



BSI Standards Publication

Wind energy generation systems

Part 12-1: Power performance measurement of
electricity producing wind turbines

National foreword

This British Standard is the UK implementation of EN 61400-12-1:2017. It is identical to IEC 61400-12-1:2017, incorporating corrigenda September 2019, March 2020 and May 2021. It supersedes BS EN 61400-12-1:2006, which is withdrawn.

The UK participation in its preparation was entrusted to Technical Committee PEL/88, Wind turbines.

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English Version

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(IEC 61400-12-1:2017)**

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Mesures de performance de puissance des éoliennes de
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European foreword

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Endorsement notice

The text of the International Standard IEC 61400-12-1:2017 was approved by CENELEC as a European Standard without any modification.

In the official version, for Bibliography, the following notes have to be added for the standards indicated:

IEC 61400-1:2005	NOTE	Harmonized as EN 61400-1:2005.
IEC 61400-1:2005/AMD1:2010	NOTE	Harmonized as EN 61400-1:2005/A1:2010.
IEC 61400-2:2013	NOTE	Harmonized as EN 61400-2:2013.
IEC 61400-12-2	NOTE	Harmonized as EN 61400-12-2.

Annex ZA

(normative)

Normative references to international publications with their corresponding European publications

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

NOTE 1 When an International Publication has been modified by common modifications, indicated by (mod), the relevant EN/HD applies.

NOTE 2 Up-to-date information on the latest versions of the European Standards listed in this annex is available here:

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<u>Publication</u>	<u>Year</u>	<u>Title</u>	<u>EN/HD</u>	<u>Year</u>
IEC 60688	2012	Electrical measuring transducers for converting A.C. and D.C. electrical quantities to analogue or digital signals	EN 60688	2013
IEC 61400-12-2	2013	Wind turbines -- Part 12-2: Power performance of electricity producing wind turbines based on nacelle anemometry	EN 61400-12-2	2013
IEC 61869-1 (mod)	2007	Instrument transformers -- Part 1: General requirements	EN 61869-1	2009
IEC 61869-2	2012	Instrument transformers -- Part 2: Additional requirements for current transformers	EN 61869-2	2012
IEC 61869-3	2011	Instrument transformers -- Part 3: Additional requirements for inductive voltage transformers	EN 61869-3	2011
ISO 2533	1975	Standard Atmosphere	-	-
ISO 3966	2008	Measurement of fluid flow in closed conduits -- Velocity area method using Pitot static tubes	-	-
ISO/IEC 17025	2005	General requirements for the competence of testing and calibration laboratories	EN ISO/IEC 17025	2005
ISO/IEC 17043	2010	Conformity assessment - General requirements for proficiency testing	EN ISO/IEC 17043	2010
ISO/IEC Guide 98-3	2008	Uncertainty of measurement - Part 3: Guide to the expression of uncertainty in measurement (GUM:1995)	-	-

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

WIND ENERGY GENERATION SYSTEMS –**Part 12-1: Power performance measurements
of electricity producing wind turbines****FOREWORD**

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International Standard IEC 61400-12-1 has been prepared by IEC technical committee 88: Wind energy generation systems.

This second edition cancels and replaces the first edition published in 2005. This edition constitutes a technical revision. This edition includes the following significant technical changes with respect to the previous edition:

- a) new definition of wind speed,
- b) inclusion of wind shear and wind veer,
- c) revision of air density correction,
- d) revision of site calibration,
- e) revision to definition of power curve,
- f) interpolation to bin centre method,
- g) revision of obstacle model,

- h) clarification of topography requirements,
- i) new annex on mast induced flow distortion,
- j) revision to anemometer classifications,
- k) inclusion of ultrasonic anemometers,
- l) cold climate annex added,
- m) database A changed to special database,
- n) revision of uncertainty annex,
- o) inclusion of remote sensing.

IEC 61400-12-2 is an addition to IEC 61400-12-1.

The text of this standard is based on the following documents:

FDIS	Report on voting
88/610/FDIS	88/617/RVD

Full information on the voting for the approval of this standard can be found in the report on voting indicated in the above table.

A list of all parts in the IEC 61400, published under the general title *Wind energy generation systems*, can be found on the IEC website.

Future standards in this series will carry the new general title as cited above. Titles of existing standards in this series will be updated at the time of the next edition.

This publication has been drafted in accordance with the ISO/IEC Directives, Part 2.

The committee recognizes that this revision represents a significant increase in complexity and perhaps greater difficulty to implement. However, it represents the committee's best attempt to address issues introduced by larger wind turbines operating in significant wind shear and complex terrain. The committee recommends that the new techniques introduced be validated immediately by test laboratories through inter-lab proficiency testing. The committee recommends a Review Report be written within three years of the release of this document which includes recommendations, clarifications and simplifications that will improve the practical implementation of this standard. If necessary a revision should be proposed at the same time to incorporate these recommendations, clarifications and simplifications.

The committee has decided that the contents of this publication will remain unchanged until the stability date indicated on the IEC website under "<http://webstore.iec.ch>" in the data related to the specific publication. At this date, the publication will be

- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

The contents of the corrigenda 1 (2019), 2 (2020) and 3 (2021) have been included in this copy.

IMPORTANT – The 'colour inside' logo on the cover page of this publication indicates that it contains colours which are considered to be useful for the correct understanding of its contents. Users should therefore print this document using a colour printer.

INTRODUCTION

The purpose of this part of IEC 61400 is to provide a uniform methodology that will ensure consistency, accuracy and reproducibility in the measurement and analysis of power performance by wind turbines. The standard has been prepared with the anticipation that it would be applied by:

- a) a wind turbine manufacturer striving to meet well-defined power performance requirements and/or a possible declaration system;
- b) a wind turbine purchaser in specifying such performance requirements;
- c) a wind turbine operator who may be required to verify that stated, or required, power performance specifications are met for new or refurbished units;
- d) a wind turbine planner or regulator who shall be able to accurately and fairly define power performance characteristics of wind turbines in response to regulations or permit requirements for new or modified installations.

This document provides guidance in the measurement, analysis, and reporting of power performance testing for wind turbines. The document will benefit those parties involved in the manufacture, installation planning and permitting, operation, utilization, and regulation of wind turbines. The technically accurate measurement and analysis techniques recommended in this standard should be applied by all parties to ensure that continuing development and operation of wind turbines is carried out in an atmosphere of consistent and accurate communication relative to wind turbine performance. This document presents measurement and reporting procedures expected to provide accurate results that can be replicated by others. Meanwhile, a user of the standard should be aware of differences that arise from large variations in wind shear and turbulence. Therefore, a user should consider the influence of these differences and the data selection criteria in relation to the purpose of the test before contracting the power performance measurements.

A key element of power performance testing is the measurement of wind speed. This document prescribes the use of cup or sonic anemometers or remote sensing devices (RSD) in conjunction with anemometers to measure wind. Even though suitable procedures for calibration/validation and classification are adhered to, the nature of the measurement principle of these devices may potentially cause them to perform differently. These instruments are robust and have been regarded as suitable for this kind of test with the limitation of some of them to certain classes of terrain.

Recognising that, as wind turbines become ever larger, a wind speed measured at a single height is increasingly unlikely to accurately represent the wind speed through the entire turbine rotor, this standard introduces an additional definition of wind speed. Whereas previously wind speed was defined as that measured at hub height only, this may now be supplemented with a so called Rotor Equivalent Wind Speed (REWS) defined by an arithmetic combination of simultaneous measurements of wind speed at a number of heights spanning the complete rotor diameter between lower tip and upper tip. The power curves defined by hub height wind speed and REWS are not the same and so the hub height wind speed power curve is always presented for comparison whenever a REWS power curve is measured. As a consequence of this difference in wind speed definition, the annual energy production (AEP) derived from the combination of a measured power curve with a wind speed distribution uses an identical definition of wind speed in both the power curve and the wind speed distribution.

Procedures to classify cup anemometers and ultrasonic anemometers are given in Annexes I and J. Procedures to classify remote sensing devices are given in Annex L. Special care should be taken in the selection of the instruments chosen to measure the wind speed because it can influence the result of the test.

WIND ENERGY GENERATION SYSTEMS –

Part 12-1: Power performance measurements of electricity producing wind turbines

1 Scope

This part of IEC 61400 specifies a procedure for measuring the power performance characteristics of a single wind turbine and applies to the testing of wind turbines of all types and sizes connected to the electrical power network. In addition, this standard describes a procedure to be used to determine the power performance characteristics of small wind turbines (as defined in IEC 61400-2) when connected to either the electric power network or a battery bank. The procedure can be used for performance evaluation of specific wind turbines at specific locations, but equally the methodology can be used to make generic comparisons between different wind turbine models or different wind turbine settings when site-specific conditions and data filtering influences are taken into account.

The wind turbine power performance characteristics are determined by the measured power curve and the estimated annual energy production (*AEP*). The measured power curve, defined as the relationship between the wind speed and the wind turbine power output, is determined by collecting simultaneous measurements of meteorological variables (including wind speed), as well as wind turbine signals (including power output) at the test site for a period that is long enough to establish a statistically significant database over a range of wind speeds and under varying wind and atmospheric conditions. The *AEP* is calculated by applying the measured power curve to reference wind speed frequency distributions, assuming 100 % availability.

This document describes a measurement methodology that requires the measured power curve and derived energy production figures to be supplemented by an assessment of uncertainty sources and their combined effects.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 60688:2012, *Electrical measuring transducers for converting A.C. and D.C. electrical quantities to analogue or digital signals*

IEC 61400-12-2:2013, *Wind turbines – Part 12-2: Power performance of electricity-producing wind turbines based on nacelle anemometry*

IEC 61869-1:2007, *Instrument transformers – Part 1: General requirements*

IEC 61869-2:2012, *Instrument transformers – Part 2: Additional requirements for current transformers*

IEC 61869-3:2011, *Instrument transformers – Part 3: Additional requirements for inductive voltage transformers*

ISO/IEC GUIDE 98-3:2008, *Uncertainty of measurement – Part 3: Guide to the expression of uncertainty in measurement (GUM:1995)*

ISO/IEC 17025:2005, *General requirements for the competence of testing and calibration laboratories*

ISO/IEC 17043:2010, *Conformity assessment – General requirements for proficiency testing*

ISO 2533:1975, *Standard atmosphere*

ISO 3966:2008, *Measurement of fluid flow in closed conduits – Velocity area method using Pitot static tubes*

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at <http://www.electropedia.org/>
- ISO Online browsing platform: available at <http://www.iso.org/obp>

3.1

accuracy

closeness of the agreement between the result of a measurement and a true value of the measurand

3.2

annual energy production

AEP

estimate of the total energy production of a wind turbine during a one-year period by applying the measured power curve to different reference wind speed frequency distributions at hub height, assuming 100 % availability

3.3

atmospheric stability

a measure of tendency of the wind to encourage or suppress vertical mixing

Note 1 to entry: Stable atmosphere is characterized by a high temperature gradient with altitude, high wind shear, possible wind veer and low turbulence relative to unstable conditions. Neutral and unstable atmosphere generally result in lower temperature gradients and low wind shear.

