6. ENERGY YIELD ESTIMATION

6.1. Wind Shear

When wind speed is measured at two heights, it is possible to derive a relationship between wind speed and heights using the standard power law, defined below.

$$\alpha = \frac{\ln\left(\frac{v_1}{v_2}\right)}{\ln\left(\frac{h_1}{h_2}\right)}$$

The resulting wind shear exponent can be used to extrapolate hub height wind speeds from wind speeds measured at lower heights. It is best practice for the mast primary monitoring height to be at least 2/3 of the proposed hub height to minimize the associated prediction and flow modelling uncertainties. The Rokem mast is well within the 2/3 hub height limit for the 67m hub height and only 3m shy of being within the limit with the 95m hub height.. The measured shear exponent from the mast data was found to be 0.23. This exceeds the upper limit of turbine manufacturers design requirements and may require further investigation.

As the northern region of the Rokem mast is below the recommended 2/3 hub height a higher uncertainty when extrapolating to hub height is applied.

When calculating measured shear, it is important that the instruments are subject to the same wind exposure and mast shadow. The mast shear was computed between the anemometers at 40 m, 50m and 60 m that were oriented in the same direction (180°) for the sectors where they were not affected by tower shadow.
Shear values were found to vary significantly depending on the time of day, season, and wind direction. Because this site is largely unidirectional, wind shear was applied on a monthly and hourly basis to account for the variations.

6.2. Turbulence Intensity

Ambient turbulence intensity has an impact on turbine performance and on the dissipation of wakes. Measured ambient turbulence intensity at mast height is 12.4% for wind speeds greater that 3 m/s. The mean turbulence intensity extrapolated to hub height at the mast location is 12.2% (67 m HH) and 11.7% (95 m HH).

6.3. Air Density

Air density impacts wind farm performance, as power output is positively correlated to density. Density was calculated using the standard ISO model (International Organisation for Standardization, 1975) based on a mean temperature of 26° C, derived from the Vortex model for the mast location, and a mean turbine hub-height elevation of 70 m AMSL and 105 m AMSL. The mean hub-height air density is 1.172 kg/m3 for 70m ASL and 1.173 kg/m3 for 105m ASL.

6.4. Power and Thrust Curves

The turbine power and thrust curves (Annex D) were obtained for the Vestas V100-1.8 MW and Vestas V90-1.8MW turbines and provided by the client. The power curves shown in Annex D are for a mean density of 1.225 kg/m^3 and were corrected to each site air density in the WindFarmer software package.

The WindFarmer software used for energy optimization adjusts the standard air density power curve based on the site air density as part of its internal algorithm. The site air density was calculated for both parcels using reference temperatures, incorporating the elevation (AMSL) of the Rokem mast and the elevation (AMSL) of each proposed turbine location and are detailed in Section 6.3.

6.5. Wind Flow Modeling

As the Rokem wind farm is located in non-complex terrain, the wind flow across the site can be calculated with a linearized wind flow model. The wind flow across the site was modeled using WAsP 10 with the topographical and roughness inputs described in Section 2. WAsP is a linearized wind flow model that gives the wind speed ratio at a given point with respect to a reference location, the Rokem mast.

Roughness changes were also modeled in the WAsP 10 software, the roughness map used was as-discussed in Section 2.1.

6.6. Forestry Displacement Height Adjustment

No adjustment for any displacement effect resulting from forestry surrounding the site was made.

6.7. Wake (Eddy Viscosity) Modeling

The presence of a wind turbine in front of another will have a detrimental effect on the performance of the downwind turbine(s). This is due to the velocity deficit and additional turbulence in the wake of the upwind turbine(s). The extent of the wakes depends, among other things, on the thrust coefficient of the wind turbines, the ambient turbulence intensity and roughness length. Wake effects are estimated for each turbine, and for each sector of the wind rose, using the standard Ainslie method (Ainslie J. F., 1985). Combined velocity deficits, where two or more turbines are affecting a turbine downwind, are estimated by assuming only the largest wind speed deficit is present. Wake-added turbulence is calculated using the Quarton & Ainslie model (Quarton & Ainslie, 1990).

