ONE ENERGY
WIND FOR INDUSTRY®

WIND RESOURCE ASSESSMENT
METHODOLOGIES

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CONTENTS

GLOSSARY

Ambient Turbulence Intensity: The turbulence intensity without influence of neighboring wind turbines.

Baseline Annual Energy Production (Baseline AEP): The total amount of energy generated by the turbine(s) in one year before any wake loss or average P50 Scale Factors are applied. Only used within the Prospecting phase of a project.

Baseline Capacity Factor: The ratio of the Baseline AEP to the theoretical energy production if the turbine were running at its rated capacity for the entire year. Only used within the Prospecting phase of a project.

Capacity Factor: The ratio of the actual power output over a period of time to the theoretical maximum output if generation was at rated capacity continuously for the same period of time.

Characteristic Turbulence Intensity: The ambient Turbulence Intensity plus one standard deviation. This is not used in the most recent International Electrotechnical Commission (IEC) standards (edition 4).

Coefficient of Determination (R^2): The proportion of the variance in the dependent variable that is determined from the independent variable, with a value between 0 and 1.

Effective Turbulence Intensity: A turbulence intensity that considers the wakes of neighboring turbines and accounts for the added turbulence intensity. The Wake Induced Turbulence Intensity is a component of the Effective Turbulence Intensity.

ECMWF Reanalysis 5th Gen. (ERA5): A long-term reanalysis dataset provided by the European Center for Medium-Range Weather Forecasts (ECMWF). Contains 30+ years of global hourly reanalysis data, which include wind speed, direction, surface wind gusts, and temperature.

Gross Annual Energy Production (Gross AEP): The total amount of energy generated by the turbine(s) in one year before any Wake Loss or Performance Factors are considered. Only the wind resource affects the Gross AEP, and only used within the Project Due Diligence phase of the project.

Gross Capacity Factor: The ratio of the Gross AEP to the theoretical energy production if the turbine were running at its rated capacity for the entire year. Only used within the Project Due Diligence phase of a project.

Icing: An event in which ice buildup occurs on a turbine blade.

IEC Classes: Wind turbine IEC classes are determined by the average wind speed, extreme 50-year gust, and the turbulence intensity. The current classes have high, medium, and low wind as well as higher or lower turbulence values.

Inflow Angle (α): Angle at which the wind will be approaching the turbine.

LiDAR: A remote sensing instrument used to collect wind data, short for Light Detection and Ranging. The data collected by LiDARs are volume measurements as opposed to point measurements.

Long-Term: Describes a consecutive period of the most recent 30 years.

Measure-Correlate-Predict (MCP): A statistical technique that is used to create a simulated, long-term dataset by relating a concurrent short, measured target dataset to a long-term reference dataset.

Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA2): A satellite-derived long-term reanalysis data source from NASA. Contains 30+ years of global hourly reanalysis data, which include wind speed, direction, and temperature.

Meteorological Towers (MET): Set of instrumentation used to collect wind data, including speed, direction, and temperature at typically three different heights, typically on a tower. These are point measurements as opposed to volume measurements.

Near-site Data: Data that has been collected within 20 miles of the project site.

Net Capacity Factor: The ratio of the Net AEP to the theoretical energy production if the turbine were running at its rated capacity for an entire year. Only used during the Project Due Diligence phase of a project.

Net Annual Energy Production (Net AEP): Gross AEP minus any Wake Loss effects. No other Performance Factors are included in the Net Annual Energy Production calculation. Only used during the Project Due Diligence phase of a project.

On-site Data: Data that has been collected on the project site or customer property.

Original Equipment Manufacturer (OEM): The manufacturer that makes components used in other companies' products.

Pearson Correlation Coefficient (R): A measurement of linear correlation between two variables, with a value between -1 and 1.

Point Dataset: Any chosen short-term MET or LiDAR dataset in the near vicinity of a project. It is only representative of its measurement location. A Point Dataset can be, but will not always be, a Site Dataset.

Point MCP Dataset: An MCP dataset created with a Point Dataset and the reanalysis grid-point closest to the Point Dataset measurement location.

Power Curve: The relationship between the wind speed and power output of a specific wind turbine.

Project Performance Report (PPR): Includes the summary from the Wind Resource Assessment Report and its main outcome values (Gross Annual Energy Production and Net Annual Energy Production), explanations of Performance Factors, the Composite Performance Distribution, and the Exceedance Table.

Prospecting Phase: The initial stage of project development. The result includes an Initial Evaluation document sent to potential customers.

Prudent Wind Industry Practices: The practices, methods, specifications and standards of safety, performance, quality, dependability, efficiency, and economy generally recognized by industry members in the US as good and proper. Other practices, methods, or acts which, in the exercise of reasonable judgment by those reasonably experienced in the industry in light of the specific projects and facts known at the time a decision is made, would be expected to accomplish the result intended at a reasonable cost and consistent with applicable laws, reliability, safety, and expedition. Prudent Wind Industry Practices are not intended to be limited to the optimum practices, methods, or acts to the exclusion of all others, but rather to be a spectrum of good and proper practices, methods, and acts.

Reanalysis Data: A modeled dataset with measured in-situ observations assimilated into forecast models; typically long-term, globally complete, and consistent timestamps.

Representative Turbulence Intensity: The 90th percentile of the ambient Turbulence Intensity distribution. Sometimes this is also calculated as the mean value of the ambient Turbulence Intensity plus 1.28x the standard deviation of the ambient Turbulence Intensity, assuming a normal distribution.

Site Dataset: The most representative Point Dataset of the project site. A Site Dataset will always be a Point Dataset.

Site MCP Dataset: A long-term MCP dataset created with the Site Dataset and the closest available reanalysis grid-point to the site.

TAILS 3.0: One Energy's proprietary software used to model turbine icing, shadow flicker, and wake loss.

Terrain Slope Index (TSI): The energy-weighted terrain slope parameter.

Terrain Variation Index (TVI): The parameter relating the standard deviation of terrain slope within a radius of a single location.

Turbulence Intensity (TI): The ratio of the wind speed standard deviation to the mean wind speed.

Turbulence Structure Correction Parameter (C_{CT}): A parameter used to assess the turbulence structure at a site based on the lateral and vertical turbulence standard deviations relative to the longitudinal. Can be derived from site wind measurements or the terrain complexity category of the site.

Wake Induced Turbulence Intensity: The additional turbulence intensity caused by the wake of a neighboring turbine. It is included as a variable within the Effective Turbulence Intensity equation.

Wake Loss: When obstacles upwind create a wake that reduces the wind available at the downwind wind turbines. Wake loss results in a reduction of energy production.

Waked Sector: The directional sector(s) in which wake will affect a turbine.

Weibull Distribution: Standard distribution used in the wind industry for wind speed distribution. Dependent on two parameters, the shape parameter (k) and the scale parameter (A).

Wind Resource Assessment Report (WRA): Includes the site wind resource analysis, Gross AEP, and Wake Loss. The outcome is the Net Annual Energy Production.

Wind Shear: The variation in wind speed over a given height range.

Wohler Exponent (m): A constant used in determining the Effective TI. This exponent is used to characterize the fatigue behavior of varying materials. Typically, values used in the wind industry are m=1 (for steel) and m=10 (for fiber glass).

1. INTRODUCTION

Within the Wind Resource Assessment (WRA), information necessary for turbine confirmation by the Original Equipment Manufacturer (OEM) and gross energy production estimates is provided. Included is information regarding site conditions, environmental conditions, and the first stages in obtaining fully-burdened energy production estimates. The Gross Annual Energy Production and Net Annual Energy Production are included within the WRA, whereas the continuation of the full-burdened energy production estimates is within the Project Performance Report (PPR).

One Energy's WRA includes four main steps:

1) Choose a data input selection method and data set(s).

2) Analyze data for environmental and site conditions, including average and extreme values in order to determine site suitability.

3) Determine the Gross Annual Energy Production based on the wind resource and turbine power curve.

4) Apply wake losses to the Gross Annual Energy Production to obtain the Net Annual Energy Production.

The objective of this methodology is to allow for explanation and derivation of each section within One Energy's WRA. Each section states which variables and key pieces of information are presented within the Project Due Diligence Package **Appendix 1: WRA**. The deliverables within the formal WRA from each section are designated in bold text throughout this document.

This Wind Resource Assessment Methodology is version 2021.1.

2. PROJECT INFORMATION

A. SITE LAYOUT

Knowledge of the turbine layout in relation to other turbines within the project is necessary for the WRA. See methodology for **Appendix 3: Siting** for more information on how wind turbine locations are determined.

The following information is presented in WRA Section 2A – Site Layout:

1) **Image with turbine siting and surrounding parcels**
2) **Table with the project wind turbine(s) latitude, longitude, and elevation**

B. TERRAIN COMPLEXITY

Complex terrain is a region that has irregular topography. This irregularity can affect the wind flow within a region and can ultimately change the wind characteristics. One Energy uses the IEC 16400-1:11.2.1 Ed. 4 [1] method with USGS elevation data at a 10m resolution within ArcGIS to determine the terrain complexity category of the project site.

The slope of the terrain and the variations of the terrain from a plane are assessed at varying distances radially in 12 wind direction sectors. Two parameters are defined and calculated for each directional sector and radial distance: terrain slope index (TSI), and terrain variation index (TVI). To obtain the slope of the terrain, planes are fit to the terrain within specific distances ($5z_{hub}$, $10z_{hub}$, and $20z_{hub}$) for all 30° directional sectors to the turbine location, where z_{hub} is the hub height. Figure 1 from the IEC standard is shown for reference.

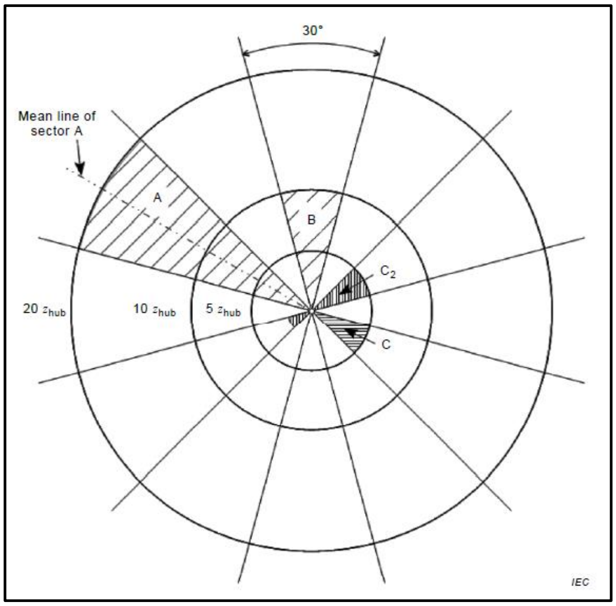


Figure 1: IEC Terrain Complexity Sectors [1]

The planes are fit to the existing elevation data for each radial direction sector (37 in total) using the method of least squares and generally will not need to pass through the tower base. The slope (θ) is defined as the angle between the horizontal and the mean line of the fitted plane for each radial directional sector, and the terrain variation (Δz) is defined as the vertical distance between the fitted plane and the terrain surface (see Figure 2).

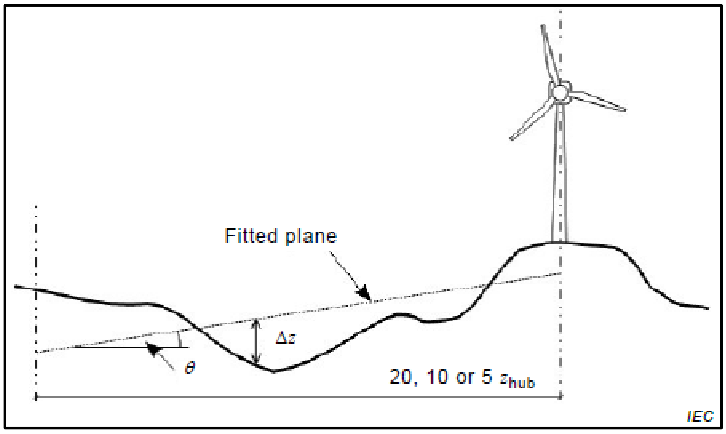


Figure 2: IEC Terrain Variation and Slope [1]

With these variable definitions, along with the energy distribution by sector (see Section 7F: Wind Rose), the TSI and TVI can be calculated at each radial distance using the following equations:

$$TSI_{30,R} = \sum_{i=1}^{12} f_{E,i} |\theta_i| \qquad \textit{Equation 1}$$

$$TVI_{30,R} = \sum_{i=1}^{12} f_{E,i} \frac{D_{TV,i}}{R} \qquad \text{Equation 2}$$

where $TSI_{30,R}$ is the terrain slope index calculated using 30° sectors at radial distance R, $TVI_{30,R}$ is the terrain variation index calculated using 30° sectors at radial distance R, i is the wind direction sector, $f_{E,i}$ is the percentage of wind energy coming from sector i, θ_i is the slope of the fitted plane for sector i with radial distance R, and $D_{TV,i}$ is the standard deviation of the terrain variation for sector i with radial distance R.

The TSI and TVI are also calculated at a radial distance of $5z_{hub}$ using the entire circle plane (360°) using these equations:

$$TSI_{360} = k_1 \theta_{360} \qquad \text{Equation 3}$$

$$TVI_{360} = \frac{D_{TV360}}{k_2 R} \qquad \text{Equation 4}$$

where TSI_{360} is the terrain slope index calculated using the circle plane, TVI_{360} is the terrain variation index calculated using the circle plane, θ_{360} is the slope of the fitted 360° circle plane, D_{TV360} is the standard deviation of the terrain variation of the 360° circle plane, k_1 is an adjustment factor equal to 5/3, and k_2 is an adjustment factor equal to 3. These circle plane index parameter values are only calculated with the radius (R) of $5z_{hub}$.