3.4

complex terrain

terrain surrounding the test site that features significant variations in topography and terrain obstacles (refer to 3.18) that may cause flow distortion

3.5

cut-in wind speed

the lowest wind speed at which a wind turbine will begin to produce power

3.6

cut-out wind speed

the wind speed at which a wind turbine cuts out from the grid due to high wind speed

3.7

data set

a collection of data sampled over a continuous period

3.8

distance constant

indication of the response time of an anemometer, defined as the length of air that shall pass the instrument for it to indicate 63 % of the final value for a step input in wind speed

3.9

extrapolated power curve

extension of the measured power curve by estimating power output from the maximum measured wind speed to cut-out wind speed

3.10

flow distortion

change in air flow caused by obstacles, topographical variations, or other wind turbines that results in the wind speed at the measurement location to be different from the wind speed at the wind turbine location

3.11

hub height (of wind turbines)

height of the centre of the swept area of the wind turbine rotor above the ground at the tower

Note 1 to entry: For a vertical axis wind turbine the hub height is defined as the height of the centroid of the swept area of the rotor above the ground at the tower.

3.12

measured power curve

table and graph that represents the measured, corrected and normalized net power output of a wind turbine as a function of measured wind speed, measured under a well-defined measurement procedure

3.13

measurement period

period during which a statistically significant database has been collected for the power performance test

3.14

measurement sector

a sector of wind directions from which data are selected for the measured power curve

3.15

method of bins

data reduction procedure that groups test data for a certain parameter into intervals (bins)

Note 1 to entry: For each bin, the number of data sets or samples and their sum are recorded, and the average parameter value within each bin is calculated.

3.16

net active electric power

measure of the wind turbine electric power output that is delivered to the electrical power network

3.17

normal maintenance

any intervention which is done according to a defined regular maintenance program, independent from the fact that a power performance test is being done, e.g. oil change, blade washing (if due anyway, i.e. independent from the power performance test) and any intervention which is out of the scope of the regular maintenance program (e.g. repair of a failed component) and which is not a machine configuration change

3.18**obstacles**

obstructions that block the wind and create distortion of the flow, such as buildings and trees

3.19**pitch angle**

angle between the chord line at a defined blade radial location (usually 100 % of the blade radius) and the rotor plane of rotation

3.20**power coefficient**

ratio of the net electric power output of a wind turbine to the power available in the free stream wind over the rotor swept area

3.21**power performance**

measure of the capability of a wind turbine to produce electric power and energy

3.22**rated power**

quantity of power assigned, generally by a manufacturer, for a specified operating condition of a component, device or equipment

3.23**rotor equivalent wind speed**

wind speed corresponding to the kinetic energy flux through the swept rotor area when accounting for the variation of the wind speed with height, as represented in Equation (5)

3.24**special maintenance**

any intervention which is out of the scope of the regular maintenance program and which is not a machine configuration change, i.e. any intervention which is done in order to improve the power performance during a test period, e.g. an unscheduled blade washing, any replacement of an essential component

3.25**standard uncertainty**

uncertainty of the result of a measurement expressed as a standard deviation

3.26**swept area**

for a horizontal axis wind turbine, the projected area of the moving rotor upon a plane normal to axis of rotation

Note 1 to entry: For teetering rotors, it should be assumed that the rotor remains normal to the low-speed shaft. For a vertical axis wind turbine, the projected area of the moving rotor upon a vertical plane.

3.27**test site**

location of the wind turbine under test and its surroundings

3.28**uncertainty in measurement**

parameter, associated with the result of a measurement, which characterizes the dispersion of the values that could reasonably be attributed to the measurand

3.29**wind measurement equipment**

meteorological mast or remote sensing device

3.30

wind shear

change of wind speed with height across the wind turbine rotor

3.31

wind shear exponent

exponent α of the power law defining the variation of wind speed with height

Note 1 to entry: This parameter is used as a measure of the magnitude of wind shear for site calibration in Annex C and may be otherwise useful. The power law equation is

$$v_{zi} = v_h \left(\frac{z_i}{H} \right)^\alpha \quad (1)$$

where

v_h is the hub height wind speed;

H is the hub height (m);

v_{zi} is the wind speed at height z_i ;

α is the wind shear exponent.

3.32

wind veer

change of wind direction with height across the wind turbine rotor

4 Symbols and units

A	swept area of the wind turbine rotor	[m ²]
A_i	area of the i^{th} wind turbine rotor segment	[m ²]
A_w	Weibull scale factor	[m/s]
AEP	annual energy production	[Wh]
B	barometric pressure	[Pa]
$B_{10\text{min}}$	measured air pressure averaged over 10 min	[Pa]
Ch	pitot tube head coefficient	
$C_{P,i}$	power coefficient in bin i	
C_{QA}	generalized aerodynamic torque coefficient	
C_T	thrust coefficient	
c	sensitivity factor of a parameter (the partial differential)	
$c_{B,i}$	sensitivity factor of air pressure in bin i	[W/Pa]
$c_{d,i}$	sensitivity factor of data acquisition system in bin i	
c_{index}	sensitivity factor of index parameter	
$c_{k,i}$	sensitivity factor of component k in bin i	
$c_{T,i}$	sensitivity factor of air temperature in bin i	[W/K]
$c_{V,i}$	sensitivity factor of wind speed in bin i	[Ws/m]
$c_{\rho,i}$	sensitivity factor of air density correction in bin i	[Wm ³ /kg]
D	rotor diameter	[m]
D_e	equivalent rotor diameter	[m]
D_n	rotor diameter of neighbouring and operating wind turbine	[m]
d	meteorological mast diameter	[m]
$F(V)$	the Rayleigh cumulative probability distribution function for wind speed	
f_i	the relative occurrence of wind speed in a wind speed interval	

$f_{r,MM}$	wind shear correction factor, measured using meteorological mast mounted instruments	
$f_{r,RSD}$	wind shear correction factor, measured using a remote sensing device	
H	hub height of wind turbine	[m]
h	height of obstacle	[m]
I	inertia of cup anemometer rotor	[kgm ²]
k	class number	
k	Weibull shape factor	
k_b	blockage correction factor	
k_c	wind tunnel calibration factor	
k_f	wind tunnel correction factor to other tunnels (only used in uncertainty estimate)	
k_ρ	humidity correction to density	
$K_{B,t}$	barometer sensitivity	[N/m ² V]
$K_{B,s}$	barometer gain	
$K_{B,d}$	barometer sampling conversion	
$K_{T,t}$	temperature transducer sensitivity	[K/A]
$K_{T,s}$	temperature transducer gain	[A/V]
$K_{T,d}$	temperature transducer sampling conversion	
$K_{p,t}$	pressure transducer sensitivity	
$K_{p,s}$	pressure transducer gain	
$K_{p,d}$	pressure transducer sampling conversion	
L_m	distance between adjacent legs of lattice meteorological mast	[m]
L	distance between the wind turbine and the wind measurement equipment	[m]
L_e	distance between the wind turbine or the wind measurement equipment and an obstacle	[m]
L_n	distance between the wind turbine or the wind measurement equipment and a neighbouring and operating wind turbine	[m]
l_h	height of obstacle	[m]
l_w	width of obstacle	[m]
M	number of uncertainty components in each bin	
M_A	number of category A uncertainty components	
M_B	number of category B uncertainty components	
N	number of bins	
N_h	number of hours in one year $\approx 8\,760$	[h]
N_i	number of 10 min data sets in wind speed bin i	
N_j	number of 10 min data sets in wind direction bin j	
n	number of samples within sampling interval	
n_h	number of available measurement heights	
P_o	porosity of obstacle (0: solid, 1: no obstacle)	
P_i	normalized and averaged power output in bin i	[W]
P_n	normalized power output	[W]
$P_{n,i,j}$	normalized power output of data set j in bin i	[W]
P_{10min}	measured power averaged over 10 min	[W]
P_w	vapour pressure	[Pa]
Q_A	aerodynamic torque	

Q_f	friction torque	[Nm]
R	rotor radius	[m]
R_0	gas constant of dry air (287,05)	[J/kgK]
R_d	distance to meteorological mast centre	[m]
R_w	gas constant of water vapour (461,5)	[J/kgK]
RSD	remote sensing device	
r	correlation coefficient	
s	category A standard uncertainty component	
s_A	category A standard uncertainty of tunnel wind speed time series	
$s_{k,i}$	category A standard uncertainty of component k in bin i	
s_i	combined category A uncertainties in bin i	
$s_{P,i}$	category A standard uncertainty of power in bin i	[W]
s_{SC}	category A standard uncertainty of site calibration	[m/s]
$s_{w,i}$	category A standard uncertainty of climatic variations	[Wh]
$s_{\alpha,j}$	category A standard uncertainty of wind speed ratios in bin j	
S	meteorological mast solidity	
T	absolute temperature	[K]
TI	turbulence intensity	
T_{10min}	measured absolute air temperature averaged over 10 min	[K]
t	time	[s]
U	wind speed	[m/s]
U_d	centreline wind speed deficit	[m/s]
U_{eq}	equivalent horizontal wind speed	[m/s]
U_i	wind speed in bin i	[m/s]
U_t	threshold wind speed	[m/s]
U	wind speed vector	
u	category B standard uncertainty component	
u_{AEP}	combined standard uncertainty in the estimated annual energy production	[Wh]
$u_{B,i}$	category B standard uncertainty of air pressure in bin i	[Pa]
$u_{C,i}$	combined standard uncertainty of the power in bin i	[W]
u_i	combined category B uncertainties in bin i	
u_{index}	category B standard uncertainty of index parameter	
$u_{k,i}$	category B standard uncertainty of component k in bin i	
$u_{P,i}$	category B standard uncertainty of power in bin i	[W]
$u_{V,i}$	category B standard uncertainty of wind speed in bin i	[m/s]
$u_{T,i}$	category B standard uncertainty of air temperature in bin i	[K]
$u_{\alpha,i,j}$	combined standard uncertainty of site calibration in wind speed bin i and wind direction bin j	[m/s]
$u_{\rho,i}$	category B standard uncertainty of air density correction in bin i	[kg/m ³]
V	wind speed	[m/s]
V_{ave}	annual average wind speed at hub height	[m/s]
V_i	normalized and averaged wind speed in bin i	[m/s]
V_n	normalized wind speed	[m/s]
$V_{n,i,j}$	normalized wind speed of data set j in bin i	[m/s]
V_{10min}	measured wind speed averaged over 10 min	[m/s]