Energy yields were computed for each parcel independently, such that wake effects from northern parcel were not considered on the southern parcel and wake effects from the southern parcel were not considered on the northern parcel. In addition, the energy yield for the northern parcel was computed considering wake effects from both parcels.

6.8. Wind Resource Data

Wind speed and direction distributions were created for the mast location based on one year of data scaled to the predicted long-term mean wind speeds and extrapolated to hub height at the mast location.

6.9. TAB File Association

WindFarmer allows the observed wind speed and direction distribution to be applied to the energy yield calculations rather than applying a fitted Weibull distribution; this is the Tab File Association (TFA) method. This is a more accurate method in the case of bimodal or non Weibull shaped observed distributions, giving a more representative site wind speed distribution. The Weibull curve fitted to the observed site data is generally well matched, however, it is considered more accurate to use the TFA method. The wind distribution in *.tab format given in Table C-2 and Table C-3 was used to apply the measured wind speed and direction frequency distribution by the TFA method.

7. ENERGY YIELD LOSSES

In order to estimate the average energy delivered to the metering point, it is necessary to include some additional loss factors. Standard loss factors have been applied as given in Table 7-1. Further investigation is recommended into these loss figures, especially with respect to the electrical grid losses, availability and substation down-time.

7.1. Turbine Availability

On the basis of operational data, it is estimated that lost availability will account for, on average, 7.0% of annual production. Actual availability will depend largely on the nature of the contractual agreements with the manufacturer, and the quality of O&M provision. The client is urged to pay particular attention to the detail of availability guarantees, how these are enforced and what they are referenced against. Natural Power can assist with reviewing and/or negotiating these provisions.

This estimated loss takes into account potential additional losses caused by the site's remote location and potentially unworkable conditions during tropical storm season. This value should be further investigated with turbine suppliers in order to determine the service provision available on Puerto Rico, and the resulting availability guarantee.

7.2. Turbine Performance

7.2.1. Turbulence

Power curves are typically measured at low turbulence values. Often turbines are subject to higher turbulence on-site due to topography, roughness and wakes from other turbines. The power curves used in this analysis are valid for ambient turbulence values ranging from 8%-12% for the V100 and 6%-12% for the V90. The mean turbulence intensity computed at 95 m AGL and 67 m AGL at the turbine locations fell just above and within this range, at 11.2% and 10.7%. An investigation into the variation in energy yield with an increase in ambient turbulence was carried out, and based on those results a loss factor of 1.0% has been applied.

7.2.2. Control Losses

Wind turbine control systems shut down turbines at an upper wind speed cut-off and restart them once the wind speed has dropped sufficiently. This difference causes a hysteresis loss not accounted for in the power curve. Losses are also caused by cable unwind, generator switching and other second-order effects. Given the wind distribution for this site and the turbine types, this loss is conservatively estimated at 0.5%. Further investigation of the extent of these losses is advised.

7.3. Electrical Losses

Losses related to the delivery of electricity from the turbine HV connections to the metering point are estimated, from experience, to be around 2.0%. This estimate is based on an analysis of data from a number of operating wind farms. However, no detailed power system analysis has been performed to arrive at this result. These losses do not include grid outages. Further investigation is recommended to confirm both electrical losses and losses associated with grid outages.

7.4. Environmental Losses

7.4.1. Turbine Blade Degradation

Over the lifetime of the wind farm, the blade surfaces will degrade, which will compromise their aerodynamic properties. An average loss of 0.5% was applied to account for this degradation.

7.4.2. Icing losses

This site is in a tropical climate and will not be affected by icing.

7.5. RIX Adjustment

One of the basic assumptions of the WAsP wind flow model, used in this analysis, is that the flow of the wind always remains attached, i.e. follows the terrain surface. However, in areas of complex terrain where the ground is steep enough for the flow separation to occur, WAsP will be operating outside of its acceptable performance envelope.