From these two terrain parameters (TSI_{30} and TVI_{30}) at the three radial distances, along with the circle plane TSI_{360} and TVI_{360} parameters, the complexity and category of the site can be determined (Table 1). A site can be complex or not complex, and if it is determined complex then a complexity category is assigned (low complexity (L), moderate complexity (M), and highly complex (H)). If the TSI_{30} and TVI_{30} values for all three radial distances, as well as the TSI_{360} and TVI_{360} values, are all below the thresholds for category L, then the site is determined to be not complex. If even one of the TSI or TVI indices exceeds the L threshold, the site is assessed as complex, and the category (L, M, H) is assigned depending on the highest category TSI or TVI value.

RADIUS OF CIRCLE	SECTOR AMPLITUDE OF FITTED PLAN	THRESHOLD VALUES (LOWER LIMIT)					
		TERRAIN SLOPE INDEX (TSI)			TERRAIN VARIATION INDEX (TVI)		
		L	M	H	L	M	H
$5z_{hub}$	360°	10°	15°	20°	2%	4%	6%
$5z_{hub}$	30°						
$10z_{hub}$							
$20z_{hub}$							

Table 1: Threshold values of the terrain complexity categories L, M, and H [1]

Depending on the terrain categorization, the turbulence intensity is adjusted (see Section 7E: Turbulence Intensity) and the data selection method may be impacted (see Section 4: Data Input Selection Method).

The following information is presented in WRA Section 2B – Terrain Complexity:

1) **TSI_{30} at radial distances $5z_{hub}$, $10z_{hub}$, and $20z_{hub}$**
2) **TVI_{30} at radial distances $5z_{hub}$, $10z_{hub}$, and $20z_{hub}$**
3) **TSI_{360} at radial distance $5z_{hub}$**

4) **TVI$_{360}$ at radial distance 5z_{hub}**
5) **Site complexity and category**

C. TURBINE INFORMATION

The power curve that is utilized for the WRA is the contractual manufacturer's power curve supplied to One Energy. If the manufacturer provides power curves for varying air densities, the air density power curve that is most representative of the site will be used (see Site Conditions for air density calculations). If the manufacturer does not provide air density dependent power curves, the IEC standard (IEC 61400-12:9.1.5 [2]) air density normalization will be used in correction to the power curve for the site-specific air density.

Graphed below are three of the power curves at different air densities for an example power curve to show differences. Using an accurate power curve that is representative of the site can result in more accurate Gross Annual Energy Production estimates.

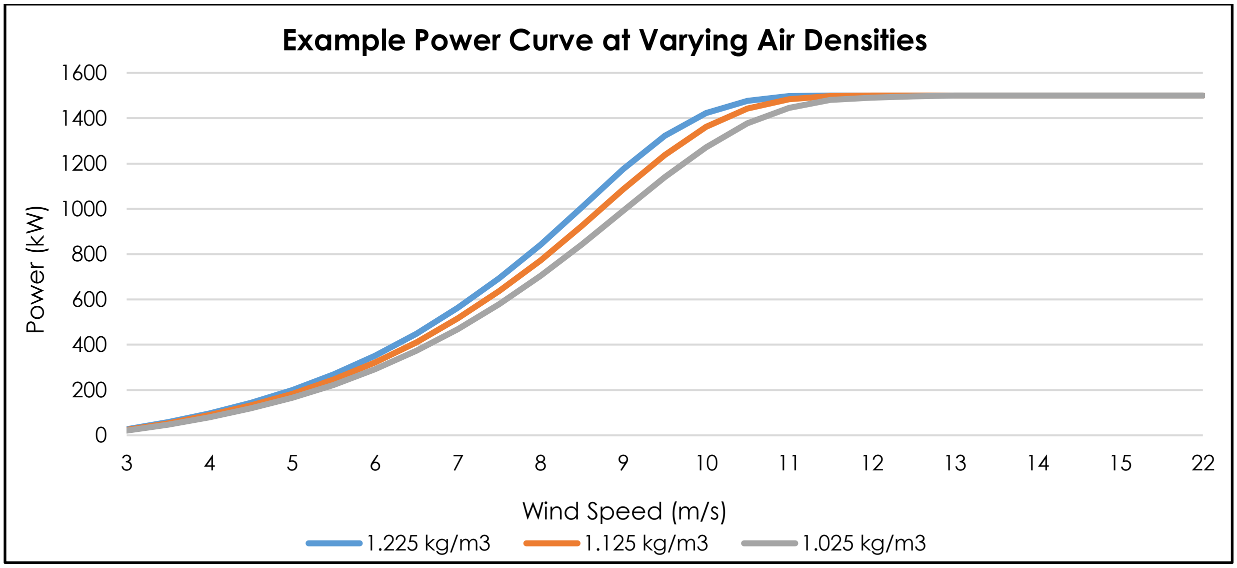


Figure 3: Example Power Curve at Varying Air Densities

The proposed turbine specifications are presented, including the following in WRA Section 2C – Turbine Information:

1) **Manufacturer and model**
2) **Rated power**
3) **Hub height, rotor diameter, and the maximum height**
4) **Cut-in wind speed, cut-out wind speed, and rated wind speed**
5) **Manufacturer-supplied power curve table at specified air density including the power output and thrust coefficient at varying wind speeds**

3. REFERENCE WIND PROJECTS

One Energy references additional wind projects in the near vicinity of the proposed site.

An image of nearby wind turbine projects along with a table is presented in WRA Section 3 – Reference Wind Projects with the following information:

1) **Name of the wind project**
2) **Distance to proposed site**
3) **Turbine make and model**
4) **Project size**
5) **Year of installation**

4. DATA INPUT SELECTION METHOD

One of three different methods of analysis is used depending on the dataset accessibility for a project-specific WRA. A primary data source is indicated and a method is chosen based on the measurement type, terrain complexity, and land cover at both the measurement and turbine sites. Each method has slight differences that reflect the nuances of its primary data measurement type and location.

The following information is presented in WRA Section 4 – Data Input Selection:

1) **Method Selection**
2) **Image of dataset locations**

METHOD 1: ON- OR NEAR-SITE METEOROLOGICAL TOWER

Method 1 uses a single MET and long-term reanalysis grid-point(s) to estimate the energy production and site conditions of the project. Airport data or reanalysis data is used for environmental conditions. Nearby long-term reanalysis data is used with the primary MET data to create simulated long-term datasets. Data from the MET must be deemed sufficient, as indicated in Section 5B(1): Binning During Data Campaigns, and regarded as representative of the project site.

METHOD 2: ON- OR NEAR-SITE LIDAR

Method 2 uses a single LiDAR and long-term reanalysis grid-point(s) to estimate the energy production and site conditions of the project. Airport data or reanalysis data is used for environmental conditions. Nearby long-term reanalysis data is used with the LiDAR data to create simulated long-term datasets. Data from the LiDAR must be deemed sufficient, as indicated in Section 5B(1): Binning During Data Campaigns, and regarded as representative of the project site.

METHOD 3: CONTINUUM MODEL

If on- or near-site MET or LiDAR data is unavailable, or there are substantial terrain changes between the measured data and the project site, or the measured data is not representative of the wind regime expected at the site, then the software package Continuum is used to model the wind resource at the proposed site. Continuum is a terrain-based wind flow model that uses multiple nearby available MCP simulated long-term datasets to generate a site-calibrated model. The model is based on a simplified analysis of the Navier-Stokes conservation of momentum equation and follows an intuitive model that estimates the wind speed based on the variations in the upwind and downwind terrain exposure and surface roughness across a project area. The measured datasets incorporated into Continuum must also be deemed sufficient, as indicated in Section 5B(1): Binning Data During Data Campaigns.

5. DATA INFORMATION

Various datasets are used within a WRA. This section explains the different types that may be used, along with the quality assurance and quality control measures in place.

A. DATA TYPES

Meteorological Tower (MET)

METs are used to collect wind data at multiple heights (typically three) to characterize the site's wind resource. They typically use measuring instruments such as cup anemometers, sonic anemometers, wind vanes, and various temperature and pressure sensors. They have been historically installed across the globe, usually temporarily, and many make their data publicly or privately available. The wind speed, wind direction, and associated standard deviations are recorded at multiple levels above the ground, in addition to providing general surface weather data such as temperature and pressure. METs are used by One Energy as target datasets for MCP and may also be used as Site Datasets (see Section 5D: Standardized Datasets) to determine site conditions.

One Energy has obtained a variety of MET datasets throughout the United States, with a focus on the Midwest. Some states implemented anemometer loan programs allowing METs to be installed and data made publicly available. One Energy uses all existing MET data made accessible.

LiDAR

A LiDAR (short for Light Detection and Ranging) is a remote sensing instrument used to collect wind data at a multiple heights and to characterize the site's wind resource. They are highly mobile devices which allow for quick installation and convenient operation. The wind speed, wind direction, and associated standard deviations are recorded at multiple levels above the ground, often across the entire rotor. A LiDAR may also provide general surface level weather data such as temperature and pressure when a weather station is installed with it. The measured heights are, whenever possible, programmed to include the full rotor sweep of the anticipated turbine make and model. LiDAR datasets are used by One Energy to create target datasets for MCP and may be used as Site Datasets to determine site conditions.

One Energy owns a fleet of ZephIR 300 LiDAR units that are used to characterize the wind resource when adequate existing data (MET) is unavailable. This LiDAR model has been successfully evaluated according to IEC 61400-12-1:2017 [1]. In addition, according to DNV GL, this model is also accepted as bankable (Stage 3) for wind speed and energy assessments in simple terrain. Additional LiDAR models may be assessed in the future if they are accepted as bankable.

Reanalysis

Publicly available long-term reanalysis data is offered through governmental agencies. These datasets are the output from weather forecast models and data assimilation of in-situ observations. Two of the common reanalysis datasets used are MERRA-2 (Modern-Era Retrospective Analysis for Research and Applications Version 2) and ERA5 (ECMWF Reanalysis 5th Generation).

MERRA-2 is a product developed and maintained by National Aeronautical and Space Administration (NASA). In the United States, MERRA-2 is widely used in the wind industry as a long-term reference dataset. It is available at a 0.5° latitude x 0.625° longitude resolution globally and contains hourly data since 1980, which includes wind speed components, temperature, cloud cover, and other variables. The time-averaged assimilated model variables at the native resolution are used in One Energy analysis.

ERA5 is a product developed and maintained by the European Centre for Medium-Range Weather Forecasts (ECMWF). ERA5 is also used in the wind industry as a long-term reference dataset. It is available at a 0.25° x 0.25° resolution globally and contains hourly data since 1979. This data includes wind components, wind gust, temperature, and other variables. The hourly time-averaged reanalysis data are used in One Energy's analysis.

Airport

Weather data collected at select airports is offered through the National Climatic Data Center (NCDC) via Automated Surface Observing Systems (ASOS) and provides hourly surface level wind speed, direction, temperature, pressure, and humidity measurements, along with weather conditions data. A minimum of ten years of airport ASOS data is used to evaluate environmental conditions wherever possible.

Simulated Long-Term

Simulated long-term data is created by One Energy to observe long-term trends in meteorological variables. The simulated long-term data is created using Measure-Correlate-Predict (MCP; see section Data Processing, MCP) with a nearby representative reanalysis grid-point as the long-term reference and a measured dataset from either a MET or a LiDAR as the target. The simulated long-term dataset is representative of the target dataset location.

B. DATA PROCESSING

1) Binning During Data Campaigns

Occasionally, a data campaign will not be able to encompass a full year due to external limitations, such as customer requests or shortened project development timelines. A binning method has been developed to determine when a dataset is deemed sufficient for use in a WRA. This method assumes a 10-minute temporal dataset resolution where each 10-minute interval is deemed one datapoint. A dataset is determined sufficient when all conditionals are met or a full year of data is collected, whichever occurs first.

A bin matrix is defined as a 2D array with 30° wind direction sectors and 2 m/s wind speed sectors. All bins are center binned. Three wind speed 'bands' are determined, where each band has a different set of conditionals. Long-term ERA5 data and turbine cut-in wind speed is used to create bounds of these wind speeds bands:

- The **first wind speed band** is from the wind speed interval bin at or below the cut-in wind speed in 2 m/s increments to, and including, the bin below the 85th percentile 100m wind speed from ERA5 (e.g., if cut-in is 2 m/s and the 85th percentile 100m wind speed is 9.4 m/s, the first wind speed band would be from 2 m/s through 8 m/s in 2 m/s intervals). For all directions and all wind speed sectors within the first wind speed band, each bin must contain a minimum of 54 datapoints (9 hours).
- The **second wind speed band** is defined as the bin below the 85th percentile of the 100m ERA5 wind speed through, and including, the bin below 90th percentile of the 10m ERA5 gust value. Within

this wind speed band, in one wind speed interval across all wind directions, there must be a minimum of 144 datapoints (1 day).

- The **third wind speed band** is defined as the bin below the 90th percentile 10m ERA5 gust value and above. For all wind speeds and wind directions, there must be a minimum cumulative total of 432 datapoints (3 days).

In addition to the wind speed band conditionals, within the prevailing wind direction across all wind speeds there must be a minimum of 1,008 datapoints (1 week).

For additional information and validation, see One Energy white paper "*Short-term Data Campaign Formation*" [3].

2) Extrapolation to Hub Height

Some data campaigns do not have measured data at the required turbine hub height for a specific project. If not, wind data is extrapolated to hub height following industry-standard methods. The wind profile power law is a widely used method and assumes that within the boundary layer that winds increase on a logarithmic scale using the following equation:

$$v_2 = v_1 \left(\frac{z_2}{z_1}\right)^{\alpha} \qquad \textit{Equation 5}$$

where v_2 is the wind speed in m/s at height z_2 [m], v_1 is the measured wind speed in m/s at reference height z_1 [m], and α is the dimensionless wind shear parameter.