v	transversal wind speed component	[m/s]
$\bar{v}$	mean flow air speed	[m/s]
v_{eq}	measured equivalent wind speed	[m/s]
$v_{eq,final}$	final rotor equivalent wind speed	[m/s]
$v_{eq,MM}$	equivalent wind speed based on meteorological mast measurements	[m/s]
$v_{eq,RSD}$	equivalent wind speed based on remote sensing device measurements	[m/s]
v_h	hub height wind speed	[m/s]
$v_{h,MM}$	wind speed measured at hub height with meteorological mast	[m/s]
v_{hn}	hub height wind speed normalised for a specific wind shear profile	[m/s]
$v_{h,RSD}$	wind speed measured at hub height by the remote sensing device	[m/s]
v_i	wind speed measured at height i	[m/s]
v_{zi}	wind speed at height z_i	[m/s]
WME	wind measurement equipment	
w	vertical wind speed component	[m/s]
w_i	weighting function to define deviation envelope	
X_k	parameter averaged over pre-processing time period	
X_{10min}	parameter averaged over 10 min	
x	distance downstream from obstacle to wind measurement equipment or wind turbine	[m]
z	height above ground	[m]
z_i	height of the i^{th} wind turbine rotor segment	[m]
α	wind shear exponent from power law	[°]
$\mathcal{E}_{max,i}$	maximum deviation for any wind speed bin i in the wind speed range	[m/s]
θ	disturbed sector	[°]
κ	von Karman constant 0,4	
λ	speed ratio	
ρ	air density	[kg/m ³]
ρ_0	reference air density	[kg/m ³]
ρ_{10min}	derived air density averaged over 10 min	[kg/m ³]
$\sigma_{P,i}$	standard deviation of the normalized power data in bin i	[W]
σ_{10min}	standard deviation of parameter averaged over 10 min	
$\sigma_u/\sigma_v/\sigma_w$	standard deviations of longitudinal/transversal/vertical wind speeds	
Φ	relative humidity (range 0 % to 100 %)	
ω	angular speed	[s ⁻¹]

5 Power performance method overview

The wind shear and wind veer may vary significantly over the rotor height of large wind turbines for atmospheric stability conditions and it is also dependent on topography at the site. The occurrence of extreme atmospheric stability conditions is a site specific issue, and if occurring during a power performance test, the power curve may vary significantly.

The power performance measurement method used in this standard is based on a definition of the power curve that expresses power produced versus the wind speed that represents effectively the kinetic energy flux in the wind flowing across the swept area of the rotor.

The kinetic energy flux (referring to a certain point in time or period of time, typically 10 min, assuming that the wind speed does not change within this time¹) across the vertical capture area is in general terms expressed as:

$$P_{\text{kin}} = \int_A \frac{1}{2} \rho V^3 dA \quad (2)$$

Here the wind speed V , measured at a point in space over the rotor area, is the horizontal wind speed². The horizontal wind speed is defined as the average magnitude of the horizontal component of the instantaneous wind velocity vector, including only the longitudinal and lateral (but not the vertical) components. When we consider a horizontal axis wind turbine the wind veer is also taken into account and the kinetic energy in the wind is corrected according to the wind direction at hub height:

$$P_{\text{kin}} = \int_A \frac{1}{2} \rho (V \cos(\varphi - \varphi_{\text{hub}}))^3 dA \quad (3)$$

Here φ_{hub} is the wind direction at hub height. The wind veer may vary significantly over the rotor height of large wind turbines for extreme atmospheric stability conditions and it is also dependent on topography at the site.

In this standard we do not consider wind shear and wind veer in the horizontal plane. Thus the energy equivalent wind speed that corresponds to the kinetic energy in the wind as derived from the expression of kinetic energy in Equation (3) in general is described as:

$$V_{\text{eq}} = \left(\frac{1}{A} \int_i (V_i \cos(\varphi_i - \varphi_{\text{hub}}))^3 dA_i \right)^{1/3} \quad (4)$$

Here the index i refers to the height within the rotor area³.

Although horizontal wind speed is considered to be the influential wind speed parameter, on sites with significant non-horizontal flow (up or down-flow), there is additional uncertainty associated with both the measurement of the horizontal wind speed and the response of the wind turbine.

At sites with low and homogeneous wind shear and wind veer over the rotor (and for turbines with small rotor diameters in possibly more complex wind flow conditions), the wind speed measured at hub height can be a good representation of the kinetic energy to be captured by the rotor. Hub height wind speed is the wind speed upon which power curves have historically been defined in all previous editions of this standard. For that reason, the wind speed measured at hub height is the default definition of wind speed and shall always be measured and reported, even when more comprehensive measurements of wind speed are available over the rotor height.

¹ If the wind speed changes (i.e. if the turbulence intensity is >0) during a certain time period, then the kinetic power (averaged over this time period) is higher than in case of a constant wind speed, whereas a wind turbine has only a limited possibility to transform this additional kinetic power into additional electric power. This issue is not taken into further consideration here. As a simplification, the Equations (2), (3), (4) are considered valid here, even in case of a turbulence intensity >0. The impact of wind speed changes on the time averaged kinetic power and the associated impact on the wind turbine power curve is treated by the turbulence normalisation procedure as included in Annex M.

² Wind turbine power seems to correlate better with the horizontal wind speed definition than with a vector wind speed definition for a one point hub height wind speed measurement.

³ However when wind speed is mentioned in the document, it is by default referring to the hub height wind speed definition unless specifically stated to be this energy equivalent wind speed definition.

At sites and seasons where extreme atmospheric stability conditions are expected to be frequent, it is recommended always to measure wind shear.

If wind shear and wind veer are not measured over the full height of the rotor, there is added uncertainty in the equivalent wind speed. This uncertainty decreases as more wind speed and wind direction measurement heights are used. If measurements are limited to only hub height and there is no measurement of wind shear over the most significant parts of the rotor then this implies an uncertainty in determination of the equivalent wind speed.

For small wind turbines⁴, where the influence of the wind shear and wind veer are insignificant, the wind speed shall be represented by a hub height wind speed measurement alone without adding uncertainty due to lack of wind shear and wind veer measurements.

For vertical axis wind turbines, where the influence of the wind veer is not present, the wind veer shall be neglected.

As the wind conditions at the position of the test turbine and at the position of the wind measurement may differ significantly if the test turbine or the wind measurement is located in wakes of any wind turbines, such situations shall be excluded from the test.

The air density ρ also varies over the height of a large wind turbine rotor. However, this variation is small. For practical implementation of the power performance measurement method, it is sufficient to define and determine the air density only at hub height. The power curve is normalized to the average air density at the measurement site over the measurement period or to a pre-defined reference air density.

Power curves are also influenced by the turbulence at the test site, and turbulence may vary over the rotor. In this standard, only the site turbulence at hub height is considered. High turbulence increases the radius of curvature of the power curve at cut-in and at the start of power regulation at nominal power while low turbulence will make these corners of the power curve sharper. Site turbulence shall be measured and presented as a supplement to the power curve. If needed, a normalisation to a specified turbulence can be done using the method of Annex M.

In summary, the power curve according to this standard is a climate specific power curve, where:

- a) the wind speed at a point in space is defined as the horizontal wind speed;
- b) the wind speed of a power curve is defined as the hub height wind speed. This definition may be supplemented with the equivalent wind speed, as defined in Equation (4), taking account of vertical wind shear and wind veer⁵;
- c) air density is measured at hub height and the power curve is normalized to a site average air density during the measurement period or to a pre-defined reference air density;
- d) turbulence is measured at hub height and the power curve is presented without a turbulence normalization;
- e) the power curve can be normalized to a broader range of climatic conditions (e.g. specific air density, turbulence intensity, vertical shear and veer)⁶.

⁴ Small turbines, refer to IEC 61400-2.

⁵ For vertical axis wind turbines, the wind veer is omitted in Equation (3) (setting $\varphi_i = \varphi_{\text{hub}}$).

⁶ The power curve normalization is only valid for limited ranges of climatic conditions from the actual site conditions.

In this standard, all necessary procedures for measurements, calibration, classification, data correction, data normalization and determination of uncertainties are provided. However, if not all parameters are sufficiently measured, then uncertainty shall be applied due to the lack of measurement. This applies, for example, to the measurement of a power curve of a large wind turbine with only a hub height wind speed sensor. In this case, an uncertainty shall be applied for the variability of the wind shear and of the wind veer.

The best results from the use of the standard are achieved by measurement of all required parameters and use of all relevant procedures. However, if this is not possible, there are options both for the measurement setup and for the use of the procedures. These options are described in Table 1. The options refer to the use of wind measurement equipment, the applied normalizations, and additional uncertainties connected to the lack of measurements.

Table 1 – Overview of wind measurement configurations for power curve measurements that meet the requirements of this standard

Wind measurement configuration	1. Meteorology mast to hub height and remote sensing to all heights	2. Meteorology mast below hub height and remote sensing to all heights	3. Meteorology mast above hub height	4. Meteorology mast to hub height
Typical application	Large wind turbines ⁷ in flat terrain (see Annex B)	Large wind turbines in flat terrain (see Annex B)	Large and small wind turbines in all types of terrain	Large and small wind turbines in all types of terrain
Wind measurement sensors	7.2.3, 7.2.5	7.2.3, 7.2.5	7.2.3, 7.2.4	7.2.3
Normalisation procedures for climate specific power curve determination	Air density, wind shear; 9.1.5 and 9.1.3.4	Air density, wind shear; 9.1.5 and 9.1.3.4	Air density, wind shear; 9.1.5 and 9.1.3.4	Air density; 9.1.5
Additional uncertainty due to lack of wind shear measurement	No additional uncertainty dependent on measurement height coverage; E.11.2.2	No additional uncertainty dependent on measurement height coverage; E.11.2.2	No additional uncertainty dependent on measurement height coverage; E.11.2.2	Additional gross uncertainty for large wind turbines due to lack of vertical wind shear; E.11.2.2
Optional normalization procedures ⁸	Turbulence, wind veer and upflow angle; 9.1.6 and 9.1.4	Turbulence, wind veer and upflow angle; 9.1.6 and 9.1.4	Turbulence, wind veer and upflow angle; 9.1.6 and 9.1.4. Meteorological mast flow distortion; 9.1.2, Site calibration; Annex C.	Turbulence and upflow angle; 9.1.6. Site calibration; Annex C.