In order to assess whether or not the terrain characteristics are likely to lead to flow separation, and hence introduce errors in to the WAsP modelling results, an assessment was made of the ruggedness of the terrain described by the WAsP *.map file. The WAsP 10 software includes a RIX Ruggedness Index tool which is used to assess the terrain in the region of any point of interest.

The RIX tool allows the user to assess the ruggedness of terrain relative to a specific site, and provide the user with a figure that indicates what percentage of the surrounding terrain exceeds the user-definable slope threshold. For a non-complex site the RIX value would be close to 0%, whereas for a complex site the RIX value may be as much as 30%, indicating that one third of the terrain analysed is steeper than the critical slope threshold.

The RIX analysis for this site used the recommended WAsP default slope threshold of 0.3 (i.e. a slope of 1 in 3.33), and a radius of 3.5 km from each point of interest was evaluated.

The overall RIX value was obtained for the mast location and for all associated turbine locations. Results indicate that the overall ruggedness of the terrain is low and therefore no RIX adjustment was applied.

7.6. Curtailment Losses

Per client request, NP assessed curtailment losses to comply with maximum power output restrictions of 10 MW. This estimate was derived by reducing project power production to 10 MW for all hours that were expected to exceed this limit after wake, turbulence, and electrical losses had been taken into account. Given the wind distribution for the northern parcel, a curtailment loss of 1.5% has been applied. A curtailment loss of 1.0% was applied for the southern parcel.

7.7. Summary of Loss Factors

Loss Category	% Loss, Northern Parcel	% Loss, Southern Parcel	% Loss, Northern Parcel including Southern Parcel wake effects
Availability	7.0	7.0	7.0
Wake Effects	5.7	3.2	6.4
Turbine Performance			
Turbulence	1.0	1.0	1.0
Turbine control	0.5	0.5	0.5
Electrical	2.0	2.0	2.0
Environmental			
Icing	0.0	0.0	0.0
Blade contamination	0.5	0.5	0.5
Curtailment	1.5	1.0	1.5
Other	0.0	0.0	0.0
Total secondary losses	**12.0**	**11.6**	**12.0**
Total losses, including wakes	**17.0**	**14.4**	**17.6**

Table 7-1 Summary of loss factors

8. UNCERTAINTY ANALYSIS

There are a number of steps within the process used to derive the above energy figures which have an associated uncertainty. These uncertainties are introduced in either the wind speed or the wind flow modelling and energy yield prediction methodologies. Both types of uncertainty will have an impact on the predicted energy yield figure.

8.1. Wind Speed at Site Mast Location

Table 8-1 summarizes the wind speed uncertainties applied for the Rokem site.

Anemometry uncertainty	4%	0.24 m/s
Meso-scale model	2%	0.12 m/s
Correlation Scatter		0.06 m/s
Long-term representativeness		0.13 m/s
Combined wind speed uncertainty		**0.55 m/s**

Table 8-1 Summary of wind speed uncertainty factors for Vestas V100-1.8MW

Anemometry uncertainty	4%	0.24 m/s
Meso-scale model	2%	0.11 m/s
Correlation Scatter		0.05 m/s
Long-term representativeness		0.12 m/s
Combined wind speed uncertainty		**0.52 m/s**

Table 8-2 Summary of wind speed uncertainty factors for Vestas V90-1.8MW

8.1.1. Anemometer Uncertainty

The anemometers used were calibrated according to the calibration certificates obtained from NRG online resources.

The structure of the mast and booms influences the wind flow and consequently the wind speeds measured at the anemometers. Depending on instrument mounting, these effects may be exaggerated or mitigated. The anemometers on the Rokem mast were not oriented such that these effects would be minimized. The recommended best practice for anemometer orientation on a tubular mast is for two anemometers at the same height to be oriented 90-120 degrees apart from each other, each 45-60 degrees off the predominant wind direction. There are two anemometers at each height (60m, 50m and 40m).on the Rokem mast. The 60m and 50m sensors are oriented approximately 90 degrees apart mounted approximately at 90° and 180°. The 90° sensors are directly in line with the predominant wind direction, which subjects them to a deceleration in flow around the mast, and the 180° sensors are 90 degrees off the predominant wind direction, which subjects them to acceleration in flow. The 40m sensors are oriented 180 degrees apart and 90 degrees off the predominant wind direction, which subjects both anemometers at this level to acceleration in flow around the mast. The top anemometers were mounted at the very top of the mast, where they experience less of an effect from the wind flowing around the mast but may experience a small speed-up effect over the top of the mast. This mounting increases the uncertainty in the wind speeds measured.

