										feet		meters		inches		cm			

Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation	Anchor Type	Usage	Distance	Orientation
Rebar in concrete	Guy			Rebar in concrete	Guy			Rebar in concrete	Guy		

INCIDENT/SITE VISIT LOG: (Reference any documentation completed)						Page 3 of 3
No.	**Date**	**Company**	**Technician**	**Company Phone**	**On-site Client Representative**	**Incident Description/Work Performed**
1	6/16/2008	RES				Tower installation
2	6/16/2009	RES				Logger program update and replacement of satellite modem with CDMA
3	9/16/2009	DNV-GEC	Katy Briggs & Erin Heard	206-387-4200		Site integration visit

Appendix D – Wind Speed, Gross Energy Estimate, and Wake Loss for Each Turbine

Table D-1. Average Wind Speed, Gross Energy Estimate, and Wake Loss for Each Turbine Including Impact of Phase I Wakes Only

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
A-01	6.5	6771	-10.6	6052
A-02	6.5	6779	-11.3	6014
A-03	6.5	6761	-12.1	5941
A-04	6.4	6691	-11.6	5917
A-05	6.1	6264	-10.6	5597
A-06	6.2	6455	-10.6	5768
A-07	6.0	6152	-10.2	5528
A-08	5.9	5925	-10.3	5314
A-09	5.9	5972	-9.5	5404
B-01	7.0	7393	-3.3	7147
B-02	6.9	7332	-4.2	7024
B-03	6.9	7302	-6.7	6811
B-04	6.9	7271	-8.8	6628
B-05	6.9	7303	-9.2	6632
B-06	6.9	7309	-10.2	6565
B-07	6.8	7082	-9.4	6414
B-08	6.9	7309	-5.7	6895
B-09	6.9	7307	-6.8	6810
B-10	6.9	7308	-7.8	6740
C-01	6.8	7095	-8.3	6504
C-02	6.8	7148	-9.7	6456
C-03	6.8	7084	-16.2	5935
C-04	7.0	7422	-8.6	6782
C-05	7.0	7517	-9.0	6837
C-06	7.0	7548	-9.5	6828
C-07	6.9	7296	-9.8	6580
C-08	7.0	7441	-10.4	6665
C-09	7.0	7524	-9.8	6787
D-01	7.0	7413	-10.4	6643
D-02	6.9	7268	-9.9	6546
D-03	7.0	7424	-9.8	6696
D-04	7.0	7482	-9.8	6746
D-05	7.0	7437	-9.6	6722
D-06	7.0	7405	-9.9	6673
D-07	7.0	7390	-9.8	6665

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
D-08	6.9	7210	-9.4	6532
D-09	6.9	7322	-9.1	6658
E-01	7.0	7441	-8.8	6787
E-02	6.9	7264	-8.7	6632
E-03	6.8	7075	-8.0	6510
E-04	6.8	7161	-8.0	6588
E-05	6.8	7189	-8.0	6618
E-06	6.8	7100	-7.7	6551
E-07	6.8	7162	-7.0	6663
F-01	7.0	7418	-2.6	7226
F-02	7.1	7664	-3.8	7369
F-03	7.0	7507	-3.3	7262
F-04	7.0	7438	-3.4	7183
F-05	6.8	7177	-3.3	6941
F-06	6.9	7258	-5.4	6868
F-07	6.8	7057	-3.6	6801
F-08	6.8	7039	-3.4	6798
F-09	6.8	7100	-5.3	6723
G-01	6.9	7214	-6.6	6738
G-02	6.9	7210	-7.6	6664
G-03	7.0	7447	-8.2	6839
G-04	7.0	7551	-7.9	6955
G-05	7.0	7554	-8.0	6952
G-06	7.0	7522	-8.1	6910
G-07	7.0	7515	-8.3	6892
H-01	7.0	7531	-9.5	6818
H-02	7.0	7518	-13.1	6537
H-03	7.1	7685	-8.6	7025
H-04	7.1	7704	-8.8	7028
H-05	7.1	7640	-8.3	7005
H-06	7.1	7601	-7.2	7057
I-01	6.7	6932	-9.6	6266
I-02	6.7	6980	-11.1	6209
I-03	6.7	6971	-9.3	6320
I-04	6.8	7192	-9.6	6502
I-05	6.8	7156	-9.1	6501
I-06	6.8	7123	-10.4	6384
I-07	6.8	7099	-11.4	6293
I-08	7.3	7946	-12.6	6948
I-09	7.3	8072	-9.5	7302
J-01	7.3	7907	-6.8	7373
J-02	7.3	7948	-4.5	7592
J-03	7.3	8037	-4.9	7645

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
J-04	7.3	7953	-6.3	7455
J-05	7.2	7761	-7.4	7189
J-06	7.2	7845	-9.8	7074
J-07	7.1	7606	-9.7	6864
J-08	7.2	7797	-9.7	7040
J-09	7.2	7800	-9.4	7064
K-01	7.1	7608	-9.3	6897
K-02	7.2	7746	-9.9	6980
K-03	7.1	7718	-9.7	6972
K-04	7.2	7783	-10.0	7003
K-05	7.2	7834	-10.4	7016
K-06	7.0	7474	-11.7	6598
K-07	7.1	7572	-9.6	6847
K-08	7.1	7654	-6.2	7181
L-01	7.0	7451	-11.2	6618
L-02	7.1	7644	-12.2	6711
L-03	7.0	7542	-12.3	6613
L-04	7.1	7607	-13.4	6590
L-05	7.1	7706	-14.1	6620
L-06	7.1	7628	-14.9	6495
L-07	7.1	7725	-15.9	6500
L-08	7.2	7839	-16.3	6561
L-09	7.2	7881	-16.8	6559
M-01	7.2	7838	-12.3	6876
M-02	7.2	7901	-10.0	7108
M-03	7.2	7876	-11.2	6996
M-04	7.2	7884	-12.9	6868
M-05	7.2	7793	-16.7	6491
M-06	7.3	7984	-14.4	6832
M-07	7.2	7802	-7.2	7238
M-08	7.2	7835	-4.3	7495
M-09	7.2	7869	-3.4	7600
N-01	7.2	7897	-2.8	7674
N-02	7.3	7956	-1.5	7839
N-03	7.2	7770	-2.7	7564
N-04	7.2	7850	-2.2	7681
N-05	7.3	7927	-1.9	7776
N-06	7.3	7942	-2.4	7752
N-07	7.3	7969	-1.6	7843
N-08	7.3	8034	-0.6	7983
O-01	6.8	7131	-5.9	6708
O-02	6.7	7008	-7.9	6451
O-03	6.8	7061	-9.0	6425

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
O-04	6.8	7054	-9.2	6409
O-05	6.8	7039	-10.2	6324
O-06	6.8	7132	-10.9	6355
O-07	6.8	7084	-4.7	6754
O-08	6.8	7161	-3.5	6907
O-09	6.8	7115	-3.3	6883
P-01	6.8	7066	-5.8	6657
P-02	6.8	7067	-2.6	6883
P-03	6.8	7093	-2.8	6893
P-04	6.8	7076	-3.4	6835
P-05	6.8	7098	-3.2	6869
P-06	6.8	7099	-2.7	6905
Q-01	6.8	7040	-4.0	6760
Q-02	6.7	7005	-2.6	6825
Q-03	6.7	6947	-11.8	6129
Q-04	6.7	6863	-7.1	6376
Q-05	6.6	6839	-3.2	6619
Q-06	6.6	6804	-1.1	6726
R-01	7.1	7681	-3.0	7453
R-02	7.1	7638	-3.5	7369
R-03	7.1	7643	-4.3	7314
R-04	7.3	7929	-2.3	7749
R-05	7.2	7900	-2.7	7688
R-06	7.3	7937	-3.2	7680
R-07	7.2	7859	-3.8	7559
R-08	7.2	7874	-6.7	7350
R-09	7.2	7747	-3.4	7484
R-10	7.2	7820	-3.6	7538
Average	**7.0**	**7405**	**-7.9**	**6823**

Table D-2. Average Wind Speed, Gross Energy Estimate, and Wake Loss for Each Turbine Including Impact of Phase I and II Wakes

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
A-01	6.5	6771	-13.9	5832
A-02	6.5	6779	-14.6	5788
A-03	6.5	6761	-15.5	5714
A-04	6.4	6691	-14.7	5706
A-05	6.1	6264	-13.7	5408
A-06	6.2	6455	-13.6	5579
A-07	6.0	6152	-13.0	5350
A-08	5.9	5925	-12.8	5169
A-09	5.9	5972	-11.9	5262
B-01	7.0	7393	-7.5	6840
B-02	6.9	7332	-8.6	6703
B-03	6.9	7302	-11.2	6482
B-04	6.9	7271	-13.2	6312
B-05	6.9	7303	-13.7	6304
B-06	6.9	7309	-14.7	6234
B-07	6.8	7082	-14.0	6092
B-08	6.9	7309	-11.9	6441
B-09	6.9	7307	-12.9	6367
B-10	6.9	7308	-13.4	6326
C-01	6.8	7095	-13.0	6173
C-02	6.8	7148	-14.4	6122
C-03	6.8	7084	-21.0	5600
C-04	7.0	7422	-13.7	6407
C-05	7.0	7517	-14.0	6468
C-06	7.0	7548	-14.5	6452
C-07	6.9	7296	-14.8	6219
C-08	7.0	7441	-14.7	6350
C-09	7.0	7524	-14.0	6474
D-01	7.0	7413	-14.3	6353
D-02	6.9	7268	-13.7	6276
D-03	7.0	7424	-13.3	6435
D-04	7.0	7482	-13.3	6490
D-05	7.0	7437	-12.8	6487
D-06	7.0	7405	-12.9	6447
D-07	7.0	7390	-12.8	6444
D-08	6.9	7210	-12.3	6324
D-09	6.9	7322	-11.9	6450
E-01	7.0	7441	-11.6	6580
E-02	6.9	7264	-11.4	6435
E-03	6.8	7075	-10.6	6324

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
E-04	6.8	7161	-10.6	6405
E-05	6.8	7189	-10.5	6437
E-06	6.8	7100	-10.2	6379
E-07	6.8	7162	-9.4	6492
F-01	7.0	7418	-14.6	6337
F-02	7.1	7664	-15.3	6490
F-03	7.0	7507	-14.4	6426
F-04	7.0	7438	-14.1	6389
F-05	6.8	7177	-13.6	6203
F-06	6.9	7258	-14.3	6219
F-07	6.8	7057	-12.9	6146
F-08	6.8	7039	-12.5	6156
F-09	6.8	7100	-13.5	6138
G-01	6.9	7214	-14.3	6184
G-02	6.9	7210	-14.6	6155
G-03	7.0	7447	-14.5	6367
G-04	7.0	7551	-13.5	6534
G-05	7.0	7554	-13.3	6550
G-06	7.0	7522	-13.1	6535
G-07	7.0	7515	-12.9	6543
H-01	7.0	7531	-13.8	6490
H-02	7.0	7518	-17.2	6223
H-03	7.1	7685	-12.9	6697
H-04	7.1	7704	-12.9	6707
H-05	7.1	7640	-12.2	6706
H-06	7.1	7601	-10.8	6781
I-01	6.7	6932	-20.5	5508
I-02	6.7	6980	-20.6	5540
I-03	6.7	6971	-18.6	5678
I-04	6.8	7192	-17.8	5909
I-05	6.8	7156	-16.9	5945
I-06	6.8	7123	-17.9	5846
I-07	6.8	7099	-18.6	5780
I-08	7.3	7946	-20.6	6308
I-09	7.3	8072	-17.7	6647
J-01	7.3	7907	-14.1	6788
J-02	7.3	7948	-12.1	6983
J-03	7.3	8037	-11.7	7099
J-04	7.3	7953	-12.4	6969
J-05	7.2	7761	-12.8	6769
J-06	7.2	7845	-14.0	6750
J-07	7.1	7606	-13.7	6561
J-08	7.2	7797	-13.1	6776

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
J-09	7.2	7800	-12.7	6812
K-01	7.1	7608	-12.3	6670
K-02	7.2	7746	-12.7	6762
K-03	7.1	7718	-12.4	6759
K-04	7.2	7783	-12.9	6777
K-05	7.2	7834	-13.3	6790
K-06	7.0	7474	-15.9	6285
K-07	7.1	7572	-15.6	6388
K-08	7.1	7654	-14.1	6572
L-01	7.0	7451	-14.2	6392
L-02	7.1	7644	-15.0	6499
L-03	7.0	7542	-15.0	6411
L-04	7.1	7607	-16.0	6388
L-05	7.1	7706	-16.7	6420
L-06	7.1	7628	-17.5	6295
L-07	7.1	7725	-18.5	6299
L-08	7.2	7839	-18.8	6361
L-09	7.2	7881	-19.3	6359
M-01	7.2	7838	-14.9	6674
M-02	7.2	7901	-12.9	6883
M-03	7.2	7876	-14.2	6759
M-04	7.2	7884	-16.3	6600
M-05	7.2	7793	-20.5	6197
M-06	7.3	7984	-19.8	6404
M-07	7.2	7802	-14.1	6702
M-08	7.2	7835	-11.7	6918
M-09	7.2	7869	-11.0	7002
N-01	7.2	7897	-10.8	7042
N-02	7.3	7956	-10.1	7150
N-03	7.2	7770	-7.9	7159
N-04	7.2	7850	-7.3	7278
N-05	7.3	7927	-6.8	7387
N-06	7.3	7942	-8.4	7271
N-07	7.3	7969	-9.8	7192
N-08	7.3	8034	-10.4	7196
O-01	6.8	7131	-12.3	6251
O-02	6.7	7008	-12.9	6105
O-03	6.8	7061	-13.3	6125
O-04	6.8	7054	-13.0	6139
O-05	6.8	7039	-13.7	6077
O-06	6.8	7132	-14.1	6128
O-07	6.8	7084	-8.0	6515
O-08	6.8	7161	-7.0	6660

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
O-09	6.8	7115	-6.7	6635
P-01	6.8	7066	-9.2	6417
P-02	6.8	7067	-6.6	6603
P-03	6.8	7093	-6.9	6604
P-04	6.8	7076	-7.6	6536
P-05	6.8	7098	-7.6	6556
P-06	6.8	7099	-7.8	6548
Q-01	6.8	7040	-7.3	6525
Q-02	6.7	7005	-6.2	6572
Q-03	6.7	6947	-14.9	5913
Q-04	6.7	6863	-10.2	6164
Q-05	6.6	6839	-6.6	6384
Q-06	6.6	6804	-5.2	6447
R-01	7.1	7681	-19.2	6207
R-02	7.1	7638	-19.5	6146
R-03	7.1	7643	-19.9	6123
R-04	7.3	7929	-20.9	6274
R-05	7.2	7900	-15.3	6690
R-06	7.3	7937	-16.2	6654
R-07	7.2	7859	-16.3	6575
R-08	7.2	7874	-18.9	6384
R-09	7.2	7747	-21.7	6068
R-10	7.2	7820	-15.6	6600
Average	**7.0**	**7405**	**-13.5**	**6406**

Table D-3. Average Wind Speed, Gross Energy Estimate, and Wake Loss for Each Turbine Including Impact of Phase I and III Wakes

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
A-01	6.5	6771	-11.2	6009
A-02	6.5	6779	-11.9	5974
A-03	6.5	6761	-12.7	5901
A-04	6.4	6691	-12.1	5878
A-05	6.1	6264	-11.1	5568
A-06	6.2	6455	-11.1	5738
A-07	6.0	6152	-10.6	5500
A-08	5.9	5925	-10.7	5292
A-09	5.9	5972	-9.9	5382
B-01	7.0	7393	-4.3	7072
B-02	6.9	7332	-5.2	6948
B-03	6.9	7302	-7.7	6739
B-04	6.9	7271	-9.8	6561
B-05	6.9	7303	-10.1	6568
B-06	6.9	7309	-11.0	6502
B-07	6.8	7082	-10.3	6354
B-08	6.9	7309	-6.9	6803
B-09	6.9	7307	-8.0	6722
B-10	6.9	7308	-8.8	6664
C-01	6.8	7095	-9.1	6449
C-02	6.8	7148	-10.5	6401
C-03	6.8	7084	-17.0	5878
C-04	7.0	7422	-9.5	6719
C-05	7.0	7517	-9.8	6778
C-06	7.0	7548	-10.3	6770
C-07	6.9	7296	-10.6	6524
C-08	7.0	7441	-11.1	6614
C-09	7.0	7524	-10.5	6735
D-01	7.0	7413	-11.0	6595
D-02	6.9	7268	-10.5	6505
D-03	7.0	7424	-10.3	6657
D-04	7.0	7482	-10.4	6706
D-05	7.0	7437	-10.1	6684
D-06	7.0	7405	-10.4	6638
D-07	7.0	7390	-10.3	6630
D-08	6.9	7210	-9.8	6502
D-09	6.9	7322	-9.5	6628
E-01	7.0	7441	-9.2	6756
E-02	6.9	7264	-9.1	6601
E-03	6.8	7075	-8.4	6481

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
E-04	6.8	7161	-8.4	6559
E-05	6.8	7189	-8.3	6589
E-06	6.8	7100	-8.1	6524
E-07	6.8	7162	-7.4	6635
F-01	7.0	7418	-4.4	7089
F-02	7.1	7664	-5.7	7230
F-03	7.0	7507	-5.1	7128
F-04	7.0	7438	-5.2	7053
F-05	6.8	7177	-5.0	6820
F-06	6.9	7258	-6.8	6762
F-07	6.8	7057	-5.1	6698
F-08	6.8	7039	-4.9	6696
F-09	6.8	7100	-6.7	6626
G-01	6.9	7214	-7.9	6644
G-02	6.9	7210	-8.8	6578
G-03	7.0	7447	-9.2	6759
G-04	7.0	7551	-8.9	6881
G-05	7.0	7554	-8.9	6885
G-06	7.0	7522	-9.0	6849
G-07	7.0	7515	-9.0	6835
H-01	7.0	7531	-10.2	6765
H-02	7.0	7518	-13.7	6485
H-03	7.1	7685	-9.4	6966
H-04	7.1	7704	-9.5	6970
H-05	7.1	7640	-9.0	6949
H-06	7.1	7601	-7.8	7005
I-01	6.7	6932	-11.4	6144
I-02	6.7	6980	-12.7	6093
I-03	6.7	6971	-11.0	6205
I-04	6.8	7192	-11.2	6385
I-05	6.8	7156	-10.7	6389
I-06	6.8	7123	-11.9	6279
I-07	6.8	7099	-12.8	6189
I-08	7.3	7946	-14.3	6812
I-09	7.3	8072	-11.1	7175
J-01	7.3	7907	-8.3	7251
J-02	7.3	7948	-6.1	7463
J-03	7.3	8037	-6.5	7518
J-04	7.3	7953	-7.7	7340
J-05	7.2	7761	-8.7	7087
J-06	7.2	7845	-10.8	7001
J-07	7.1	7606	-10.6	6801
J-08	7.2	7797	-10.4	6987

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
J-09	7.2	7800	-10.0	7018
K-01	7.1	7608	-9.8	6859
K-02	7.2	7746	-10.4	6944
K-03	7.1	7718	-10.1	6942
K-04	7.2	7783	-10.4	6976
K-05	7.2	7834	-10.8	6989
K-06	7.0	7474	-12.0	6574
K-07	7.1	7572	-9.9	6824
K-08	7.1	7654	-6.5	7156
L-01	7.0	7451	-11.8	6570
L-02	7.1	7644	-12.7	6671
L-03	7.0	7542	-12.8	6577
L-04	7.1	7607	-13.8	6558
L-05	7.1	7706	-14.5	6590
L-06	7.1	7628	-15.2	6467
L-07	7.1	7725	-16.2	6475
L-08	7.2	7839	-16.6	6537
L-09	7.2	7881	-17.1	6537
M-01	7.2	7838	-12.5	6857
M-02	7.2	7901	-10.3	7085
M-03	7.2	7876	-11.5	6972
M-04	7.2	7884	-13.2	6846
M-05	7.2	7793	-17.0	6471
M-06	7.3	7984	-14.7	6813
M-07	7.2	7802	-7.4	7222
M-08	7.2	7835	-4.6	7475
M-09	7.2	7869	-3.7	7578
N-01	7.2	7897	-3.1	7649
N-02	7.3	7956	-1.8	7812
N-03	7.2	7770	-2.9	7544
N-04	7.2	7850	-2.4	7659
N-05	7.3	7927	-2.2	7753
N-06	7.3	7942	-2.7	7730
N-07	7.3	7969	-1.9	7821
N-08	7.3	8034	-0.9	7961
O-01	6.8	7131	-7.2	6619
O-02	6.7	7008	-9.0	6377
O-03	6.8	7061	-10.0	6358
O-04	6.8	7054	-10.0	6351
O-05	6.8	7039	-10.9	6272
O-06	6.8	7132	-11.5	6308
O-07	6.8	7084	-5.2	6712
O-08	6.8	7161	-4.2	6861

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
O-09	6.8	7115	-3.9	6837
P-01	6.8	7066	-6.4	6616
P-02	6.8	7067	-3.4	6828
P-03	6.8	7093	-3.7	6830
P-04	6.8	7076	-4.4	6767
P-05	6.8	7098	-4.3	6793
P-06	6.8	7099	-3.9	6824
Q-01	6.8	7040	-4.6	6717
Q-02	6.7	7005	-3.2	6782
Q-03	6.7	6947	-12.2	6100
Q-04	6.7	6863	-7.5	6349
Q-05	6.6	6839	-3.7	6587
Q-06	6.6	6804	-1.7	6689
R-01	7.1	7681	-5.5	7262
R-02	7.1	7638	-6.0	7180
R-03	7.1	7643	-6.7	7132
R-04	7.3	7929	-4.8	7552
R-05	7.2	7900	-5.1	7499
R-06	7.3	7937	-5.6	7494
R-07	7.2	7859	-6.1	7379
R-08	7.2	7874	-8.8	7180
R-09	7.2	7747	-5.5	7324
R-10	7.2	7820	-5.6	7384
Average	**7.0**	**7405**	**-8.7**	**6758**

Table D-4. Average Wind Speed, Gross Energy Estimate, and Wake Loss for Each Turbine Including Impact of Phase I, II and III Wakes