⁷ Refer to IEC 61400 -2 for definition of large and small wind turbines.

⁸ Upflow influences the power curve and can be measured with 3D sonic anemometers or upflow vanes. If an upflow angle normalization is applied then the method should be documented (uncertainty on upflow is considered in Annex E). However, no specific procedure is described in this standard on how to normalise for upflow angle.

6 Preparation for performance test

6.1 General

The specific test conditions related to the power performance measurement of the wind turbine shall be well-defined and documented in the test report, as detailed in Clause 10.

6.2 Wind turbine and electrical connection

As detailed in Clause 10, the wind turbine and electrical connection shall be described and documented to identify uniquely the specific machine configuration that is tested.

6.3 Test site

6.3.1 General

At the test site wind measurement equipment shall be set up in the neighbourhood of the wind turbine to determine the wind speed that drives the wind turbine.

Wind shear and atmospheric stability characteristics of the site may have significant influences on the wind measurement and the actual power performance of the wind turbine. Often there is a diurnal cycle of atmospheric stability, with stable atmosphere forming at night and neutral or unstable atmosphere during the day as the sun heats the ground, increasing turbulence and mixing in the boundary layer. Wind shear, wind veer, and turbulence are all a function of atmospheric stability and impact the relationship between the hub height wind speed to the rotor equivalent wind speed and unusual profiles may impact a wind turbine's energy conversion. In addition, flow distortion effects may cause the wind speed at the position of the wind speed measurement and wind turbine to be different, though correlated.

The test site shall be assessed for sources of wind flow distortion in order to:

- a) choose the position of the wind measurement equipment;
- b) define a suitable measurement sector;
- c) determine if a site calibration is required then determine the appropriate flow corrections by measurement according to Annex C;
- d) evaluate the uncertainty due to wind flow distortion.

The following factors shall be considered, in particular:

- 1) topographical variations and roughness;
- 2) other wind turbines;
- 3) obstacles (buildings, trees, etc.).

The test site shall be documented as detailed in Clause 10.

6.3.2 Location of the wind measurement equipment

Care shall be taken in locating the wind measurement equipment. The wind measurement equipment shall not be located too close to the wind turbine, since the wind speed will be influenced in front of the wind turbine. Also, it shall not be located too far from the wind turbine, since the correlation between wind speed and electric power output will be reduced. The wind speed measurement instrumentation shall be positioned at a distance from the wind turbine of between 2 and 4 times the rotor diameter D of the wind turbine. A distance of 2,5 times the rotor diameter D is recommended. In the case of a vertical axis wind turbine, refer to Clause H.4.

Prior to carrying out the power performance test and in helping to select the location for the wind measurement equipment, account should be taken of the need to exclude measurements

from all sectors in which either the wind measurement equipment or the wind turbine will be subject to flow disturbance.

In most cases, the best location for the wind measurement equipment will be upwind of the wind turbine in the direction from which most valid wind is expected to come during the test. In other cases, however, it may be more appropriate to place the wind measurement equipment alongside the wind turbine as the wind conditions will be more similar, for example for a wind turbine sited on a ridge.

6.3.3 Measurement sector

The measurement sector(s) shall exclude directions having significant obstacles and other wind turbines, as seen from both the wind turbine under test and the wind measurement equipment.

For all neighbouring wind turbines and significant obstacles, the directions to be excluded due to wake effects shall be determined using the procedure in Annex A. The disturbed sectors due to the wind measuring equipment being in the wake of the wind turbine under test are shown in Figure 1 for distances of $2D$, $2,5D$ and $4D$. Reasons to reduce the measurement sector(s) might be special topographic conditions or unexpected measurement data from directions with complicated structures. All reasons for reducing the measurement sector shall be clearly documented.

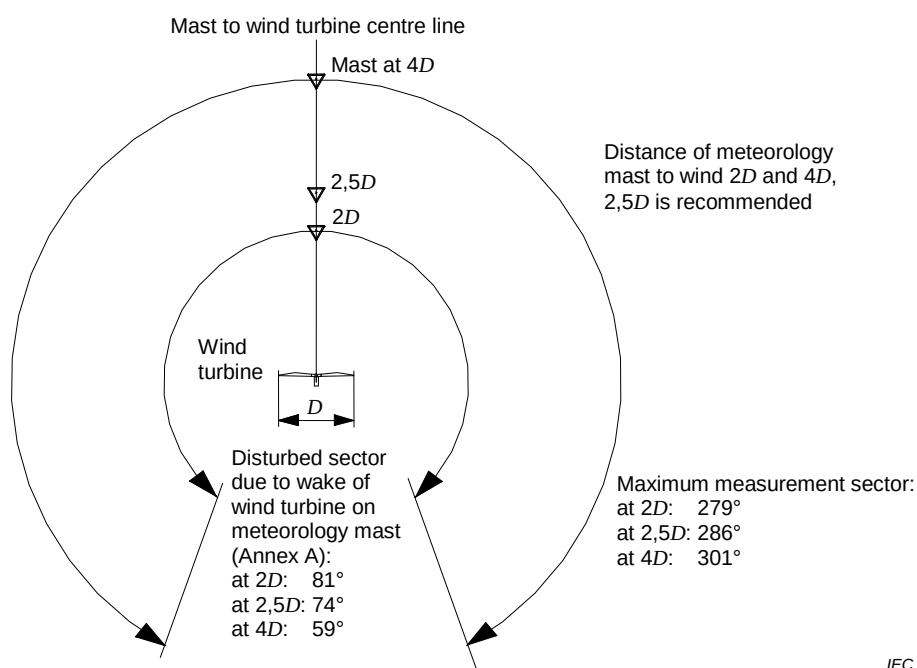


Figure 1 – Requirements as to distance of the wind measurement equipment and maximum allowed measurement sectors

6.3.4 Correction factors and uncertainty due to flow distortion originating from topography

The test site shall be assessed for sources of wind flow distortion due to topographical variations. The assessment in Annex B shall identify whether the power curve can be measured without a site calibration. If the criteria of Annex B are met, the wind flow regime of the site does not need a site calibration. However, in assuming that no flow correction is necessary, the applied uncertainty due to flow distortion of the test site shall be a minimum of 2 % of the measured wind speed if the wind measurement equipment is positioned at a distance between 2 and 3 times the rotor diameter of the wind turbine and 3 % or greater if

the distance is between 3 and 4 times the rotor diameter⁹, unless objective evidence can be provided quantifying a different uncertainty.

If the criteria of Annex B are not met, or a smaller uncertainty due to flow distortion of the test site is desired, then an experimental site calibration shall be undertaken in accordance with Annex C. The measured flow correction factors for each sector shall be used.

7 Test equipment

7.1 Electric power

The net electric power of the wind turbine shall be measured using a power measurement device (e.g. power transducer) and be based on measurements of current and voltage on each phase.

The class of the current transformers shall meet the requirements of IEC 61869-2 and the class of the voltage transformers, if used, shall meet the requirements of IEC 61869-3. They shall be of class 0,5 or better.

The accuracy of the power measurement device, if it is a power transducer, shall meet the requirements of IEC 60688 and shall be class 0,5 or better. If the power measurement device is not a power transducer then the accuracy should be equivalent to class 0,5 power transducers. The operating range of the power measurement device shall be set to measure all positive and negative instantaneous power peaks generated by the wind turbine. As a guide for MW-size active control regulated wind turbines, the full-scale range of the power measurement device should be set to –25 % to +125 % of the wind turbine rated power¹⁰. All data shall be periodically reviewed during the test to ensure that the range limits of the power measurement device have not been exceeded. The power transducer shall be calibrated to traceable standards. The power measurement device shall be mounted between the wind turbine and the electrical connection to ensure that only the net active electric power (i.e. reduced by self-consumption) is measured. It shall be stated whether the measurements are made on the wind turbine side or the network side of the transformer.

7.2 Wind speed

7.2.1 General

The wind speed measured at Hub Height only (HH) is the default wind speed definition and shall always be used. This may be considered the limiting case of the rotor equivalent wind speed where there is only one measurement height and additional uncertainty due to the lack of a wind shear or wind veer profile measurement (see E.11.2.2). It is recommended that the hub height wind speed measurement is supplemented with wind shear measurements in the lower half of the rotor to reduce the wind speed uncertainty. To further reduce the wind speed uncertainty, the Rotor Equivalent Wind Speed (REWS), see 9.1.3.2 and Annex Q, should be used as the wind speed input variable to the power curve.

The wind speed measurement configurations are summarized in Table 2 which takes account of the current limitations of each measurement technology with respect to the terrain complexity classification. Remote sensing devices that assume horizontal flow uniformity through the scanned volume limit the application of these technologies to non-complex terrain conditions for power performance testing. Thus only configurations based on Table 2 shall be applied.

⁹ These uncertainties were derived from a WAsP (Wind Atlas Analysis and Application Program, DTU Wind Energy) analysis of a Gaussian hill meeting the terrain requirements of Annex B.

¹⁰ In other cases, a higher range may be necessary. This has to be checked individually.

Table 2 – Wind speed measurement configurations (X indicates allowable configuration)

Wind speed measurement	HH	HH	REWS	REWS
Terrain type	Non-complex	Complex	Non-complex	Complex
Hub height meteorological mast	X	X		
Hub height meteorological mast + RSD	X	X	X	
RSD + non-hub height meteorological mast	X		X	
Meteorological mast covering heights above HH + 2/3 R	X	X	X	X

The different possible sensor configurations comprise meteorological mast top-mounted anemometers, meteorological mast side-mounted anemometers and remote sensing devices and these provide measurements of hub height wind speed, rotor equivalent wind speed and wind shear profile. Subclauses 7.2.3 to 7.2.5 describe the general, common requirements of top-mounted, side-mounted and remote sensing sensor configurations whilst 7.2.6 to 7.2.8 describe the application specific details for the measurements using these sensor configurations.

7.2.2 General requirements for meteorological mast mounted anemometers

The following requirements apply to all cup and sonic anemometer applications described in Subclauses 7.2.3 to 7.2.8.

The sensor shall meet the requirements in Annex I for cup and sonic anemometers. For power performance measurements an anemometer with a class better than 1,7A or 1,7C shall be used. Additionally, in terrain that requires a site calibration, it is recommended that a class better than class 2,5B, 2,5D or 1,7S shall be used, see Annex I and Annex J.