Several tests were performed on the wind speed data for all instruments to detect the possibility of DFW. In addition, correlations between multiple instruments on the same

mast were performed and the relationships between the wind speeds from multiple instruments over time were assessed. The results of these tests did not indicate any significant sensor degradation or other phenomena that would increase the uncertainty on the wind speed.

An overall anemometry uncertainty of 4% was applied to the wind speed prediction accounting for the wind speeds measured on site.

8.1.2. Meso-scale Model

An additional uncertainty is introduced to account for the use of meso-scale data as a long term reference. Although the reference data set correlated well with the site masts, there is an inherent uncertainty in the model calculation itself as well as the data that is used to seed the virtual climate model. A 2% uncertainty was applied to account for this.

8.1.3. Correlation Scatter

The correlation scatter was quantified for the correlations between Rokem masts wind speeds and Vortex wind speeds for both the Vestas V100-1.8MW and Vestas V90-1.8MW turbines. The resulting standard error associated with the predicted wind speed is 0.06 m/s for Vestas V100 and 0.05 m/s for Vestas V90.

8.1.4. Long-Term Period

Standard climatological practice is to use at least a 30-year period to represent a true long-term wind climate. There is therefore an uncertainty associated with the assumption that the ten-year long-term data period used from the Vortex model is representative of the true long-term wind climate at the reference location. Based on the observed variability at nearby reference stations and knowledge of the regional climate, the inter-annual variability of wind speeds in this location is assumed to be 7.0%. The uncertainty of the 10-year data set was computed by dividing the inter-annual variability by the square root of the number of years, leading to a long-term representativeness uncertainty of 2.2% or 0.13 m/s for Vestas V100 and 0.12 m/s for Vestas V90.

8.1.5. Overall wind speed uncertainty

In order to calculate the overall uncertainty associated with the wind speed prediction, the individual uncertainties are expressed in meters per second (m/s) and added as independent errors on a root-sum-square basis.

Assuming a normal distribution of errors, the 90% exceedance value and 90% confidence limits for the long-term mean annual wind speed for a 95m hub height is given in Table 8-3 and a 67m hub height in Table 8-4.

Wind Speed: 90% Exceedance	95-m hub height
Central Estimate Wind Speed (m/s)	5.9
90% Probability of Exceedance (m/s)	5.6
Wind Speed: 90% Confidence Limits	95-m hub height
Lower 90% Confidence Limit (m/s)	5.5
Central Estimate Wind Speed (m/s)	5.9
Upper 90% Confidence Limit (m/s)	6.4

Table 8-3 90% wind speed exceedance and confidence values at 95-m hub height

Wind Speed: 90% Exceedance	67-m hub height
Central Estimate Wind Speed (m/s)	5.4
90% Probability of Exceedance (m/s)	5.1
Wind Speed: 90% Confidence Limits	67-m hub height
Lower 90% Confidence Limit (m/s)	5.0
Central Estimate Wind Speed (m/s)	5.4
Upper 90% Confidence Limit (m/s)	5.8

Table 8-4 90% wind speed exceedance and confidence values at 67-m hub height

8.2. Energy Uncertainty

In order to estimate the overall standard error associated with the final energy prediction, the wind speed uncertainties expressed in units of m/s were converted to energy yield uncertainties expressed in units of GWh/annum. The sensitivity of the energy yield prediction to the predicted site wind speed was derived via a perturbation analysis around the central estimate. It was found that the annual energy yield figure is sensitive to the predicted wind speed at the rates given in Table 8-5 and Table 8-7. The response rate in (GWh/annum)/(m/s) is assumed to be linear over the size of the perturbation being considered.

The areas of uncertainty on energy are summarized in Table 8-8 and Table 8-9.