There are two common ways in the wind industry to determine the wind shear parameter: 1) using a table based on the surface characteristics from the Wind Resource Assessment Handbook, and 2) derive the value based on measured values at a minimum of two different heights. One Energy uses the latter method and derives site-specific shear parameters as explained below.

Using MET Data

If a measured dataset is recorded from a MET, there are likely three heights of recorded data at each timestamp. Using those levels, a shear parameter is calculated at each timestamp for use in Equation 5 to extrapolate to hub height.

A wind shear parameter is calculated for each of the different height ranges (i.e., if there are three heights, between h_1 and h_2, between h_2 and h_3, and between h_1 and h_3) using the following equation:

$$\alpha = \frac{ln\left(\frac{v_2}{v_1}\right)}{ln\left(\frac{z_2}{z_1}\right)}, \qquad \textit{Equation 6}$$

where the wind speeds are in m/s and the heights are in m. For each timestamp, the different shear parameters based on the different height combinations are averaged together to create the overall shear parameter value for that timestamp. If the absolute value of a wind shear parameter value for a height range in the same time stamp is greater than 2.5, it is not included within the average at that timestamp.

The averaged shear parameter for the timestamp is then used to extrapolate the measured level closest to, but not above, hub height using Equation 5. The resulting dataset is the extrapolated wind speeds at hub height for the same timespan as the measured dataset.

Using LiDAR Data

If the measured dataset is recorded from a LiDAR, one of the recorded heights will typically be set at the hub height before unit deployment. The measured data at hub height will not need to be extrapolated to hub height.

If one of the measured heights from the LiDAR deployment is not at hub height, all measured heights are used to derive the shear exponent. Rearranging Equation 6 using logarithmic rules shows a different association between wind speeds and height levels:

$$\alpha = \frac{ln(v_2) - ln(v_1)}{ln(z_2) - ln(z_1)} \qquad \textit{Equation 7}$$

Equation 7 indicates the wind shear parameter is a linear slope within the logarithmic-space between wind speed and height. This concept is used to derive the shear parameter. All the wind speed data between the minimum tip height and maximum tip height are transferred into the logarithmic-space, and a best-fit linear slope between the resulting wind speeds is computed. This slope is representative of the wind shear parameter and is calculated at each timestamp to be used within Equation 5 to extrapolate the wind speed closest to, but not above, hub height to the hub height wind speed. The resulting dataset, if data was not measured at hub height, is the extrapolated wind speeds at hub height for the same timespan as the measured dataset.

3) Measure-Correlate-Predict (MCP)

Measure-Correlate-Predict is a method used to create a simulated long-term wind speed and wind direction dataset (MCP dataset) at the site of a measured dataset. To perform an MCP, a long-term reference dataset and a shorter measured target dataset are needed. Typically, the long-term reference dataset is reanalysis data and the target dataset is measured data from a MET or a LiDAR. Relationships are formed between the target and reference datasets over the concurrent data collection period. Then, based on the established relationships, the long-term wind speed and wind direction data at the target location are predicted by applying this relationship to the long-term reference data.

Currently, One Energy employs the commonly used orthogonal regression MCP approach. Data is binned into 16 wind direction sectors, where the best-fit line found when using an orthogonal regression minimizes the distance between the trendline and both the reference and target datasets. This approach addresses the fact that there is measurement uncertainty in both datasets. A Correlation of Determination (R^2) over all wind directions (only one wind speed sector of 360°) of 0.6 or greater for an MCP dataset is deemed acceptable for use within the WRA. Less than 16 wind direction sectors are used if the target dataset is less than 6 months and the target dataset is not representative of the reference dataset in any specific directional sector. In this instance, one wind direction sector is used withing the orthogonal regression analysis.

C. QUALITY CONTROL

Nearby Obstructions

When deploying a measurement campaign, all reasonable measures will be taken to account for nearby obstructions such as nearby buildings or tall trees. If during deployment, obstructions are unavoidable in certain directional sectors, the impacted sectors are noted along with the type of obstruction. Depending on the obstruction type and height, affected measured data may be filtered to remove obstruction effects.

MET Filters

Wind Speed Filter

A wind speed standard deviation filter is applied that omits data if:

$$\sigma > 0.22v + 1.1 \qquad \text{Equation 8}$$

Or:

$$\sigma < 0.02v \qquad \text{Equation 9}$$

where σ is the standard deviation and v is the wind speed. Equation 9 is only valid if wind speeds are greater than 1 m/s. Data will also be omitted if the range between the maximum and minimum wind speeds is greater than 20 m/s (~45mph) or the maximum wind speed is greater than 40 m/s (~90mph).

To remove invalid ‘zero’ wind speed measurements, a filter is applied based on the linear relationship calibration equation that relates the anemometer signal to wind speed. This applies specifically to NRG Max40 cup anemometers commonly installed on MET towers. When there is no signal due to instrument issues, the logger will record a ‘zero’ reading which is equal to the y-intercept value of the linear relationship. For the NRG Max40 cup anemometers, the most commonly-used cup anemometers in North America, the y-intercept value is approximately 0.35 m/s. By implementing a minimum wind speed filter, the invalid ‘zero’ readings are removed from the dataset. This filter can be applied in two ways:

- For measurement levels that have redundant sensors, data is filtered if one sensor is reading less than 0.4 m/s while the other is reading greater than 1 m/s. The sensor that is recording less than 0.4 m/s is filtered out and for the timestamp, the wind speed is determined to be the sensor reading greater than 1 m/s.
- For measurement levels that do not have redundant sensors, data is filtered if the wind speed is recording less than 0.4 m/s and the wind speed at the closest height level is reading greater than 1 m/s. The sensor that is recording less than 0.4 m/s is filtered out of the dataset if these criteria is met.

An additional filter is included if:

$$3\sigma > v \qquad \text{Equation 10}$$

where σ is the standard deviation and v is the wind speed. Only the standard deviation is omitted, while the wind speed is kept. This is done to exclude standard deviations which allow for the possibility of negative wind speed magnitudes.

Tower Shadow Filter

Tower shadow is the effect on wind speed when the MET tower's structure obstructs wind flow to the anemometer. Because the tower disrupts the free-stream wind speed distribution behind the tower, a filter is applied to remove bias in the wind speed data when the sensor is downwind of the tower.

For most of the MET tower datasets used, there are typically two anemometers at a single level on two booms, offset by 90°. This data is binned by wind direction with bin width of 2° for each sensor, and the average difference between the two anemometers' wind speeds is calculated in each wind direction sector. When identifying tower shadow sectors any difference (or bias) between the two sensors must be removed. This is done by calculating the average wind speed difference over all wind direction sectors, then adjusting the data to eliminate the data affected by tower shadow.

With these debiased datasets for both anemometers, the tower shadow sectors are defined. The tower shadows sectors are determined to be when the wind speed difference is greater than ±0.2 m/s for all direction sectors on either side of the largest difference. Both sensors experience tower shadow during different ranges of wind direction. When tower shadow is determined, the sensor within the shadow is filtered. The two anemometer datasets are then combined. At every timestamp, if the wind direction falls outside both defined tower shadow sectors, the average wind speed between the two sensors is computed and taken as the wind speed. If the wind direction falls inside one of the defined tower shadow sectors, the anemometer that is outside the tower shadow sector is taken to be the wind speed for that timestamp.

If there is only one anemometer at a specific height, the tower shadow sector is defined using the boom orientation and assuming a tower shadow width of 36°. The wind speed data within the tower shadow sector is filtered out and the remaining dataset is used for analysis.

Icing Filter

Icing events may affect the MET tower data and are omitted from the data sets. Icing events are defined to occur when the standard deviation of the wind direction is less than or equal to 1 and the temperature is less than or equal to 34˚F. The standard deviation of the wind speed must also be less than or equal to 0.01 to be considered an icing event.

Dry-Friction Whip Filter

Some cup anemometers manufactured by NRG between 2006 and 2008 have experienced dry-friction whip. This condition affected anemometers and would report wind speeds that were lower than actual speeds. If dry-friction whip was determined to affect historical datasets, a correction is used to adjust the wind speeds. AWS Truepower (now UL Renewables) created and tested different standard correction factors based on the wind speed recorded (Table 2) [4] that is used within One Energy data processing. If a post-deployment calibration confirms dry-friction whip, Standard Correction I is used. If post-deployment calibration of the anemometer is unavailable and dry-friction whip is found within a MET dataset, Standard Correction II is used.

WIND SPEED (M/S)	STANDARD CORRECTION I		STANDARD CORRECTION II	
	BIAS CHANGE OVER TIME (M/S)/TOTAL HZ[7])	INITIAL OFFSET (M/S)	BIAS CHANGE OVER TIME (M/S)/TOTAL HZ[7])	INITIAL OFFSET (M/S)
4	0.144	0.087	0.145	0.083
5	0.785	0.092	0.752	0.083
6	1.790	0.098	1.779	0.084
7	2.470	0.120	2.406	0.101
8	2.140	0.159	2.045	0.138
9	1.714	0.179	1.619	0.161
10	1.383	0.185	1.284	0.168
11	1.022	0.179	0.963	0.163
12	0.906	0.162	0.788	0.149
13	0.910	0.145	0.846	0.132
14	0.746	0.136	0.745	0.120
15	0.286	0.132	0.242	0.120
16	0.036	0.132	0.000	0.120

Table 2: Standard Correction I&II Time Correction and Initial Offset Parameters [4]

LiDAR Filters

The ZephIR300 LiDAR instruments quality control the data internally and do not report data unless the data pass internal quality control measures. A filter code is indicated for each data point that is removed, which typically is a result of either low wind speeds, partial obstruction of the window, significant interference with the laser beam at a specified height, or atmospheric conditions which would adversely affect the wind speed measurements. One Energy does not further filter any data output from the ZephIR300 LiDAR instruments.

Additional data filters may be required if a different LiDAR is used for data acquisition.

Data Recovery & Availability

Data recovery is the percentage of recovered data from a measurement deployment. Typically, a LiDAR data set that has a minimum of 80% data recovery or a MET dataset that has 90% data recovery are considered suitable for a wind analysis. These data availability percentages are common within the wind industry [5].

D. STANDARDIZED DATASETS

Standard dataset names have been introduced to create naming consistencies across the three WRA methods (see Section 4: Data Input Selection Method). All datasets are assumed to be filtered and scrubbed before being deemed one of the standard datasets. The list of standard datasets used are:

1. **Point Dataset**: any short-term, measured dataset from either a MET or a LiDAR that is used within the WRA. Can be any distance from the project site.
2. **Site Dataset**: a single short-term, measured dataset from either a MET or a LiDAR reflective of the project location. Can be on- or near-project site. A Site Dataset is also considered a Point Dataset.
3. **Point MCP Dataset**: long-term, MCP dataset using a Point Dataset and the closest reanalysis grid-point to the measurement point of the Point Dataset. If there is complex topography between the Point Dataset and the closest reanalysis grid-point, another nearby reanalysis grid-point may be determined to be the most representative of the Point Dataset location.

4. **Site MCP Dataset**: long-term, MCP dataset using the Site Dataset and the closest reanalysis grid-point to the project site. If there is complex terrain between the site and the reanalysis grid-point, another nearby reanalysis grid-point may be determined to be the most representative of the project site. Site MCP Datasets may also be considered Point MCP Datasets if the reanalysis grid-point is the closest available point to both the site and Site Dataset.

Figure 4 is shown to explain the differences between the various Standardized Datasets.

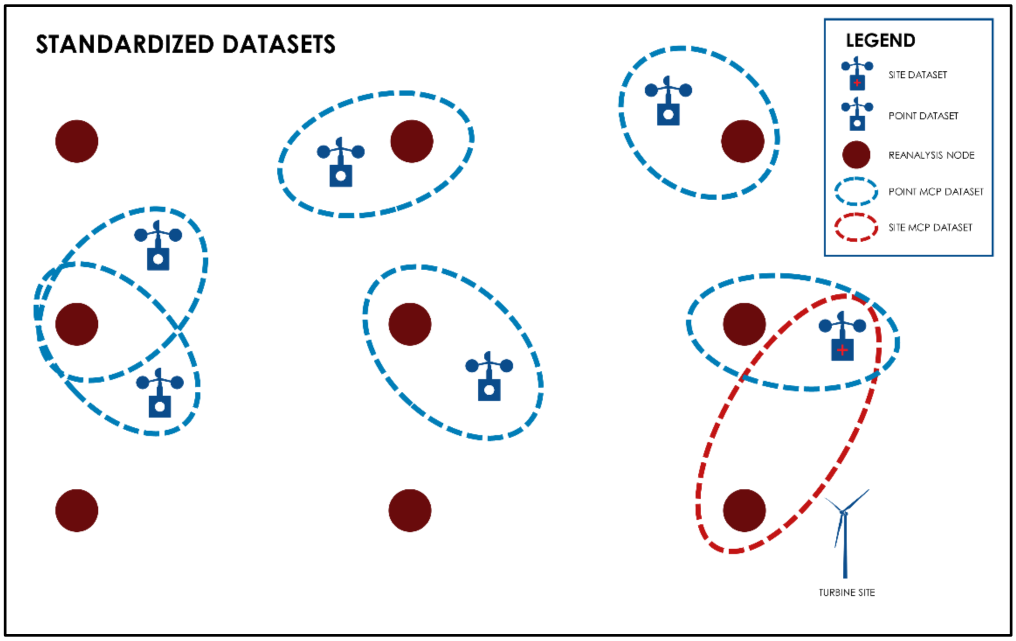


Figure 4: Standardized Datasets

Standardized Dataset Uses

Within all methods, the following standard datasets are used in the WRA:

1. **Point Dataset**: if using Method 3, one of the Point Datasets will be deemed the Site Dataset. With this method, all other Point Datasets are only used to create Point MCP Datasets for input into the Continuum model. If using Method 1 or 2, there is only one Point Dataset, which is also the Site Dataset.
2. **Site Dataset:** used for the site conditions, specifically the TI, shear, and extreme wind speeds.
3. **Point MCP Dataset:** used for energy production estimates. If using Method 3, there will be multiple Point MCP Datasets for input into the Continuum model. If using Method 1 or 2, there will only be one Point MCP Dataset.
4. **Site MCP Dataset:** used for the site directional flow analysis, wind variability, and portions of the extreme wind calculations. If the Site Dataset is measured on-site, the Site MCP Dataset and Point MCP Dataset will have the same reanalysis grid-point used during creation.