The anemometer shall be calibrated before and, if required, calibrated again after the measurement campaign (post-calibration). It is mandatory to check and document that the anemometer maintains the validity of its calibration throughout the measurement period. This can be achieved by either comparing the initial calibration results with the outcome of the post-calibration or as an alternative, the in-situ anemometer comparison following Annex K is permissible.

Where a post-calibration is carried out, the difference between the regression lines of calibration and post-calibration shall be within $\pm 0,1$ m/s in the range 4 m/s to 12 m/s. Only the calibration before the measurement campaign shall be used for the performance test. Calibration of the anemometer shall be made according to the procedure of Annex F. If the maximum difference between the regression lines of calibration and post-calibration is outside of $\pm 0,1$ m/s in the range of 4 m/s to 12 m/s, then the standard uncertainty of the anemometer calibration $u_{VS,precal,i}$ shall be increased (at least to this max. difference, but not to more than $\pm 0,2$ m/s). If the difference is above $\pm 0,2$ m/s, then the in-situ anemometer comparison of Annex K is to be used to identify the point in time when the deviation in the data occurred and the subsequent faulty data shall be rejected. If the in-situ test cannot determine the point at which the deviation began then the post-calibration difference is added as an uncertainty.

As an alternative, the in-situ calibration procedure of Annex K shall be used to check the anemometer integrity throughout the measurement period. In this procedure a control anemometer is used to monitor the primary anemometer. Where a cup anemometer is used as the primary anemometer, then either a cup anemometer or a sonic anemometer may be used as the control anemometer. Where a sonic anemometer is used as the primary anemometer, then the control anemometer shall be a cup anemometer. In the case where a REWS derived power curve is obtained from taller than hub height meteorological mast measurements, there shall be a side mounted primary anemometer at hub height on the mast with an associated control anemometer satisfying the mounting requirements from Annex G.

The uncertainty in wind speed measurement derives from several sources of uncertainty as specified in Table D.1. Uncertainty in calibration shall be derived from Annex F. Uncertainty due to operational characteristics shall be derived from Annex I on classification of anemometry. Uncertainty due to mounting effects shall be derived from Annex G.

7.2.3 Top-mounted anemometers

Where wind speed measurements are made with a top-mounted anemometer the requirements given in Annex G with respect to mounting shall be adhered to. The installed height of the sensor above ground level¹¹ shall be verified by measurement and the measurement method and its standard uncertainty documented¹². The standard uncertainty of the measurement of the height of the wind speed sensor above the estimated ground level shall be less than or equal to 0,2 m. The control anemometer shall be mounted according to the requirements of Annex G.

7.2.4 Side-mounted anemometers

The mounting shall follow the requirement for side mounted anemometers according to Annex G. The installed height of the side-mounted anemometers above ground level (see footnote 11) shall be verified by measurement and the measurement method and its uncertainty documented. The height measurement standard uncertainty shall be less than or equal to 0,2 m.

Correction of side-mounted anemometers for meteorological mast flow distortion is permitted and further described in 9.1.2 and Annex S. The technical basis for the correction and the effect of the correction shall be documented. The booms shall have identical orientations to ensure similarity of flow distortion between different heights. The meteorological mast and boom design should have similar flow distortion effect at the sensor with a maximum allowed difference in wind speed distortion of 1 % between all different heights. The meteorological mast cross-sectional dimensions should be consistent at each elevation, thus in the case of free-standing meteorological masts where the meteorological mast cross-sectional area is larger at the lower elevations, special care should be taken following the recommendations in Annex G. An alternative option is to mount a second anemometer at each measurement height on a separate boom and to limit the measurement sector such that the wind speed measurements do not deviate by more than 1 %.

7.2.5 Remote sensing device (RSD)

Remote sensing devices that assume horizontal flow uniformity through the scanned volume limit the application of these technologies to non-complex terrain conditions for power performance testing as defined by Annex B. The remote sensing device shall be verified before the measurement campaign or in-situ according to Clause L.3. The remote sensing device can be used to measure hub height wind speed, wind shear profile, wind veer and/or the rotor equivalent wind speed based on measurements at more than one height (see 7.2.8). In any case, the remote sensing device shall be simultaneously compared with a top-mounted anemometer on a meteorological mast at a height not less than the minimum of the wind turbine rotor lower tip-height or 40 m as defined in Clause L.1. Requirements on the top-mounted anemometer are identical to those described in 7.2.3.

The uncertainty of the RSD wind speed measurements shall be derived according to Annex L.

¹¹ For the purpose of defining ground level, an estimate of the mean elevation over a radius of 2 m around the mast base or 5 m radius around the turbine base can be made. The sensor height measurement uncertainty should exclude the uncertainty of the ground level estimate. For offshore conditions, ground level should be considered as mean sea level.

¹² The measurement can be performed by means of measurement device with a traceable calibration for example a theodolite able to derive heights from an angle measurement in the vertical plane.

7.2.6 Rotor equivalent wind speed measurement

If the wind speed is measured at three or more heights across the wind turbine rotor as defined in 7.2.8, then the rotor equivalent wind speed can be calculated according to 9.1.3. Note that more than three measurement heights are recommended. There are three options for measuring the rotor equivalent wind speed as described below.

- a) Where a hub height top-mounted anemometer satisfying the requirements of 7.2.3 is used together with an RSD satisfying the requirements of 7.2.5 and the terrain meets the requirements of Annex B then the measurements from the hub height anemometer and RSD are combined to determine the rotor equivalent wind speed according to 9.1.3.
- b) Where an anemometer not at hub height but otherwise satisfying the requirements for top-mounted anemometers of 7.2.3 is used with an RSD satisfying the requirements of 7.2.5 and the terrain meets the requirements of Annex B then the RSD measurements are used directly to determine the rotor equivalent wind speed according to 9.1.3.
- c) Where a taller than hub height meteorological mast is used with side-mounted measurements distributed across the rotor height, including an anemometer at hub height, then the side-mounted anemometer wind speed measurements may be used directly to measure the rotor equivalent wind speed according to 9.1.3.

7.2.7 Hub height wind speed measurement

There are three options for measuring hub height wind speed as described below.

- a) Where a hub height meteorological mast is used, the hub height wind speed measurements shall meet the requirements described in 7.2.3.
- b) If the terrain meets the requirements of Annex B, then the hub height wind speed can be measured with an RSD meeting the requirements of 7.2.5 and noting specifically the requirement to compare the RSD against a simultaneous top-mounted anemometer.
- c) A meteorological mast that is taller than the hub height may be used to better capture the wind speeds across the rotor area. In this case, the hub height wind speed shall be measured with a side-mounted sensor on a boom following the requirements described in 7.2.4.

For the hub height definition of wind speed, the lack of knowledge of the vertical wind shear or wind veer across the wind turbine rotor shall be accounted for by adding an uncertainty term according to Annex E based on the estimated or measured wind shear or wind veer. Where only a hub height wind speed measurement is available, an estimated wind shear or wind veer based on site characteristics (e.g. roughness) or prior measurement or modelling at the site (e.g. during a resource assessment campaign) shall be used as input to the uncertainty analysis. Where the hub height wind speed is determined using an RSD or taller than hub height meteorological mast with side-mounted wind speed measurements across the rotor or where below hub height side-mounted instruments are present and satisfying the minimum requirements described in 7.2.8, then wind shear or wind veer derived from the RSD or side-mounted instruments shall be used as input to the uncertainty assessment.

7.2.8 Wind shear measurements

Where wind speed measurements are available over a range of heights wind shear shall be measured and used for the rotor equivalent wind speed or for wind shear exponent determination.

Wind shear measurements shall either be performed using side-mounted anemometers as described in 7.2.4 or by a single remote sensing instrument as described in 7.2.5. Further specifications on wind shear measurement using remote sensing instruments or meteorological mast measurements are given in Annex L and Annex G respectively.

The rotor equivalent wind speed measurement shall include wind speed measurements above hub height. To apply a measurement-based wind shear correction, there shall be at least three wind speed measurements distributed over the rotor swept area. However, to minimise

wind speed uncertainty, it is recommended to have as many measurement heights as possible. Measurement heights should be distributed symmetrically around hub height and evenly over the vertical range of the rotor swept area.

The measurement heights shall include the following heights as a minimum:

- a) hub height $\pm 1,0\%$;
- b) between $H - R$ and $H - 2/3R$;
- c) between $H + 2/3R$ and $H + R$,

where H is the hub height of the wind turbine and R the radius of the rotor swept area, see Figure 2.

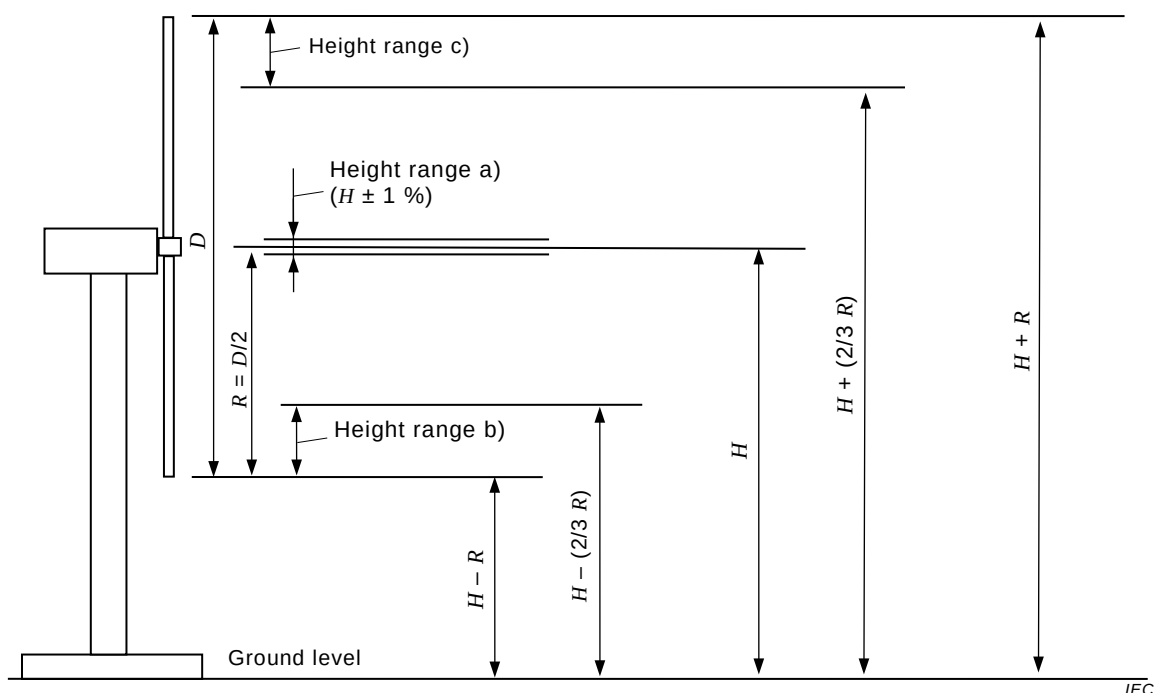


Figure 2 – Wind shear measurement heights appropriate to measurement of rotor equivalent wind speed

If the meteorological mast is hub height or a little above, then no wind speed measurements above hub height may be available for wind shear measurement. In that case, the measurements used to derive wind shear shall include at least the following heights:

- a) a side-mounted anemometer as close to hub height satisfying the requirements of Annex G for separation from the top-mounted anemometer,
- b) between $H - R$ and $H - 2/3R$ and satisfying the requirements of Annex G for side mounted anemometers.

where H is the hub height of the wind turbine and R the radius of the rotor swept area, see Figure 3.