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
A-01	6.5	6771	-14.2	5807
A-02	6.5	6779	-15.0	5766
A-03	6.5	6761	-15.8	5692
A-04	6.4	6691	-15.0	5687
A-05	6.1	6264	-13.9	5393
A-06	6.2	6455	-13.8	5563
A-07	6.0	6152	-13.3	5336
A-08	5.9	5925	-12.9	5158
A-09	5.9	5972	-12.1	5251
B-01	7.0	7393	-8.1	6794
B-02	6.9	7332	-9.2	6657
B-03	6.9	7302	-11.9	6436
B-04	6.9	7271	-13.8	6264
B-05	6.9	7303	-14.3	6256
B-06	6.9	7309	-15.3	6190
B-07	6.8	7082	-14.5	6055
B-08	6.9	7309	-12.7	6381
B-09	6.9	7307	-13.7	6310
B-10	6.9	7308	-14.1	6275
C-01	6.8	7095	-13.5	6138
C-02	6.8	7148	-14.9	6085
C-03	6.8	7084	-21.6	5555
C-04	7.0	7422	-14.2	6367
C-05	7.0	7517	-14.4	6431
C-06	7.0	7548	-14.9	6421
C-07	6.9	7296	-15.2	6190
C-08	7.0	7441	-15.1	6320
C-09	7.0	7524	-14.4	6441
D-01	7.0	7413	-14.7	6326
D-02	6.9	7268	-14.0	6254
D-03	7.0	7424	-13.6	6416
D-04	7.0	7482	-13.5	6471
D-05	7.0	7437	-13.0	6468
D-06	7.0	7405	-13.2	6429
D-07	7.0	7390	-13.0	6428
D-08	6.9	7210	-12.5	6310
D-09	6.9	7322	-12.1	6437
E-01	7.0	7441	-11.8	6566
E-02	6.9	7264	-11.6	6419
E-03	6.8	7075	-10.8	6308

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
E-04	6.8	7161	-10.8	6389
E-05	6.8	7189	-10.7	6422
E-06	6.8	7100	-10.4	6365
E-07	6.8	7162	-9.6	6477
F-01	7.0	7418	-15.8	6246
F-02	7.1	7664	-16.5	6402
F-03	7.0	7507	-15.5	6345
F-04	7.0	7438	-15.1	6315
F-05	6.8	7177	-14.5	6134
F-06	6.9	7258	-15.1	6161
F-07	6.8	7057	-13.7	6092
F-08	6.8	7039	-13.3	6103
F-09	6.8	7100	-14.3	6086
G-01	6.9	7214	-15.0	6132
G-02	6.9	7210	-15.3	6106
G-03	7.0	7447	-15.1	6322
G-04	7.0	7551	-14.0	6497
G-05	7.0	7554	-13.8	6514
G-06	7.0	7522	-13.6	6503
G-07	7.0	7515	-13.4	6511
H-01	7.0	7531	-14.2	6459
H-02	7.0	7518	-17.6	6192
H-03	7.1	7685	-13.3	6661
H-04	7.1	7704	-13.4	6671
H-05	7.1	7640	-12.7	6672
H-06	7.1	7601	-11.2	6747
I-01	6.7	6932	-21.8	5424
I-02	6.7	6980	-21.8	5456
I-03	6.7	6971	-19.7	5600
I-04	6.8	7192	-18.9	5831
I-05	6.8	7156	-18.0	5866
I-06	6.8	7123	-19.0	5770
I-07	6.8	7099	-19.6	5706
I-08	7.3	7946	-21.8	6217
I-09	7.3	8072	-18.8	6558
J-01	7.3	7907	-15.1	6710
J-02	7.3	7948	-13.2	6903
J-03	7.3	8037	-12.6	7021
J-04	7.3	7953	-13.3	6897
J-05	7.2	7761	-13.6	6705
J-06	7.2	7845	-14.6	6701
J-07	7.1	7606	-14.3	6519
J-08	7.2	7797	-13.5	6741

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
J-09	7.2	7800	-13.0	6782
K-01	7.1	7608	-12.7	6645
K-02	7.2	7746	-13.0	6738
K-03	7.1	7718	-12.7	6737
K-04	7.2	7783	-13.2	6757
K-05	7.2	7834	-13.6	6772
K-06	7.0	7474	-16.1	6267
K-07	7.1	7572	-15.9	6371
K-08	7.1	7654	-14.4	6555
L-01	7.0	7451	-14.7	6359
L-02	7.1	7644	-15.4	6470
L-03	7.0	7542	-15.3	6387
L-04	7.1	7607	-16.3	6366
L-05	7.1	7706	-17.0	6400
L-06	7.1	7628	-17.7	6277
L-07	7.1	7725	-18.7	6282
L-08	7.2	7839	-19.0	6347
L-09	7.2	7881	-19.5	6345
M-01	7.2	7838	-15.0	6661
M-02	7.2	7901	-13.1	6868
M-03	7.2	7876	-14.4	6743
M-04	7.2	7884	-16.5	6585
M-05	7.2	7793	-20.7	6183
M-06	7.3	7984	-20.0	6390
M-07	7.2	7802	-14.3	6689
M-08	7.2	7835	-11.9	6903
M-09	7.2	7869	-11.2	6987
N-01	7.2	7897	-11.0	7026
N-02	7.3	7956	-10.3	7135
N-03	7.2	7770	-8.0	7148
N-04	7.2	7850	-7.4	7266
N-05	7.3	7927	-7.0	7375
N-06	7.3	7942	-8.6	7260
N-07	7.3	7969	-9.9	7180
N-08	7.3	8034	-10.6	7185
O-01	6.8	7131	-13.1	6195
O-02	6.7	7008	-13.6	6057
O-03	6.8	7061	-13.9	6079
O-04	6.8	7054	-13.6	6097
O-05	6.8	7039	-14.2	6039
O-06	6.8	7132	-14.6	6092
O-07	6.8	7084	-8.4	6486
O-08	6.8	7161	-7.4	6628

Turbine ID	Assigned 80-m Wind Speed (m/s)	Gross Energy (MWh/yr)	Wake Effect (%)	Gross Energy minus Wakes (MWh/yr)
O-09	6.8	7115	-7.2	6604
P-01	6.8	7066	-9.6	6389
P-02	6.8	7067	-7.1	6565
P-03	6.8	7093	-7.5	6562
P-04	6.8	7076	-8.3	6491
P-05	6.8	7098	-8.3	6507
P-06	6.8	7099	-8.5	6495
Q-01	6.8	7040	-7.7	6496
Q-02	6.7	7005	-6.6	6542
Q-03	6.7	6947	-15.2	5892
Q-04	6.7	6863	-10.5	6144
Q-05	6.6	6839	-7.0	6361
Q-06	6.6	6804	-5.6	6422
R-01	7.1	7681	-20.8	6085
R-02	7.1	7638	-21.1	6027
R-03	7.1	7643	-21.4	6010
R-04	7.3	7929	-22.5	6147
R-05	7.2	7900	-16.9	6568
R-06	7.3	7937	-17.7	6536
R-07	7.2	7859	-17.7	6464
R-08	7.2	7874	-20.3	6275
R-09	7.2	7747	-22.9	5971
R-10	7.2	7820	-16.8	6510
Average	**7.0**	**7405**	**-14.0**	**6365**

Appendix E – Net Turbine Energy for Four Wake Loss Scenarios

Table E-1. Average Annual Net Energy Production Estimate for Each Turbine Including Impact of Phase I Wakes Only

Turbine ID	Net Energy (MWh/yr)	Turbine ID	Net Energy (MWh/yr)	Turbine ID	Net Energy (MWh/yr)
A-01	5350	C-07	5817	F-07	6012
A-02	5317	C-08	5892	F-08	6010
A-03	5252	C-09	6000	F-09	5944
A-04	5231	D-01	5873	G-01	5957
A-05	4948	D-02	5787	G-02	5891
A-06	5100	D-03	5920	G-03	6046
A-07	4887	D-04	5964	G-04	6148
A-08	4698	D-05	5943	G-05	6146
A-09	4777	D-06	5900	G-06	6109
B-01	6319	D-07	5892	G-07	6093
B-02	6209	D-08	5775	H-01	6027
B-03	6022	D-09	5886	H-02	5779
B-04	5859	E-01	6000	H-03	6211
B-05	5863	E-02	5863	H-04	6214
B-06	5804	E-03	5756	H-05	6193
B-07	5670	E-04	5824	H-06	6239
B-08	6095	E-05	5850	I-01	5540
B-09	6021	E-06	5792	I-02	5489
B-10	5958	E-07	5890	I-03	5587
C-01	5750	F-01	6388	I-04	5748
C-02	5707	F-02	6515	I-05	5748
C-03	5247	F-03	6420	I-06	5644
C-04	5995	F-04	6351	I-07	5564
C-05	6044	F-05	6136	I-08	6143
C-06	6037	F-06	6072	I-09	6455

Turbine ID	Net Energy (MWh/yr)
J-01	6518
J-02	6712
J-03	6759
J-04	6591
J-05	6355
J-06	6254
J-07	6068
J-08	6224
J-09	6245
K-01	6098
K-02	6171
K-03	6164
K-04	6191
K-05	6203
K-06	5833
K-07	6053
K-08	6349
L-01	5850
L-02	5933
L-03	5846
L-04	5826
L-05	5853
L-06	5742
L-07	5747
L-08	5800

Turbine ID	Net Energy (MWh/yr)
L-09	5799
M-01	6079
M-02	6284
M-03	6185
M-04	6072
M-05	5738
M-06	6040
M-07	6399
M-08	6626
M-09	6719
N-01	6784
N-02	6930
N-03	6687
N-04	6791
N-05	6874
N-06	6853
N-07	6934
N-08	7058
O-01	5930
O-02	5703
O-03	5680
O-04	5666
O-05	5591
O-06	5619
O-07	5971

Turbine ID	Net Energy (MWh/yr)
O-08	6107
O-09	6085
P-01	5885
P-02	6085
P-03	6094
P-04	6043
P-05	6072
P-06	6104
Q-01	5976
Q-02	6034
Q-03	5418
Q-04	5637
Q-05	5852
Q-06	5946
R-01	6589
R-02	6514
R-03	6466
R-04	6851
R-05	6797
R-06	6789
R-07	6682
R-08	6498
R-09	6616
R-10	6664
Total (GWh/yr)	**899**

Table E-2. Average Annual Net Energy Production Estimate for Each Turbine Including Impact of Phase I and II Wakes

Turbine ID	Net Energy (MWh/yr)	Turbine ID	Net Energy (MWh/yr)	Turbine ID	Net Energy (MWh/yr)
A-01	5134	D-01	5593	G-04	5752
A-02	5096	D-02	5525	G-05	5766
A-03	5031	D-03	5665	G-06	5753
A-04	5024	D-04	5713	G-07	5760
A-05	4761	D-05	5711	H-01	5714
A-06	4911	D-06	5675	H-02	5478
A-07	4710	D-07	5673	H-03	5896
A-08	4550	D-08	5567	H-04	5904
A-09	4632	D-09	5678	H-05	5904
B-01	6022	E-01	5793	H-06	5969
B-02	5901	E-02	5665	I-01	4849
B-03	5706	E-03	5568	I-02	4877
B-04	5557	E-04	5638	I-03	4998
B-05	5550	E-05	5667	I-04	5202
B-06	5488	E-06	5616	I-05	5233
B-07	5363	E-07	5715	I-06	5146
B-08	5670	F-01	5579	I-07	5089
B-09	5605	F-02	5713	I-08	5553
B-10	5569	F-03	5657	I-09	5852
C-01	5435	F-04	5624	J-01	5976
C-02	5389	F-05	5460	J-02	6147
C-03	4929	F-06	5475	J-03	6249
C-04	5641	F-07	5411	J-04	6135
C-05	5694	F-08	5420	J-05	5959
C-06	5680	F-09	5404	J-06	5942
C-07	5475	G-01	5444	J-07	5776
C-08	5590	G-02	5418	J-08	5965
C-09	5699	G-03	5605	J-09	5997

Turbine ID	Net Energy (MWh/yr)
K-01	5872
K-02	5953
K-03	5950
K-04	5966
K-05	5978
K-06	5533
K-07	5623
K-08	5785
L-01	5627
L-02	5721
L-03	5644
L-04	5624
L-05	5651
L-06	5541
L-07	5545
L-08	5600
L-09	5598
M-01	5875
M-02	6059
M-03	5950
M-04	5810
M-05	5456

Turbine ID	Net Energy (MWh/yr)
M-06	5638
M-07	5900
M-08	6090
M-09	6164
N-01	6199
N-02	6295
N-03	6302
N-04	6407
N-05	6503
N-06	6401
N-07	6331
N-08	6335
O-01	5503
O-02	5375
O-03	5392
O-04	5405
O-05	5349
O-06	5394
O-07	5736
O-08	5863
O-09	5841
P-01	5649

Turbine ID	Net Energy (MWh/yr)
P-02	5813
P-03	5814
P-04	5754
P-05	5771
P-06	5765
Q-01	5744
Q-02	5786
Q-03	5206
Q-04	5426
Q-05	5620
Q-06	5676
R-01	5464
R-02	5410
R-03	5390
R-04	5523
R-05	5889
R-06	5858
R-07	5788
R-08	5620
R-09	5341
R-10	5810
Total (GWh/yr)	**840**

Table E-3. Average Annual Net Energy Production Estimate for Each Turbine Including Impact of Phase I and III Wakes

Turbine ID	Net Energy (MWh/yr)
A-01	5311
A-02	5280
A-03	5215
A-04	5195
A-05	4921
A-06	5072
A-07	4861
A-08	4677
A-09	4756
B-01	6250
B-02	6141
B-03	5956
B-04	5799
B-05	5805
B-06	5747
B-07	5616
B-08	6013
B-09	5941
B-10	5890
C-01	5700
C-02	5657
C-03	5195
C-04	5938
C-05	5990
C-06	5984
C-07	5766
C-08	5846
C-09	5953

Turbine ID	Net Energy (MWh/yr)
D-01	5829
D-02	5749
D-03	5883
D-04	5927
D-05	5908
D-06	5866
D-07	5860
D-08	5747
D-09	5858
E-01	5971
E-02	5834
E-03	5728
E-04	5797
E-05	5824
E-06	5766
E-07	5864
F-01	6265
F-02	6390
F-03	6299
F-04	6234
F-05	6028
F-06	5976
F-07	5920
F-08	5918
F-09	5856
G-01	5872
G-02	5814
G-03	5973

Turbine ID	Net Energy (MWh/yr)
G-04	6081
G-05	6085
G-06	6053
G-07	6041
H-01	5979
H-02	5732
H-03	6156
H-04	6160
H-05	6142
H-06	6191
I-01	5430
I-02	5385
I-03	5484
I-04	5643
I-05	5647
I-06	5549
I-07	5470
I-08	6021
I-09	6341
J-01	6408
J-02	6596
J-03	6645
J-04	6487
J-05	6264
J-06	6187
J-07	6010
J-08	6175
J-09	6203

Turbine ID	Net Energy (MWh/yr)
K-01	6062
K-02	6137
K-03	6136
K-04	6165
K-05	6177
K-06	5810
K-07	6031
K-08	6325
L-01	5807
L-02	5896
L-03	5813
L-04	5796
L-05	5824
L-06	5716
L-07	5723
L-08	5778
L-09	5778
M-01	6061
M-02	6262
M-03	6162
M-04	6051
M-05	5719

Turbine ID	Net Energy (MWh/yr)
M-06	6021
M-07	6383
M-08	6606
M-09	6698
N-01	6761
N-02	6904
N-03	6668
N-04	6770
N-05	6853
N-06	6832
N-07	6912
N-08	7037
O-01	5850
O-02	5636
O-03	5619
O-04	5613
O-05	5544
O-06	5576
O-07	5933
O-08	6064
O-09	6043
P-01	5847

Turbine ID	Net Energy (MWh/yr)
P-02	6034
P-03	6037
P-04	5981
P-05	6004
P-06	6031
Q-01	5937
Q-02	5994
Q-03	5392
Q-04	5611
Q-05	5821
Q-06	5912
R-01	6418
R-02	6346
R-03	6303
R-04	6675
R-05	6628
R-06	6624
R-07	6522
R-08	6346
R-09	6473
R-10	6526
Total (GWh/yr)	**890**

Table E-4. Average Annual Net Energy Production Estimate for Each Turbine Including Impact of Phase I, II and III Wakes

Turbine ID	Net Energy (MWh/yr)	Turbine ID	Net Energy (MWh/yr)	Turbine ID	Net Energy (MWh/yr)
A-01	5108	D-01	5565	G-04	5715
A-02	5072	D-02	5502	G-05	5731
A-03	5007	D-03	5644	G-06	5720
A-04	5002	D-04	5693	G-07	5728
A-05	4744	D-05	5689	H-01	5682
A-06	4894	D-06	5655	H-02	5447
A-07	4694	D-07	5654	H-03	5860
A-08	4537	D-08	5551	H-04	5868
A-09	4620	D-09	5662	H-05	5869
B-01	5977	E-01	5776	H-06	5935
B-02	5856	E-02	5647	I-01	4772
B-03	5662	E-03	5549	I-02	4799
B-04	5510	E-04	5620	I-03	4927
B-05	5503	E-05	5650	I-04	5130
B-06	5446	E-06	5600	I-05	5160
B-07	5326	E-07	5698	I-06	5076
B-08	5613	F-01	5495	I-07	5019
B-09	5550	F-02	5632	I-08	5469
B-10	5520	F-03	5582	I-09	5769
C-01	5400	F-04	5555	J-01	5902
C-02	5353	F-05	5396	J-02	6072
C-03	4887	F-06	5420	J-03	6176
C-04	5601	F-07	5359	J-04	6067
C-05	5658	F-08	5369	J-05	5899
C-06	5648	F-09	5354	J-06	5895
C-07	5445	G-01	5394	J-07	5735
C-08	5560	G-02	5371	J-08	5930
C-09	5666	G-03	5561	J-09	5966

Turbine ID	Net Energy (MWh/yr)
K-01	5845
K-02	5927
K-03	5927
K-04	5944
K-05	5957
K-06	5513
K-07	5604
K-08	5766
L-01	5594
L-02	5692
L-03	5619
L-04	5600
L-05	5630
L-06	5522
L-07	5526
L-08	5583
L-09	5582
M-01	5859
M-02	6041
M-03	5932
M-04	5792
M-05	5439

Turbine ID	Net Energy (MWh/yr)
M-06	5621
M-07	5885
M-08	6073
M-09	6146
N-01	6181
N-02	6276
N-03	6288
N-04	6392
N-05	6488
N-06	6387
N-07	6316
N-08	6321
O-01	5450
O-02	5328
O-03	5348
O-04	5364
O-05	5313
O-06	5359
O-07	5705
O-08	5831
O-09	5810
P-01	5620

Turbine ID	Net Energy (MWh/yr)
P-02	5775
P-03	5773
P-04	5710
P-05	5724
P-06	5713
Q-01	5714
Q-02	5755
Q-03	5183
Q-04	5405
Q-05	5596
Q-06	5650
R-01	5353
R-02	5302
R-03	5287
R-04	5407
R-05	5778
R-06	5750
R-07	5686
R-08	5520
R-09	5252
R-10	5727
Total (GWh/yr)	**834**

GARRAD HASSAN

ASSESSMENT OF THE ENERGY PRODUCTION OF THE PROPOSED KLONDIKE III WIND FARM

Client	**PPM Energy, Inc.**
Contact	Tim Hughes
Document No	4941/AR/01
Issue	C
Status	FINAL
Classification	Client's Discretion
Date	30 June 2006

Author:

R Sweet

Checked by:

C Johnson

Approved by:

A Schwarz

DISCLAIMER

Acceptance of this document by the client is on the basis that Garrad Hassan America are not in any way to be held responsible for the application or use made of the findings of the results from the analysis and that such responsibility remains with the client.

GH has not conducted wind measurements itself and cannot, therefore, be responsible for the accuracy of the data supplied to it.

Key To Document Classification

Strictly Confidential	:	Recipients only
Private and Confidential	:	For disclosure to individuals directly concerned within the recipient's organisation
Commercial in Confidence	:	Not to be disclosed outside the recipient's organisation
GH only	:	Not to be disclosed to non GH staff
Client's Discretion	:	Distribution at the discretion of the client subject to contractual agreement
Published	:	Available to the general public

Revision History

Issue	Issue date	Summary
A	05.05.06	Original Issue
B	18.05.06	Draft revision
C	30.06.06	Final Issue

Circulation:	Copy No:
Client	1 & 2
GH Bristol	3
GH San Diego	4

Copy No: _____

CONTENTS

		Page
1	**INTRODUCTION**	**1**
2	**DESCRIPTION OF THE SITE AND MONITORING EQUIPMENT**	**2**
	2.1 The site	2
	2.2 Monitoring equipment	2
3	**SELECTION OF A REFERENCE METEOROLOGICAL STATION**	**7**
4	**WIND DATA**	**8**
	4.1 Wind data recorded at the site	8
5	**DESCRIPTION OF THE PROPOSED WIND FARM**	**9**
	5.1 The wind turbine	9
	5.2 Wind farm layout	9
6	**RESULTS OF THE ANALYSIS**	**10**
	6.1 Long-term mean wind regime at Klondike site masts	11
	6.2 Hub height wind speeds	13
	6.3 Site wind speed variations	14
	6.4 Projected energy production	15
	6.5 Uncertainty analysis	16
	6.6 Seasonal and diurnal variation	17
7	**CONCLUSIONS AND RECOMMENDATIONS**	**18**

REFERENCES

LIST OF TABLES

LIST OF FIGURES

APPENDIX 1 Data analysis procedure

1 INTRODUCTION

PPM Energy, Inc. (PPM) is developing the Klondike III Wind Farm and has instructed Garrad Hassan America (GH) to carry out an independent assessment of the wind climate and expected energy production of the proposed wind farm. The results of the work are reported here.

A description of the long-term wind climate at a potential wind farm is best determined using wind data recorded at the site. PPM has supplied 5 years of data recorded at the Klondike site to GH.

When only a short period of site data is available, it is usual to combine the site measurements with long-term measurements from a local meteorological station. GH has obtained and analyzed data from the Goodnoe Hills and Sevenmile Hill reference meteorological stations. However, for the purposes of this assessment neither is considered suitable as a quantitative long-term reference.

The proposed layout and turbine models under consideration have been supplied by PPM. These have been analyzed here, in conjunction with the results of the wind analysis, to predict the long-term energy output of the proposed wind farm.

2 DESCRIPTION OF THE SITE AND MONITORING EQUIPMENT

2.1 The site

The site is located at the eastern extent of the Columbia River Gorge in Sherman County, Oregon, approximately 160 km east of Portland, as shown in Figure 2.1.

The proposed wind farm lies east of the Cascade Mountains in an area of open farmland along the western side of the John Day River, near its confluence with the Columbia River. The topography on site is moderately complex, consisting primarily of rolling hills divided by a series of small draws entering the John Day River and Grass Valley Canyon. On the southern and eastern edges of the site, the complexity of the terrain increases as the elevation drops significantly to the John Day River and Grass Valley Canyons. The site elevation ranges from approximately 350 m to 550 m. The existing Klondike I and II projects are situated immediately adjacent to the proposed Klondike III turbine locations. Additionally, the proposed Biglow Canyon Wind Farm is located to the north of the Klondike development.