WRA Section 5 – Data Information specifies the details of each dataset used in the evaluation including the following:

1. **Table of raw datasets used that include:**
    a. **Type of measurement dataset**
    b. **Location**

- c. **Distance to site in miles**
    - d. **Elevation of the data set**
    - e. **If LiDAR, terrain complexity of measurement site (see section 2B: Terrain Complexity)**
    - f. **Collection period and length**
    - g. **Data recovery and data availability**
    - h. **Data collection heights**
    - i. **Extrapolated wind data height**
2. **Table with simulated long-term dataset creation information**
    - a. **Target and Reference datasets used within MCP**
    - b. **R^2 value of MCP dataset**
    - c. **Average hub height wind speed for each MCP dataset**
3. **Table indicating the Standardized Datasets that include:**
    - a. **Standardized dataset type**
    - b. **Location**

6. ENVIRONMENTAL CONDITIONS

Airport data is typically used for environmental conditions. If there is not an airport representative of the project site, reanalysis data may be used.

A. TEMPERATURE

Temperature is typically a measured variable. If airport data is used, the temperature is averaged into hourly data to create an hourly temperature dataset. The average long-term temperature is then calculated by averaging the hourly temperature dataset. The minimum and maximum are found from the original airport dataset, not the hourly averaged dataset.

In WRA Section 6A - Temperature, the following is specified:

1. **Average long-term temperature**
2. **Minimum/maximum long-term temperature**
3. **Days per year the minimum temperature is below -20°C**
4. **Days per year the minimum temperature is below -40°C**

B. RELATIVE HUMIDITY

Relative humidity is typically a measured variable. If airport data is used, the relative humidity is averaged into hourly data to create an hourly relative humidity dataset. The average long-term relative humidity is then calculated by averaging the hourly humidity dataset. The minimum and maximum are found from the original airport dataset, not the hourly averaged dataset.

In WRA Section 6B – Relative Humidity, the following is specified:

1. **Average long-term relative humidity**
2. **Minimum/maximum long-term relative humidity**

C. BAROMETRIC PRESSURE

Barometric pressure is typically a measured variable. If airport data is used, the pressure is averaged into hourly data to create an hourly pressure dataset. The average long-term pressure is then calculated by averaging the hourly pressure dataset. The minimum and maximum are found from the original airport dataset, not the hourly averaged dataset.

In WRA Section 6C – Barometric Pressure, the following is specified:

1. **Average long-term pressure**
2. **Minimum/maximum long-term pressure**

D. AIR DENSITY

Air density is not a measured variable for most data sets. If a full year of on-site data is available, notably from a LiDAR deployment, the air density is calculated and shown using both the LiDAR data and either the airport or reanalysis data. To determine the air density of humid air, both the density of vapor and dry air must be calculated and combined. Nomenclature of variables remain the same for the entirety of the section. The ideal gas law is rearranged to form the equation:

$$\rho = \frac{p}{RT},$$

Equation 11

where ρ is air density in kg/m^3, p is total air pressure in Pa, T is temperature in K, and R is the gas constant for the air in J/kg*K.

Utilizing this equation of state, we can modify it to account for water vapor in the air, resulting in:

$$\rho = \rho_d + \rho_v$$

Equation 12

where ρ_v is the density of the water vapor in kg/m^3 and ρ_d is the density of dry air in kg/m^3. Combining Equation 11 and Equation 12, results in:

$$\rho = \frac{p_d}{R_d T} + \frac{e}{R_v T}$$

Equation 13

where p_d is the partial pressure of dry air in Pa, R_d is the gas constant for dry air which is equal to 287 J/kg*K, e is the partial pressure of water vapor in Pa, and R_v is the gas constant for water vapor which is equal to 461.5 J/kg*K.

Using two additional measured variables obtained from the airport data, the relative humidity and the temperature, the partial pressure of water vapor can be calculated. The following equations are definitions:

$$RH = \frac{e}{e_s}$$

Equation 14

$$e_s = 6.112\exp\left(\frac{17.67T_C}{T_C + 243.5}\right)$$

Equation 15

where e_s is the saturation vapor pressure in Pa, RH is the relative humidity in decimal form, and T_C is the temperature in Celsius.

Combining Equation 14 and Equation 15 results in:

$$e = RH * 6.112\exp\left(\frac{17.67T_C}{T_C + 243.5}\right)$$

Equation 16

Dalton's Law of Partial Pressures indicates the sum of the different gases' partial pressures must total the total pressure. Total air pressure is a measured variable available in the airport data and is considered a known.

$$p = p_d + e$$

Equation 17

$$p_d = p - RH * 6.112\exp\left(\frac{17.67T_C}{T_C + 243.5}\right) \quad \text{Equation 18}$$

Combining Equation 13, Equation 16, and Equation 18 the density of humid air is then calculated to be:

$$\rho = \frac{p - RH * 6.112\exp\left(\frac{17.67T_C}{T_C + 243.5}\right)}{R_d T} + \frac{RH * 6.112\exp\left(\frac{17.67T_C}{T_C + 243.5}\right)}{R_v T} \quad \text{Equation 19}$$

For each time stamp, *i*, of the data, the air density is determined, as shown in Equation 19. Because airport data typically does not have consistent temporal resolution, the air density is averaged hourly to create an hourly air density dataset. The hourly air density dataset is then averaged to realize the long-term average humid air density of a site as shown in Equation 21.

$$\rho_i = \frac{p_i - RH_i * 6.112\exp\left(\frac{17.67T_{C,i}}{T_{C,i} + 243.5}\right)}{R_d T_i} + \frac{RH_i * 6.112\exp\left(\frac{17.67T_C, i}{T_{C,i} + 243.5}\right)}{R_v T_i} \quad \text{Equation 20}$$

$$\rho = \frac{1}{n}\sum_{d=1}^{n} \rho_d \quad \text{Equation 21}$$

where *d* is the day index, and *n* is the number of data points in the hourly air density dataset. The minimum and maximum air density values are obtained from the full dataset with each timestamp, not the hourly dataset.

In WRA Section 6D – Air Density, the following is specified:

1. **Data set used to calculate the air density**
2. **Average long-term air density**
3. **Minimum/maximum long-term air density**

E. ICING

Two main forms of icing are considered when evaluating the ice conditions of a site: precipitation icing and in-cloud icing. Both are evaluated independently. The precipitation icing uses airport data, while the in-cloud icing uses the publicly available WIceAtlas from VTT [6].

Precipitation Icing Time

Using the airport data for the project site, the number of hours any freezing precipitation event (METAR code including 'FZRA' or 'FZDZ') is totaled, and the percentage of occurrence is calculated for each complete year within the dataset. The average of the annual percentages is then calculated and used as the project site annual precipitation icing time.

In-Cloud Icing Time

The WIceAtlas provides a contour map (Figure 5) that is used to indicate the International Energy Agency (IEA) Ice Class [7] of a specified location. This map is created by combining data from over 4,000 meteorological stations globally to evaluate icing severities specifically for wind power applications. The WIceAtlas defines icing severity as the icing frequency resulting from in-cloud icing. The IEA ice class legend and associating icing frequencies are shown in Table 3. Meteorological icing is used to indicate the average percentage of the year where in-cloud icing conditions exist, while the instrumental icing indicates the average percentage of the year where instrumentation maintains ice accumulation. Within this WRA, meteorological icing is used to indicate annual in-cloud icing time.

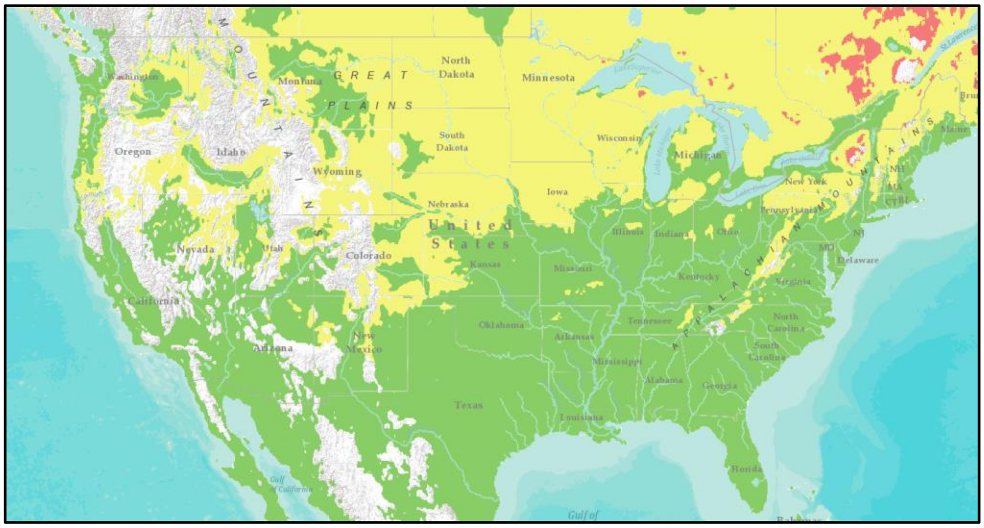


Figure 5: VTT WIceAtlas Map [6]

IEA ICE CLASS	METEOROLOGICAL ICING (% OF YEAR)	INSTRUMENTAL ICING (% OF YEAR)	AEP LOSS (% OF GROSS AEP)	PUBLIC WICEATLAS MAP
5	>10	>20	>20	🟥
4	5-10	10-30	10-25	🟥
3	3-5	6-15	3-12	🟥
2	0.5-3	1-9	0.5-5	🟨
1	0-0.5	<1.5	0-0.5	🟩

Table 3: IEA Ice Class [7]

Icing Thickness

Annual design icing thickness information is found in ANSI/TIA-222-G [8]. The design ice thickness is defined in ANSI/TIA-222-G as the uniform radial thickness of glaze ice at 10m in exposure category C for the 50-year mean recurrence interval. For example, Figure 6 shows the design icing thickness found across the contiguous United States, from ANSI/TIA-222G.

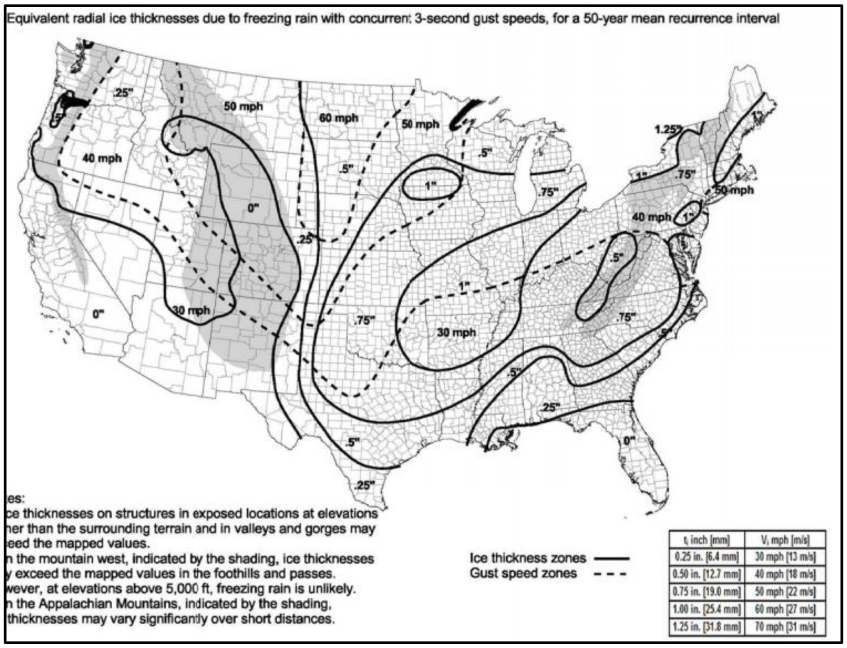


Figure 6: Icing Thickness [8]

In WRA Section 6E - Icing, the following is specified:

1. **Annual precipitation icing time**
2. **Annual in-cloud icing time**
3. **Indicated IEA Ice Class**
4. **Icing thickness**

F. SNOWFALL

The annual average snowfall total per season is shown to indicate precipitation impact and seasonal conditions. Airport ASOS data is used for this assessment. Annual snowfall totals are determined by summing the hourly precipitation variable by year if the hourly present weather type indicated is snow (-SN). The hourly precipitation is reported as liquid equivalent, so the average ratio of 10:1 is applied to convert to snowfall total equivalent. From these annual snowfall totals, the average value is calculated. If there is no available airport data, all reasonable efforts will be made to obtain local climate data from various sources.

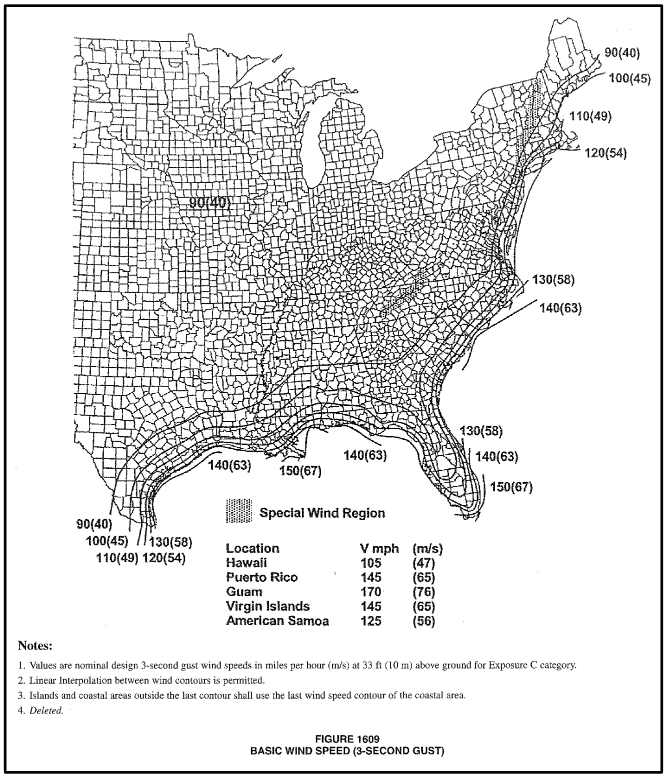
In WRA Section 6F - Snowfall, the following is specified:

1. **Average annual snowfall**

G. HURRICANE

The hurricane records and building codes are determined using the International Building Code. For example, the 2018 International Building Code, which is based on ASCE 7 [9], is used for projects in Ohio.