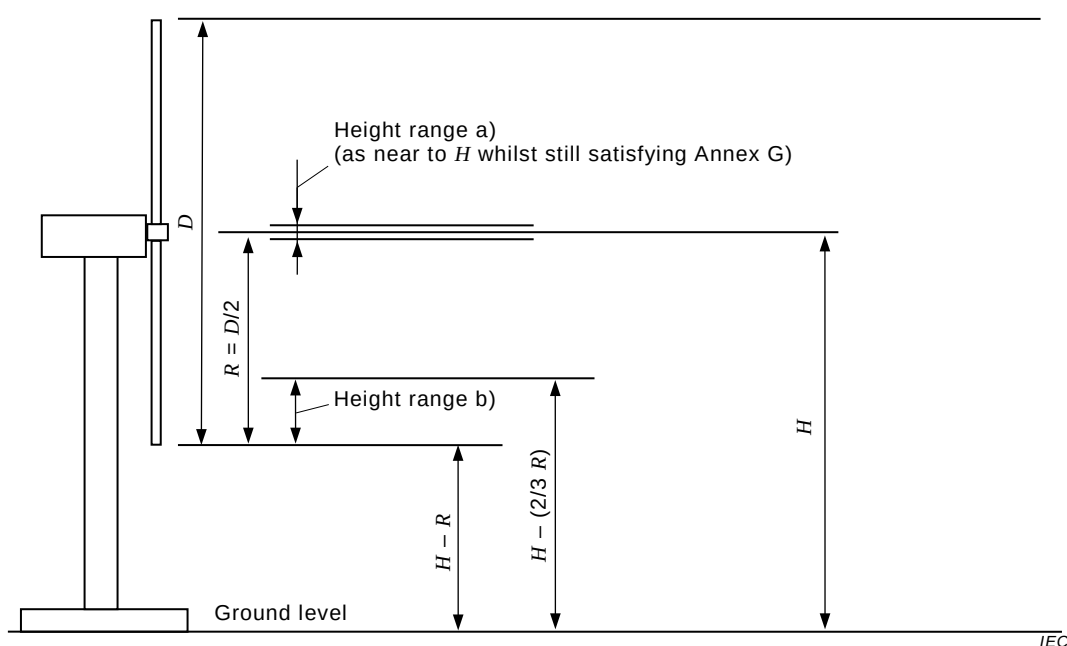


Figure 3 – Wind shear measurement heights when no wind speed measurements above hub height are available (for wind shear exponent determination only)

7.3 Wind direction

Wind direction measurements are used as an input to the site calibration, for filtering data to the valid direction sector and for determining wind veer. Wind direction shall be measured with a wind direction sensor. This may be a wind vane or a 2D or 3D sonic anemometer or an RSD. Where a sonic anemometer is used it shall be used in conjunction with a conventional wind vane as a control. If an RSD is used, it should be subjected to a verification test on the wind direction according to Annex L.

The instantaneous horizontal wind direction shall be determined and averaged over 10 min. Vector averaging (averaging of cosine and sine components of instantaneous wind direction values taking arc tan of the average values and adjusted to the 0° to 360° scale) is one method for deriving the average wind direction. Another method is to extend the wind direction scale for values above 360° and calculating the 10 min average, then adjusting the average value to the 0° to 360° range. Data measured within the dead band of a wind vane, usually at the north mark of the wind direction sensor body, are usually not defined (open circuit or short circuit) and shall be excluded. The combined calibration, operation, and orientation standard uncertainty of the wind direction measurement shall be less than 5°. The wind direction sensor shall be calibrated. Annex N provides guidance.

7.4 Air density

Air density shall be derived from measurement of air temperature, air pressure and relative humidity. As an alternative to the humidity measurement, an assumed value of 50 % relative humidity may be used if humidity is not measured. The air density shall be calculated using Equation (12) in 9.1.5.

The air temperature sensor shall be mounted within 10 m of hub height to represent the air temperature at the wind turbine rotor centreline. Refer to Annex G for temperature sensor mounting requirements where a meteorological mast shorter than hub height is used.

The air pressure sensor should be mounted within 10 m of hub height to represent the barometric pressure at the wind turbine rotor centreline. Air pressure measurements shall be always corrected to the appropriate hub height according to ISO 2533.

The humidity sensor should be mounted within 10 m of hub height to represent the humidity at the wind turbine rotor centreline.

7.5 Rotational speed and pitch angle

Rotational speed and pitch angle should be measured throughout the test if there is a specific need for it. For example if there is a need to apply the measurements in connection with acoustic noise tests. If measured, the measurements shall be reported according to Clause 10.

7.6 Blade condition

The condition of the blades may influence the power curve particularly for stall regulated wind turbines. It may be useful in understanding the characteristics of the wind turbine to monitor the factors that affect blade condition including precipitation, icing and bug and dirt accretion.

7.7 Wind turbine control system

Sufficient status signals shall be identified, verified and monitored to allow the rejection criteria of 8.4 to be applied. Obtaining these parameters from the wind turbine controller's data system is adequate¹³. The definition of each status signal shall be reported.

7.8 Data acquisition system

A digital data acquisition system having a sampling rate per channel of at least 1 Hz shall be used to collect measurements and store either sampled data or statistics of the data sets as described in 8.3.

The calibration and accuracy of the data system chain (transmission, signal conditioning and data recording) shall be verified by injecting known signals from a traceable, calibrated source at the transducer ends and comparing these inputs against the recorded readings. As a guideline, the uncertainty of the data acquisition system should be negligible compared with the uncertainty of the sensors.

8 Measurement procedure

8.1 General

The objective of the measurement procedure is to collect data that meet a set of clearly defined criteria to ensure that the data are of sufficient quantity and quality to determine the power performance characteristics of the wind turbine accurately. The measurement procedure shall be documented, as detailed in Clause 10, so that every procedural step and test condition can be reviewed and, if necessary, repeated.

Accuracy of the measurements shall be expressed in terms of standard uncertainty, as described in Annex D. During the measurement period, data should be periodically validated to ensure high quality. Test logs shall be maintained to document all important events during the power performance test.

8.2 Wind turbine operation

During the measurement period, the wind turbine shall be in normal operation, as prescribed in the wind turbine operations manual, and the machine configuration shall not be changed. The operational status of the wind turbine shall be reported as described in Clause 10. Normal maintenance of the wind turbine shall be carried out throughout the measurement

¹³ A status signal on generator cut-in is adequate to verify cut-out hysteresis control algorithm.

period, but such work shall be noted in the test log. Any special maintenance actions, such as frequent blade washing, which ensure good performance during the test shall in particular be noted. Such special maintenance actions should be avoided.

8.3 Data collection

Data shall be collected continuously at a sampling rate of 1 Hz or higher. Air temperature, air pressure and humidity and precipitation, if measured, may be sampled at a slower rate, but at least once per minute.

The data acquisition system shall store either sampled data or statistics of data sets as follows:

- a) mean value;
- b) standard deviation;
- c) maximum value;
- d) minimum value.

Selected data sets shall be based on 10-min periods derived from contiguous measured data. Data shall be collected until the requirements defined in 8.5 are satisfied.

8.4 Data rejection

To ensure only data obtained during normal operation of the wind turbine are used in the analysis, and to ensure data are not corrupted, data sets shall be excluded from the database under the following circumstances:

- a) external conditions other than wind speed are out of the operating range of the wind turbine;
- b) the wind turbine cannot operate because of a wind turbine fault condition;
- c) the wind turbine is manually shut down or in a test or maintenance operating mode;
- d) failure or degradation (e.g. due to icing) of measurement equipment;
- e) wind direction outside the measurement sector(s) as defined in 6.3.3;
- f) wind directions outside valid (complete) site calibration sectors;
- g) any special atmospheric condition filtered during the site calibration shall also be filtered during the power curve test.

Any other rejection criteria shall be clearly reported.

The effect on the power curve of a large hysteresis loop in the cut-out control algorithm may be considerable. This effect shall not be included in the power curve, and all data sets where the wind turbine has stopped generating power due to cut-out at high wind speed shall be excluded. If cut-out behaviour has been reached during the measurement period, the measurements may be presented in a special database that includes all data points in the database. The power curve shall capture the effect of hysteresis at the cut-in control algorithm, as well as the effect of parasitic losses below cut-in. Cut-out hysteresis affects the higher wind speed bins and neglecting it may therefore lead to overestimation of energy production especially for scenarios with higher annual average wind speeds.

Subsets of the database collected under special operational conditions (e.g. high blade roughness due to dust, salt, insects and ice or if grid conditions vary significantly) or atmospheric conditions (e.g. precipitation, wind shear) that occur during the measurement period may be selected as special databases.

8.5 Database

After data normalisation (see 9.1) the selected data sets shall be sorted using the “method of bins” procedure, see 9.2. The wind speed range shall be divided into 0,5 m/s contiguous bins centred on multiples of 0,5 m/s. The selected data sets shall at least cover a wind speed range extending from 1 m/s below cut-in to 1,5 times the wind speed at 85 % of the rated power of the wind turbine. Alternatively, the wind speed range shall extend from 1 m/s below cut-in to a wind speed at which “*AEP-measured*” is greater than or equal to 95 % of “*AEP-extrapolated*”, see 9.3, where “*AEP-measured*” and “*AEP-extrapolated*” are defined using the appropriate, consistent definitions of wind speed (i.e. the hub height wind speed derived power curve and wind speed distribution and, in the case where REWS is derived, by the REWS derived power curve and wind speed distribution). For active pitch controlled wind turbines, the power curve may also be considered complete when the rated power has been reached and the average power does not change by more than the larger of 0,5 % of the power or 5 kW for three consecutive wind speed bins and there is not a trend of increasing power across these three bin-averages. The report shall state which of the three wind speed range criteria has been used.