Turbine	Hub height (m)	Energy sensitivity (GWh/m/s)
Vestas V100-1.8 MW	95	8.5

Table 8-5 Energy sensitivity to wind speed changes for a 95m hub height

Turbine	Hub height (m)	Energy sensitivity (GWh/m/s)
Vestas V90-1.8 MW	67	7.5

Table 8-6 Energy sensitivity to wind speed changes for a 67m hub height

Turbine	Hub height (m)	Energy sensitivity (GWh/m/s)
Vestas V100-1.8 MW with Vestas V90-1.8 MW effects	95	8.6

Table 8-7 Energy sensitivity to wind speed changes for a 95m hub height

	Wind speed uncertainty	Energy uncertainty	Energy (GWh)
Wake modelling		2.0%	0.5
Flow modelling – Extrapolation and RIX	1.0%	-	0.5
Flow Modelling – Shear	4.0%	-	2.0
Power curve uncertainty		1.6%	0.4
Short term onsite wind rose (TFA)		1.0%	0.2
Annual Variability - 90%			3.6
10 Year Variability - 90%			1.1
Overall Standard Error - Any 1 Year			4.8
Overall Standard Error - Any 10 years			3.4
Overall Standard Error – Long-term			3.2

Table 8-8 Summary of energy uncertainty factors for Vestas V100-1.8MW

	Wind speed uncertainty	Energy uncertainty	Energy (GWh)
Wake modelling		1.5%	0.3
Flow modelling – Extrapolation and RIX	1.0%	-	0.4
Flow Modelling – Shear	1.0%	-	0.5
Power curve uncertainty		1.6%	0.3
Short term onsite wind rose (TFA)		1.0%	0.1
Annual Variability - 90%			2.9
10 Year Variability - 90%			0.9
Overall Standard Error - Any 1 Year			3.6
Overall Standard Error - Any 10 years			2.2
Overall Standard Error – Long-term			2.1

Table 8-9 Summary of energy uncertainty factors for Vestas V90-1.8MW

	Wind speed uncertainty	Energy uncertainty	Energy (GWh)
Wake modelling		2.0%	0.5
Flow modelling – Extrapolation and RIX	1.0%	-	0.5
Flow Modelling – Shear	4.0%	-	2.0
Power curve uncertainty		1.6%	0.4
Short term onsite wind rose (TFA)		1.0%	0.2
Annual Variability - 90%			3.6
10 Year Variability - 90%			1.1
Overall Standard Error - Any 1 Year			4.8
Overall Standard Error - Any 10 years			3.4
Overall Standard Error – Long-term			3.2

Table 8-10 Summary of energy uncertainty factors for Vestas V100-1.8MW with Vestas V90-1.8MW

8.2.1. Wake Modelling

There is uncertainty associated with the wind turbine wake modeling. The Rokem wind farm layouts display a minimum elliptical separation distance with 4 rotor diameters (RD) in the predominant wind direction (90 degrees) and 2 RD in the direction perpendicular to the predominant wind direction. Wake modeling uncertainties of 2.0% for Vestas V100-1.8MW and 1.5% for Vestas V90-1.8MW were applied to take this into account.

8.2.2. Wind Flow Modeling – Extrapolation and RIX

In areas of complex terrain, flow separation can lead to prediction errors in the WAsP wind flow analysis software. This site is flat and has low ruggedness values. The uncertainty in any flow modelling scenario increases with the distance between the turbine locations and the locations of the masts used to seed the model, which is greater than 2 km for some turbines in this layout.

An uncertainty of 1.0% was applied to both Vestas V100-1.8MW and V90-1.8MW to account for extrapolation and RIX.

8.2.3. Wind Flow Modelling – Shear

The predicted site wind regime is valid for 95 m AGL for the northern parcel of Rokem wind farm and 67 m AGL for the southern parcel of Rokem wind farm. As discussed in section 6.1, the average shear by month and hour observed across multiple measurement heights on the mast was applied to adjust the predicted wind regime from measurement height to hub height, and there is an uncertainty associated with this adjustment.