The ASCE 7-10 defines a hurricane prone region as the United States coast along the Atlantic Ocean and the Gulf of Mexico where the Basic Wind Speed (3-Second Gust) is greater than 90 miles per hour. Also included in a hurricane prone region is all of Hawaii, Puerto Rico, Guam, Virgin Islands, and American Samoa. To determine the Basic Wind Speed (3-Second Gust) for a project, Figure 7 from ASCE 7-10 is used.



Location	V mph	(m/s)
Hawaii	105	(47)
Puerto Rico	145	(65)
Guam	170	(76)
Virgin Islands	145	(65)
American Samoa	125	(56)

Notes:

1. Values are nominal design 3-second gust wind speeds in miles per hour (m/s) at 33 ft (10 m) above ground for Exposure C category.
2. Linear Interpolation between wind contours is permitted.
3. Islands and coastal areas outside the last contour shall use the last wind speed contour of the coastal area.
4. *Deleted.*

FIGURE 1609
BASIC WIND SPEED (3-SECOND GUST)

Figure 7: ASCE 7-05 Basic Wind Speed (3-Second Gust) [9]

In WRA Section 6G - Hurricane, the following is specified:

1. **International Building Code Basic Wind Speed (3-Second Gust) at 10 meters above ground**
2. **Indication if project is within hurricane-prone region**

H. EARTHQUAKE

Turbine manufacturers use earthquake 'design' spectral response acceleration parameters and building codes when confirming turbine suitability. The spectral response acceleration parameter is a quantification of the seismic intensities that will be considered. These parameters account for the soil type and the potential g-force that a mass will experience during an earthquake at a certain location. There are two parameters calculated that are based on the time periods of 0.2 seconds and 1 second.

The building codes used are the international building code ASCE 7-10 [9]. From the maps included in this code, the spectral response acceleration parameters are found dependent on the project location. Figure 8 and Figure 9 show the spectral acceleration parameters for the 0.2 second period (S_s) and 1 second period (S_1), respectively.

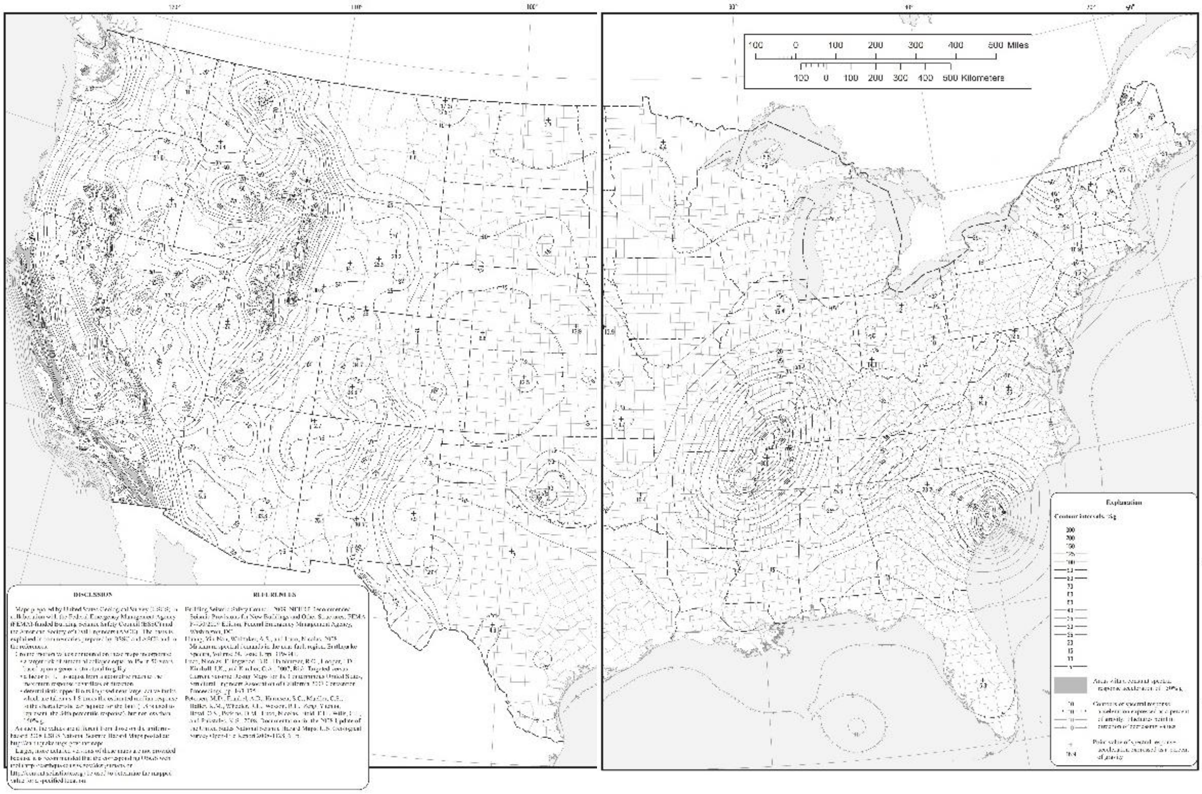


Figure 8: ASCE 7-10 Spectral Acceleration 0.2-second period (S_s) [9]

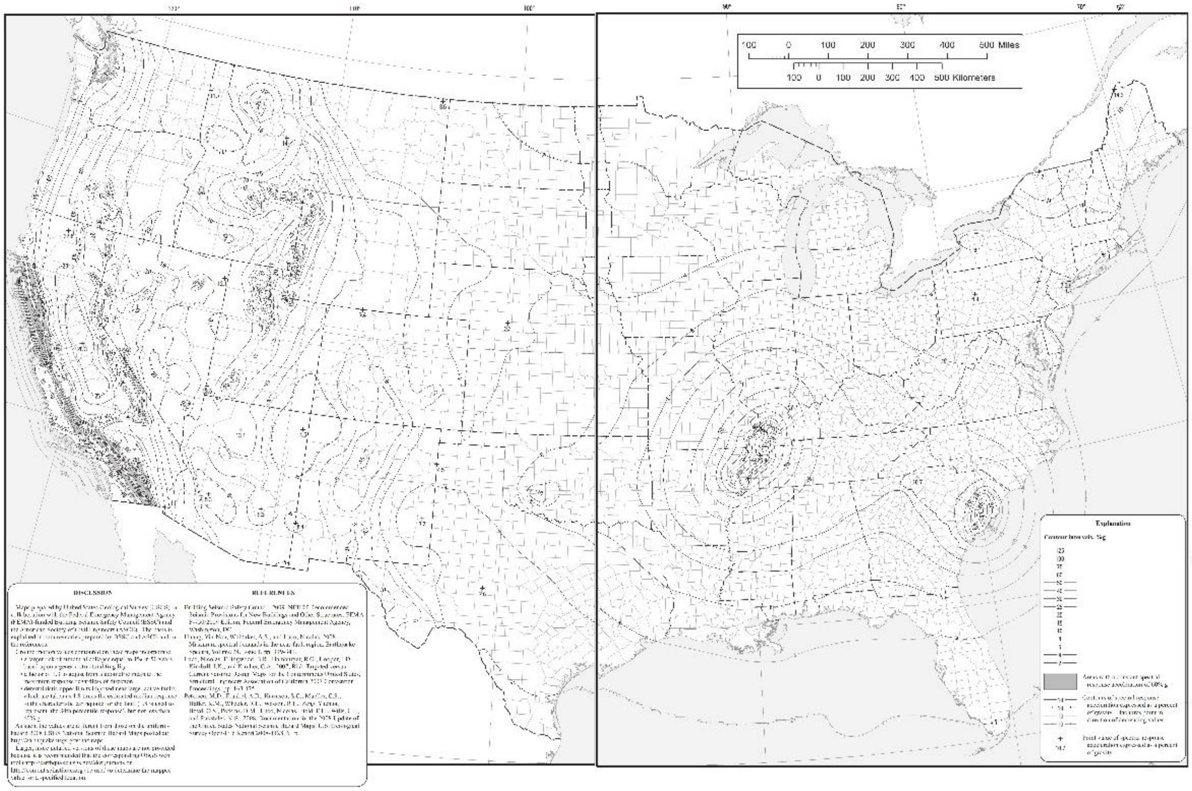


Figure 9: ASCE 7-10 Spectral Acceleration 1-second period (S_1) [9]

The spectral response acceleration parameters for both periods are then multiplied by a site-specific classification coefficient to obtain the maximum spectral response acceleration parameters (S_{MS}, S_{M1}). The classification coefficient is dependent on the soil type of the location and is representative of how the soil type will move during an earthquake event. Prior to the geotechnical study, the specific soil type is unknown, therefore for all projects in the United States the assumed soil type is Class D. From the soil type classification, the site coefficient values (F_a, F_v) are found for both time periods and then multiplied by the respective spectral response acceleration parameter. Table 4 from ASCE 7 are the tables to obtain the site coefficient values dependent on soil type and the values of the spectral response acceleration parameters.

SITE CLASS	**MAPPED SPECTRAL RESPONSE ACCELERATION AT SHORT PERIOD (F_a)**					**MAPPED SPECTRAL RESPONSE ACCELERATION AT 1-SECOND PERIOD (F_v)**				
	$S_S \leq 0.25$	$S_S = 0.50$	$S_S = 0.75$	$S_S = 1.00$	$S_S \geq 1.25$	$S_1 \leq 0.1$	$S_1 = 0.2$	$S_1 = 0.3$	$S_1 = 0.4$	$S_1 \geq 0.5$
A	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
B	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
C	1.2	1.2	1.1	1.0	1.0	1.7	1.6	1.5	1.4	1.3
D	1.6	1.4	1.2	1.1	1.0	2.4	2.0	1.8	1.6	1.5
E	2.5	1.7	1.2	0.9	0.9	3.5	3.2	2.8	2.4	2.4
F	Note b	Note b	Note b	Note b	Note b	Note b	Note b	Note b	Note b	Note b

Table 4: ASCE 7 Values of Site Coefficients F_a and F_v [9]

The maximum spectral response acceleration parameters are then calculated by the following equations:

$$S_{MS} = F_a S_S \quad \text{Equation 22}$$

$$S_{M1} = F_v S_1 \quad \text{Equation 23}$$

From the maximum spectral response acceleration parameters, the final design spectral response acceleration parameters (S_{DS}, S_{D1}) are calculated by the following equations:

$$S_{DS} = \frac{2}{3} S_{MS} \quad \text{Equation 24}$$

$$S_{D1} = \frac{2}{3} S_{M1} \quad \text{Equation 25}$$

Based on these spectral response acceleration parameters, an ASCE7 table (Table 5) is referenced to assess the seismic design category for each response period. The risk category for all projects is assumed to be Risk Category II.

SEISMIC DESIGN CATEGORY BASED ON SHORT PERIOD RESPONSE ACCELERATION PARAMETER			SEISMIC DESIGN CATEGORY BASED ON 1-S PERIOD RESPONSE ACCELERATION PARAMETER		
	Risk Category			Risk Category	
Value of S_{DS}	I or II or III	IV	Value of S_{D1}	I or II or III	IV
$S_{DS} < 0.167$	A	A	$S_{D1} < 0.067$	A	A
$0.167 \leq S_{DS} < 0.33$	B	C	$0.067 \leq S_{D1} < 0.133$	B	C
$0.33 \leq S_{DS} < 0.50$	C	D	$0.133 \leq S_{D1} < 0.20$	C	D
$0.50 \leq S_{DS}$	D	D	$0.20 \leq S_{D1}$	D	D

Table 5: ASCE 7 Seismic Design Category [9]

Wind developers do not typically provide this level of detail for seismic design. One Energy calculates the spectral response acceleration parameters addressed above during development for internal reference only. Third-party foundation and tower engineers complete their own analyses for the spectral response acceleration parameters once additional information, such as soil types determined from a Geotechnical Survey, are completed prior to construction.

In WRA Section 6H – Earthquake, the following is specified:

1. **0.2-second and 1-second spectral response acceleration parameters (S_S, S_1)**
2. **0.2-second and 1-second design spectral response acceleration parameters (S_{DS}, S_{D1})**
3. **Earthquake seismic design category for 0.2-second and 1-second response period**

7. SITE CONDITIONS

Understanding the site conditions is important to the turbine OEM for turbine selection. The extreme wind speeds, annual wind speed variation, wind shear, turbulence intensity, wind direction distribution, and the inflow angle are necessary to determine site conditions. The Site Dataset and Site MCP Dataset are primarily used, unless otherwise indicated.

A. WIND SPEED DISTRIBUTIONS

One Energy uses true hub height wind speed distributions for energy production estimates.