The database shall be considered complete when it has met the following criteria:

- a) each bin includes a minimum of 30 min of sampled data;
- b) the database includes a minimum of 180 h of sampled data.

Should a single incomplete bin be preventing completion of the test, then that bin value can be estimated by linear interpolation from the two adjacent complete bins.

The database shall be presented in the test report as detailed in Clause 10.

9 Derived results

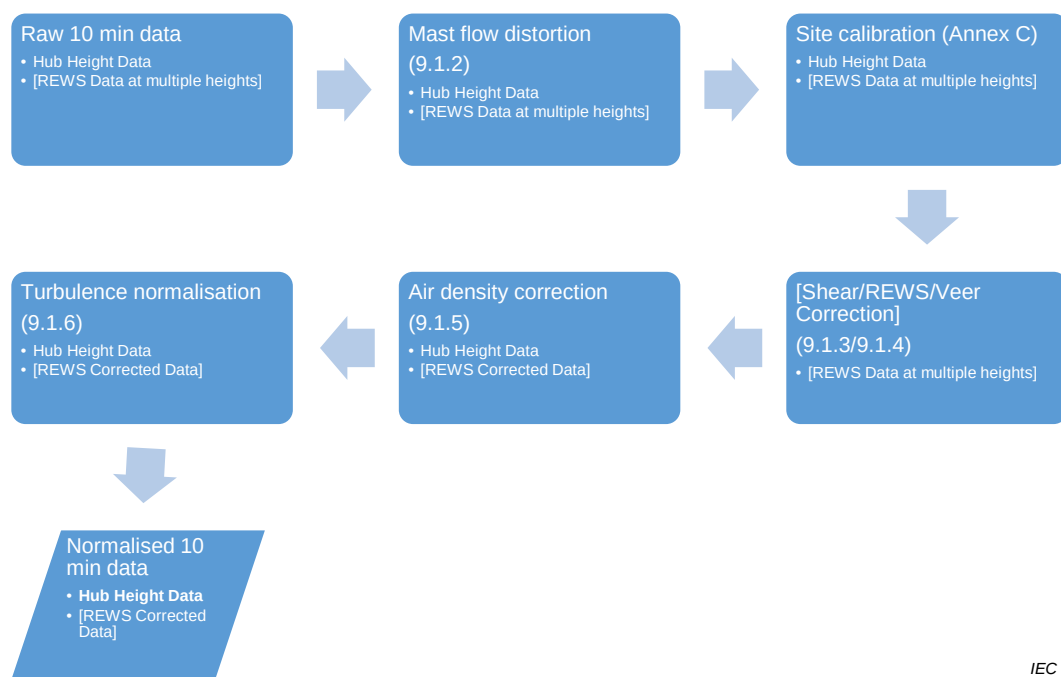
9.1 Data normalisation

9.1.1 General

In the following subclauses, three methods of normalisation are described for the main atmospheric drivers on the power curve results: air density, wind shear and turbulence intensity.

The purpose of these normalisations is to improve the accuracy of the results by means of concrete formulations for each variable. This will to some extent allow the comparison of results from different data sets bringing them to similar scale.

The various normalisations should be applied as indicated in the flow chart in Figure 4.



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Figure 4 – Process of application of the various normalisations¹⁴

9.1.2 Correction for meteorological mast flow distortion of side-mounted anemometer

Correction of the wind speeds from side mounted anemometers for meteorological mast flow distortion is permitted (the requirement from Annex G for a maximum of 1 % meteorological mast flow distortion before application of the correction is still required). Any correction method shall be documented and reported following the requirements of 10.

The impact of the meteorological mast flow distortion on the wind shear measurement may be minimized by reducing the measurement sector where meteorological mast flow distortion is below a certain limit. The technical basis for any such reduction in sector width shall be documented. Annex S gives a possible method for determining the flow distortion correction for a lattice mast.

9.1.3 Wind shear correction (when REWS measurements available)

9.1.3.1 General

If the wind speed over the wind turbine rotor area is constant, the wind speed at hub height would be representative of the wind speed over the wind turbine rotor and the use of the hub height wind speed would be justified. However, the assumption of a point wind speed such as at hub height representing the wind speed over the wind turbine rotor area may not be representative for large wind turbines. It is therefore necessary to introduce corrections that account for the wind speed at hub height and the variations introduced by the wind shear over the wind turbine rotor. In the following, three quantities are defined:

- the rotor equivalent wind speed;
- the wind shear correction factor;

¹⁴ Where the optional REWS measurements are available, the REWS data follow a normalisation path parallel to the default hub height data normalisations as indicated by the terms in square brackets. The normalisation of the REWS data is carried out separately at each measurement height for all normalisation steps up to the step where the results from each height are combined into the wind shear/REWS/veer correction. A single REWS corrected value is derived for each 10-minute data point at each subsequent step in parallel to the corrections applied to each hub height data point.

c) the wind shear corrected wind speed.

The wind shear correction factor may be used to derive a climate specific power curve as explained in Annex P. However, this correction is based on the assumption that a wind turbine is able to convert all of the available kinetic energy.

9.1.3.2 Rotor equivalent wind speed

The rotor equivalent wind speed is the wind speed corresponding to the kinetic energy flux through the swept rotor area, when accounting for the vertical wind shear. Where the wind speed for at least three measurement heights are available (see 7.2.6), the rotor equivalent wind speed is defined as:

$$v_{eq} = \left(\sum_{i=1}^{n_h} v_i^3 \frac{A_i}{A} \right)^{1/3} \quad (5)$$

where

n_h is the number of available measurement heights ($n_h \geq 3$);

v_i is the wind speed measured at height i ;

A is the complete area swept by the rotor (i.e. πR^2 with radius R);

A_i is the area of the i^{th} segment, i.e. the segment the wind speed v_i is representative for, derived from Equation (6).

The segments (with areas A_i) shall be chosen in the way that the horizontal separation line between two segments lies in the middle of two measurement points. The segment areas are then derived according to Equation (6):

$$A_i = \int_{z_i}^{z_{i+1}} c(z) dz = g(z_{i+1}) - g(z_i) \quad (6)$$

where

z_i is the height of the i^{th} segment separation line ($H-R < z_i < H+R$), numbered in the same order as v_i (either top down or bottom up).

The rotor width at height z is:

$$\zeta(z) = 2\sqrt{R^2 - (z - H)^2} \quad (7)$$

where

R is the rotor radius;

H is the hub height.

The integrated function is:

$$g(z) = (z - H)\sqrt{R^2 - (z - H)^2} + R^2 \arctan \left(\frac{z - H}{\sqrt{R^2 - (z - H)^2}} \right) \quad (8)$$

Example of REWS calculation for one 10 minute wind speed profile

In this example, a wind turbine is assumed to have a hub height of 80 m and a rotor diameter of 100 m. The wind speed was measured at 5 heights with a meteorological mast. If the

heights could have been chosen, ideally they would have been evenly distributed (40 m, 60 m, 80 m, 100 m and 120 m). This example shows a case where the heights were fixed independently from the REWS evaluation purpose. The segment limits were set in the middle of two consecutive measurements. The resulting REWS is equal to 9,38 m/s, see Table 3.

Table 3 – Example of REWS calculation

Measurement Heights [m]	Wind speed [m/s]	Segment weighting* [%]	Segment inferior limit height (z_i) [m]	Segment superior limit height (z_{i+1}) [m]	Segment height [m]
116	11,46	16,31	108	130	22
100	10,43	21,04	90	108	18
80	9,24	25,29	70	90	20
60	7,81	23,12	50	70	20
40	6,05	14,24	30	50	20
* Segment weighting is defined as the ratio between the segment area and the total swept rotor area.					

9.1.3.3 Wind shear correction factor

9.1.3.3.1 Case 1: Hub height meteorological mast with remote sensing device or remote sensing device with short (below hub height) meteorological mast

A wind shear correction factor measured using a remote sensing device is defined as the ratio of the rotor equivalent wind speed relative to the wind speed measured at hub height according to Equation (9):

$$f_{r,RSD} = v_{eq,RSD} / v_{h,RSD} \quad (9)$$

where

$v_{eq,RSD}$ is the rotor equivalent wind speed measured by the remote sensing device, as defined in Equation (5);

$v_{h,RSD}$ is the wind speed measured at hub height by the remote sensing device.

9.1.3.3.2 Case 2: Meteorological mast above hub height

A wind shear correction factor measured using a meteorological mast is defined as the ratio of the rotor equivalent wind speed to the wind speed measured at hub height according to Equation (10)¹⁵:

$$f_{r,MM} = v_{eq,MM} / v_{h,MM} \quad (10)$$

where

$v_{eq,MM}$ is the rotor equivalent wind speed measured by the anemometers on the meteorological mast, as defined in Equation (5);

$v_{h,MM}$ is the wind speed measured by the anemometer at hub height.

¹⁵ Note that $f_{r,MM}$ is for reporting purposes only.

9.1.3.4 Wind shear correction of wind speed

If the hub height wind speed and the wind shear are measured with the same type of WME, the rotor equivalent wind speed is calculated according to Equation (5).

If the hub height wind speed is measured using an anemometer mounted on a meteorological mast and the wind shear measurement with an RSD, the final rotor equivalent wind speed is calculated according to Equation (11):

$$v_{eq,final} = f_{r,RSD} v_{h,MM} \quad (11)$$

9.1.4 Wind veer correction

As explained in Annex Q, the change of wind direction over the rotor height range (wind veer) can have a significant impact on the wind turbine power output. In the case of large wind turbine rotors, it is recommended to apply the extended definition of equivalent wind speed including wind veer.

9.1.5 Air density normalisation

The air density shall be determined from measured air temperature, air pressure and relative humidity according to the Equation (12):

$$\rho_{10min} = \frac{1}{T_{10min}} \left(\frac{B_{10min}}{R_0} - \phi P_w \left(\frac{1}{R_0} - \frac{1}{R_w} \right) \right) \quad (12)$$

where

- ρ_{10min} is the derived 10 min averaged air density;
- T_{10min} is the measured absolute air temperature averaged over 10 min [K];
- B_{10min} is the air pressure corrected to hub height averaged over 10 min [Pa];
- R_0 is the gas constant of dry air 287,05 [J/kgK];
- ϕ is the relative humidity (range 0 % to 100 %);
- R_w is the gas constant of water vapour 461,5 [J/kgK];
- P_w is the vapour pressure equal to $0,000\,020\,5 \exp(0,0631\,846\,T_{10min})$ [Pa];

Vapour pressure P_w depends on mean air temperature over the 10 min.