The ground cover on the site is comprised primarily of dryland wheat interspersed occasionally by homes, outbuildings, and small wind breaks of deciduous trees.

A more detailed map showing the site is presented in Figure 2.2, which also shows the locations of the anemometry masts. A view of the site is shown in Figure 2.3 as seen facing west from the location of Mast 2021.

The surface roughness length of the site and surrounding area was assessed during a site visit made by GH staff on 28 March 2006. Following the Davenport classification [2.1], the following general figures are considered appropriate:

Areas of wheat and grasses	0.03 m
Towns and Cities	0.5 m
Water	0.0002 m

2.2 Monitoring equipment

The site monitoring campaign consists of nine 50 m and three 60 m temporary meteorological masts. Details of the measurements recorded on site and the grid coordinates of each mast are presented in Table 2.1.

The wind data have been recorded using NRG systems throughout with NRG Maximum 40 anemometers and #200P wind vanes. PPM has provided mast installation documents from which, in combination with details from the site visit, the following information is derived.

The wind data have been recorded using a mixture of NRG 9300 and Symphonie data loggers. NRG 9300 data loggers were programmed to record hourly mean wind speed and direction, wind speed and direction standard deviation. NRG Symphonie data loggers were programmed to record ten-minute mean wind speed and direction, wind speed and direction standard deviation and 2-second gust. The following transfer function was applied to the output signal from the anemometers by both types of data logger:

Recorded wind speed [m/s] = 1.711 x Data frequency [Hz] + 0.78 mph

The anemometers on the site have not been individually calibrated. An investigation of the calibration of 472 NRG Maximum 40 anemometers has been reported in [2.2], the results of which include a proposed consensus transfer function for this model of anemometer. Since the applied transfer function is equivalent to the consensus calibration, no adjustment of the mean wind speed was necessary other than conversion to SI units where necessary.

Masts 344, 346, 347, 2001, 2010, 2012, 2018, 2020 and 2021 are standard NRG tubular tilt up masts of 50 m height with an 8 inch outer diameter. Masts 343, 345 and 2002 are standard NRG 60 m tubular masts with an outer diameter than tapers from 8" from 0 m to 21 m, to 6" from 22 m to 47 m and 4.5" from 48 m to 60 m. The site masts have been installed with a variety of instrument mounting configurations as outlined in Table 2.1 and described in further detail below.

Mast 343

From 01 March 2004 to 02 July 2004, instruments mounted on Mast 343 included boom-mounted anemometers mounted at 50 m, 40 m and 30 m oriented west and a boom-mounted anemometer at 49 m oriented to the west-southwest. Wind vanes were mounted at 50 m and 30 m.

On 02 July 2004, the 50 m tower was replaced with a 60 m tower. From 02 July 2004 to 30 October 2004, instruments mounted on Mast 343 included boom-mounted anemometers at 60 m, 50 m and 30 m oriented west and a boom-mounted anemometer at 59 m oriented to the west-southwest. Wind vanes were mounted at 60 m and 30 m.

Masts 344, 346 and 347

Instruments mounted on Masts 344, 346 and 347 include boom-mounted anemometers at 50 m, 40 m and 30 m oriented west and a boom-mounted anemometer at 49 m oriented to the west-southwest. Wind vanes are mounted at 50 m and 30 m.

Mast 345

From 01 November 2004 to 07 December 2004, instruments mounted on Mast 345 included boom-mounted anemometers at 60 m, 50 m and 30 m oriented west and a boom-mounted anemometer at 59 m oriented to the west-southwest. Wind vanes were mounted at 60 m and 30 m.

On 07 December 2004, the 60 m tower was lowered to 44 m. From 07 December 2004 to 18 April 2005, instruments mounted on Mast 345 included boom-mounted anemometers at 44 m, 43 m and 30 m, with all sensors oriented west. Wind vanes were mounted at 44 m and 30 m.

On 18 April 2005, the 44 m tower was raised to 60 m. From 18 April 2005 to 05 April 2006, instruments mounted on Mast 345 included boom-mounted anemometers at 60 m, 43 m and 30 m oriented west and a boom-mounted anemometer at 59 m oriented to the west-southwest. Wind vanes were mounted at 60 m and 30 m.

Mast 2001

From 20 April 2001 to 05 March 2004, instruments mounted on Mast 2001 included a top-mounted anemometer at 50 m and boom-mounted anemometers at 30 m and 10 m. It is noted that the orientation on the boom-mounted anemometers for this period could not be confirmed; however, these instruments were not considered necessary for this assessment. Wind vanes were mounted at 50 m and 10 m.

On 09 March 2004, Mast 2001 was lowered and reconfigured. From 09 March 2004 to 08 February 2006, instruments mounted on Mast 2001 included a top-mounted anemometer at 50 m and boom-mounted anemometers at 49 m, 30 m and 10 m. All boom-mounted anemometers were oriented south. Wind vanes were mounted at 50 m and 10 m. It is noted that the 50 m data set is considered consistent throughout the entire recording period.

Mast 2002

From 15 May 2001 to 07 August 2004, instruments mounted on Mast 2002 included a top-mounted anemometer at 30 m and boom-mounted anemometer at 10 m. Wind vanes were mounted at 30 m and 10 m.

On 07 September 2004, Mast 2002 was replaced with a 60 m tower. From 07 September 2004 to 07 February 2006, instruments mounted on Mast 2002 included boom-mounted anemometers at 60 m, 59 m, 50 m, 43 m, 42 m and 30 m. All boom-mounted sensors were oriented west save the 59 m and 42 m sensors which were oriented west-southwest. Wind vanes were mounted at 60 m and 30 m.

Mast 2010

From 19 February 2002 to 21 May 2004, instruments mounted on Mast 2010 included a top-mounted anemometer at 50 m and boom-mounted anemometers at 30 m and 10 m. All boom-mounted sensors were oriented south. Wind vanes were mounted at 50 m and 10 m.

On 31 August 2004, Mast 2010 was lowered and reconfigured. From 31 August 2004 to 03 March 2006, instruments mounted on Mast 2010 included boom-mounted anemometers at 50 m, 49 m, 30 m and 10 m. All boom-mounted sensors were oriented south save the 49 m anemometer which was oriented to the west. Wind vanes were mounted at 50 m and 30 m. It is noted that the 30 m data set is considered consistent throughout the entire recording period.

Mast 2012

From 24 April 2002 to 21 May 2004, instruments mounted on Mast 2012 included a top-mounted anemometer at 50 m and boom-mounted anemometers at 30 m and 10 m. All boom-mounted sensors were oriented south. Wind vanes were mounted at 50 m and 10 m.

On 01 September 2004, Mast 2012 was lowered and reconfigured. From 01 September 2004 to 05 April 2005, instruments mounted on Mast 2012 included-boom mounted anemometers at 50 m, 49 m, 30 m and 10 m. All boom-mounted sensors were oriented south save the 49 m anemometer which was oriented to the west. Wind vanes were mounted at 50 m and 30 m. It is noted that the 30 m data set is considered consistent throughout the entire recording period.

Mast 2018

From 09 November 2001 to 20 May 2004, instruments mounted on Mast 2018 included a top-mounted anemometer at 50 m and boom-mounted anemometers at 30 m and 10 m. It is noted that the orientation on the boom-mounted anemometers for this period could not be confirmed; however, measurements from these instruments were not considered necessary for this assessment. Wind vanes were mounted at 50 m and 10 m.

On 30 August 2004, Mast 2018 was lowered and reconfigured. From 30 August 2004 to 07 February 2006, instruments mounted on Mast 2018 included boom-mounted anemometers at 50 m, 49 m, 30 m and 10 m. All boom-mounted sensors were oriented south save the 49 m anemometer which was oriented to the west. Wind vanes were mounted at 50 m and 30 m.

Masts 2020 and 2021

From October 2001 to July 2004, instruments mounted on Masts 2020 and 2021 included a top-mounted anemometer at 30 m and boom-mounted anemometers at 10 m and wind vanes at 30 m and 10 m.

In July 2004, both masts were replaced with 50 m tower. Post July 2004, instruments mounted on Masts 2020 and 2021 included boom-mounted anemometers at 50 m, 49 m, 30 m and 10 m. All boom-mounted sensors were oriented west with the exception of the 49 m anemometer which was oriented to the west-southwest. Wind vanes were mounted at 50 m and 30 m. It is noted that due to the change in configuration in July 2004, the measurements recorded at 30 m and 10 m are not considered consistent, and therefore data recorded prior to July 2004 at Masts 2020 and 2021 have not been employed further in this analysis.

All boom-mounted anemometers on all site masts are mounted on booms approximately 7 mast diameters long; the cups of the anemometers are approximately 10 boom diameters above the boom. These mounting arrangements are broadly consistent with the recommendations of the IEA [2.3].

In the case of the top-mounted anemometers at Mast 2001 and 2002, the measurements are expected to be influenced by the geometry of the mast and the proximity of the other sensors at the same height. While these mounting arrangements are not considered consistent with the recommendations of the IEA [2.3], for the purpose of the present analysis it is the consistency and not absolute accuracy of the measurements which is critical. Therefore, the data recorded from these configurations are considered sufficient to employ within this analysis. It is noted that no other data recorded by a top-mounted anemometer have employed within this analysis.

The site inspection for the Klondike site was performed by GH on 28 March 2006, during which the current mounting configurations of Masts 345, 346, 2001, 2010, 2018, 2020 and 2021 were confirmed. It is also noted that GH was unable to independently verify the original instrument mounting arrangements of these masts. Additionally, GH was also unable to independently verify previous instrument mounting arrangements of Masts 343, 344, 347 and 2002 as the towers had been removed at the time of the GH site inspection.

In addition to the above masts, PPM has provided one month of data for the recently installed Mast 2042. Mast 2042 is a 50 m tilt-up NRG tower located north of Mast 2012. Due the relatively short period of available data, Mast 2042 has primarily been used as a validation of the wind flow modelling, as described further in Section 6.

In addition to the mast measurements, sodar measurements were conducted at the Klondike site [2.4]. The results from the sodar measurement campaign were presented to GH for use in this assessment. The sodar instrumentation was set-up in the vicinity of Mast 343 and acquired measurements from 22 July 2004 to 22 August 2004 from 20 m up to 200 m height. Data recovery was reported to be 75% and 65% for this period at 50 m and 80 m, respectively [2.4]. GH has not independently observed the location and configuration of the sodar unit and has relied upon the information provided by PPM. The sodar unit employed by PPM for undertaking measurements at the Klondike site was the AeroVironment Model 400 Mini-SODAR Doppler Sodar System which operates at an acoustic frequency of 4500 Hz.

It is noted that there are a number of additional meteorological masts on or near the site that were not used in this assessment due to the period of available data or proximity to the proposed Phase III turbines.

3 SELECTION OF A REFERENCE METEOROLOGICAL STATION

In the assessment of the wind regime at a potential wind farm site it is sometimes necessary to correlate data recorded on the site with data recorded from a nearby long-term reference meteorological station. Wind data at a site are often only recorded for a short period and such correlation is required to ensure that the estimates of the wind speeds at the site are representative of the long-term. When selecting an appropriate meteorological station for this purpose it is important that it should have good exposure and that data are consistent over the measurement period being considered.

GH has reviewed potential sources of long-term meteorological data at Goodnoe Hills and Sevenmile Hill. The Goodnoe Hills Mast is a 60 m lattice tower located in Washington approximately 20 km north of the Klondike site, while the Sevenmile Hill station consists of a 50 m lattice tower situated about 50 km west of the site. Both masts are operated and maintained by Oregon State University, in conjunction with the Bonneville Power Administration. Wind data have been recorded using an RM Young propvane anemometer at 59 m and 15 m, in the case of Goodnoe Hills, and at 30 m and 15 m at Sevenmile Hill. Wind data have been provided for the Goodnoe Hill and Sevenmile Hill masts starting in 1995. It is understood that data are available prior to 1995; however, a change in anemometer type at both masts in 1994 has affected the measurement consistency. It is also noted that limited documentation is available to verify the provenance of these data sets.

Wind speed correlation analyses have been conducted between the references and the site masts using hourly, daily and monthly averaging periods. While both references exhibit a reasonable level of correlation to the site over some seasons, different seasonal wind speed patterns are observed between the references and the site and between the references themselves. Consequently, the uncertainty associated with the correlations from these reference masts is significant. This is also borne out in the different predicted results from the correlation of each reference to the site. As a result, neither the Sevenmile Hill reference station nor the Goodnoe Hill reference station was considered suitable for use in the assessment as a quantitative reference.

The analysis of the long-term wind regime therefore relies on data recorded at the Klondike site since May 2001. The uncertainty associated with assuming this period to be representative of the long-term is considered in Section 6. It is noted that, if either of the above reference stations were to be employed in this assessment, the overall uncertainty in the prediction of the long-term wind regime would be expected to be greater than that based on the use of the site data only.

4 WIND DATA

4.1 Wind data recorded at the site

The data sets which have been used in the analysis described in the following sections are summarised in Table 2.1.

The wind data have been subject to a quality checking procedure by GH to identify records which were affected by equipment malfunction and other anomalies. Characteristic of this region, the instruments on all masts experienced some periods of icing, resulting in erroneous or inconsistent data during the winter months. These data were excluded from the analysis.

The main periods for which valid data were not available are summarized below, together with details of the errors identified:

- 09 March 2004 to 03 May 2004: Mast 344 sensor failure at 50 m anemometer;
- 07 December 2004 to 05 April 2006: Mast 345 sensor failure at 43 m anemometer;
- 28 October 2003 to 09 March 2004: Mast 2001 sensor failure at 50 m anemometer;
- 18 March 2004 to 21 May 2004: Mast 2002 sensor failure at 30 m anemometer;
- 22 May 2004 to 30 August 2004: Mast 2010 all data missing;
- 21 May 2004 to 01 September 2004: Mast 2012 all data missing;
- 21 May 2004 to 01 September 2004: Mast 2018 all data missing;
- 28 April 2004 to 07 July 2004: Mast 2020 sensor malfunction at 30 m anemometer;
- 18 November 2003 to 12 August 2004: Mast 2021 sensor malfunction at 30 m anemometer.

It is noted that when possible, missing data from upper height sensors were synthesized from the same mast. This additional step was required for Masts 343, 344, 345, 2001, 2010 and 2012.

It is further noted that construction on Phase I of the Klondike Project began in November 2001. The presence of the Phase I turbines is expected to affect of the consistency of wind speed measurements at Mast 2001. To avoid the introduction of wake effects from the Phase I turbines on Mast 2001, data recorded at this mast prior to 01 November 2001 have been excluded. Furthermore, Mast 2001 has only been employed as a reference in the current analysis.

Construction on Phase II began in June 2005. The presence of the Phase II turbines is expected to affect of the consistency of wind speed measurements at Masts 344, 2001 and 2002. To avoid the introduction of wake effects from newly constructed Phase II turbines on Masts 343, 2001 and 2002, data recorded at these masts after to 31 May 2005 have been excluded.

In the case of the sodar measurements, while the data have not been independently quality checked or analyzed by GH, the information provided and analysis undertaken by PPM has been reviewed. Given the limited use of the sodar data in the current assessment, this approach is considered reasonable. Use of the sodar data is discussed further in Section 6.

The duration, basic statistics and data coverage for each of the twelve site masts are summarized in Tables 4.1 to 4.12.

5 DESCRIPTION OF THE PROPOSED WIND FARM

5.1 The wind turbine

The turbines which are proposed for the Klondike III Wind Farm are the GE 1.5sle and the Siemens SWT-2.3-93 both with a hub height of 80 m. The basic parameters of the turbines are presented in Tables 5.1 to 5.2.

The power curves used in this analysis have been obtained from the manufacturers. The GE 1.5sle power curve is for an air density of 1.16 kg/m³, and is valid for turbulence intensities of 10 % to 15 %. The Siemens SWT-2.3-93 power curve is for an air density of 1.17 kg/m³, and is valid for a turbulence intensity of 8 %. While in the case of the Siemens turbine this level of turbulence intensity is less than that typically specified by other manufacturers, it is noted that the actual turbulence intensity across the site at 15 m/s is approximately 8 % and hence the supplied power curve is considered reasonable.

The supplied power curves are based on calculations and exhibit peak power coefficients, Cp, of 0.45 and 0.43 for the GE 1.5sle and the Siemens SWT-2.3-93, respectively. These are considered to be reasonable for a modern wind turbine. Independently measured power curves were not available at the time of writing. Consequently no check of the validity of the supplied power curves other than that above has been undertaken.

Using historical pressure and temperature records from nearby meteorological stations and standard lapse rate assumptions, GH has estimated the long-term mean air density at the site. Due to the observed seasonal correlation of mean wind speed and air density at the site, GH has adjusted the long-term annual mean site air density to produce an “energy-weighted” value of 1.170 kg/m³ at an average hub height elevation of 527 m asl.

The supplied power curves used in this analysis have been adjusted to the predicted site air density, in accordance with the recommendations of [5.1]. This has been undertaken on an individual turbine basis.

5.2 Wind farm layout

PPM has supplied the layout for the Klondike III Wind Farm [5.2]. A map of the site showing the wind turbine locations is presented in Figure 5.1 with the grid reference of each of the turbines given in Table 5.3. It is noted that some turbines in Klondike III Wind Farm have inter-turbine spacing under two rotor diameters. Even though these separations are in non-prevailing wind directions, the increased turbulence levels will increase fatigue loads. It is recommended that the turbine supplier be approached at an early stage to gain approval for the proposed layout.

It is noted that Phase III of the Klondike Wind Farm surrounds Phases I and II to the southwest, east and northeast. Additionally, the Biglow Canyon Wind Farm is proposed directly north of the Klondike development. Coordinates of both existing phases of the Klondike Project as well as the proposed Orion project have been provided by PPM [5.3, 5.4]. A map of the site showing the wind turbine locations of Klondike Wind Farm Phases I, II and III as well as the Orion project is presented in Figure 5.2. The potential wake impact on each of these has been analyzed and is discussed in further detail in Section 6.

6 RESULTS OF THE ANALYSIS

The analysis of the wind farm involved several steps, which are summarized below:

- Data recorded at Mast 2002 at 30 m and at Mast 2010 at 30 m were correlated to data recorded at Mast 2001 at 50 m on an hourly basis. These correlations were used to synthesize missing data at Mast 2001 at 50 m from the historical wind speeds recorded at Masts 2002 and 2010. The long-term wind speed and direction frequency distribution at Mast 2001 at 50 m was established from the resulting valid measured and synthesized data.

- Data recorded at Mast 2001 at 50 m and at Mast 2002 at 30 m were correlated to data recorded at Mast 2010 at 30 m on an hourly basis. These correlations were used to synthesize missing data at Mast 2010 at 30 m from the historical wind speeds recorded at Masts 2001 and 2002. The long-term wind speed and direction frequency distribution at Mast 2010 at 30 m was established from the resulting valid measured and synthesized data.

- Data recorded at Mast 2001 at 50 m were correlated to data recorded at Mast 2018 at 50 m on an hourly basis. This correlation was used to synthesize missing data at Mast 2018 at 50 m from the historical measured and synthesized wind speeds recorded at Mast 2001 at 50 m. The long-term wind speed and direction frequency distribution at Mast 2018 at 50 m was established from the resulting valid measured and synthesized data. A similar methodology was adopted to predict the long-term mean wind speed and direction frequency distributions at Mast 343 at 60 m and Mast 344 at 50 m.

- Data recorded at Mast 2010 at 30 m were correlated to data recorded at Mast 2012 at 50 m on an hourly basis. This correlation was used to synthesize missing data at Mast 2012 at 50 m from the historical measured and synthesized wind speeds recorded at Masts 2010 at 30 m. The long-term wind speed and direction frequency distribution at Mast 2012 at 50 m was established from the resulting valid measured and synthesized data.

- Data recorded at Mast 2010 at 30 m were correlated to data recorded at Mast 346 at 50 m on a daily basis. This correlation was used to derive the long term mean wind speed at Mast 346 at 50 m. The measured wind speed and direction frequency distribution at Mast 346 at 50 m was scaled to reflect the predicted long-term mean wind speed.

- Data recorded at Mast 2018 at 50 m were correlated to data recorded at Mast 345 at 60 m and Masts 347, 2020 and 2021 at 50 m on a daily basis. These correlations were used to derive the long term mean wind speeds at Mast 345 at 60 m and Masts 347, 2020 and 2021 at 50 m. The measured wind speed and direction frequency distribution at each mast was scaled to reflect the predicted long-term mean wind speed.

- Wind speed data recorded at 60 m and 30 m at Masts 343 and 345, and at 50 m and 30 m for all other site masts were used to establish the mean shear profile at each location. These were used to extrapolate the long-term wind speed and direction frequency distribution to the proposed hub height of 80 m. The results from the analysis of the sodar data have been compared to the observations from the anemometry measurements at various heights.

- Wind flow modelling was carried out to determine the hub height wind speed variations over the site relative to the anemometry masts.

- The energy production of the wind farm was calculated taking account of array losses, topographic effects, availability, electrical transmission efficiency, air density effects and other potential losses.

- An assessment of the uncertainty in the predicted wind farm energy production was undertaken.

A more complete description of the methods employed is included in Appendix 1.

6.1 Long-term mean wind regime at Klondike site masts

Mast 2001

Wind measurements from Mast 2001 over a period of approximately 4 years were available for the analysis. As detailed in Section 2, the top-mounted anemometer installed at Mast 2001 at 50 m is expected to be influenced by the proximity of the mast and sensors near it. However, since this data set is used as a reference only, it is consistency not absolute accuracy that is critical, and thus the 50 m measurements are considered acceptable for use in this analysis.

In order to extend the period used for the analysis of the wind regime at Mast 2001 at 50 m, a correlation of hourly mean wind speeds was undertaken on a directional basis between Mast 2010 at 30 m and Mast 2001 at 50 m. Figure 6.1 presents a correlation of hourly mean wind speed on a directional basis between Mast 2010 at 30 m and Mast 2001 at 50 m. Directional wind speed ratios have been calculated and are presented in Table 6.1. The wind speed ratios derived in each direction sector were then used to synthesize missing wind speed data at 50 m from the historical wind speeds recorded at Mast 2010 at 30 m. The data are observed to be reasonably correlated with little non-linearity in the predominant wind sectors.

As a check of the validity of the synthesis methodology, the average wind speed and power content of the wind speed and direction frequency distribution developed from the synthesized data were compared with the average wind speed and power content of the wind speed and directional frequency distribution developed from the concurrent period of measured data. The average wind speed and power content of the synthesised data set were noted to be in close agreement.