It is acknowledged that the industry uses Weibull distributions to assess the wind characteristics of a site. One Energy determines the A and k parameters for consistency with the industry but does not use it within energy production estimates. A Weibull distribution probability density function has the form of:

$$f(x, A, k) = \begin{cases} \frac{k}{A}\left(\frac{x}{A}\right)^{k-1} e^{-(x/A)^k} & \geq 0, \\ 0 & x < 0 \end{cases} \qquad \textit{Equation 26}$$

i. Annual Distribution

Using the Site MCP Dataset, a true annual hub height wind speed distribution is created. The hub height wind speeds are center binned in 0.5 m/s intervals and annual Weibull distribution parameters are determined. The Weibull A and k parameters are determined by the best fit distribution of the true data distribution for an average year. If using Method 3, Continuum is used to assess the annual distribution and find the A and k parameters.

In WRA Section 7Ai – Annual Distribution, the following is specified:

1. **Table of annual Weibull parameters**

ii. Monthly Distribution

The monthly distribution calculations are similar to the annual hub height wind speed distribution, but the distributions look specifically at the average month of the Site MCP Dataset. Both the monthly true distributions and the Weibull distributions are determined. Under Method 3, monthly A and k parameters are not provided.

In WRA Section 7Aii – Monthly Distribution, the following is specified:

1. **Table of monthly Weibull parameters (not applicable if using Method 3)**

iii. Wind Speed 12x24

A wind speed 12x24 is a table that indicates the average hub height wind speed at every hour for each month. To calculate this 12x24 matrix, the Site MCP Dataset is used. The hub height wind speeds are binned by hour of the day and by month and averaged. This average wind speed is the value associated with the specified hour and month.

In WRA Section 7Aiii – Wind Speed 12x24, the following is specified:

1. **A 12x24 table of hub height wind speeds, conditionally formatted**

B. EXTREME WINDS

The extreme wind speeds for 10-minute and 3-second with various recurrence periods are calculated dependent on the length of the on- or near-site measured Site Dataset. Long-term annual maximum 10-minute and 3-second datasets are created and then used with a Gumbel distribution to calculate the extreme wind speeds at different recurrence periods.

Less than 8 Months of Measured Data

If less than 8 months of measured on- or near-site data are available, 20 years of ERA5 data from the closest grid-point to the project is used. The 10m U and V wind components, 100m U and V wind components, and the ‘10m gust since previous post-processing’ variables are used within the assessment.

The wind speed at 10m and 100m are calculated, then an alpha value is determined using the wind profile power law (Equation 6 or Equation 7) at each timestamp. The wind speed is extrapolated to hub height using Equation 5 and its respective timestamp alpha value.

The maximum hourly wind speeds for each year are combined to create an annual maximum wind speed dataset. Because this dataset is based on hourly data and not 10-minute or 3-second data, a Gust Factor from Table 6 (WMO, 2008 [10]) is found and applied to each value within the annual maximum wind speed dataset. Two separate annual maximum datasets are created: one for the 10-minute values and one for the 3-second values. The appropriate Gust Factor must be used and is dependent on the terrain exposure of the ERA5 grid point. For Wind for Industry projects, typically the 10-minute Gust Factor used is 1.08 and the 3-second Gust Factor used is 1.75.

EXPOSURE AT +10M		**REFERENCE PERIOD T_O (S)**	**GUST FACTOR G_{t,T_O}**				
CLASS	DESCRIPTION		GUST DURATION τ (S)				
			3	60	120	180	600
In-Land	Roughly open terrain	3600	1.75	1.28	1.19	1.15	1.08
		600	1.66	1.21	1.12	1.09	1.00
		180	1.58	1.15	1.07	1.00	
		120	1.55	1.13	1.00		
		60	1.49	1.00			
Off-Land	Offshore winds at a coastline	3600	1.60	1.22	1.15	1.12	1.06
		600	1.52	1.16	1.09	1.06	1.00
		180	1.44	1.10	1.04	1.00	
		120	1.42	1.08	1.00		
		60	1.36	1.11			
Off-Sea	Onshore winds at a coastline	3600	1.45	1.17	1.11	1.09	1.05
		600	1.38	1.11	1.05	1.03	1.00
		180	1.31	1.05	1.00	1.00	
		120	1.28	1.03	1.00		
		60	1.23	1.00			
At-Sea	> 20 km offshore	3600	1.30	1.11	1.07	1.06	1.03
		600	1.23	1.05	1.02	1.00	1.00
		180	1.17	1.00	1.00	1.00	
		120	1.15	1.00	1.00		
		60	1.11	1.00			

Table 6: Gust Factor [10]

These newly created datasets will be the annual 10-minute equivalent maximum wind speed by year as well as the annual 3-second equivalent maximum gust speed by year for the length of the ERA5 dataset.

Greater than 8 Months of Measured Data

If the measured Site Dataset is greater than 8 months, the Site MCP Dataset and Site Dataset are used to find the maximum hourly wind speed for each year.

The maximum hourly wind speeds for each year are combined to create a new dataset. Because this dataset is hourly and not in 10-minute or 3-second gust time periods, a conversion factor is created for each to apply to the dataset. These conversion factors are defined as

$$C_{10\mathrm{min}} = \frac{\frac{1}{M}\sum_{i=1}^{M} v_{a,i}}{\frac{1}{M}\sum_{i=1}^{M} v_{h,i}} \qquad \textit{Equation 27}$$

$$C_{\mathrm{gust}} = \frac{\frac{1}{M}\sum_{i=1}^{M} v_{g,i}}{\frac{1}{M}\sum_{i=1}^{M} v_{h,i}} \qquad \textit{Equation 28}$$

where C_{10min} is the conversion factor for the 10-minute equivalent simulated data, C_{gust} is the conversion factor for the 3-second equivalent simulated data, M is the number of years of the Site Dataset, $v_{a,i}$ is the actual maximum 10-minute Site Dataset wind speed at year i, $v_{g,i}$ is the actual maximum Site Dataset wind gust at year i, and $v_{h,i}$ is the maximum Site MCP Dataset hourly wind speed at year i. This conversion factor is a similar concept to a Gust Factor but the factor is created using the measured data from the site as opposed to pulling a value from a reference table.

This newly created dataset will be the annual 10-minute equivalent maximum wind speed by year as well as the annual 3-second equivalent maximum gust speed by year for the length of the long-term dataset.

Gumbel Distribution

The Gumbel distribution is commonly used within the wind industry to determine the extreme 10-minute wind speed and 3-second gust values for different recurrence periods.

The Gumbel cumulative distribution function (CDF) is defined as

$$F(U_e) = e^{\left(-e^{\left(\frac{(-U_e-\mu)}{\beta}\right)}\right)} \qquad \textit{Equation 29}$$

$$\mu = \overline{U_e} - 0.577\beta \qquad \textit{Equation 30}$$

$$\beta = \frac{\sigma_e\sqrt{6}}{\pi} \qquad \textit{Equation 31}$$

where U_e is the extreme wind over some recurrence time period, N, in years, $\overline{U_e}$ is the mean of a set of extreme annual values, and σ_e is the standard deviation of the set of extreme annual values [11].

The maximum wind speed with a recurrence year of N years (when $N>1$) is the wind speed where

$$1 - F(U_e) = \frac{1}{N} \qquad \textit{Equation 32}$$

Combining Equation 29 and Equation 32 results in

$$1-\frac{1}{N}=e^{(-e^{(\frac{-(U_e-\mu)}{\beta})})} \qquad \textit{Equation 33}$$

Rearranging Equation 33 to isolate U_e, the resulting equation is

$$U_e=\mu-\beta\, ln\left(-\,ln(1-\frac{1}{N})\right) \qquad \textit{Equation 34}$$

Using this equation, the extreme wind speed and extreme gust based on specific recurrence intervals can be determined.

The annual equivalent 10-minute maximum dataset and annual simulated 3-second maximum dataset are used to create the distribution with the above equations. From the annual 10-minute equivalent maximum wind speed and 3-second equivalent maximum gust speed datasets, the mean and standard deviation are determined for each. These means and standard deviations are incorporated into the Gumbel distribution (Equation 30, Equation 31, Equation 34) to determine the extreme wind speeds with a 50-year and 1-year recurrence period. For the 10-minute 50-year extreme, $\overline{U_e}$ is the average of the annual maximum 10-minute equivalent wind speed dataset, σ_e is the standard deviation of the annual maximum 10-minute equivalent wind speed dataset, and N is 50 years. For the 3-second gust 50-year extreme, $\overline{U_e}$ is the average of the annual maximum 3-second equivalent gust, σ_e is the standard deviation of annual maximum 3-second equivalent gust dataset, and N is 50 years.

For additional information and validation, see One Energy white paper "*Determining Extreme Wind Speed for Suitability*" [12].

In WRA Section 7B – Extreme Winds, the following are specified:

1) **Data sets and Site Dataset height level used for gust**
2) **50-year recurrence extreme 10-minute sustained wind speed**
3) **50-year recurrence extreme 3-second gust wind speed**
4) **1-year recurrence extreme 10-minute sustained wind speed**
5) **1-year recurrence extreme 3-second gust wind speed**

C. ANNUAL WIND SPEED VARIATION

The Site MCP Dataset is used to calculate the annual wind speed variation. The yearly average wind speeds and overall long-term average wind speed are found. Each yearly average is compared to the long-term average by taking the difference and dividing by the long-term average to determine the percentage variation.

In WRA Section 7C – Annual Wind Speed Variation, the following are specified:

1. **Data set used**
2. **Variation from the long-term average by year**

D. WIND SHEAR

Wind shear is the change of wind speed with relation to height. The unitless wind shear parameter (α) is useful to describe how the wind speed changes vertically when using the wind profile law (Equation 5).

Large values of the wind shear parameter indicate large vertical changes in wind speed, whereas small values of the wind shear parameter indicate a smaller vertical change in wind speed.

Using the Site Dataset, a time series of shear parameters are calculated as indicated in Section 5B(2): Extrapolation to Hub Height. If the Site Dataset is a MET, then the average of all variations of the levels are used and only a single time series of shear parameter values are determined. If the Site Dataset is a LiDAR, two shear parameter time series datasets are created using the previously described method: 1) from the measurement level closest to minimum tip height to hub height, and 2) from the measurement level closest to minimum tip height to the measurement level closest to maximum tip height.

For all shear parameter time series, distributions are created within specific hub height wind speed bins. The shear parameters are binned into 5 m/s increments. For the wind speed bins of 5-10 m/s, 10-15 m/s, and 15+ m/s, the P1, P10, and P50 shear parameter value as well as the bin count for each interval are presented.

The overall average shear parameter value is calculated by considering all data points above cut-in wind speed. From those datapoints, a distribution of the shear parameter is created and the P50 shear parameter is determined to be the median value of the filtered shear dataset.

If less than one year of data is used within the WRA but the dataset has passed the Binning Method (Section 5B(1): Binning During Data Campaigns), see One Energy white paper "*Short-term Data Campaign Formation*" for validation and associated directional shear uncertainty.

In WRA Section 7D – Wind Shear, the following are specified:

1) **Dataset(s) used**
2) **Wind shear parameter at P1, P10, and P50 and bin count for three wind speed intervals and over all wind speeds above cut-in, if using MET tower**
3) **Wind shear parameter at P1, P10, and P50 and bin count from minimum tip height to hub height for three wind speed intervals and overall wind speeds above cut-in, if a LiDAR deployment was conducted**
4) **Wind shear parameter at P1, P10, and P50 and bin count from minimum tip height to maximum tip height for three wind speed intervals and over all wind speeds above cut-in, if a LiDAR deployment was conducted**
5) **Directional wind shear table with wind shear parameter values binned by hub height wind speed in 2 m/s increments and 30° wind direction sectors**

E. TURBULENCE INTENSITY

The turbulence intensity (TI) of the wind quantifies the steadiness of wind and is necessary for wind turbine structural design. The METs typically record the standard deviation of the wind speed at each recording level. If a LiDAR is deployed, both the MET and the LiDAR data can be used to calculate the turbulence intensity for comparison of on-site data. Using the 10-minute standard deviation data and the 10-minute wind speed data, TI can be calculated at each data point. For MET data, the level closest to, but not above, hub height is used for the standard deviation in the TI calculations along with the extrapolated hub height wind speeds at each timestamp. For the LiDAR data, the hub height wind speed and standard deviations are used to calculate the TI at each timestamp. TI at each timestamp is then averaged over the dataset, resulting in the average TI. The TI at each timestamp is calculated using the formula:

$$\mathrm{TI} = \sigma/\mathrm{v},$$

Equation 35

where v is the wind speed and σ is the mean standard deviation at a specified height. TI values tend to be higher with slower wind speeds at lower heights. This is directly related to the amount of surface friction.

If less than one year of data is used within the WRA but the dataset has passed the Binning Method (Section 5B(1): Binning During Data Campaigns), see One Energy white paper *"Short-term Data Campaign Formation"* for validation and associated TI by wind speed uncertainty.

To see how the TI varies by wind speed and direction, the 10-minute wind speed extrapolated to hub height and the wind speed standard deviation measured at the height closest to, but not above, hub height are also binned by wind speed and wind direction. The wind speed bin size is 1 m/s and the bins are centered. The wind direction bin size is 22.5° and the bins are centered on cardinal directions. For each wind speed and wind direction bin, average wind speed, average wind speed standard deviation, standard deviation of the wind speed standard deviation, 90th percentile wind speed standard deviation, and data count are determined. The directional averages are then combined and weighted by data count to find the TI, standard deviation of the TI, and 90th percentile of the TI as a function of wind speed.

Representative TI & Characteristic TI

The TI is presented along with IEC classes A, B, and C representative TI from the 2005 IEC-64100-1 [1] standards. For each 1 m/s bin, the characteristic TI and the representative TI are also calculated. The characteristic TI is the TI plus one standard deviation. The representative TI is the 90th percentile of the TI distribution within that wind speed bin. These two TI values are typically calculated within the industry by:

$$\mathrm{TI}_{char} = \overline{\mathrm{TI}} + \sigma_{\mathrm{TI}}$$

Equation 36

$$\mathrm{TI}_{rep} = \overline{\mathrm{TI}} + 1.28\ \sigma_{\mathrm{TI}}$$

Equation 37

where TI_{char} is the characteristic TI, TI_{rep} is the representative TI, $\overline{TI}$ is the average TI, and σ_{TI} is the standard deviation of the TI.