The selected data sets shall be normalised to at least one reference air density. The reference air density shall be the average of the measured air density of the valid collected data at the site during the test period (see 8.4), or alternatively a pre-defined nominal air density for the site. The average measured air density shall be rounded to the nearest 0,01 kg/m³ and reported in accordance with 10.

For a stall-regulated wind turbine with constant pitch and constant rotational speed, data normalisation shall be applied to the measured power output according to Equation (13):

$$P_n = P_{10min} \left(\frac{\rho_0}{\rho_{10min}} \right) \quad (13)$$

where

- P_n is the normalised power output;
- P_{10min} is the measured power averaged over 10 min;

ρ_0 is the reference air density;

$\rho_{10\min}$ is the air density derived according to Equation (12) averaged over 10 min.

For a wind turbine with active power control, the normalisation shall be applied to the wind speed according to Equation (14):

$$V_n = V_{10\min} \left(\frac{\rho_{10\min}}{\rho_0} \right)^{1/3} \quad (14)$$

where

V_n is the normalised wind speed;

$V_{10\min}$ is the measured wind speed averaged over 10 min.

9.1.6 Turbulence normalisation

Wind turbine power curve measurements are influenced by the turbulence intensity. A significant part of the turbulence intensity effect is caused by the averaging of the measured power output and the measured wind speed over 10-minute periods. It is recommended to remove this effect from the measurements by normalising the power curve data to a reference turbulence intensity according to Annex M. The reference turbulence intensity shall be defined prior to the power curve test. It may be defined as a function of the wind speed at hub height. If not defined otherwise, a reference turbulence intensity of 10 % shall be applied. The uncertainty of the turbulence normalisation shall be accounted for. If no turbulence normalisation of the power curve data is performed, the uncertainty of the power curve due to turbulence effects shall be estimated. As a recommendation use the uncertainty method described in Annex M¹⁶.

9.2 Determination of the measured power curve

The power curve shall be determined based on the hub height wind speed and, if measured, the rotor equivalent wind speed. However, it should be remembered that the uncertainty in a power curve derived from hub height measurements only is subject to higher uncertainty due to the lack of knowledge of other influential wind condition parameters. Therefore to account for the vertical wind shear, wind veer and turbulence intensity and to reduce power curve measurement uncertainty, it is recommended to consider the rotor equivalent wind speed as the representative wind speed and the turbulence normalised power output according to Annex M as the relevant power output. The derivation of power curves based on wind speed normalised for a specific wind shear profile (see Annex P) and the turbulence normalised power output are options that are recommended if a comparison between different power curves is wanted or if the power curves are applied for wind resource assessment.

To indicate single 10-min averages, a further index j should be added to the respective wind speeds.

The measured power curve is determined by applying the "method of bins" for the normalized data sets, using 0,5 m/s wind speed bins and by calculation of the mean values of the normalized wind speed and normalized power output for each wind speed bin according to Equations (15) and (16):

$$V_i = \frac{1}{N_i} \sum_{j=1}^{N_i} V_{n,i,j} \quad (15)$$

¹⁶ It should be noted that turbulence intensity measured by cup anemometers, remote sensing devices and ultra sonic anemometers are measured differently. This should be considered when interpreting the results.

$$P_i = \frac{1}{N_i} \sum_{j=1}^{N_i} P_{n,i,j} \quad (16)$$

where

- V_i is the normalized and averaged wind speed in bin i ;
- $V_{n,i,j}$ is the normalized wind speed of data set j in bin i ;
- P_i is the normalized and averaged power output in bin i ;
- $P_{n,i,j}$ is the normalized power output of data set j in bin i ;
- N_i is the number of 10 min data sets in bin i .

The measured power curve shall be presented as detailed in Clause 10 and where REWS power curves are measured, the hub height wind speed power curve shall also be presented.

9.3 Annual energy production (AEP)

The *AEP* shall be calculated in two ways, one designated “*AEP*-measured”, the other “*AEP*-extrapolated”. If the measured power curve does not include data up to cut-out wind speed, the power curve shall be extrapolated from the maximum complete measured wind speed up to cut-out wind speed.

Furthermore, *AEP* may be defined as generic *AEP* or site specific *AEP*. Generic *AEP* is estimated by applying the measured power curve to different reference wind speed frequency distributions. For a specific development, nominal site conditions specifying the wind climate of the site may be known. If so, a site specific *AEP* may, additionally, be reported and computed based on this site specific information.

It is emphasised that a power curve derived from hub height wind speed measurements shall only be combined with a wind speed frequency distribution based on the hub height wind speed definition to derive *AEP* whereas a power curve derived from REWS measurements shall only be combined with a REWS frequency distribution to derive *AEP*. The *AEP* derived from combining a REWS power curve with a hub height wind speed frequency distribution (and vice versa) is not a valid calculation. A Rayleigh distribution, which is identical to a Weibull distribution with a shape factor of 2, shall be used as the reference wind speed frequency distribution. *AEP* estimations shall be made for hub height annual average wind speeds of 4 m/s, 5 m/s, 6 m/s, 7 m/s, 8 m/s, 9 m/s, 10 m/s and 11 m/s according to Equation (17):

$$AEP = N_h \sum_{i=1}^N [F(V_i) - F(V_{i-1})] \left(\frac{P_{i-1} + P_i}{2} \right) \quad (17)$$

where

- AEP* is the annual energy production;
- N_h is the number of hours in one year $\approx 8\,760$;
- N is the number of bins;
- V_i is the normalized and averaged wind speed in bin i ;
- P_i is the normalized and averaged power output in bin i .

$$F(V) = 1 - \exp \left(-\frac{\pi}{4} \left(\frac{V}{V_{ave}} \right)^2 \right) \quad (18)$$

where

- $F(V)$ is the Rayleigh cumulative probability distribution function for wind speed;

V_{ave} is the annual average wind speed;
 V is the wind speed.

The summation is initiated by setting V_{i-1} equal to $V_i - 0,5$ m/s and P_{i-1} equal to 0,0 kW.

For a specific site, nominal site conditions specifying the wind climate of the site may be known. If so, a site specific *AEP* may, additionally, be reported and computed based on this site specific information. If the site specific wind distribution is known and is present in tabular form, the site-specific *AEP* may be calculated by first transforming the wind distribution to the corresponding cumulative distribution. The amount of hours up to each measured wind speed of the measured power curve will be derived by linear interpolation between two adjacent values of the cumulative distribution. The hours will be divided by the sum of hours in the table, which is typically the nominal number of hours within a calendar year. Finally the *AEP* will be calculated by using Equation (17). The tabular wind speed distribution shall use the same definition of wind speed (hub height or REWS) as the measured power curve otherwise a valid *AEP* cannot be derived.

If the site specific wind distribution is presented as a Weibull distribution with known shape and scale factors, then the *AEP* may be calculated with Equation (17) and substituting the cumulative Rayleigh distribution Equation (18) with the Weibull distribution Equation (19):

$$F(V) = 1 - e^{-\left(\frac{V}{A_W}\right)^k} \quad (19)$$

where

$F(V)$ is now the Weibull cumulative probability distribution function for wind speed;

V is the wind speed;

A_W is the Weibull scale factor;

k is the Weibull shape factor;

AEP-measured shall be obtained from the measured power curve by assuming zero power for all wind speeds above and below the range of the measured power curve and carrying out the summation according to Equation (17).

AEP -extrapolated shall be obtained from the measured power curve by assuming zero power for all wind speeds below the lowest wind speed in the measured power curve and constant power for wind between the highest wind speed in the measured power curve and the cut-out wind speed. The constant power used for the extrapolated *AEP* shall be the power value from the bin at the highest wind speed in the measured power curve.

AEP -measured and *AEP* -extrapolated shall be presented in the test report, as detailed in Clause 10. For all *AEP* calculations, the availability of the wind turbine shall be set to 100 %. For given annual average wind speeds, estimations of *AEP* -measured shall be labelled as "incomplete" when calculations show that the *AEP* -measured is less than 95 % of the *AEP* -extrapolated.

Estimations of measurement uncertainty in terms of standard uncertainty of the *AEP* according to Annex D, shall be reported for the *AEP* -measured for all the used wind speed distributions.

The uncertainties in *AEP*, described above, only deal with uncertainties originating from the power performance test and do not take into account uncertainties due to other important factors relating to actual energy production for a given installation.

9.4 Power coefficient

The power coefficient, C_P , of the wind turbine shall be added to the test results and presented as detailed in Clause 10. C_P shall be determined from the measured power curve according to Equation (20):

$$C_{P,i} = \frac{P_i}{\frac{1}{2} \rho_0 A V_i^3} \quad (20)$$

where

- $C_{P,i}$ is the power coefficient in bin i ;
- V_i is the normalized and averaged wind speed in bin i (matching the defined wind speed as either rotor equivalent wind speed or hub height wind speed);
- P_i is the normalized and averaged power output in bin i ;
- A is the swept area of the wind turbine rotor;
- ρ_0 is the reference air density.

10 Reporting format

The test report shall contain the following information:

- a) Identification and description of the specific wind turbine configuration under test (see 6.2), including:
 - 1) wind turbine make, type, serial number, production year;
 - 2) rotor diameter and a description of the verification method used or reference to rotor diameter documentation;
 - 3) rotor speed or rotor speed range;
 - 4) rated power and rated wind speed;
 - 5) blade data: make, type, serial numbers, number of blades, fixed or variable pitch, and pitch angle(s);
 - 6) hub height and tower type;
 - 7) description of the control system (device and software version) and documentation of status signals being used for data reduction;
 - 8) description of grid conditions at the wind turbine, i.e. voltage, frequency and their tolerances, and a drawing indicating where the power transducer is connected, specifically in relation to an internal or external transformer and self-consumption of power;
- b) A description of the test site (see 6.3), including:
 - 1) photographs of all measurement sectors preferably taken from the wind turbine at hub height;
 - 2) a test site map showing the surrounding area covering a radial distance of at least 20 times the wind turbine rotor diameter and indicating the topography, location of the wind turbine, wind measurement equipment, significant obstacles, other wind turbines, and measurement sector;
 - 3) results of site assessment, i.e. the limits of the valid measurement sector(s);
 - 4) if site calibration is undertaken, the limits of the final measurement sector(s) shall also be reported, including the rationale for any changes from the results of the site assessment;
 - 5) a table of the coordinates and elevation of the test wind turbine, wind measurement equipment and any significant obstacles considered in the assessment of obstacles.