A similar methodology was used to synthesize missing wind speed data at Mast 2001 at 50 m from the historical wind speeds recorded at Mast 2002 at the top-mounted 30 m anemometer. By this method, approximately 9,000 hours of data from Mast 2010 at 30 m and 4,500 hours of data from Mast 2002 at 30 m were added to the available data set at Mast 2001 at 50 m.

From the 4.8 years of measured and synthesized data a total of approximately 4.6 years of valid wind data were available at Mast 2001 at 50 m. In order to avoid the introduction of bias into the annual mean wind speed estimate from seasonally uneven data coverage, the following procedure was followed:

- The mean wind speed and direction frequency distribution for each month was determined from the average of all valid data recorded in that month over the period. This was taken as the monthly mean thereby assuming that the valid data are representative of any missing data.

- The mean of the monthly means was taken to determine the annual mean ("mean of means") to eliminate the effect of seasonal bias in the data.

By this method, the predicted long-term mean wind speed at Mast 2001 at 50 m was found to be 7.1 m/s at 50 m.

Mast 2010

Wind measurements from Mast 2010 over a period of approximately 4 years were available for the analysis. In order to extend the period used for the analysis of the wind regime at Mast 2010 at 30 m, a correlation of hourly mean wind speeds was undertaken on a directional basis between the top-mounted anemometer at 30 m at Mast 2002 and Mast 2010 at 30 m. The wind speed ratios derived in each direction sector were then used to synthesize missing wind speed data at Mast 2010 at 30 m from the historical wind speeds recorded at Mast 2002. A similar methodology was used to synthesize missing wind speed data at Mast 2010 at 30 m from the historical wind speeds recorded at Mast 2001 at 50 m. By this method, approximately 7,000 hours of data from Mast 2002 at 30 m and 3,500 hours of data from Mast 2001 at 50 m were added to the available data set at Mast 2010 at 30 m. Accounting for seasonally uneven data coverage, the predicted long-term mean wind speed at Mast 2010 at 30 m was found to be 6.7 m/s from the 4.6 years of valid measured and synthesized data.

To predict the long-term wind regime at Mast 2010 at 50 m, data were correlated from Mast 2010 at 30 m to Mast 2010 at 50 m. This correlation was used to synthesize missing wind speed and direction data at Mast 2010 at 50 m from the measured and synthesized historical wind speeds recorded at Mast 2010 at 30 m. By this method, as shown in Table 6.2, the predicted long-term mean wind speed at Mast 2010 at 50 m was found to be 7.1 m/s. The corresponding long-term joint wind speed and direction frequency distribution is presented in Table 6.3 and in Figure 6.3 in the form of a wind rose.

Masts 343, 344, 2012 and 2018

In order to extend the period of available data at Mast 2018 at 50 m, it is considered appropriate to synthesize missing data where possible through a correlation analysis with Mast 2001 at 50 m. A correlation of hourly mean wind speeds on a directional basis was undertaken between Mast 2001 at 50 m and Mast 2018 at 50 m. The resulting wind speed ratios and directional relationship were then applied to the hourly data at Mast 2001 in order to synthesize the wind speed and direction at Mast 2018 at 50 m from historical measured and synthesized data at Mast 2001 at 50 m. The long term mean wind speed and direction frequency distribution at Mast 2018 at 50 m was subsequently developed from the resulting measured and synthesized data. By this method, as shown in Table 6.4, the predicted long-term mean wind speed at Mast 2018 at 50 m was found to be 7.2 m/s.

A similar methodology was used to predict the long-term mean wind speed and frequency distributions at Mast 343 at 60 m and Mast 344 at 50 m, using Mast 2001 as a reference. A parallel analysis was also used to predict the long-term mean wind speed and frequency distribution at Mast 2012 at 50 m, using Mast 2010 at 30 m as a reference. By this method, the predicted long-term mean wind speeds at Masts 343, 344 and 2012 were found to be 7.7 m/s, 6.9 m/s, and 7.0 m/s, respectively.

A validation of the synthesis methodology, as described above, was undertaken for each synthesis step, and each case was found to be appropriate for the assessment.

Masts 345, 346, 347, 2020 and 2021

As detailed in Section 4, approximately 1.5 years of data were available at Masts 345, 346, 347, 2020, and 2021. In order to maximize the duration of the reference period used for the analysis of the long-term wind regime at these three masts, the correlation analyses described below were used to reference the longer-term record at Masts 2010 and 2018.

The correlation of daily mean wind speeds at Mast 2018 at 50 m and Mast 345 at 60 m was established and presented in Figure 6.4. The correlation is considered good, with a correlation coefficient (r^2) of 0.98. The slope of the linear regression fit to these data was applied to the long-term mean wind speed for Mast 2018 at 50 m giving a predicted long term mean wind speed at Mast 345 at 60 m of 7.6 m/s. The measured wind speed and direction frequency distribution at Mast 345 at 60 m was then factored to reflect this long-term mean wind speed.

A daily correlation was employed in preference to an hourly correlation due to an observed diurnal variation in the correlation relationship between the measured wind speeds across the site. While it is recognized that a daily correlation does not fully describe the physical basis for the variation, it is considered a reasonable approach in this analysis to estimate the long-term wind speed relationships between these masts.

The same methodology was used to predict the long-term mean wind regime at Masts 347, 2020 and 2021 at 50 m, using Mast 2018 as a reference, and at Mast 346 at 60 m, using Mast 2010 as a reference. By this method, the predicted long-term mean wind speeds were found to be 7.1 m/s, 7.0 m/s, 7.2 m/s and 7.0 m/s at Masts 346, 347, 2020 and 2021, respectively.

6.2 Hub height wind speeds

The ratio of long-term mean wind speeds between 60 m and 30 m at Masts 343 and 345, and between 50 m and 30 m for all other site masts was used to derive boundary-layer power-law shear exponents at each mast location. These values were applied to extrapolate the long-term mean wind speed and direction frequency distribution at each of the site masts to the proposed 80 m hub height. Given the period of data available from Mast 343, a check of the measured shear for the concurrent period compared to that for an annual period was undertaken at Mast 345 and found to be in reasonable agreement.

The report presenting the results from the sodar measurements [2.4] has been reviewed by GH. The results show good agreement between the wind shear measured at Mast 343 and the sodar over the approximately one month period of sodar operation. Specifically, the power-law shear exponent calculated between the 80 m and 60 m sodar data compares favorably with the shear exponent calculated from the measured 60 m and 30 m sodar data, as well as that derived from the 60 m and 30 m measured data at Mast 343 for the one month period. Given this result, it is considered reasonable to employ the calculated shear at each mast, as developed above, to extrapolate to hub height.

A summary of the estimated shear exponent and extrapolated hub height mean wind speed for each mast is presented in Table 6.5.

6.3 Site wind speed variations

The variation in wind speed over the wind farm site has been predicted using the WAsP computational flow model as described in Appendix 1. The wind flow model has been initiated from the long-term mean hub height wind speed and direction frequency distributions derived for Masts 343, 344, 345, 346, 347, 2010, 2012, 2018, 2020 and 2021.

A comparison of the predicted wind speeds using WAsP across the site indicate generally good agreement between the site masts in relatively close proximity to each other but poor agreement at greater distances, which is likely attributable to the complexity of the terrain and the wind regime at the site. As a result, WAsP has been employed locally in this assessment to limit the extent of extrapolation.

In addition, a few turbines in the wind farm are located within complex terrain which includes some areas of steep slopes. The presence of steep slopes can cause localised separation of the flow. In regions of separated flow it is known that the accuracy of wind flow modelling is poor due to the formation of a separation bubble which reduces the effective slope, as described by Cook [6.1].

For turbine locations with slopes significantly in excess of 17 degrees in the prevailing wind directions, to a greater extent than at the initiation anemometry mast location, there is a tendency for the WAsP model to over-predict the wind speed and consequently energy production of such turbines. Conversely, if the initiation anemometry mast is located in an area more heavily influenced by slopes in excess of 17 degrees than the turbine locations, there is a tendency for the WAsP model to under-predict the wind speed at such turbines. A review of the wind farm was therefore undertaken to establish whether such conditions were present.

GH has examined the hub height wind speeds at individual turbine locations predicted by WAsP and, adjustments have then been made to the results of the wind flow modelling at 14 turbine locations. These adjustments were made in the southern portion of the site in which WAsP tended to predict higher wind speeds immediately adjacent to the steep slopes of the Grass Valley Canyon and lower wind speeds further upland in the flatter terrain north of the canyon; a trend which site measurements belie. For example, the hub height wind speed predictions at Masts 341 and 2042 based on the measured data are greater than the WAsP wind speed predictions in this area when WAsP is initiated from Masts 2010 and 2012. It is noted that the overall effect of these adjustments is small.

It is clear from the above that the prediction of the variation in wind speed over the site is challenging. In moderately complex terrain, GH generally recommends that all proposed turbine locations are within 2 km of a measurement mast which is at least three quarters of the proposed turbine hub height. These conditions are generally met at the majority of turbine locations at the Klondike III site. The uncertainty associated with predicting the variation in wind flow using the WAsP computational flow model is considered in Section 6.5.

Table 5.4 presents the predicted long-term mean wind speed at each turbine location at hub height. The average long-term mean hub height wind speed for Phase III as a whole was found to be 7.6 m/s.

6.4 Projected energy production

The predicted energy production of the Klondike III Wind Farm is detailed in the table below. Definitions of the various loss factors are included in Appendix 1. The predicted energy capture of individual turbine is given in Table 5.4.

Rated Power	**225.7**	**MW**
Ideal output	807.4	GWh/annum
Topographic effect	98.6%	GH calculated
Wake effect	95.5%	GH calculated
Electrical efficiency	98.0%	PPM value [6.2]
Availability	97.0%	GH assumption
Icing and blade degradation	99.0%	GH assumption
High wind hysteresis	99.8%	GH estimate
Substation maintenance	99.8%	Typical value
Utility downtime	100.0%	Not considered by GH
Power curve adjustment	100.0%	Not considered by GH
Extreme temperature shutdown	100.0%	Not considered by GH
Wind sector management	100.0%	Not considered by GH
Wake from Klondike Phase I and II	98.7%	GH estimate
Wake from Orion Project	99.7%	GH estimate
Net output	**703.9**	**GWh/annum**
Capacity Factor	**35.6%**	

The ideal energy production is the theoretical output of the wind farm with the hub height wind speeds at the mast location applied uniformly across the whole site. The values for topographic and array effect have been calculated using methods described in Appendix 1.

The impacts of the existing phases of the Klondike Wind Farm and the proposed Orion Project on Phase III were modelled and are presented as separate loss factors in the overall energy calculation.

A value for the electrical transmission efficiency has been provided by PPM [6.2] and has been assumed in the current assessment. It is noted that no review of the loss calculations or assumptions made by PPM have been undertaken by GH at this stage. It is recommended that this value be reviewed once details of the electrical design have been provided.

The table above includes potential sources of energy loss that have been estimated, assumed or not considered. It is recommended that the client consider each of these losses and the possible effect they may have on the wind farm.

6.5 Uncertainty analysis

The main sources of deviation from the central estimate have been quantified and are shown in Tables 6.6 to 6.15. The figures in each table are added as independent errors giving the following uncertainties in net energy production for the wind farm. These represent the standard deviation of what is assumed to be a Gaussian process:

In any one year period	83.2	GWh/annum
In any ten year period	60.9	GWh/annum

The uncertainties that have been considered in the analysis of the wind farm include the following:

- Accuracy of the wind measurements;
- Correlation accuracy;
- The assumption that the period of data available is representative of the long-term wind regime;
- The accuracy of the extrapolation of wind speeds from the mast height to hub height;
- The accuracy of the wind flow modelling;
- The accuracy of the wake modelling;
- The accuracy of the fiscal sub-station meter;
- The variability of the future annual wind speeds at the site.

There are a number of uncertainties that have not been considered at this stage, including those listed below. It is recommended that the client 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.

- Compliance with the assumed power curve;
- Turbine availability;
- Electrical losses;
- High wind hysteresis;
- Icing and blade degradation;
- Substation maintenance;
- Utility downtime.

6.6 Seasonal and diurnal variation

The expected long-term average seasonal and diurnal variation in energy production has been approximately assessed from the available measurements at the site masts.

Based on the predicted long-term hub height mean wind speed and direction frequency distributions at the site masts, a power performance matrix was developed for the Klondike III Wind Farm. A time series of air density was developed from temperature and pressure records from the Yakima and Pendleton meteorological stations and scaled to the predicted on-site air density. By applying the 4.6 years of concurrent density, wind speed and direction data recorded at the site to the power performance matrix, a simulated time series of power production data was produced.

Based on the above methodology, the expected seasonal and diurnal variation in energy production is presented in Table 6.16 in the form of a 12 x 24 matrix. It is noted that the uncertainty associated with the prediction of any given month of hour of day is significantly greater than that associated with the prediction of the annual energy production as presented above. It is also noted that the results presented are inclusive of topographical and array losses only.

7 CONCLUSIONS AND RECOMMENDATIONS

Wind data have been recorded at the Klondike site for a period of approximately 5 years. Based on the results from the analysis of these data the following conclusions are made concerning the site wind regime.

1. The long-term mean wind speed at a height of 80 m above ground level is presented in the table below for each mast. Also included are the standard errors associated with each of these predictions. If a normal distribution is assumed, the confidence limits for the predictions are presented for the P50, P75 and P90 exceedance levels.

Probability of exceedance [%]	**Long-term mean wind speed at 80 m [m/s]**									
	343	**344**	**345**	**346**	**347**	**2010**	**2012**	**2018**	**2020**	**2021**
90	7.5	7.1	7.5	7.1	7.1	7.1	7.0	7.2	7.4	7.1
75	7.7	7.3	7.7	7.3	7.3	7.4	7.2	7.4	7.6	7.3
50	8.0	7.5	8.0	7.5	7.6	7.6	7.4	7.6	7.8	7.6
Standard Error	0.41	0.35	0.37	0.36	0.37	0.34	0.34	0.35	0.36	0.36

Site wind flow and array loss calculations have been carried out and from these we draw the following conclusions:

2. The long-term mean wind speed averaged over all turbine locations at hub height is 7.6 m/s.

3. The projected energy capture of the Klondike III Wind Farm is 703.9 GWh/annum. This includes calculation of the topographical, array and air density effects and assumptions or estimates for electrical transmission losses, availability, power curve adjustment, high wind hysteresis, substation maintenance, wake effects from neighboring turbines, and the effect of blade fouling or icing.

   There are a number of other losses that could affect the net energy output of the wind farm, as detailed in Appendix 1, but these have not been considered here. It is recommended that the client considers each of these losses and the possible effect they may have on the net energy production.

   The net energy prediction presented above represents the long-term mean, 50% exceedance level, for the annual energy production of the wind farm. This value is the best estimate of the long-term mean value to be expected from the project. There is therefore a 50% chance that, even when taken over very long periods, the mean energy production will be less than the value given.

4. The standard error associated with the prediction of energy capture has been calculated and the confidence limits for the prediction are given in the table below for each scenario:

Probability of Exceedance [%]	**Net energy output** 1 year average [GWh/annum]	**10 year average [GWh/annum]**
90	597.1	603.7
75	647.8	662.8
50	703.9	703.9

There are a number of uncertainties that have not been considered at this stage, as detailed in Section 6. It is recommended that the client 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.

5. The manufacturer-supplied power curves should be verified against independently measured power curves for both turbines presented in the report.

REFERENCES

2.1 "Wind speed profiles over terrain with roughness changes", Engineering Sciences Data, Item No. 84011, April 1993.

2.2 Lockhart T J and Bailey B H, "The Maximum Type 40 Anemometer Calibration Project", Proceedings of the AWEA Conference, California 1998.

2.3 Recommended Practices for Wind Turbine Testing and Evaluation, "11. Wind speed measurement and use of cup anemometry", IEA, Edition 1, 1999.

2.4 Wade, J, "Calibration of the Model 400 MINI-SODAR and Determination of Shear at Klondike Meteorological Site 343", 23 September 2004

5.1 "Wind turbine generator systems – Part 12: Wind turbine power performance testing", BS EN 61400-12: BSI, 1998.

5.2 Email from Timothy Hughes, PPM to Clint Johnson, GH, 08 Apr 2006.

5.3 Email from Linda Withrow, PPM to Clint Johnson, GH, 08 Mar 2006.

5.4 Email from Timothy Hughes, PPM to Regina Sweet, GH, 02 May 2006.

6.1 Cook N J "The Designer's" guide to wind loading of building structures", Part 1, Butterworths, 1985.

6.2 Email from Timothy Hughes, PPM to Regina Sweet, GH, 04 May 2006.

LIST OF TABLES

2.1 Summary of measurements made at the site.

4.1 Measurements made at Mast 343 at a height of 60 m.

4.2 Measurements made at Mast 344 at a height of 50 m.

4.3 Measurements made at Mast 345 at a height of 60 m.

4.4 Measurements made at Mast 346 at a height of 50 m.

4.5 Measurements made at Mast 347 at a height of 50 m.

4.6 Measurements made at Mast 2001 at a height of 50 m.

4.7 Measurements made at Mast 2002 at a height of 30 m

4.8 Measurements made at Mast 2010 at heights of 50 m and 30 m.

4.9 Measurements made at Mast 2012 at heights of 50 m and 30 m.

4.10 Measurements made at Mast 2018 at a height of 50 m.

4.11 Measurements made at Mast 2020 at a height of 50 m.

4.12 Measurements made at Mast 2021 at a height of 50 m.

5.1 Main parameters of the wind turbines analyzed.

5.2 Performance data for the GE 1.5 sle wind turbine analyzed.

5.3 Performance data for the Siemens SWT-2.3-93 wind turbine analyzed.

5.4 Phase III turbine layout with predicted individual turbine wind speed and energy production.

6.1 Directional correlation ratios between Masts 2010 at 30 m and 2001 at 50 m.

6.2 Predicted monthly and annual mean wind speeds at Mast 2010 at 50m (May 2001 to Mar 2006).

6.3 Predicted wind speed and direction frequency distribution at the Mast 2010 at 50 m.

6.4 Predicted monthly and annual mean wind speeds at Mast 2018 at 50m (May 2001 to Mar 2006).

6.5 Predictions of the wind speeds at the site masts.

6.6 Uncertainty in projected energy output of turbines G50 to G53 based on Mast 343.

6.7 Uncertainty in projected energy output of turbines G67 to G70 and G81 to G83 based on Mast 344.

6.8 Uncertainty in projected energy output of turbines G54 to G66 based on Mast 345.

6.9 Uncertainty in projected energy output of turbines G1 to G17 based on Mast 346.

6.10 Uncertainty in projected energy output of turbines S32 to S35 based on Mast 347.

6.11 Uncertainty in projected energy output of turbines G18 to G40 based on Mast 2010.

6.12 Uncertainty in projected energy output of turbines G41 to G49 based on Mast 2012.

6.13 Uncertainty in projected energy output of turbines S8 to S15 and S24 to S31 based on Mast 2018.

6.14 Uncertainty in projected energy output of turbines S1 to S7, S16 to S23 and G71 to G80 based on Mast 2020.

6.15 Uncertainty in projected energy output of turbines S36 to S44 based on Mast 2021.

6.16 Predicted seasonal and diurnal variation in energy production.

LIST OF FIGURES

2.1 Location of the Klondike site.

2.2 Location of the Klondike meteorological masts.

2.3 View of the Klondike site from Mast 2021 looking west.

5.1 Klondike Wind Farm Phase III proposed turbine layout.

5.2 Klondike Wind Farm Phase III proposed turbine layout with Klondike Phases I and II and Orion project.

6.1 Correlation of hourly mean wind speed at Mast 2010 at 30 m and Mast 2001 at 50 m.

6.2 Correlation of hourly mean wind direction at Mast 2010 and Mast 2001.

6.3 Annual wind rose from Mast 2010 at 50 m.

6.4 Correlation of daily mean wind speeds at Mast 2018 at 50 m and Mast 345 at 60 m.

Location	Description of measurements	Period
Mast 343 (688107, 5053161)	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 40 m and 30 m. 10-minute mean wind direction recorded at 50 m and 30 m.	01 Mar 2004 – 02 Jul 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 60 m, 59 m, 50 m and 30 m. 10-minute mean wind direction recorded at 60 m and 30 m.	02 Jul 2004 – 30 Oct 2004
Mast 344 (690237, 5054515)	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 40 m and 30 m. 10-minute mean and standard deviation of wind direction recorded at 50 and 30 m.	09 Mar 2004 – 19 Jan 2006
Mast 345 (690865, 5054515)	10-minute mean, maximum, and standard deviation of wind speed recorded at 60 m, 59 m, 50 m and 30 m height. 10-minute mean wind direction recorded at 60 m and 30 m.	01 Nov 2004 – 07 Dec 2004
	10-minute mean, maximum, and standard deviation of wind speed recorded at 44 m, 43 m, and 30 m height. 10-minute mean wind direction recorded at 44 m and 30 m.	07 Dec 2004 – 18 Apr 2005
	10-minute mean, maximum, and standard deviation of wind speed recorded at 60 m, 59 m, 43 m and 30 m height. 10-minute mean wind direction recorded at 60 m and 30 m.	18 Apr 2005 – 05 Apr 2006

Coordinates are UTM NAD27 Zone 10

Table 2.1 Summary of measurements made at the site - continued.

Location	Description of measurements	Period
Mast 346 (682531, 5046379)	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 40 m and 30 m. 10-minute mean and standard deviation of wind direction recorded at 50 and 30 m.	03 Nov 2004 – 22 Mar 2006
Mast 347 (696252, 5052797)	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 40 m and 30 m. 10-minute mean and standard deviation of wind direction recorded at 50 and 30 m.	10 Dec 2004 – 29 Mar 2006
Mast 2001 (690808, 5048939)	Hourly mean wind speed and standard deviation recorded at 50 m, 30 m and 10 m. Hourly mean wind direction recorded at 50 m and 10 m.	20 Apr 2001 – 05 Mar 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 30 m and 10 m. 10-minute mean wind direction recorded at 50 m and 10 m.	09 Mar 2004 – 08 Feb 2006
Mast 2002 (689379, 5049546)	Hourly mean wind speed and standard deviation recorded at 30 m and 10 m. Hourly mean wind direction recorded at 30 m and 10 m.	15 May 2001 – 07 Aug 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 60 m, 59 m, 50 m,43 m, 42 m and 30 m. 10-minute mean wind direction recorded at 60 m and 30 m.	07 Sep 2004 – 07 Feb 2006

Coordinates are UTM NAD27 Zone 10

Table 2.1 Summary of measurements made at the site - continued.