When calculating representative TI, One Energy uses the actual wind speed standard deviation distribution to determine the 90th percentile as opposed to using Equation 37, which by definition assumes a normal distribution. For the remaining subsections, the variable T_{arep} will be used to indicate when actual data was used to calculate the representative TI, whereas T_{rep} indicates the empirical method of calculating representative TI with Equation 37.

Figure 10 shows the IEC class A, B, and C representative TI from the 2005 IEC standards.

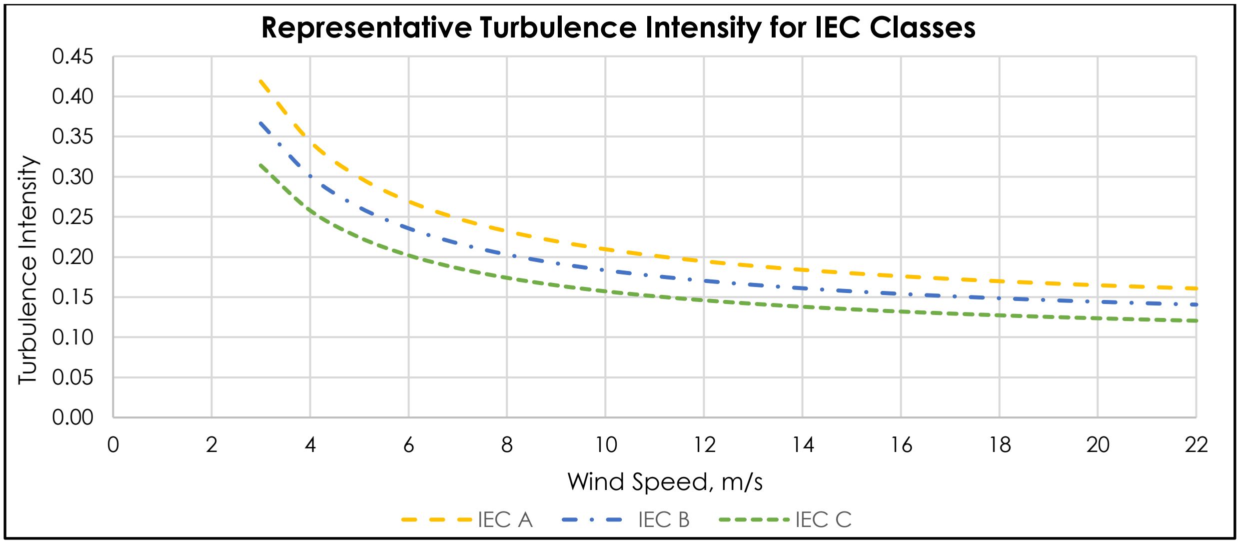


Figure 10: Representative Turbulence Intensity for IEC Classes

Effective TI

The effective TI takes the wakes of neighboring turbines into consideration to account for the additional TI and is a combination of the representative TI and the wake-induced TI. The effective TI is determined for each turbine within the project. The equation to calculate the effective TI is defined in the IEC 61400-1 standard as

$$\mathrm{TI}_{\mathrm{eff,k}} = \left(\left(1 - \mathrm{N}\mathrm{p}_{w,avg}\right)\mathrm{TI}_{arep}^{\mathrm{m}} + \sum_{\mathrm{i}=1}^{N} \left(\mathrm{p}_{w,k,i}\mathrm{TI}_{wake}^{\mathrm{m}}\right) \right)^{1/\mathrm{m}} \qquad \textit{Equation 38}$$

where TI_{arep} is the representative TI, $p_{w,avg}$ is the average probability of wake for all turbines, p_{wki} is the probability of wake at turbine i in directional sector k, N is number of neighboring turbines, m is the Wohler exponent, k is the directional sector, and TI_{wake} is the wake-induced TI.

The wake-induced TI is defined as

$$\mathrm{TI}_{wake} = \sqrt{\frac{1}{\left(1.5 + \frac{0.8\mathrm{d}}{\sqrt{\mathrm{C_T}}}\right)^2} + \mathrm{TI}_{arep}^2} \qquad \textit{Equation 39}$$

where d is the distance to the turbine (in rotor diameters), and C_T is the thrust coefficient.

Within Equation 38, it is assumed that the probability of wake (p_w) is the same for all neighboring turbines. In One Energy's method, the probability of wake for each neighboring turbine in relation to the turbine being investigated is calculated separately (Equation 44). This slightly adjusts the equation for calculating effective TI by directional sector, as shown by

$$\mathrm{TI}_{\mathrm{eff,k}} = \left(\left(1 - \sum_{i=1}^{N} \mathrm{p}_{w,k,i}\right)\mathrm{TI}_{arep}^{\mathrm{m}} + \sum_{\mathrm{i}=1}^{N} \left(\mathrm{p}_{w,k,i}\mathrm{TI}_{wake}^{\mathrm{m}}\right) \right)^{1/\mathrm{m}} \qquad \textit{Equation 40}$$

Using the 10-minute MET data, the wind speed and wind speed standard deviation data are binned by wind speed and wind direction. The bin sizes are 1 m/s and 22.5°, respectively. Within each bin, the average wind speed and the standard deviation that corresponds to the 90th percentile are determined. With these values for each bin, the representative TI is calculated by

$$\mathrm{TI}_{arep,\mathrm{x,y}} = \frac{\sigma_{90,\mathrm{x,y}}}{\overline{\mathrm{v}_{\mathrm{x,y}}}} \qquad \textit{Equation 41}$$

where $\sigma_{90,x,y}$ is the 90th percentile standard deviation of bin with wind speed x and wind direction y, and $\overline{v_{x,y}}$ is the average wind speed in the bin with wind speed x and wind direction y.

For each turbine in each 22.5° wind direction sector, a probability of wake value is calculated. The distance from the turbine to each of the neighboring turbines is calculated and the angle in relation to the turbine is obtained for each of the neighboring turbines. With that directional angle, the sector in which wake will affect the turbine is determined by

$$\mathrm{E}_1 = \theta - tan^{-1}\left(\frac{\mathrm{r}}{2\mathrm{b}}\right) \qquad \textit{Equation 42}$$

$$\mathrm{E}_2 = \theta + tan^{-1}\left(\frac{\mathrm{r}}{2\mathrm{b}}\right) \qquad \textit{Equation 43}$$

where E_1 is the minimum angle of the waked sector, E_2 is the maximum angle of the waked sector, θ is the directional angle in relation to the turbine and the neighbor turbine, r is the rotor diameter in meters, and b is the distance between the turbine and the neighboring turbine in meters.

For each wind direction sector and each turbine, it is determined if the waked sector falls within the bounds of the directional sector. If the waked sector lies within the directional sector, the percentage of the directional sector affected by the waked sector is determined by the ratio:

$$\mathrm{p}_{\mathrm{w,k}} = \frac{min(\mathrm{s}_2, \mathrm{E}_2) - max\,(\mathrm{s}_1, \mathrm{E}_1)}{\varphi} \qquad \textit{Equation 44}$$

where $p_{w,k}$ is the probability of wake in direction sector k, s_2 is the directional sector maximum angle, E_2 is the maximum angle of the waked sector, s_1 is the directional sector minimum angle, E_1 is the minimum angle of the directional sector, and φ is the angle size of the directional sector (22.5°). Each turbine has its own probability of wake array dependent on wind direction.

For each wind direction sector and each wind speed bin, the representative TI and the wake-induced TI (Equation 39) are found and are combined to calculate the effective TI (Equation 38). These variables are calculated regardless of the data count within each bin. The overall effective TI, as a function of wind speed, is found by weighting the directional effective TI by the directional distribution. This is done by:

$$\mathrm{TI}_{\mathrm{eff,overall}}(\mathrm{v}) = \frac{\sum_{\mathrm{k}=1}^{\mathrm{c}} \mathrm{TI}_{\mathrm{eff,k}}\omega_{\mathrm{k}}}{\sum_{\mathrm{k}=1}^{\mathrm{c}} \omega_{\mathrm{k}}} \qquad \textit{Equation 45}$$

where k is the directional sector, c is the total number of directional sectors, $\mathrm{TI}_{\mathrm{eff,k}}$ is the effective TI in directional sector k, and ω_k is the wind direction distribution data bin count in directional sector k for wind speed v.

One Energy assesses the effective TI with both Wohler exponent m=1 and m=10 to be in line with the industry standard.

Terrain-Adjusted TI

The terrain complexity of a site can affect the wind flow characteristics and turbulence intensity. Depending on the level of complexity, the turbulence intensity can be altered. IEC 61400-1:11.2.2 [1] defines a turbulence structure correction parameter, C_{CT}, to apply to and create the terrain-adjusted TI.

The correction parameter used to create the Terrain-Adjusted TI is dependent on the site terrain complexity and its category (see Section 2B: Terrain Complexity). Table 7 from IEC is used to find the adjustment factor.

	NON-COMPLEX TERRAIN	COMPLEX TERRAIN - CATEGORY		
		L	M	H
C_{CT}	1.00	1.05	1.10	1.15

Table 7: IEC Values of Turbulence Structure Correction Parameter [1]

For each wind speed and wind direction bin, the 90th percentile wind speed standard deviation is found. This 90th percentile standard deviation is then multiplied by the C_{CT}. Using this new terrain-adjusted 90th percentile standard deviation, the Terrain-Adjusted Representative TI is calculated by dividing each by its respective average wind speed.

To obtain the Terrain-Adjusted Effective TI, the same method is used as explained in the previous Effective TI section, except the Terrain-Adjusted Representative TI is used instead of the Representative TI within the calculations.

In WRA Section 7E – Turbulence Intensity, the following are specified:

1) **Data set(s) used**
2) **Average TI (using all wind speeds and all directions)**
3) **TI at hub height and 15 m/s (all directions)**
4) **Table including:**
    a. **IEC class A, B, C representative TIs by wind speed**
    b. **Site TI by wind speed**
    c. **Standard deviation of TI by wind speed**
    d. **Characteristic TI by wind speed**
    e. **Representative TI by wind speed**
    f. **Effective TI by wind speed for both Wohler coefficients of m=1 and m=10**
5) **Figure representing:**
    a. **IEC class A, B, C representative TIs by wind speed**
    b. **Site TI by wind speed**
    c. **Characteristic TI by wind speed**
    d. **Representative TI by wind speed**
6) **Figure representing:**
    a. **Effective TI by wind speed with Wohler coefficient m=1**
    b. **Effective TI by wind speed with Wohler coefficient m=10**
7) **Figure representing:**
    a. **IEC class A,B,C representative TIs by wind speed**
    b. **Terrain-adjusted Effective TI by wind speed with Wohler coefficient m=1**

c. **Terrain-adjusted Effective TI by wind speed with Wohler coefficient m=10**
d. **Terrain-adjusted Representative TI by wind speed**

F. WIND ROSE

The wind distribution is found using the Site MCP Dataset. The wind direction for the Site MCP Dataset is the same as the reanalysis data. The wind rose is calculated by counting the number of occurrences the wind direction fell within a 10° window. These 10° sectors are center binned (ie, for the 90° sector, the direction range is from 85° to 95°). The direction the wind is coming from for the highest percentage of the year is called the prevailing wind direction. It is good practice to avoid siting a wind turbine downwind of an obstacle in the prevailing wind direction. Figure 11 shows an example of a wind rose with the circles representing the percentage of the wind speed from any given direction (0-360°). Note that 0° is north, 90° is east, 180° is south, and 270° is west.

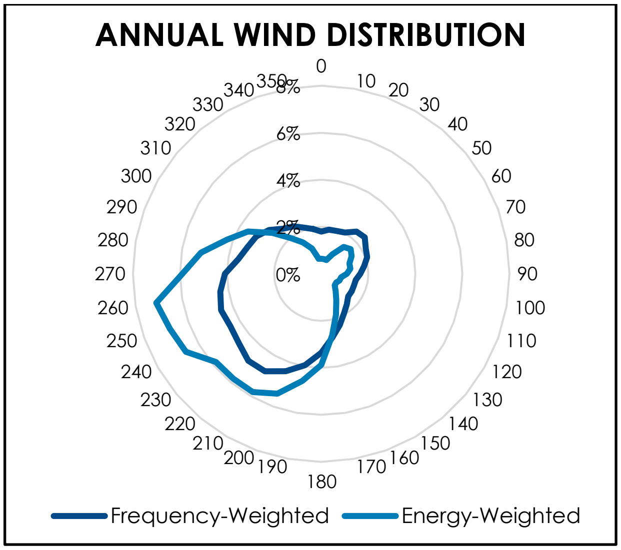


Figure 11: Example Wind Rose

Annual & Monthly

The annual and monthly wind rose distributions are calculated from the Site MCP Dataset. For the annual wind rose, the data that is included within the distribution is from the average full year. For the monthly wind roses, the data that is included within the distribution is from the average specified month. Twelve monthly wind roses are created.

Energy Weighted

The annual and monthly energy-weighted wind rose distributions are calculated from the Site MCP Dataset. To calculate an energy-weighted wind rose, the wind speed at each timestamp is converted to power to create a timeseries power dataset using the following equation:

$$P_i = \frac{1}{2}\rho A v_i^3 \qquad \text{Equation 46}$$

where ρ is assumed sea level air density 1.225 kg/m^3, A is the rotor swept area in m, v is the wind speed in m/s, P is the power output, and i is the timestamp.

From the timeseries power dataset created, a timeseries energy dataset can be created dependent on the time resolution. Then, the energy is summed by direction sector bin. The summed energy production by wind direction sector is then divided by the total energy production from within the time series dataset. This will produce a percentage of the energy generated by wind direction sector and when summed across all direction sectors should equal to 1.