The shear uncertainty for the 67 m hub height is low, as the vertical distance of extrapolation is low. The shear uncertainty for the 95m hub height is greater than that of

the 67 m hub height due to a larger distance of vertical extrapolation, falling outside the mast height standards discussed in 6.1. Because the top anemometers on Rokem mast were mounted flush with the top of the mast, they did not have the same magnitude of flow distortion, which therefore affects the shear measured. The approach used assumes the shear profile as measured between 40 m, 50 m and 60 m extends to 95 m AGL.

For the analysis presented, the shear error is assumed to have a value equivalent to 4.0% of the predicted wind speed for Vestas V100-1.8MW and 1.0% of the predicted wind speed for Vestas V90-1.8MW.

8.2.4. Power Curve Uncertainty

There is uncertainty associated with the power curves provided by the wind turbine manufacturers, which is typically assumed to be 4.0% of the predicted annual energy figure. Both the turbulence intensity and wind shear on the southern parcel are outside the operational envelope, while the northern parcel is only outside the envelope with regard to wind shear, based on the provided power curve. This may increase the uncertainty of the power curve. It is recommended to obtain a power curve that is suitable for these conditions, if possible. It is expected that some turbines will perform better and some worse than the provided power curve, so the overall uncertainty is the uncertainty on an individual turbine (4.0%) divided by the square root of the number of turbines.

8.2.5. Short Term On-site Wind Rose

The use of the one-year and two-year on-site wind direction rose and wind speed distributions in representing the long-term wind rose have an associated uncertainty. An uncertainty value of 1.0% of energy was applied to account for this for both Vestas V100-1.8MW and V90-1.8MW.

8.2.6. Time Period Variability

Due to the natural variability of wind climates, the energy production of a wind farm in any finite period of years is likely to differ from the long-term mean. This variability is based on the assumed inter-annual wind speed variability described in Section 8.1.4.

Using the estimate of the annual mean wind speed standard deviation, the Central Limit Theorem was applied to arrive at the standard error associated with a 10-year sample period, a typical bank lending term.

9. FINAL AEP ESTIMATION

Expected net AEP (P50) and net AEP with a 10-year and 1-year 90% probability of exceedance are given in Table 9-1. Capacity factors are also given. The results presented include wake and secondary losses as described in Section 7.

Turbine (hub height)	P50 Net AEP GWh/ year	P50 Net Capacity Factor %	10-year P90 Net AEP GWh/ year	10-year P90 Net Capacity Factor %	1-year P90 Net AEP GWh/ year	1-year P90 Net Capacity Factor %
Vestas V100 (95 m)	24.9	26.3	20.5	21.7	18.7	19.8
Vestas V90 (67 m)	18.0	19.0	15.2	16.0	13.5	14.3
Vestas V100 with Vestas V90 (67 m) effects	24.7	26.1	20.3	21.5	18.5	19.6

Table 9-1 Summary of site production and efficiency for the northern parcel, southern parcel and the northern parcel including wake losses from the southern parcel.

10. FURTHER WORK

If the client wishes to progress the site, then NPC would recommend that some amendments are made to the on-site mast configuration in order to minimize the flow distortions observed by some of the instruments. It is also recommended that some of the NRG anemometers are replaced with First Class instruments (Riso, Thies or Vector) to decrease measurement uncertainty.

Recommended best practice is for the mast height to be at least two thirds of the proposed hub height. The 60-m mast does not meet the recommended height for a 95-m hub height. Therefore, Natural Power would recommend the use of a remote sensing device, co-located with the mast, in order to confirm the shear profile and minimize the uncertainties associated with the vertical extrapolation of the measured data at 60 m to a hub height of 95 m.

A site visit by Natural Power is recommended to gain a full appreciation of the site and to verify the assumptions made regarding noise sensitive properties and also to confirm the anemometry equipment and specific turbine siting constraints.

Further investigation is recommended into the extreme wind speeds at the site due to hurricanes and tropical storms, as discussed in Section 5. A full site classification study is advised. Based on the results of this study, further turbine types could be suggested that comply with the site conditions.

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