Location	Description of measurements	Period
Mast 2010 (686402, 5046536)	Hourly mean wind speed and standard deviation recorded at 50 m, 30 m and 10 m. Hourly mean wind direction recorded at 50 m and 10 m.	19 Feb 2002 – 21 May 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 30 m and 10 m. 10-minute mean wind direction recorded at 50 m and 30 m.	31 Aug 2004 – 03 Mar 2006
Mast 2012 (690104, 5046671)	Hourly mean wind speed and standard deviation recorded at 50 m, 30 m and 10 m. Hourly mean wind direction recorded at 50 m and 10 m.	24 Apr 2002 – 21 May 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 30 m and 10 m. 10-minute mean wind direction recorded at 50 m and 30 m.	01 Sep 2004 – 05 Apr 2005
Mast 2018 (694500, 5050370)	Hourly mean wind speed and standard deviation recorded at 50 m, 30 m and 10 m. Hourly mean wind direction recorded at 50 m and 10 m.	09 Sep 2001 – 20 May 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 30 m and 10 m. 10-minute mean wind direction recorded at 50 m and 30 m.	30 Aug 2004 – 03 Feb 2006

Coordinates are UTM NAD27 Zone 10

Table 2.1 Summary of measurements made at the site - continued.

Location	Description of measurements	Period
Mast 2020 (693481, 5053295)	Hourly mean wind speed and standard deviation recorded at 30 m and 10 m. Hourly mean wind direction recorded at 30 m and 10 m.	02 Oct 2001 – 07 Jul 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 30 m and 10 m. 10-minute mean wind direction recorded at 50 m and 30 m.	09 Jul 2004 – 07 Feb 2006
Mast 2021 (696173, 5051310)	Hourly mean wind speed and standard deviation recorded at 30 m and 10 m. Hourly mean wind direction recorded at 30 m and 10 m.	20 Nov 2001 – 03 Aug 2004
	10-minute mean, maximum, and standard deviation of wind recorded at 50 m, 49 m, 30 m and 10 m. 10-minute mean wind direction recorded at 50 m and 30 m.	08 Aug 2004 – 31 Mar 2006

Coordinates are UTM NAD27 Zone 10

Table 2.1 Summary of measurements made at the site - concluded.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Jul 2004	9.4	95.1	100.0
Aug 2004	8.8	100.0	0.0
Sep 2004	8.6	98.4	0.0
Oct 2004	6.2	94.8	94.8

Table 4.1 Measurements made at Mast 343 at a height of 60 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Mar 2004	-	0.0	12.0
Apr 2004	-	0.0	100.0
May 2004	8.4	90.0	100.0
Jun 2004	7.9	100.0	100.0
Jul 2004	8.6	100.0	100.0
Aug 2004	7.9	100.0	100.0
Sep 2004	7.7	100.0	100.0
Oct 2004	6.0	100.0	100.0
Nov 2004	5.1	100.0	100.0
Dec 2004	4.9	84.0	84.0
Jan 2005	4.6	83.0	83.0
Feb 2005	4.7	100.0	100.0
Mar 2005	6.4	100.0	100.0
Apr 2005	6.5	100.0	100.0
May 2005	7.1	100.0	100.0

Table 4.2 Measurements made at Mast 344 at a height of 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Oct 2004	5.4	95.0	95.0
Nov 2004	4.5	19.0	82.0
Dec 2004	-	0.0	86.0
Jan 2005	-	0.0	100.0
Feb 2005	-	0.0	100.0
Mar 2005	6.7	42.0	100.0
Apr 2005	7.9	100.0	100.0
May 2005	9.9	100.0	100.0
Jun 2005	8.9	100.0	100.0
Jul 2005	8.8	100.0	100.0
Aug 2005	7.9	100.0	100.0
Sep 2005	5.5	99.0	99.0
Oct 2005	5.9	90.0	90.0
Nov 2005	4.8	69.0	69.0
Dec 2005	6.1	100.0	100.0
Jan 2006	6.6	98.0	98.0
Feb 2006	6.1	100.0	100.0
Mar 2006	6.6	15.0	15.0
Apr 2006	5.4	95.0	95.0

Table 4.3 Measurements made at Mast 345 at a height of 60 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Nov 2004	5.0	89.0	89.0
Dec 2004	5.5	74.0	74.0
Jan 2005	4.9	65.0	65.0
Feb 2005	4.7	100.0	100.0
Mar 2005	6.5	100.0	100.0
Apr 2005	6.5	100.0	100.0
May 2005	7.3	100.0	100.0
Jun 2005	9.1	100.0	100.0
Jul 2005	8.3	100.0	100.0
Aug 2005	8.0	100.0	100.0
Sep 2005	7.3	100.0	100.0
Oct 2005	5.4	100.0	100.0
Nov 2005	6.3	71.0	71.0
Dec 2005	5.4	71.0	71.0
Jan 2006	6.2	100.0	100.0
Feb 2006	6.5	100.0	100.0
Mar 2006	6.1	69.0	69.0

Table 4.4 Measurements made at Mast 346 at a height of 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Dec 2004	4.6	55.0	55.0
Jan 2005	4.2	86.0	86.0
Feb 2005	4.3	95.0	95.0
Mar 2005	6.3	100.0	100.0
Apr 2005	6.7	100.0	100.0
May 2005	7.4	100.0	100.0
Jun 2005	9.2	100.0	100.0
Jul 2005	8.2	100.0	100.0
Aug 2005	8.1	100.0	100.0
Sep 2005	7.3	100.0	100.0
Oct 2005	5.2	100.0	100.0
Nov 2005	5.1	91.0	91.0
Dec 2005	4.2	67.0	67.0
Jan 2006	5.6	100.0	100.0
Feb 2006	5.9	98.0	98.0
Mar 2006	5.6	94.0	94.0

Table 4.5 Measurements made at Mast 347 at a height of 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Nov 2001	5.6	16.0	16.0
Dec 2001	6.7	90.0	90.0
Jan 2002	6.8	90.0	90.0
Feb 2002	5.7	100.0	100.0
Mar 2002	8.2	96.0	96.0
Apr 2002	8.4	100.0	100.0
May 2002	8.7	100.0	100.0
Jun 2002	8.9	100.0	100.0
Jul 2002	9.7	100.0	100.0

Table 4.6 Measurements made at Mast 2001 at a height of 50 m - continued.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Aug 2002	8.6	100.0	100.0
Sep 2002	7.1	100.0	100.0
Oct 2002	6.3	100.0	100.0
Nov 2002	4.3	91.0	91.0
Dec 2002	5.2	69.0	69.0
Jan 2003	4.2	72.0	72.0
Feb 2003	6.3	100.0	100.0
Mar 2003	7.9	100.0	100.0
Apr 2003	6.6	100.0	100.0
May 2003	7.8	100.0	100.0
Jun 2003	8.9	100.0	100.0
Jul 2003	8.7	100.0	100.0
Aug 2003	8.2	100.0	100.0
Sep 2003	6.8	100.0	100.0
Oct 2003	6.5	90.0	100.0
Nov 2003	-	0.0	100.0
Dec 2003	-	0.0	76.0
Jan 2004	-	0.0	55.0
Feb 2004	-	0.0	98.0
Mar 2004	7.7	72.0	88.0
Apr 2004	6.7	100.0	100.0
May 2004	8.6	100.0	100.0
Jun 2004	8.0	100.0	100.0
Jul 2004	8.8	100.0	100.0
Aug 2004	7.9	100.0	100.0
Sep 2004	7.9	100.0	100.0
Oct 2004	6.3	100.0	100.0
Nov 2004	5.5	96.0	96.0
Dec 2004	5.5	75.0	75.0
Jan 2005	4.7	85.0	85.0
Feb 2005	4.9	94.0	94.0
Mar 2005	6.7	100.0	100.0
Apr 2005	6.8	100.0	100.0
May 2005	7.4	17.0	17.0

Table 4.6 Measurements made at Mast 2001 at a height of 50 m - concluded.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Nov 2001	4.3	10.0	10.0
Dec 2001	6.8	92.0	92.0
Jan 2002	5.5	78.0	78.0
Feb 2002	5.3	100.0	100.0
Mar 2002	6.5	100.0	100.0
Apr 2002	8.3	100.0	100.0
May 2002	8.8	100.0	100.0
Jun 2002	8.0	100.0	100.0
Jul 2002	8.4	100.0	100.0
Aug 2002	9.2	100.0	100.0
Sep 2002	7.6	100.0	100.0
Oct 2002	6.3	100.0	100.0
Nov 2002	4.8	100.0	100.0
Dec 2002	4.0	72.0	72.0
Jan 2003	3.9	72.0	72.0
Feb 2003	5.0	96.0	96.0
Mar 2003	7.3	100.0	100.0
Apr 2003	6.2	100.0	100.0
May 2003	7.6	100.0	100.0
Jun 2003	8.2	100.0	100.0
Jul 2003	7.9	100.0	100.0
Aug 2003	8.1	100.0	100.0
Sep 2003	7.1	100.0	100.0
Oct 2003	5.4	100.0	100.0
Nov 2003	6.3	100.0	100.0
Dec 2003	4.9	87.0	87.0
Jan 2004	4.4	55.0	55.0
Feb 2004	6.1	89.0	89.0
Mar 2004	6.3	89.0	100.0
Apr 2004	-	0.0	100.0
May 2004	-	0.0	100.0
Jun 2004	-	0.0	100.0
Jul 2004	-	0.0	100.0
Aug 2004	-	0.0	74.0

Table 4.7 Measurements made at Mast 2002 at a height of 30 m.

Month	Mean wind speed [m/s]		Wind speed data coverage at 30 m [%]	Wind direction data coverage [%]
	50 m	30 m		
Feb 2002	-	6.3	6.0	6.0
Mar 2002	-	7.6	96.0	96.0
Apr 2002	-	7.8	100.0	100.0
May 2002	-	8.1	100.0	100.0
Jun 2002	-	8.5	100.0	100.0
Jul 2002	-	9.2	100.0	100.0
Aug 2002	-	8.0	100.0	100.0
Sep 2002	-	6.8	100.0	100.0
Oct 2002	-	6.1	100.0	100.0
Nov 2002	-	4.1	92.0	92.0
Dec 2002	-	5.3	68.0	68.0
Jan 2003	-	4.1	73.0	73.0
Feb 2003	-	6.1	100.0	100.0
Mar 2003	-	7.3	96.0	96.0
Apr 2003	-	6.5	100.0	100.0
May 2003	-	7.5	100.0	100.0
Jun 2003	-	8.6	100.0	100.0
Jul 2003	-	8.5	100.0	100.0
Aug 2003	-	7.9	100.0	100.0
Sep 2003	-	6.4	90.0	90.0
Oct 2003	-	6.4	100.0	100.0
Nov 2003	-	5.8	100.0	100.0
Dec 2003	-	5.0	62.0	62.0
Jan 2004	-	5.9	54.0	54.0
Feb 2004	-	5.3	80.0	80.0
Mar 2004	-	7.1	100.0	100.0
Apr 2004	-	7.0	32.0	32.0
May 2004	-	-	0.0	0.0
Jun 2004	-	-	0.0	0.0
Jul 2004	-	-	0.0	0.0
Aug 2004	8.6	7.9	1.0	1.0
Sep 2004	7.8	7.4	100.0	100.0
Oct 2004	6.4	6.1	100.0	100.0
Nov 2004	5.4	4.9	96.0	96.0
Dec 2004	5.2	4.8	83.0	83.0

Table 4.8 Measurements made at Mast 2010 at heights of 50 m and 30 m - continued.

Month	Mean wind speed [m/s]		Wind speed data coverage at 30 m [%]	Wind direction data coverage [%]
	50 m	30 m		
Jan 2005	5.0	4.7	81.0	81.0
Feb 2005	4.9	4.6	99.0	99.0
Mar 2005	6.7	6.2	100.0	100.0
Apr 2005	6.7	6.3	99.0	99.0
May 2005	7.4	6.9	100.0	100.0
Jun 2005	9.2	8.7	100.0	100.0
Jul 2005	8.3	7.9	100.0	100.0
Aug 2005	8.1	7.7	100.0	100.0
Sep 2005	7.3	6.9	100.0	100.0
Oct 2005	5.4	4.9	100.0	100.0
Nov 2005	5.7	5.3	82.0	82.0
Dec 2005	5.1	4.5	68.0	68.0
Jan 2006	5.9	5.4	100.0	100.0
Feb 2006	6.5	6.0	100.0	100.0
Mar 2006	6.1	5.6	1.0	1.0

Table 4.8 Measurements made at Mast 2010 at heights of 50 m and 30 m - concluded.

Month	Mean wind speed [m/s]		Wind speed data coverage at 30 m [%]	Wind direction data coverage [%]
	50 m	30 m		
Apr 2002	-	7.0	4.0	4.0
May 2002	-	7.7	100.0	100.0
Jun 2002	-	8.1	100.0	100.0
Jul 2002	-	8.7	100.0	100.0
Aug 2002	-	7.7	100.0	100.0
Sep 2002	-	6.5	100.0	100.0
Oct 2002	-	5.8	100.0	100.0
Nov 2002	-	3.9	92.0	92.0
Dec 2002	-	4.9	74.0	74.0
Jan 2003	-	4.0	76.0	76.0
Feb 2003	-	6.0	100.0	100.0
Mar 2003	-	7.2	100.0	100.0
Apr 2003	-	6.2	100.0	100.0
May 2003	-	7.5	100.0	100.0
Jun 2003	-	8.6	100.0	100.0
Jul 2003	-	8.6	100.0	100.0
Aug 2003	-	7.8	100.0	100.0
Sep 2003	-	6.4	100.0	100.0
Oct 2003	-	6.4	100.0	100.0
Nov 2003	-	5.9	100.0	100.0
Dec 2003	-	4.6	75.0	75.0
Jan 2004	-	5.3	70.0	70.0
Feb 2004	-	5.1	92.0	92.0
Mar 2004	-	7.0	100.0	100.0
Apr 2004	-	6.2	100.0	100.0
May 2004	-	7.9	67.0	67.0
Jun 2004	-	-	0.0	0.0
Jul 2004	-	-	0.0	0.0
Aug 2004	-	-	0.0	0.0
Sep 2004	7.5	7.1	100.0	100.0
Oct 2004	6.2	5.9	100.0	100.0
Nov 2004	5.3	4.9	97.0	97.0
Dec 2004	5.2	4.7	83.0	83.0
Jan 2005	4.8	4.5	82.0	82.0
Feb 2005	4.7	4.5	100.0	100.0
Mar 2005	6.5	6.1	100.0	100.0
Apr 2005	6.4	6.0	3.0	3.0

Table 4.9 Measurements made at Mast 2012 at heights of 50 m and 30 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Aug 2004	6.1	5.0	5.0
Sep 2004	8.2	99.0	99.0
Oct 2004	6.4	100.0	100.0
Nov 2004	5.3	99.0	99.0
Dec 2004	5.1	85.0	85.0
Jan 2005	4.9	84.0	84.0
Feb 2005	5.0	93.0	93.0
Mar 2005	6.8	100.0	100.0
Apr 2005	7.0	100.0	100.0
May 2005	7.4	100.0	100.0
Jun 2005	9.2	100.0	100.0
Jul 2005	8.3	100.0	100.0
Aug 2005	8.2	100.0	100.0
Sep 2005	7.5	100.0	100.0
Oct 2005	5.3	98.0	98.0
Nov 2005	5.3	93.0	86.0
Dec 2005	5.0	65.0	65.0
Jan 2006	6.1	99.0	99.0
Feb 2006	7.4	21.0	21.0

Table 4.10 Measurements made at Mast 2018 at a height of 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Jul 2004	8.1	72.0	72.0
Aug 2004	8.1	100.0	100.0
Sep 2004	8.1	100.0	100.0
Oct 2004	6.3	99.0	99.0
Nov 2004	5.2	100.0	100.0
Dec 2004	5.1	86.0	86.0
Jan 2005	4.7	85.0	85.0
Feb 2005	4.6	100.0	100.0
Mar 2005	6.6	100.0	100.0
Apr 2005	6.9	100.0	100.0
May 2005	7.5	100.0	100.0
Jun 2005	9.2	100.0	100.0
Jul 2005	8.4	100.0	100.0
Aug 2005	8.2	100.0	100.0
Sep 2005	7.5	100.0	100.0
Oct 2005	5.3	100.0	100.0
Nov 2005	5.4	91.0	91.0
Dec 2005	4.6	69.0	69.0
Jan 2006	6.0	100.0	100.0
Feb 2006	6.8	23.0	23.0

Table 4.11 Measurements made at Mast 2020 at a height of 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [%]	Wind direction data coverage [%]
Aug 2004	7.5	76.0	76.0
Sep 2004	7.8	100.0	100.0
Oct 2004	6.1	100.0	100.0
Nov 2004	5.1	100.0	100.0
Dec 2004	4.7	88.0	88.0
Jan 2005	4.4	87.0	87.0
Feb 2005	4.3	100.0	100.0
Mar 2005	6.5	100.0	100.0
Apr 2005	6.7	100.0	100.0
May 2005	7.4	100.0	100.0
Jun 2005	9.1	100.0	100.0
Jul 2005	8.2	100.0	100.0
Aug 2005	8.0	100.0	100.0
Sep 2005	7.3	100.0	100.0
Oct 2005	5.2	100.0	100.0
Nov 2005	5.3	91.0	91.0
Dec 2005	4.4	70.0	70.0
Jan 2006	6.0	100.0	100.0
Feb 2006	6.1	100.0	100.0
Mar 2006	5.8	97.0	97.0

Table 4.12 Measurements made at Mast 2021 at a height of 50 m.

	GE 1.5 sle	SWT-2.3-93	
Diameter	77	93	m
Hub height	80	80	m
Rotor speed	10 to 20	6 to 16	rpm
Power regulation	Pitch	Pitch	-
Nominal rated power	1500	2300	kW

Table 5.1 Main parameters of the wind turbine analyzed.

Wind speed [m/s at hub height]	**Electrical power [kW]**
3.5	17
4.0	39
4.5	77
5.0	122
5.5	173
6.0	235
6.5	306
7.0	392
7.5	490
8.0	604
8.5	744
9.0	874
9.5	1014
10.0	1137
10.5	1245
11.0	1330
11.5	1385
12.0	1428
12.5	1454
13.0	1473
13.5	1485
14.0	1494
14.5	1498
15.0	1500
15.5	1500
16.0	1500
16.5	1500
17.0	1500
17.5	1500
18.0	1500
18.5	1500
19.0	1500
19.5	1500
20.0	1500
20.5	1500
21.0	1500
21.5	1500
22.0	1500
22.5	1500
23.0	1500
23.5	1500
24.0	1500
24.5	1500
25.0	1500

Performance for air density 1.16 kg/m^3 and 10 to 15 % turbulence intensity

Table 5.2 Performance data for the GE 1.5 sle wind turbine analyzed.

Wind speed [m/s at hub height]	Electrical power [kW]
4.0	59
5.0	169
6.0	336
7.0	568
8.0	874
9.0	1260
10.0	1697
11.0	2061
12.0	2238
13.0	2289
14.0	2299
15.0	2300
16.0	2300
17.0	2300
18.0	2300
19.0	2300
20.0	2300
21.0	2300
22.0	2300
23.0	2300
24.0	2300
25.0	2300

Performance for air density 1.17 kg/m^3 and 8 % turbulence intensity

Table 5.3 Performance data for the Siemens SWT-2.3-93 wind turbine analyzed.

Turbine #	Easting[1] [m]	Northing[1] [m]	Turbine	Mean hub-height wind speed[2] [m/s]	Energy output[3] [MWh/annum]
G1	682507	5047781	GE 1.5 sle	7.31	4952
G2	682512	5047620	GE 1.5 sle	7.37	5010
G3	682521	5047441	GE 1.5 sle	7.38	5042
G4	682531	5047242	GE 1.5 sle	7.44	5101
G5	682539	5046954	GE 1.5 sle	7.48	5098
G6	682548	5046794	GE 1.5 sle	7.45	5068
G7	682553	5046629	GE 1.5 sle	7.46	5088
G8	682561	5046465	GE 1.5 sle	7.50	5120
G9	682566	5046304	GE 1.5 sle	7.58	5206
G10	682579	5046115	GE 1.5 sle	7.63	5243
G11	682663	5045962	GE 1.5 sle	7.63	5125
G12	682876	5045805	GE 1.5 sle	7.46	4744
G13	682912	5045651	GE 1.5 sle	7.44	5035
G14	682932	5045496	GE 1.5 sle	7.49	5123
G15	682940	5045332	GE 1.5 sle	7.55	5108
G16	682885	5045174	GE 1.5 sle	7.50	5175
G17	682937	5045001	GE 1.5 sle	7.43	5120
G18	684505	5046750	GE 1.5 sle	7.42	4687
G19	684538	5046578	GE 1.5 sle	7.43	4659
G20	684546	5046421	GE 1.5 sle	7.45	4687
G21	684606	5046263	GE 1.5 sle	7.50	4715
G22	684613	5046103	GE 1.5 sle	7.55	4787
G23	684652	5045945	GE 1.5 sle	7.51	4670
G24	684613	5045771	GE 1.5 sle	7.62	4766
G25	684572	5045610	GE 1.5 sle	7.56	4844
G26	685675	5047839	GE 1.5 sle	7.53	4988
G27	685692	5047675	GE 1.5 sle	7.54	5000
G28	685707	5047514	GE 1.5 sle	7.55	4973
G29	685729	5047357	GE 1.5 sle	7.60	5027
G30	685757	5047194	GE 1.5 sle	7.50	4910
G31	686243	5046895	GE 1.5 sle	7.54	4925
G32	686361	5046726	GE 1.5 sle	7.51	4821
G33	686366	5046569	GE 1.5 sle	7.55	4888
G34	686420	5046409	GE 1.5 sle	7.59	4911
G35	686441	5046249	GE 1.5 sle	7.60	4899
G36	686471	5046084	GE 1.5 sle	7.58	4835
G37	686351	5045881	GE 1.5 sle	7.53	4927
G38	687048	5045678	GE 1.5 sle	7.52	4966
G39	687082	5045522	GE 1.5 sle	7.60	5104
G40	687115	5045351	GE 1.5 sle	7.62	5146
G41	689626	5047100	GE 1.5 sle	7.44	4944
G42	689816	5046941	GE 1.5 sle	7.42	4892
G43	690051	5046743	GE 1.5 sle	7.41	4887
G44	690058	5046551	GE 1.5 sle	7.41	4796
G45	689999	5046391	GE 1.5 sle	7.30	4785

Notes
1 Coordinate system is UTM NAD27 Zone 10
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.4 Phase III turbine layout with predicted individual turbine wind speed and energy production – continued.