The energy-weighted wind rose is calculated annually, as well as monthly. The process is the same for creating the monthly energy-weighted distributions, though an additional check is made to only include data from the time series energy dataset that is within the specified month for both the sums and total energy production.

In WRA Section 7F – Wind Rose, the following are specified:

1. **Plot of the annual wind rose, both frequency- and energy-weighted, with all wind speeds**
2. **Twelve plots of the monthly wind rose, both frequency- and energy-weighted on the same figure for each month**

G. INFLOW ANGLE

The terrain surrounding each turbine is examined to determine inflow angles. It is always assumed that terrain will be used for these calculations (IEC 61400-1:11.2 [1]) as opposed to using measured vertical speeds.

For each 30° directional sector, the terrain slope, θ_i, is determined within a radial distance of $5z_{hub}$ upwind from the turbine position by fitting a plane to the existing elevation data within the directional sector (see Section 2B: Terrain Complexity). This slope is assumed to be equal to the flow inclination for the sector. A negative slope indicates the turbine position to be lower than the radial distance of $5z_{hub}$, whereas a positive slope indicates the turbine position to be higher than the radial distance of $5z_{hub}$. The set of twelve terrain slopes is then averaged by both an energy-weighting and a frequency-weighting to obtain a single energy-weighted slope value and a single frequency-weighted slope value. The same energy and frequency weighting distributions are used as within Section 7F: Wind Rose. This process is repeated for each wind turbine within the project.

In WRA Section 7G – Inflow Angle, the following are specified:

1. **Table that includes the following by individual wind turbine:**
    a. **Slope by directional sector**
    b. **Energy-weighted inflow angle**
    c. **Frequency-weighted inflow angle**
    d. **Maximum absolute value inflow angle and the directional sector in which it occurs**
    e. **Minimum absolute value inflow angle and the directional sector in which it occurs**

8. GROSS ANNUAL ENERGY PRODUCTION

The Gross AEP estimate is calculated by summing a long-term energy time series from the Site MCP dataset (Method 1 or 2) or is output by Continuum (Method 3). For Methods 1 & 2, a long-term energy time series is created by applying the power curve to the wind speed at the timestamp. This energy time series is summed annually and an average year is assumed. Using long-term MCP datasets introduces long-term averaging to our Gross AEP estimate and accounts for the uncertainty associated with annual wind variability. Figure 12 shows a power curve of a GW 87/1500 turbine and an example Gross AEP distribution.

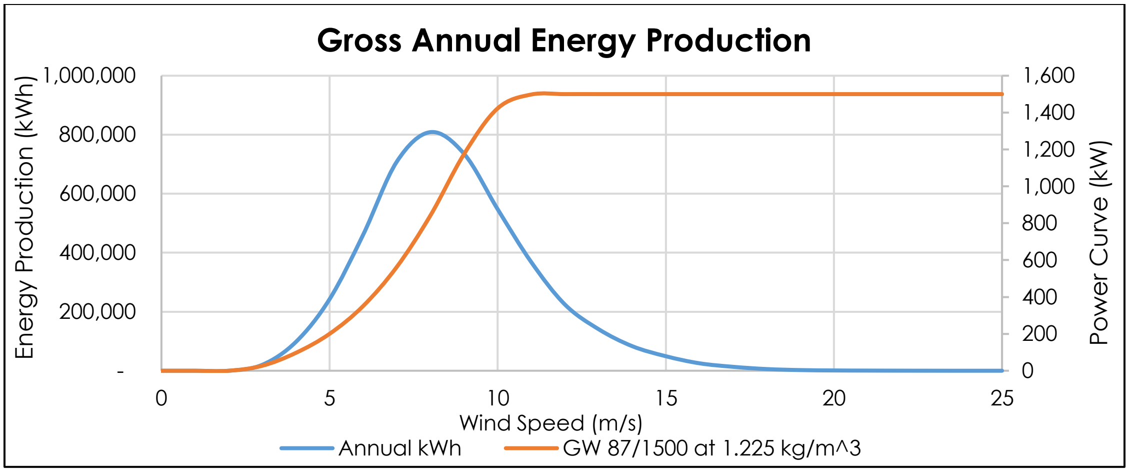


Figure 12: Example Site Gross AEP

From the Gross AEP estimate, the capacity factor of the specific site can be calculated where

$$Gross\ Capacity\ Factor = \frac{Gross\ AEP}{Turbine\ Rating * Hours\ in\ a\ Year} * 100\% \qquad \text{Equation 47}$$

The Gross capacity factor is the ratio of the Gross AEP to the theoretical energy production of the turbine if it were to run at its rated capacity for the entire year. The Gross AEP and capacity factor can be calculated for more than one wind turbine model (as long as the turbine power curve is available) as well as for multiple turbines.

When using Method 3 for energy production modeling, Continuum does not provide the monthly Gross AEP values. To generate the monthly Gross production values, the Site MCP Dataset is used to create a monthly energy production distribution. This distribution is then converted to percentage ratios and applied to the Gross AEP for each month to create the monthly Gross production values.

In WRA Section 8 – Gross Annual Energy Production, the following is specified:

1) **Gross monthly energy production by turbine and project total, rounded to the nearest thousand**
2) **Gross AEP by turbine and project total, rounded to the nearest thousand**
3) **Gross Capacity Factor by turbine and project total**

9. WAKE MODELING AND NET ANNUAL ENERGY PRODUCTION

A. WAKE LOSS MODEL

Wind turbines create a wake which can affect the energy production of downstream wind turbines. One Energy's proprietary software, TAILS 3.0, is used for wake modeling to maximize the Net AEP within the constraints of the location. Potential wake loss is based on the Gross AEP. The software uses the generally accepted Jensen Model [13] for wake characterization which assumes a linearly expanding wake that is only dependent on distance behind the rotor. Figure 13 shows the wake from a turbine with rotor diameter D modeled with the Jensen Model.

For unique projects, such as large projects with many rows, One Energy may use the Eddy Viscosity Wake Loss Model or Deep-Array Wake Model, which are also widely accepted within the industry. If the Eddy Viscosity Model is used, appropriate documentation on the method will be provided.

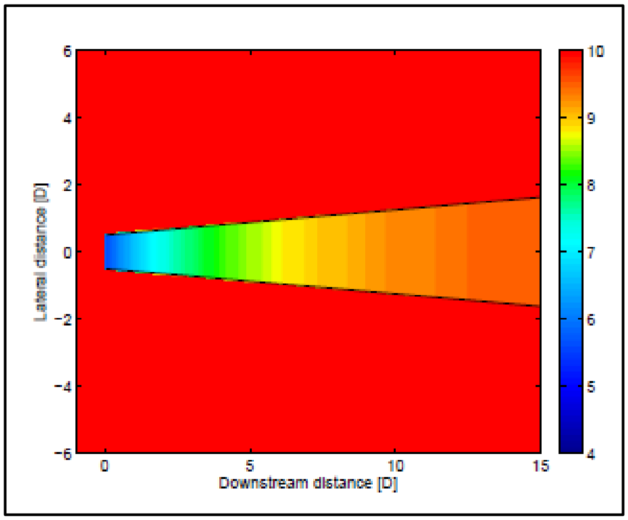


Figure 13: Jensen Model

The wake diameter is defined in the Jensen Model as:

$$D_w = D(1 + 2ks) \qquad \textit{Equation 48}$$

where k is the wake decay constant and s=x/D. The wind speed, U, in the wake a distance, D_d, downwind of the rotor is defined as:

$$U = U_0(1 - (1 - \sqrt{1 - C_t})\left(\left(\frac{1}{1 + 2kD_d}\right)^2\right) \qquad \textit{Equation 49}$$

where U_0 is the average wind speed in front of the rotor, C_t is the turbine thrust coefficient, and D_d is the distance downstream of the turbine as a function of the rotor diameter.

One Energy's TAILS 3.0 software uses wind speed and direction information from MET data files to estimate the Net AEP for different turbine layouts at a site. By moving the turbine locations around within siting constraints, the optimum energy production for the project can be achieved. Turbine locations must be optimized based on distance between the turbines and turbine orientation relative to the prevailing wind direction. According to the Jensen Model, at 15D (15 times the rotor diameter) the wind speeds should reach 98% of their initial speed. All known turbines and known proposed turbines within 15D are accounted for within the wake loss model.

The parameters of the TAILS 3.0 software include: number of wind turbines, turbine height, turbine elevation, rotor diameter, wake decay constant, turbine thrust coefficient, turbine power curve, and wind direction and wind speed distribution (called the wind resource matrix). Each of these parameters can be adjusted by the software user based on the specific site details. The typical wake decay constant is set to 0.075, whereas all additional parameters are project and turbine specific.

Wind resource matrices are derived from the Site MCP Dataset and are saved in the program. In each wind resource matrix, the 10-minute wind speed averages are binned from 0-25 m/s in 0.5 m/s intervals, and 0-

360° in 1° intervals and represented as a percentage of time throughout a long-term standard specified-month.

The Site MCP Dataset may then be used to create a wind resource matrix for each month of each year and used with the TAILS software to calculate the wake loss at the proposed site for each month. Each wind resource matrix will be the long-term average of a specified month (e.g., a 30-year MCP dataset would allow for 30 unique months of January, which are then averaged to obtain the long-term average January wind resource matrix), for a total of 12 wind resource matrices. Following the calculation of the average monthly wake loss value, the standard monthly wake loss percentages are applied to the monthly Gross AEP values to obtain the monthly Net AEP production values. The annual average wake loss is then calculated by summing the total energy lose due to wake effects and dividing by the associated Gross AEP.

Based on the parameters, the software calculates the distances and angles of the turbines relative to one another. These angles and distances are then factored into the chosen wind resource matrix. The software determines which wind directions will create wake effects on downstream turbines. The distances between the turbines then determines by how much the wind speed will be decreased.

The software steps through every element of the 2D matrix that represents the wind resource (direction x speed) and then calculates the loss each turbine experiences from every other turbine. Finally, the net production from each turbine is determined after its wind resource has been fully degraded by all other turbines. The wake effects from multiple turbines are calculated independently. Wake effects are assumed to be independent and a more complex cumulative interaction is not considered. The total number of computations is equal to 50 speed steps multiplied by 360 angular steps, multiplied by the number of turbines plus 1 factorial. A 5-turbine site goes through the equivalent of more than 12 million calculations to complete the 18,000 steps through the wind resource matrix per month.

The resulting data represents post-loss production by turbine and is presented as a wind rose that shows the energy production of each turbine as a function of wind direction (0-360° in 1° intervals). The final wake loss is shown as an energy production percent loss from a baseline instead of by a straight kWh lost per turbine. This percentage of energy production loss is turbine specific.

B. NET ANNUAL ENERGY PRODUCTION

The Net AEP is defined at One Energy as the Gross AEP with wake losses applied.

$$Net\ AEP = Gross\ AEP - Wake\ Loss \qquad \text{Equation 50}$$

The percentage of energy production loss by turbine calculated from the wake loss model is applied to the Gross AEP by turbine. This Net AEP value for each turbine is carried through to the Project Performance Report and is used as the baseline before any Performance Factors are applied to ultimately end at a P50 AEP value.

In WRA Section 9 – Wake Modeling and Net Energy Production, the following is specified:

1) **Monthly production loss percentage per turbine and per project**
2) **Net AEP values per turbine and per project**
3) **Monthly Net Energy Production values**
4) **Net Capacity Factor per turbine and per project**

5) **Figure representing the energy production in relation to wind direction which shows the wind directions where wake loss is predominant**

Net Annual Energy Production 12x24

Similar to a Wind Speed 12x24 (see Section 7A(3): Wind Speed 12x24), the Net Annual Energy Production 12x24 shows the diurnal and seasonal average trends. The Net Energy Production 12x24 shows the average waked energy production for each hour throughout each month.

The Site MCP dataset is used for this analysis. The wind speed at each hourly interval is converted into an energy production dataset by applying the project-specific power curve. From this long-term hourly production dataset, the data is binned into a 2D array by hour of day and month. The average production is then taken for each bin to create a Gross Annual Energy Production 12x24. From this Gross Energy Production 12x24, the average monthly wake loss percentage is applied to all hours within the specified month to create the Net Energy Production 12x24.

In WRA Section 9 – Wake Modeling and Net Annual Energy Production, the following is specified:

1) **A 12x24 table of the Net Annual Energy Production, conditionally formatted**

10. PROSPECTING WIND ASSESSMENT

During the Prospecting (Initial Evaluation) stage of project development, a Preliminary Site Wind Assessment is conducted. This preliminary resource assessment uses portions of the Project Due Diligence Wind Resource Assessment methods. To not confuse energy production terms from the Prospecting phase and the Project Due Diligence phase, new terminology is used. The Baseline Annual Energy Production is similar to the Gross AEP, as discussed in Section 8: Gross AEP, where it is the pure wind resource without any losses applied.

To calculate the Baseline AEP, a Site MCP Dataset is used in the same way as with the Gross AEP to create an average annual energy production. The Baseline AEP shown in the Initial Evaluation will typically not be the Gross AEP within The Project Due Diligence Package due to incomplete data campaigns during the Prospecting phase.

Once the Baseline AEP is determined, wake losses (Section 9A: Wake Loss Model) are calculated with the Preliminary Siting (see Project Siting methodology) and applied. This is the Baseline AEP with wake loss value. From this Baseline AEP with wake loss, an average P50 Scale Factor is applied to determine the Anticipated AEP (see PPR methodology).

11. CONCLUSIONS

One Energy conducts a WRA that is necessary for turbine siting, turbine suitability, and for financial models. In the WRA, the following are included: project and site information, reference wind projects, data information, wind resource assessment method, environmental conditions of the proposed site, long-term dataset creation, site conditions of the proposed site, Gross AEP, and Net AEP.

Next steps in energy production modeling include the completion of the Project Performance Report for fully-burdened P50 AEP values which takes additional losses and uncertainties into consideration.

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