Turbine #	Easting[1] [m]	Northing[1] [m]	Turbine	Mean hub-height wind speed[2] [m/s]	Energy output[3] [MWh/annum]
G46	690012	5046232	GE 1.5 sle	7.31	4807
G47	690050	5046054	GE 1.5 sle	7.37	4878
G48	690066	5045889	GE 1.5 sle	7.34	4841
G49	690089	5045731	GE 1.5 sle	7.31	4849
G50	688097	5054278	GE 1.5 sle	7.92	5600
G51	688099	5054094	GE 1.5 sle	7.89	5575
G52	688108	5053926	GE 1.5 sle	7.85	5554
G53	688120	5053761	GE 1.5 sle	7.86	5573
G54	690838	5054928	GE 1.5 sle	7.88	5535
G55	690843	5054774	GE 1.5 sle	7.83	5464
G56	690848	5054619	GE 1.5 sle	7.89	5502
G57	690854	5054462	GE 1.5 sle	7.94	5533
G58	690911	5054306	GE 1.5 sle	7.90	5459
G59	690917	5054147	GE 1.5 sle	7.89	5424
G60	690870	5053989	GE 1.5 sle	7.93	5472
G61	690875	5053834	GE 1.5 sle	7.88	5445
G62	690881	5053679	GE 1.5 sle	7.88	5454
G63	690886	5053521	GE 1.5 sle	7.84	5424
G64	690889	5053366	GE 1.5 sle	7.82	5427
G65	690895	5053210	GE 1.5 sle	7.81	5380
G66	690903	5053057	GE 1.5 sle	7.80	5341
G67	690415	5052755	GE 1.5 sle	7.49	5126
G68	690419	5052600	GE 1.5 sle	7.53	5163
G69	690425	5052444	GE 1.5 sle	7.62	5224
G70	690427	5052284	GE 1.5 sle	7.57	5197
G71	693558	5054483	GE 1.5 sle	7.63	5301
G72	693561	5054323	GE 1.5 sle	7.63	5290
G73	693569	5054167	GE 1.5 sle	7.63	5280
G74	693575	5054010	GE 1.5 sle	7.66	5298
G75	693582	5053853	GE 1.5 sle	7.69	5317
G76	693587	5053699	GE 1.5 sle	7.69	5291
G77	693592	5053545	GE 1.5 sle	7.71	5296
G78	693595	5053390	GE 1.5 sle	7.75	5308
G79	693601	5053234	GE 1.5 sle	7.75	5275
G80	693603	5053077	GE 1.5 sle	7.62	5102
G81	691003	5050380	GE 1.5 sle	7.52	5167
G82	691010	5050206	GE 1.5 sle	7.52	5165
G83	691019	5050022	GE 1.5 sle	7.53	5180
S1	692608	5052833	SWT-2.3-93	7.60	7782
S2	692613	5052646	SWT-2.3-93	7.64	7886
S3	692574	5052275	SWT-2.3-93	7.66	7992
S4	692580	5052085	SWT-2.3-93	7.66	8085
S5	692646	5051870	SWT-2.3-93	7.68	8149
S6	692653	5051670	SWT-2.3-93	7.69	8214
S7	692729	5051454	SWT-2.3-93	7.65	8175

Notes
1 Coordinate system is UTM NAD27 Zone 10
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.4 Klondike Wind Farm Phase III turbine layout with predicted individual turbine wind speed and energy production – continued.

Turbine #	Easting[1] [m]	Northing[1] [m]	Turbine	Mean hub-height wind speed[2] [m/s]	Energy output[3] [MWh/annum]
S8	692851	5050426	SWT-2.3-93	7.51	7594
S9	692851	5050235	SWT-2.3-93	7.59	7642
S10	692861	5050041	SWT-2.3-93	7.63	7700
S11	692865	5049844	SWT-2.3-93	7.68	7853
S12	692886	5049651	SWT-2.3-93	7.67	7927
S13	692907	5049464	SWT-2.3-93	7.48	7663
S14	692851	5049271	SWT-2.3-93	7.45	7719
S15	692837	5049062	SWT-2.3-93	7.45	7749
S16	694163	5052912	SWT-2.3-93	7.61	7534
S17	694161	5052731	SWT-2.3-93	7.58	7649
S18	694176	5052524	SWT-2.3-93	7.54	7591
S19	694183	5052332	SWT-2.3-93	7.52	7585
S20	694169	5052055	SWT-2.3-93	7.50	7467
S21	694176	5051837	SWT-2.3-93	7.55	7467
S22	694181	5051641	SWT-2.3-93	7.60	7514
S23	694080	5051442	SWT-2.3-93	7.63	7724
S24	694477	5051151	SWT-2.3-93	7.56	7550
S25	694484	5050940	SWT-2.3-93	7.55	7597
S26	694489	5050750	SWT-2.3-93	7.58	7637
S27	694591	5050474	SWT-2.3-93	7.65	7575
S28	694583	5050288	SWT-2.3-93	7.64	7442
S29	694683	5050101	SWT-2.3-93	7.69	7455
S30	694689	5049902	SWT-2.3-93	7.72	7539
S31	694728	5049714	SWT-2.3-93	7.74	7664
S32	696228	5052952	SWT-2.3-93	7.55	7651
S33	696187	5052760	SWT-2.3-93	7.58	7606
S34	696139	5052566	SWT-2.3-93	7.58	7614
S35	696320	5052293	SWT-2.3-93	7.55	7538
S36	696196	5052096	SWT-2.3-93	7.47	7491
S37	696113	5051901	SWT-2.3-93	7.48	7502
S38	696186	5051689	SWT-2.3-93	7.47	7471
S39	696214	5051492	SWT-2.3-93	7.49	7468
S40	696165	5051295	SWT-2.3-93	7.55	7587
S41	696185	5051099	SWT-2.3-93	7.44	7317
S42	696240	5050897	SWT-2.3-93	7.35	7205
S43	696643	5050529	SWT-2.3-93	7.40	7301
S44	696675	5050332	SWT-2.3-93	7.38	7374

Notes
1 Coordinate system is UTM NAD27 Zone 10
2 Wind speed at the location of the turbine, not including wake effects
3 Individual turbine output figures include topographic, array and air density adjustments only

Table 5.4 Klondike Wind Farm Phase III turbine layout with predicted individual turbine wind speed and energy production – concluded.

Direction sector [degrees]	Number of records	Correlation ratio
345 – 15	31	1.01
15 – 45	97	0.93
45 – 75	1128	0.85
75 – 105	1072	0.85
105 – 135	45	1.02
135 – 165	28	1.11
165 – 195	104	1.01
195 – 225	1466	1.20
225 – 255	3030	1.17
255 – 285	8220	1.06
285 – 315	740	1.04
315 – 345	49	0.99

Table 6.1 Directional correlation ratios between Masts 2010 at 30 m and 2001 at 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	5.5	3132	3132
February	5.9	3330	3330
March	7.5	3040	3040
April	7.2	2880	2880
May	8.1	3370	3370
June	8.9	3599	3600
July	9.2	3720	3720
August	8.3	3720	3720
September	7.3	3600	3600
October	6.6	3717	3717
November	5.4	3368	3368
December	5.5	2844	2844
Mean of means	**7.1**		

Table 6.2 Predicted monthly and annual mean wind speeds at Mast 2010 at 50m (May 2001 to Mar 2006).

Site: Mast 2010 at 50 m **Period: Annual (May 2001 to Mar 2006)**

Wind Speed (m/s)	Wind Direction (degrees)												No Direction	Total (%)
	0	30	60	90	120	150	180	210	240	270	300	330		
0	0.03	0.05	0.08	0.07	0.03	0.03	0.03	0.05	0.04	0.03	0.03	0.02		0.49
1	0.15	0.24	0.41	0.68	0.36	0.36	0.35	0.38	0.29	0.21	0.26	0.21		3.91
2	0.33	0.42	0.70	1.17	0.78	0.51	0.51	0.67	0.60	0.55	0.55	0.30		7.08
3	0.18	0.38	1.21	1.64	0.65	0.38	0.49	1.14	1.30	1.21	0.85	0.28		9.70
4	0.07	0.20	1.53	1.89	0.24	0.14	0.32	1.55	2.24	1.80	0.80	0.11		10.87
5	0.01	0.08	1.23	1.56	0.10	0.03	0.17	1.63	2.54	2.21	0.68	0.06		10.30
6	0.02	0.06	1.03	1.21	0.03	0.02	0.09	1.47	2.42	2.38	0.50	0.02		9.25
7	0.01	0.03	0.74	0.68		0.02	0.04	0.94	2.28	2.77	0.34	0.01		7.85
8		0.03	0.48	0.46		0.01	0.04	0.57	1.74	3.22	0.29	0.01		6.86
9	0.01	0.01	0.36	0.25		0.01	0.04	0.37	1.22	3.71	0.19			6.17
10		0.02	0.20	0.14	+		0.02	0.30	0.96	3.91	0.16	+		5.71
11		0.01	0.09	0.11		+	0.03	0.21	0.63	3.88	0.11			5.09
12	+	0.02	0.08	0.03			0.03	0.12	0.45	3.58	0.08	+		4.40
13	+	0.01	0.02	0.01			0.01	0.08	0.31	3.08	0.06			3.57
14		+	0.02	+			0.01	0.07	0.16	2.46	0.04			2.75
15			0.01				0.01	0.06	0.12	1.77	0.02			1.99
16			0.01			+	+	0.06	0.10	1.31	0.01			1.49
17								0.04	0.05	0.95	0.01			1.05
18								0.04	0.04	0.65	+			0.73
19								0.02	0.01	0.32	+			0.35
20								0.01	0.01	0.19	+			0.21
21								+	0.01	0.09				0.10
22							+	+	+	0.04				0.05
23							+	+		0.02				0.03
24								+	+	0.01				0.02
25									0.01	0.01				0.01
26														
27														
28														
29														
30														
31														
32														
33														
34														
35														
36														
37														
38														
39 - 44														
45 and over														
Total (%)	0.8	1.6	8.2	9.9	2.2	1.5	2.2	9.8	17.5	40.3	5.0	1.0		100
Av.Speed (m/s)	2.40	3.24	4.99	4.48	2.52	2.44	3.61	5.68	6.64	10.02	5.16	2.64	0.00	7.1

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

Table 6.3 Predicted wind speed and direction frequency distribution at the Mast 2010 at 50 m.

Month	Mean wind speed [m/s]	Wind speed data coverage [records]	Wind direction data coverage [records]
January	5.6	3136	3136
February	5.9	3330	3381
March	7.7	3040	3040
April	7.3	2880	2880
May	8.3	3370	3370
June	9.0	3599	3600
July	9.3	3720	3720
August	8.5	3720	3720
September	7.5	3600	3600
October	6.7	3720	3720
November	5.5	3469	3423
December	5.5	2967	2983
Mean of means	**7.2**		

Table 6.4 Predicted monthly and annual mean wind speeds at Mast 2018 at 50m (May 2001 to Mar 2006).

Mast	Measurement height [m]	Long-term mean wind speed at measurement height [m/s]	Power law shear exponent ‘α’ from measurement	Long-term mean wind speed at 80 m [m/s]
343	60	7.7	0.15	8.0
344	50	6.9	0.19	7.5
345	60	7.6	0.15	8.0
346	50	7.1	0.12	7.5
347	50	7.0	0.17	7.6
2010	50	7.1	0.13	7.6
2012	50	7.0	0.13	7.4
2018	50	7.2	0.11	7.6
2020	50	7.2	0.18	7.8
2021	50	7.0	0.17	7.6

Table 6.5 Predictions of the wind speeds at the site masts.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.20		
Synthesis from 50 m to 60 m	0.0%	0.00		
Synthesis from Mast 2001 to Mast 343	2.9%	0.24		
Uncertainty from Mast 2001 synthesis	0.2%	0.02		
Variability of 4.6 year period	2.8%	0.22		
Shear from 60 m to 80 m	2.0%	0.16		
Overall historical wind speed		**0.41**		**1.3**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			4.0%	0.8
Future wind variability (1 year)	6.0%	0.48		1.5
Future wind variability (10 years)	1.9%	0.15		0.5
Overall energy uncertainty (1 year)				**2.2**
Overall energy uncertainty (10 years)				**1.6**

Note: Sensitivity of net production to wind speed is calculated to be 3.20 GWh/annum. (m/s)

Table 6.6 Uncertainty in projected energy output of turbines G50 to G53 based on Mast 343.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.19		
Synthesis from 49 m to 50 m	0.0%	0.00		
Synthesis from Mast 2001 to Mast 344	0.9%	0.06		
Uncertainty from Mast 2001 synthesis	0.2%	0.02		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.19		
Overall historical wind speed		**0.35**		**4.1**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			4.5%	2.4
Future wind variability (1 year)	6.0%	0.45		5.2
Future wind variability (10 years)	1.9%	0.14		1.6
Overall energy uncertainty (1 year)				**7.1**
Overall energy uncertainty (10 years)				**5.1**

Note: Sensitivity of net production to wind speed is calculated to be 11.61 GWh/annum. (m/s)

Table 6.7 Uncertainty in projected energy output of turbines G67 to G70 and G81 to G83 based on Mast 344.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.20		
Synthesis from 44 m to 60 m	0.0%	0.00		
Correlation from Mast 2018 to Mast 345	1.6%	0.12		
Uncertainty from Mast 2018 synthesis	1.1%	0.09		
Variability of 4.6 year period	2.8%	0.22		
Shear from 60 m to 80 m	2.0%	0.16		
Overall historical wind speed		**0.37**		**3.6**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			4.5%	3.0
Future wind variability (1 year)	6.0%	0.48		4.7
Future wind variability (10 years)	1.9%	0.15		1.5
Overall energy uncertainty (1 year)				**6.6**
Overall energy uncertainty (10 years)				**4.9**

Note: Sensitivity of net production to wind speed is calculated to be 9.77 GWh/annum. (m/s)

Table 6.8 Uncertainty in projected energy output of turbines G54 to G66 based on Mast 345.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.19		
Correlation from Mast 2010 to Mast 346	1.6%	0.12		
Uncertainty from Mast 2010 synthesis	0.3%	0.02		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.19		
Overall historical wind speed		**0.36**		**5.6**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			4.0%	3.2
Future wind variability (1 year)	6.0%	0.45		7.0
Future wind variability (10 years)	1.9%	0.14		2.2
Overall energy uncertainty (1 year)				**9.5**
Overall energy uncertainty (10 years)				**6.8**

Note: Sensitivity of net production to wind speed is calculated to be 15.61 GWh/annum. (m/s)

Table 6.9 Uncertainty in projected energy output of turbines G1 to G17 based on Mast 346.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	**[m/s]**	**[%]**	**[GWh/annum]**
Anemometer accuracy	2.5%	0.19		
Correlation from Mast 2018 to Mast 345	1.3%	0.10		
Uncertainty from Mast 2018 synthesis	1.1%	0.08		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.19		
Overall historical wind speed		**0.37**		**1.9**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			3.0%	0.8
Future wind variability (1 year)	6.0%	0.45		2.4
Future wind variability (10 years)	1.9%	0.14		0.7
Overall energy uncertainty (1 year)				**3.2**
Overall energy uncertainty (10 years)				**2.2**

Note: Sensitivity of net production to wind speed is calculated to be 5.21 GWh/annum. (m/s)

Table 6.10 Uncertainty in projected energy output of turbines S32 to S35 based on Mast 347.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	**[m/s]**	**[%]**	**[GWh/annum]**
Anemometer accuracy	2.5%	0.20		
Synthesis from 30 m to 50 m	0.2%	0.01		
Synthesis from Mast 2001 to Mast 2010	0.2%	0.01		
Synthesis from Mast 2002 to Mast 2010	0.2%	0.01		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.19		
Overall historical wind speed		**0.34**		**7.0**
Substation Metering accuracy			0.3%	0.3
Wake and Topographic error			6.0%	6.2
Future wind variability (1 year)	6.0%	0.46		9.3
Future wind variability (10 years)	1.9%	0.14		2.9
Overall energy uncertainty (1 year)				**13.2**
Overall energy uncertainty (10 years)				**9.8**

Note: Sensitivity of net production to wind speed is calculated to be 20.42 GWh/annum. (m/s)

Table 6.11 Uncertainty in projected energy output of turbines G18 to G40 based on Mast 2010.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.20		
Synthesis from 30 m to 50 m	0.5%	0.03		
Synthesis from Mast 2010 to Mast 2012	0.9%	0.06		
Uncertainty from Mast 2010 synthesis	0.3%	0.02		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.18		
Overall historical wind speed		**0.34**		**2.8**
Substation Metering accuracy			0.3%	0.1
Wake and Topographic error			4.0%	1.6
Future wind variability (1 year)	6.0%	0.44		3.6
Future wind variability (10 years)	1.9%	0.14		1.1
Overall energy uncertainty (1 year)				**4.9**
Overall energy uncertainty (10 years)				**3.4**

Note: Sensitivity of net production to wind speed is calculated to be 8.20 GWh/annum. (m/s)

Table 6.12 Uncertainty in projected energy output of turbines G41 to G49 based on Mast 2012.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.19		
Synthesis from Mast 2001 to Mast 2018	1.1%	0.08		
Uncertainty from Mast 2001 synthesis	0.2%	0.02		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.19		
Overall historical wind speed		**0.35**		**7.5**
Substation Metering accuracy			0.3%	0.3
Wake and Topographic error			6.0%	6.8
Future wind variability (1 year)	6.0%	0.46		9.7
Future wind variability (10 years)	1.9%	0.14		3.1
Overall energy uncertainty (1 year)				**14.0**
Overall energy uncertainty (10 years)				**10.6**

Note: Sensitivity of net production to wind speed is calculated to be 21.14 GWh/annum. (m/s)

Table 6.13 Uncertainty in projected energy output of turbines S8 to S15 and S24 to S31 based on Mast 2018.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.20		
Correlation from Mast 2018 to Mast 2020	1.3%	0.10		
Uncertainty from Mast 2018 synthesis	1.1%	0.08		
Variability of 4.6 year period	2.8%	0.22		
Shear from 50 m to 80 m	2.5%	0.20		
Overall historical wind speed		**0.37**		**10.2**
Substation Metering accuracy			0.3%	0.5
Wake and Topographic error			5.0%	7.8
Future wind variability (1 year)	6.0%	0.47		13.2
Future wind variability (10 years)	1.9%	0.15		4.2
Overall energy uncertainty (1 year)				**18.4**
Overall energy uncertainty (10 years)				**13.5**

Note: Sensitivity of net production to wind speed is calculated to be 27.97 GWh/annum. (m/s)

Table 6.14 Uncertainty in projected energy output of turbines S1 to S7, S16 to S23 and G71 to G80 based on Mast 2020.

Source of uncertainty	Wind speed		Energy output [1]	
	[%]	[m/s]	[%]	[GWh/annum]
Anemometer accuracy	2.5%	0.19		
Correlation from Mast 2018 to Mast 2021	1.0%	0.07		
Uncertainty from Mast 2018 synthesis	1.1%	0.08		
Variability of 4.6 year period	2.8%	0.21		
Shear from 50 m to 80 m	2.5%	0.19		
Overall historical wind speed		**0.36**		**4.4**
Substation Metering accuracy			0.3%	0.2
Wake and Topographic error			4.0%	2.5
Future wind variability (1 year)	6.0%	0.45		5.6
Future wind variability (10 years)	1.9%	0.14		1.8
Overall energy uncertainty (1 year)				**7.5**
Overall energy uncertainty (10 years)				**5.4**

Note: Sensitivity of net production to wind speed is calculated to be 12.31 GWh/annum. (m/s)

Table 6.15 Uncertainty in projected energy output of turbines S36 to S44 based on Mast 2021.

	Energy production [%]											
Hour[1]	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
0000	0.23	0.20	0.32	0.37	0.47	0.56	0.62	0.55	0.40	0.30	0.19	0.22
0100	0.24	0.21	0.31	0.37	0.45	0.52	0.58	0.51	0.36	0.29	0.20	0.23
0200	0.25	0.21	0.33	0.36	0.44	0.50	0.55	0.49	0.34	0.27	0.19	0.23
0300	0.24	0.21	0.35	0.35	0.40	0.49	0.51	0.46	0.32	0.27	0.23	0.24
0400	0.23	0.20	0.33	0.33	0.39	0.45	0.45	0.40	0.31	0.24	0.23	0.23
0500	0.23	0.21	0.30	0.29	0.37	0.38	0.39	0.34	0.28	0.25	0.23	0.24
0600	0.24	0.22	0.30	0.27	0.33	0.35	0.37	0.29	0.26	0.26	0.23	0.26
0700	0.24	0.21	0.29	0.28	0.32	0.37	0.40	0.28	0.25	0.23	0.22	0.25
0800	0.22	0.19	0.29	0.28	0.32	0.35	0.41	0.28	0.25	0.24	0.19	0.23
0900	0.21	0.20	0.33	0.27	0.29	0.34	0.38	0.29	0.25	0.25	0.19	0.24
1000	0.20	0.21	0.38	0.27	0.29	0.34	0.37	0.29	0.26	0.26	0.20	0.23
1100	0.22	0.23	0.38	0.27	0.30	0.35	0.35	0.28	0.27	0.28	0.22	0.24
1200	0.23	0.26	0.40	0.28	0.35	0.37	0.36	0.30	0.29	0.30	0.23	0.22
1300	0.22	0.26	0.41	0.29	0.39	0.41	0.40	0.33	0.32	0.31	0.23	0.22
1400	0.23	0.27	0.44	0.32	0.43	0.44	0.45	0.38	0.35	0.33	0.23	0.25
1500	0.23	0.27	0.45	0.34	0.47	0.47	0.52	0.44	0.40	0.35	0.23	0.25
1600	0.23	0.27	0.47	0.36	0.50	0.53	0.59	0.50	0.43	0.38	0.23	0.26
1700	0.25	0.28	0.47	0.40	0.55	0.57	0.66	0.56	0.46	0.40	0.24	0.26
1800	0.23	0.27	0.47	0.43	0.59	0.59	0.70	0.61	0.49	0.40	0.23	0.24
1900	0.22	0.25	0.44	0.43	0.60	0.61	0.71	0.64	0.50	0.38	0.22	0.22
2000	0.22	0.21	0.44	0.43	0.61	0.62	0.69	0.64	0.49	0.36	0.22	0.21
2100	0.24	0.21	0.43	0.41	0.58	0.61	0.68	0.63	0.48	0.35	0.19	0.21
2200	0.23	0.21	0.40	0.40	0.57	0.59	0.66	0.60	0.46	0.32	0.19	0.20
2300	0.24	0.20	0.37	0.37	0.51	0.56	0.66	0.57	0.42	0.31	0.19	0.21

Note 1 Time of day is shown in Pacific Standard Time

Table 6.16 Predicted seasonal and diurnal variation in energy production.

Figure 2.1 **Location of the Klondike site.**

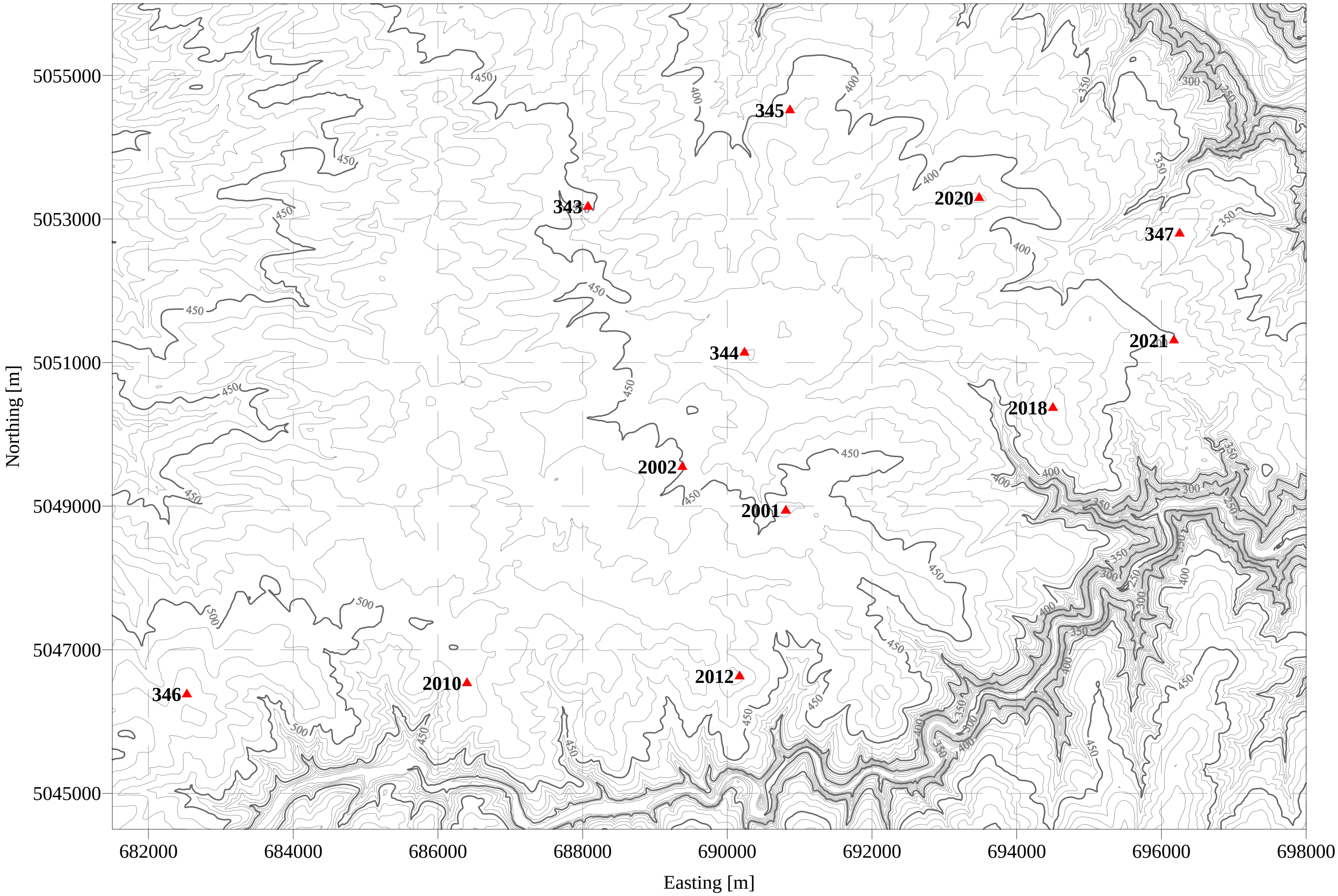


Figure 2.2 Location of the Klondike meteorological masts.

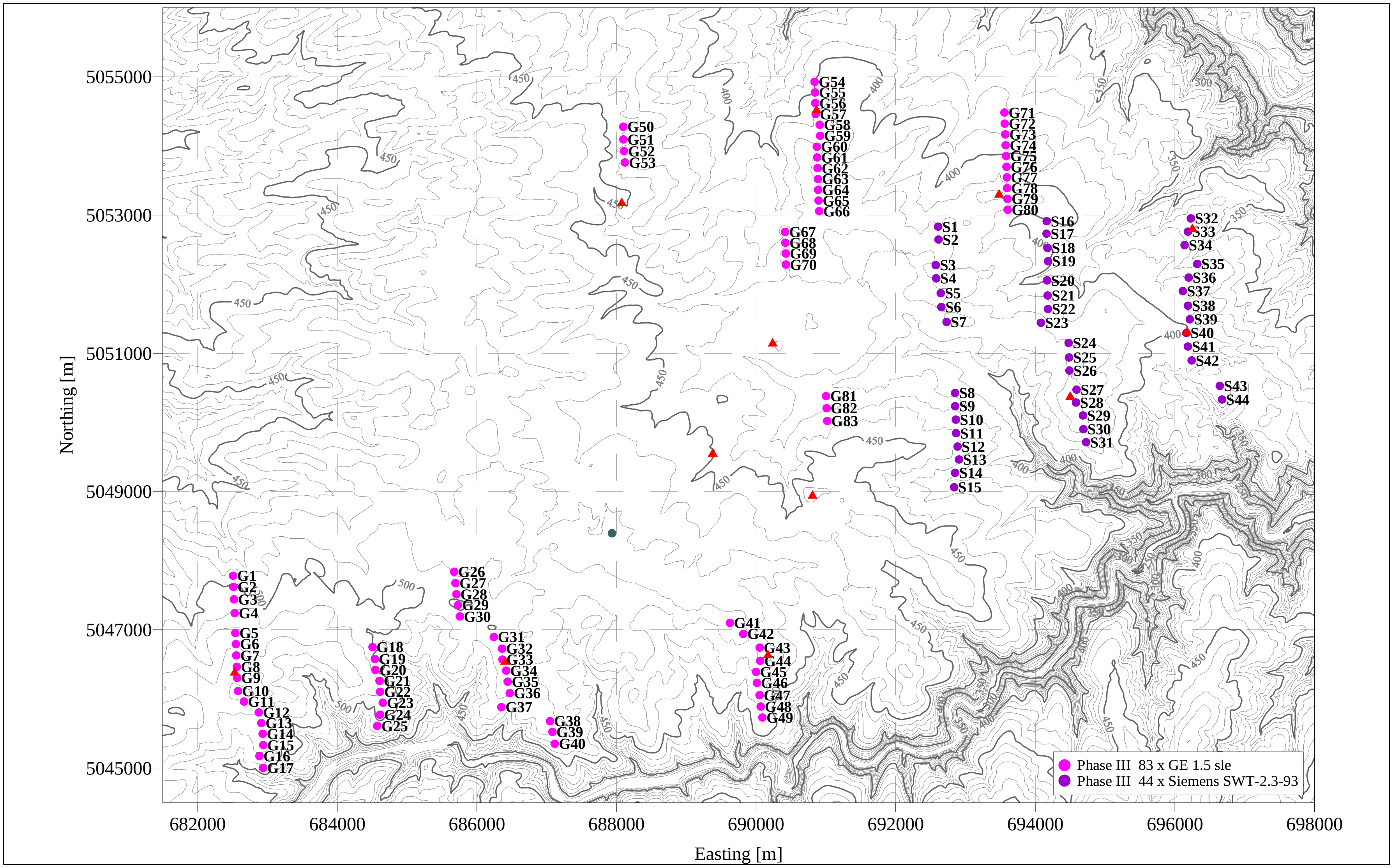


Figure 5.1 Klondike Wind Farm Phase III proposed turbine layout.

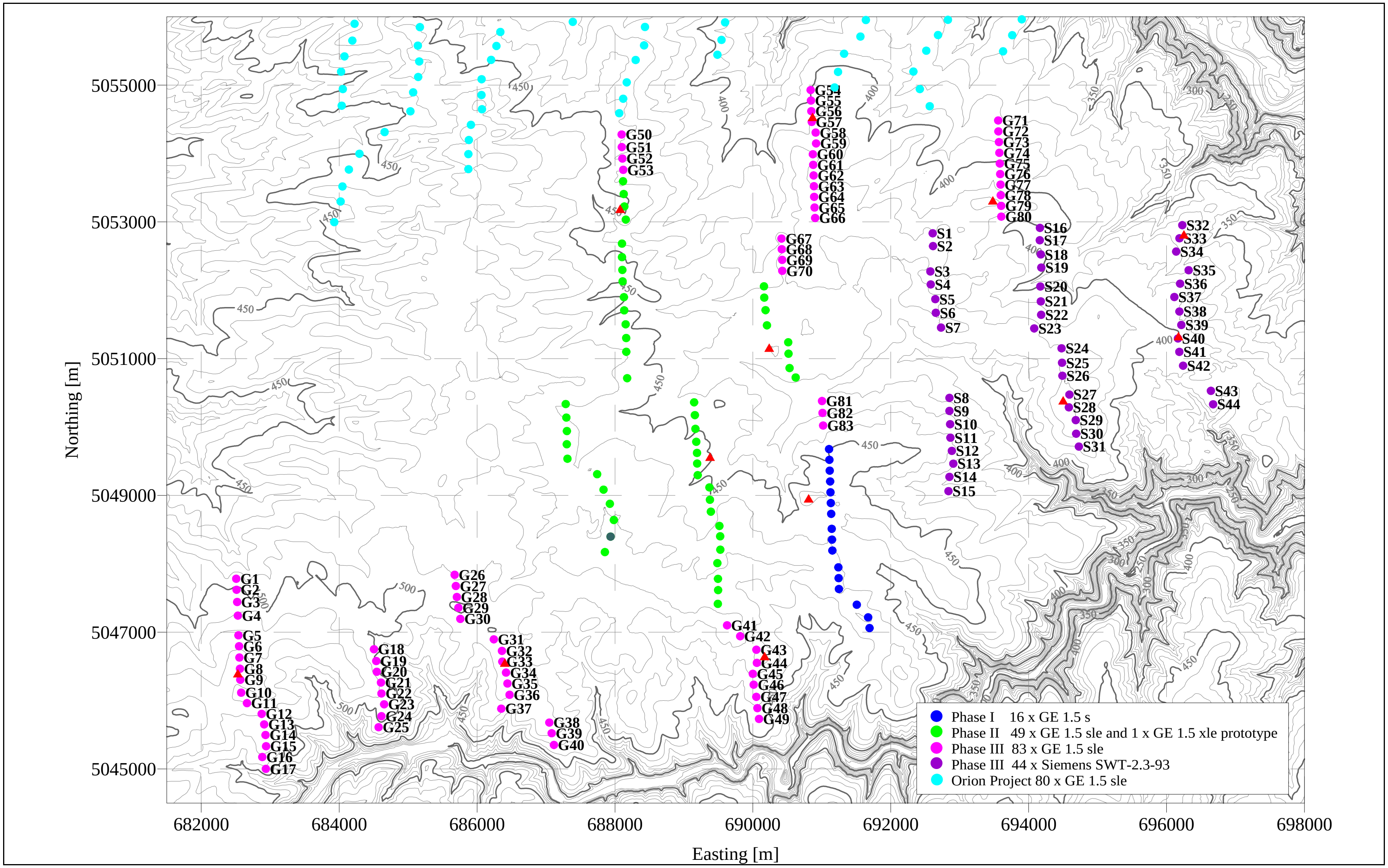


Figure 5.2 Klondike Wind Farm Phase III proposed turbine layout with Klondike Phases I and II and Orion project.

Figure 2.3 View of the Klondike site from Mast 2021 looking west.

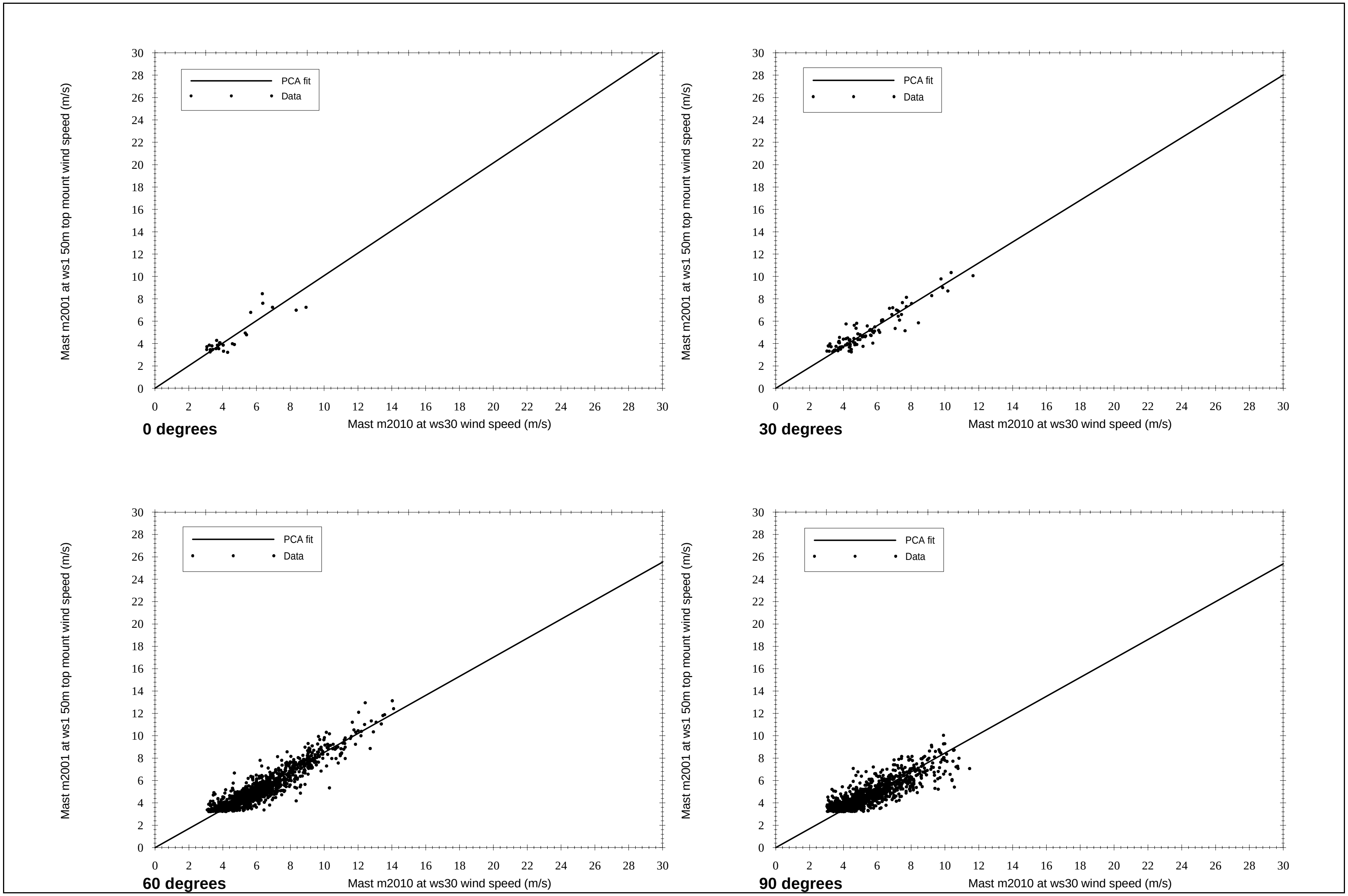


Figure 6.1 Correlation of hourly mean wind speed at Mast 2010 at 30 m and Mast 2001 at 50 m – continued.

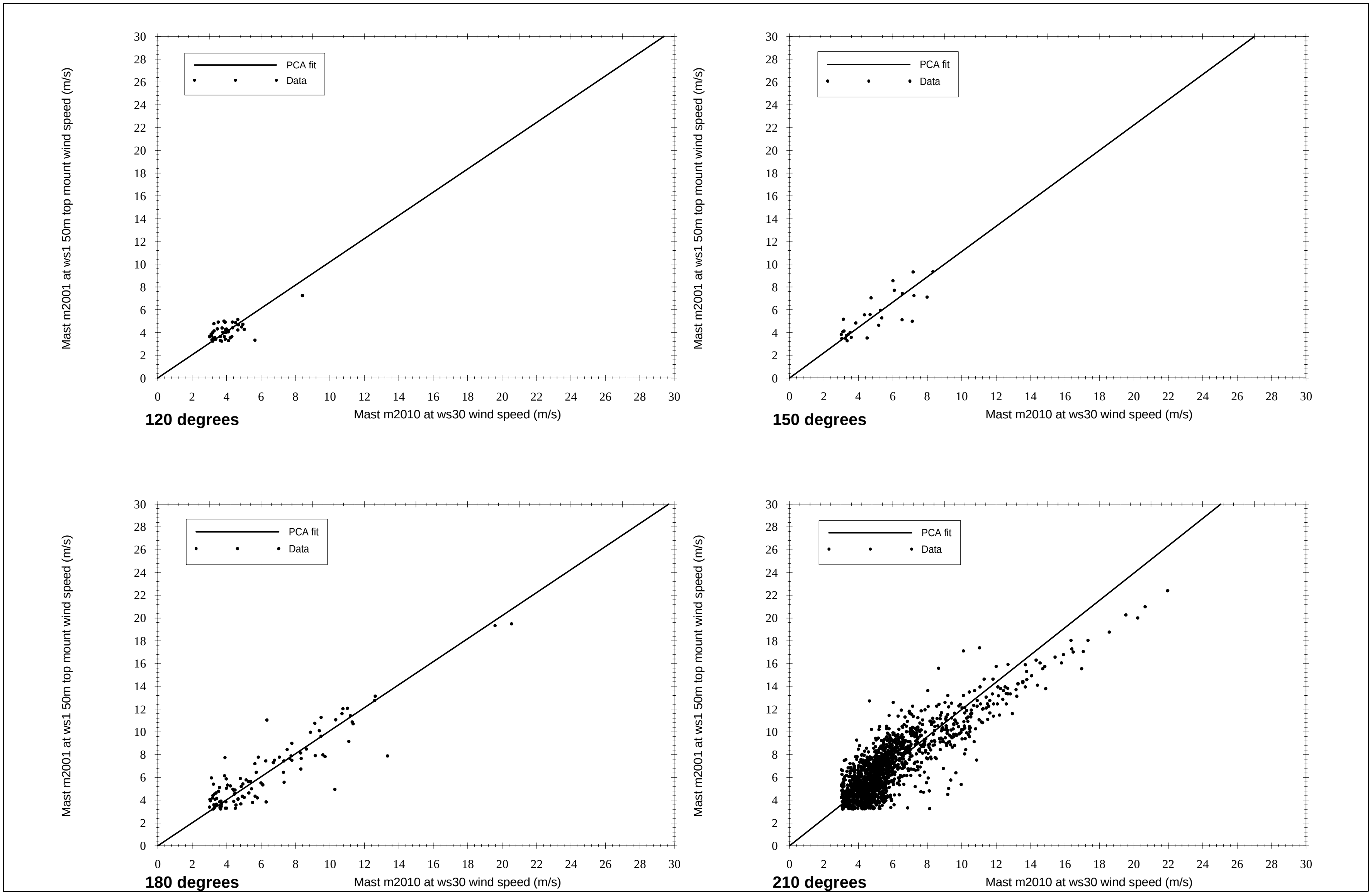


Figure 6.1 Correlation of hourly mean wind speed at Mast 2010 at 30 m and Mast 2001 at 50 m – continued.

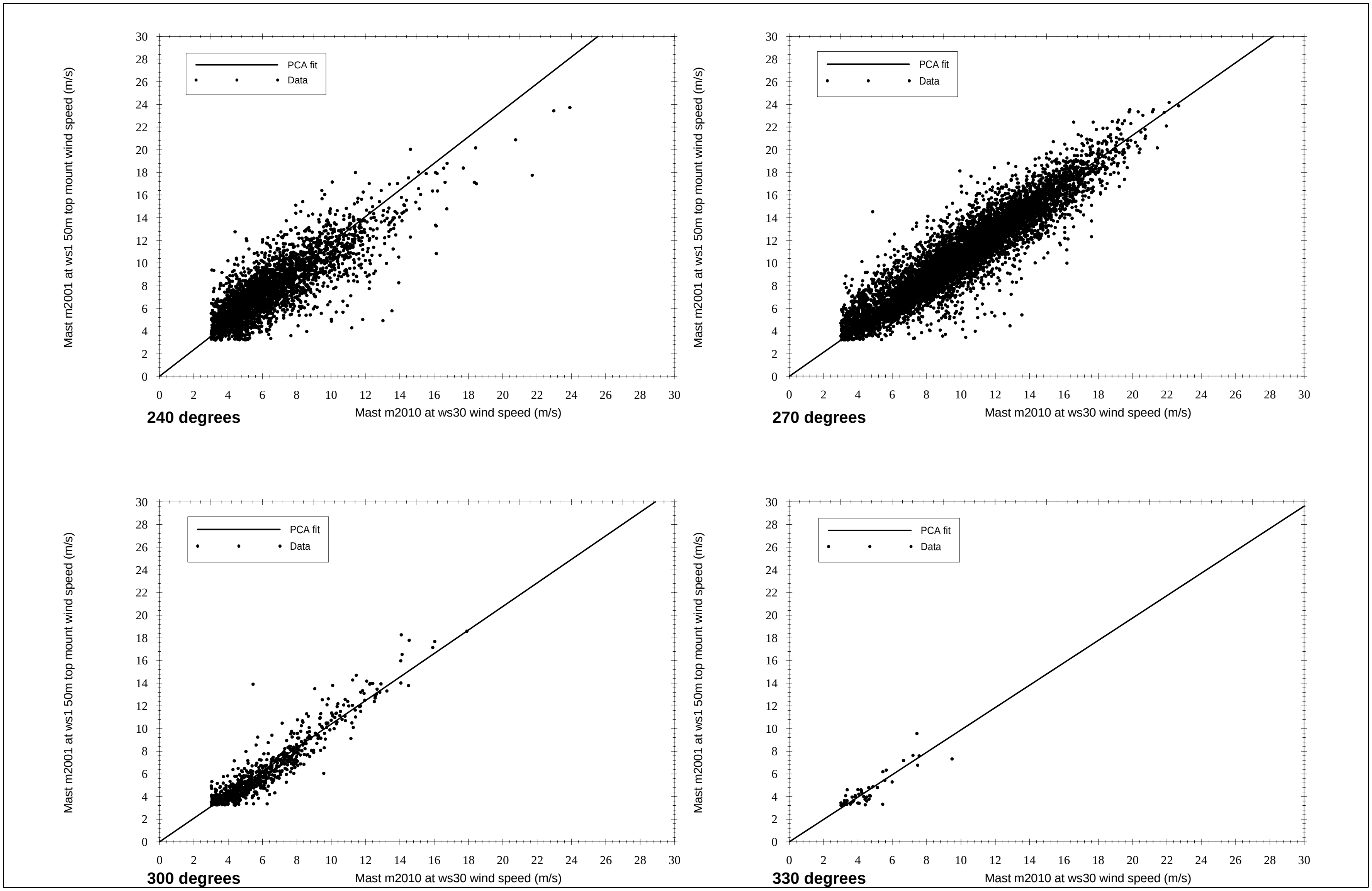
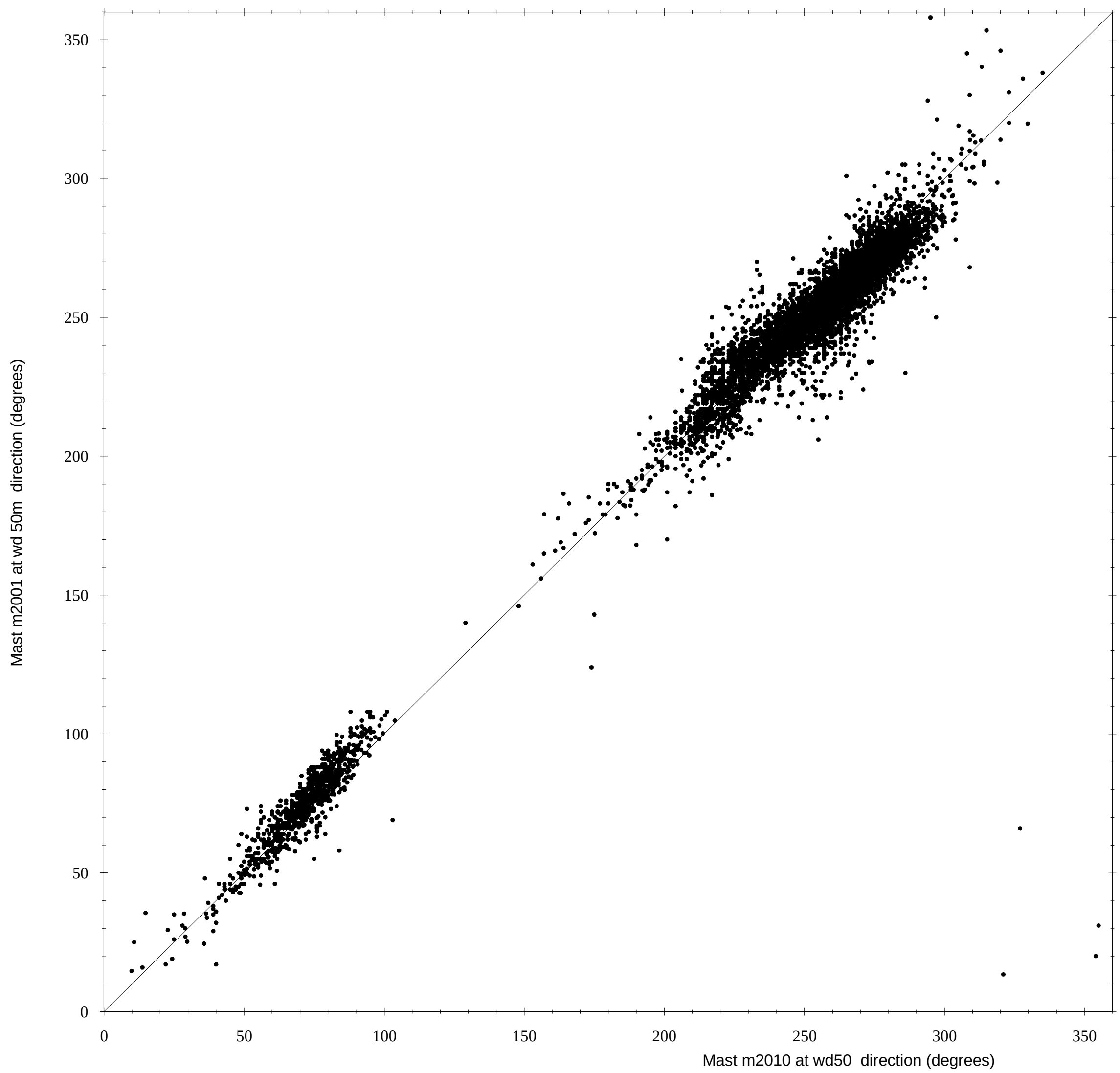


Figure 6.1 Correlation of hourly mean wind speed at Mast 2010 at 30 m and Mast 2001 at 50 m – concluded.



Wind speeds greater than 5.0 m/s

Figure 6.2 Correlation of hourly mean wind direction at Mast 2010 and Mast 2001.

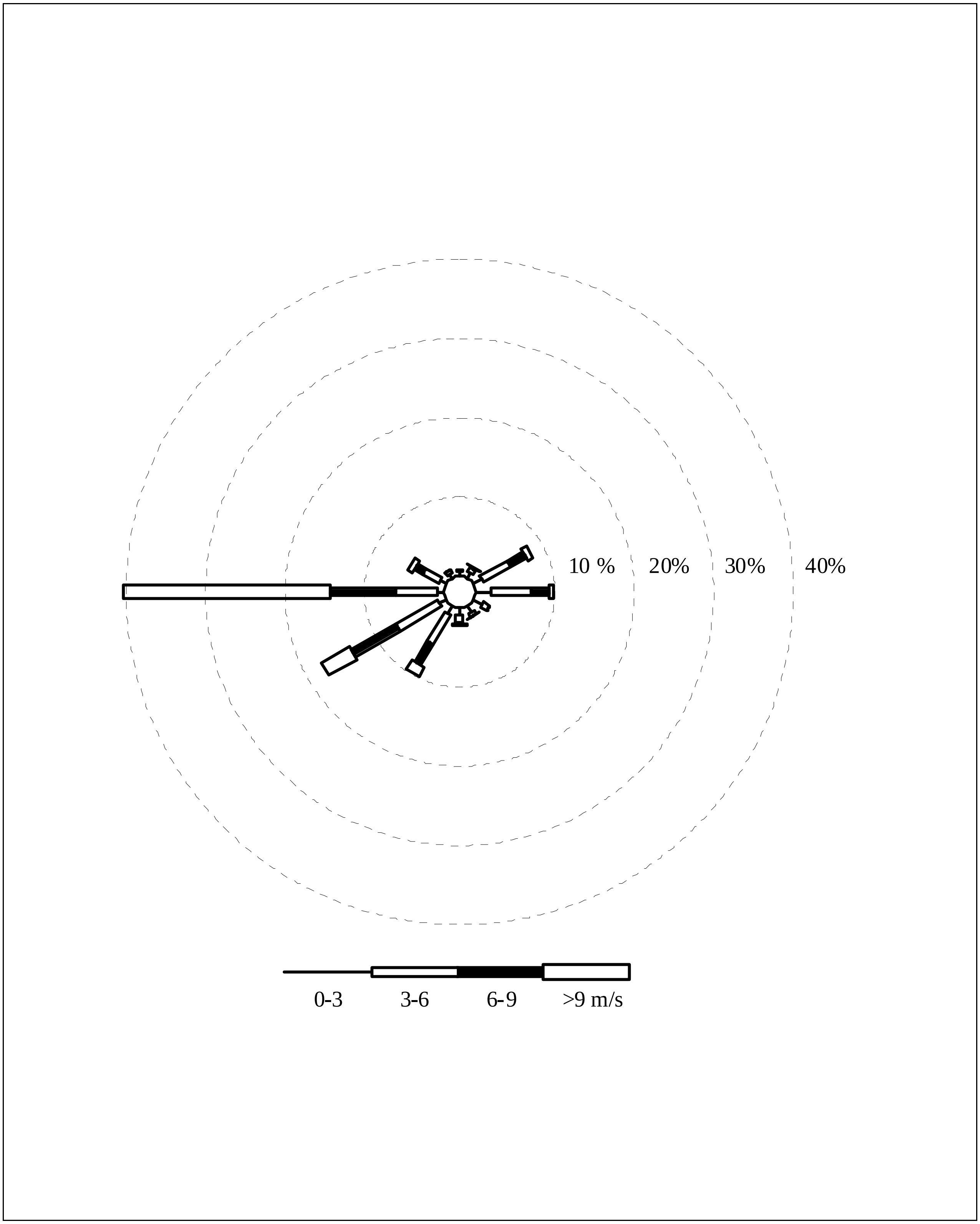


Figure 6.3 Annual wind rose from Mast 2010 at 50 m.

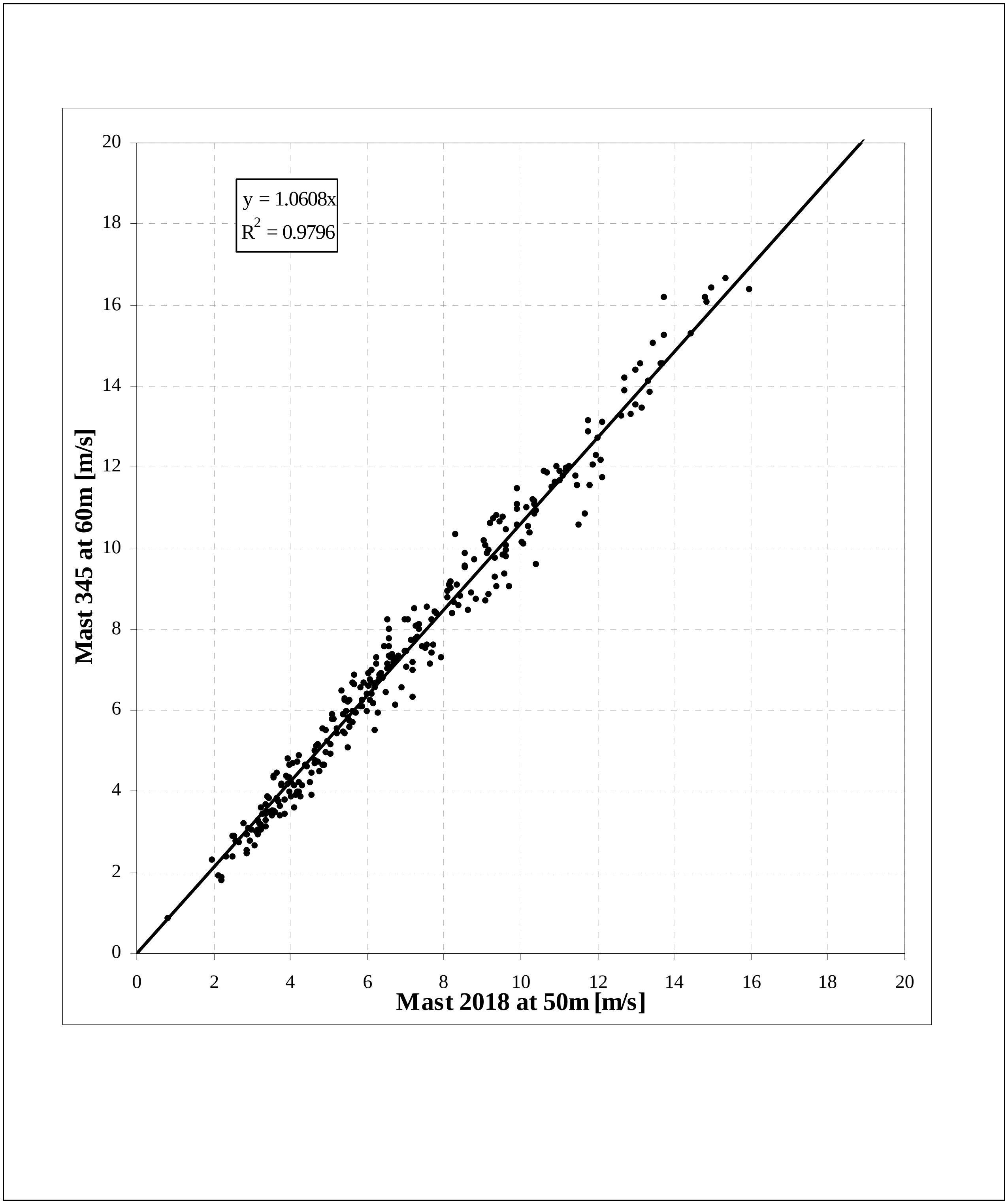


Figure 6.4 Correlation of daily mean wind speeds at Mast 2018 at 50 m and Mast 345 at 60 m.

APPENDIX 1

Data analysis procedure

1. Correlation of wind speed and direction across the site.
2. Site wind speed variations.
3. Projected energy production
4. Confidence analysis
5. References

1 Correlation of wind speed and direction across the site

The method used to determine the long-term mean wind speed for a "target" site from a "reference" site is based on the Measure-Correlate-Predict approach, which is outlined below.

The first stage in the approach is to measure, over a period of about one year, concurrent wind data from both the "target" site and the nearby "reference" site for which well established long-term wind records are available. The short-term measured wind data are then used to establish the correlation between the winds at the two locations. Finally, the correlation is used to adjust the long-term historical data recorded at the "reference" site to calculate the long-term mean wind speed at the site.

The concurrent data are correlated by comparing wind speeds at the two locations for each of twelve 30 degree direction sectors, based on the wind direction recorded at the "reference" site. 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. Only those records with speeds in excess of 5 m/s at both locations are used.

- Wind speed ratios are determined for each of the direction sectors using a principal component analysis with the solution forced through the origin. This method is equivalent to a linear least-squared regression forced through the origin minimising the orthogonal offset.

In order to minimise the influence of localised winds on the wind speed ratio, the data are screened to reject records where the speed recorded at the "reference" site falls below 3 m/s or a slightly different level at the "target" site. The average wind speed ratio is used to adjust the 3 m/s wind speed level for the "reference" site to obtain the higher level for the "target" site, to ensure unbiased exclusion of data. The wind speed at which this level is set is a balance between excluding low winds from the analysis and still having sufficient data for the analysis. The level used excludes only winds below the cut-in wind speed of a wind turbine which do not contribute to the energy production.

The result of the analysis described above is a table of wind speed ratios, each corresponding to one of twelve direction sectors. These ratios are used to factor the wind data measured at the "reference" site over the historical reference period, to obtain the long-term mean wind speed at the "target" site.

2 Site wind speed variations

To calculate the variation of mean 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 [1].

The inputs to the model are a digitised map of the topography and surface roughness length of the terrain for the site and surrounding area. A digitised map of an area surrounding the site of 30 km x 30 km was derived from 1:24,000 USGS scale maps. Although this domain size is much larger than the area of the site itself, such an area is necessary since the flow at any point is dictated by the terrain several kilometres upwind.

Wind flow is affected by the roughness of the ground. The surface roughness length of the site and surrounding area has been estimated, as detailed in the main text.

The wind flow calculations were carried out for 30 degree steps in wind direction corresponding to the measured wind rose and results were produced as speed-up factors relative to the mast location for a grid encompassing the site area.

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

3 Projected energy production

The components of the derivation of the wind farm net energy output prediction are listed and described below:

Ideal energy output

The ideal energy production is the theoretical output of the wind farm with the hub height wind speeds at the appropriate mast location applied for all associated turbines. Any density adjustment required due to a difference between the air density at hub height at the reference mast location and that assumed for the turbine power curve is applied as discussed in the main body of the report and included in the ideal energy output.

Topographic and wake effect calculations

The first step in modelling flow through an array of wind turbines is the calculation of the flow in the wake of a single machine. Immediately downstream of the rotor, there is a momentum deficit with respect to free stream conditions, which is equal to the thrust force on the machine. As the flow proceeds downstream, there is a spreading of the wake and recovery to free stream conditions. Turbulent momentum transfer is important in this process.

The model used here, WindFarmer, has been developed by GH and validated using measurements on both full-scale machines and on wind-tunnel models [2, 3, 4, 5].

The model is employed in a scheme which, taking each wind speed and direction in turn calculates the power production of the wind farm. The important parameters used in this process are:

- array layout
- upstream mean wind speed
- ambient turbulence
- wind turbine thrust characteristic
- wind turbine power characteristic
- rotor speed
- topographical speed-up factors from site wind flow calculations

Topographical effects are accounted for in the model using the speed-up factors calculated by the wind flow model described above. Any air density adjustments required due to differences between the hub height air density at the turbine locations and that at the reference mast location is applied as discussed in the main body of the report and included in the topographic effect. The array model is used to calculate the wind speed in the turbine wakes, assuming the terrain is flat, and the wind speed is adjusted by the speed-up factor when the wake reaches a downstream turbine.

Electrical transmission efficiency

A figure of 98 % has been included for the electrical efficiency of the wind farm as provided by PPM [6.2]. Neither a review of the PPM figure nor a detailed analysis of the electrical system has been undertaken by GH. It is recommended that this figure be reviewed once such an analysis has been performed.

Turbine availability

A figure of 97 % has been assumed for turbine availability based on data from modern operational wind farms. However, availability may be a matter of warranty between the owner and the turbine supplier and the assumed figure should be reviewed when the terms of that warranty are clear.

Blade degradation and fouling

The turbine production may be affected by the build up of insects, dirt or ice on the blades. This build up will change the characteristics of the blade and therefore affect the performance of the blades and the turbine output.

An adjustment has been included to allow for lost production due to blade fouling. A figure of 99.0 % has been assumed to be appropriate for these pitch regulated turbines.

High wind hysteresis

This is caused by the turbine cut in and cut out control criteria for high wind speeds. The magnitude of this loss is influenced by three factors.

1 The turbine will cut out when the maximum mean wind speed is exceeded and it will not cut in again until this mean wind speed is below a mean wind speed level lower than the cut out mean wind speed.

2 The turbine will cut out if the instantaneous gust wind speed exceeds a maximum level and the turbine will not cut in until the wind speed drops to a lower value.

3 The accuracy of the calibration of the instruments that are determining the wind characteristics at the turbine.

These three effects will cause the turbine to possibly lose production for some proportion of high mean wind speed occurrences. The magnitude of this lost production has been estimated by GH by repeating the analysis using a power curve with the cut out wind speed reduced by 1.3 m/s and 2.5 m/s for the GE 1.5sle and the Siemens SWT-2.3-93, respectively.

Substation maintenance

Net wind farm production may be reduced due to the electrical output not being transferred to the grid network while the substation is shutdown for maintenance. A typical figure of 99.8% is assumed in this analysis to represent one day per year of planned maintenance. This is included as scheduled maintenance can not generally be accurately planned to occur on a day with low wind speeds.

Utility downtime

Net wind farm production will be reduced if the grid is not available for the wind farm to output electricity to it. This type of loss must be considered on a site specific basis. It has not been considered in this analysis.

Extreme temperature shutdown

If the temperature range of the site extends beyond the operating range of the turbine considered, the control system on the turbine will shut the turbine down to protect it from damage. This issue has not been considered in this analysis.

Wind sector management

If wind turbine spacing is close the site conditions may exceed the wind conditions within the wind turbine certification criteria. In these circumstances it may be necessary to shut down some turbines which are closely spaced when the wind direction is parallel to the line of turbines. This issue has not been considered in this analysis.

4 Confidence analysis

There are 5 categories of uncertainty associated with the site wind speed prediction at the proposed site:

1. There is an uncertainty associated with the measurement accuracy of the anemometers. The instruments used have not been individually calibrated. A figure of 2.5 % is assumed here to account for these and other second order effects such as over-speeding, degradation, air density variations and additional turbulence effects.

2. The long-term mean wind speed at the site masts was derived from correlation analyses with other site masts. The uncertainty associated with correlating and synthesizing between masts is approximately evaluated from the statistical scatter in the hourly or daily correlation plots.

3. There is an uncertainty associated with the assumption made here that the historical period at the meteorological site is representative of the climate over longer periods. A study of historical wind records indicates a typical variability of 6 % in the annual mean wind speed [6]. This figure is used to define the uncertainty in assuming the long-term mean wind speed is defined by a period approximately 4.6 years in length.

4. There is uncertainty associated with the derivation of the wind shear between heights on the mast and the assumption that this is representative of the wind flow at heights up to hub height. A figure of either 2.0 % or 2.5 % has been assumed here to account for this uncertainty dependent upon the extent of extrapolation.

5. Additionally, even if the long-term mean wind speed were perfectly defined there will be variability in future mean wind speeds observed at the wind farm site. The variability in future mean wind speeds is dependant on the period considered. Performance over one and ten years of operation are therefore included in the uncertainty analysis. Account is taken of the future variability of wind speed in the energy confidence analysis but not the wind speed confidence analysis.

It is assumed that the time series of wind speed is random with no systematic trends. Care was taken to ensure that consistency of the reference measurement system and exposure has been maintained over the historical period and no allowance is made for uncertainties arising due to changes in either.

Uncertainties type 1 to 4 from above are added as independent errors on a root-sum-square basis to give the total uncertainty in the site wind speed prediction for the historical period considered.

It is considered here that there are 5 categories of uncertainty in the energy output projection:

1. Long-term mean wind speed dependent uncertainty is derived from the total wind speed uncertainty (types 1 to 4 above) using a factor for the sensitivity of the annual energy output to changes in annual mean wind speed. This sensitivity is derived by a perturbation analysis about the central estimate.

2. Wake and topographic modelling uncertainties. Validation tests of the methods used here, based on full-scale wind farm measurements made at small wind farms have shown that the methods are accurate to 2 % in most cases. For this development an uncertainty in the wake and topographic modelling of 3 % to 6 % is assumed for the site masts.

3. Future wind speed-dependent uncertainties described in ‘5’ above have been derived using the factor for the sensitivity of the annual energy output to changes in annual mean wind speed.

4. Accuracy of the fiscal substation energy meter. An uncertainty of 0.3 % is assumed here based on typical utility meter accuracy.

5. Turbine uncertainties are generally the subject of contract between the developer and turbine supplier and we have therefore made no allowance for them in this work.

Again those uncertainties which are considered are added as independent errors on a root-sum-square basis to give the total uncertainty in the projected energy output.

5 References

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

2. U Hassan, A G Glendinning and C A Morgan, “ A Wind Tunnel Investigation of the wake structure and machine loads within small wind turbine farms”, Proc of the 12th BWEA Wind Energy Conference, IMechE, 1990.

3. J Højstrup, “Turbulence measurements in a windfarm”, Proc. EWEA Wind Energy Conference, Madrid, 1990.

4. J G Warren et al. "Performance of wind farms in complex terrain", Proc. Of the 17th BWEA Wind Energy Conference, 1995.

5. Liddell et al, “Advanced wake model for closely spaced turbines’, Proc. AWEA Wind Energy Conference, Denver, 2005.

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